Report on the

# Prevention of Significant Deterioration – Air Construction Permit Application

## Lacey Randall Station – TradeWind Energy, Inc.
## Source ID 1930036

**Project No. 72125**

**Updated December 2013**

# Prevention of Significant Deterioration – Air Construction Permit Application

**prepared for**

**Lacey Randall Station – TradeWind Energy, Inc.**
**Source ID 1930036**
**Colby, Kansas**

**Updated December 2013**

**Project No. 72125**

**prepared by**

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# LIST OF ABBREVIATIONS

| Abbreviation | Term/Phrase/Name |
|---|---|
| a* | color hue |
| AERMOD | AMS/EPA Regulatory Model |
| AERMAP | AERMOD's terrain pre-processor |
| b* | saturation |
| BACT | Best Available Control Technology |
| BPIP-PRIME | Building Profile Input Program-Plume Rise Model Enhancements |
| CAA | Clean Air Act |
| CCS | Carbon Capture and Sequestration |
| CEM | Continuous Emission Monitor |
| CFR | Code of Federal Regulations |
| CO | carbon monoxide |
| $CO_2$ | carbon dioxide |
| $CO_2e$ | carbon dioxide equivalent (greenhouse gases) |
| DEM | Digital Elevation Model |
| EGU | Electric Generating Unit |
| EPA | U.S. Environmental Protection Agency |
| °F | degrees Fahrenheit |
| FLAG | Federal Land Managers' Air Quality Related Values Work Group |
| FLM | Federal Land Manager |
| ft/s | feet per second |
| GEP | Good Engineering Practice |

| Abbreviation | Term/Phrase/Name |
|---|---|
| $g/cm^3$ | gram per cubic centimeter |
| g/bhp-hr | gram per brake horsepower hour |
| g/hp-hr | gram per horsepower hour |
| $H_2SO_4$ | sulfuric acid |
| HAPs | hazardous air pollutants |
| hp | horsepower |
| K.A.R | Kansas Administrative Regulations |
| KDHE | Kansas Department of Health and Environment |
| kPa | kilopascals |
| kW | kilowatt |
| LAER | Lowest Achievable Emission Rate |
| L* | brightness |
| lb/hr | pound per hour |
| lb/MMBtu | pound per million British thermal units |
| MACT | Maximum Achievable Control Technology |
| $CH_4$ | methane |
| MMBtu/hr | million British thermal units per hour |
| MW | megawatt |
| NAAQS | National Ambient Air Quality Standards |
| NAD | North American Datum |
| NED | National Elevation Dataset |
| NESHAP | National Emission Standard for Hazardous Air Pollutants |

| Abbreviation | Term/Phrase/Name |
|---|---|
| NSPS | New Source Performance Standards |
| NO | nitrogen oxide |
| $NO_x$ | nitrogen oxides |
| $NO_2$ | nitrogen dioxide |
| $N_2O$ | nitrous oxide |
| NMHC | non-methane hydrocarbons |
| OAQPS | Office of Air Quality Planning and Standards |
| OLM | Ozone Limiting Method |
| PANs | peroxyacetyl nitrates |
| PBL | Planetary boundary layer |
| PM | particulate matter |
| $PM_{2.5}$ | particulate matter of 2.5 microns in diameter or smaller |
| $PM_{10}$ | particulate matter of 10 microns in diameter or smaller |
| ppm | parts per million |
| ppmvd | parts per million by volume, dry |
| PRIME | plume rise model enhancements |
| PSD | Prevention of Significant Deterioration |
| PVMRM | Plume Volume Molar Ratio Method |
| RBLC | RACT/BACT/LAER Clearinghouse |
| RICE | reciprocating internal combustion engines |
| RMP | risk management plan |
| ROI | radius of impact |

| Abbreviation | Term/Phrase/Name |
|---|---|
| SCR | selective catalytic reduction |
| $SO_2$ | sulfur dioxide |
| $SO_4$ | sulfate |
| TPY | tons per year |
| USGS | U.S. Geological Survey |
| UTM | Universal Transverse Mercator |
| VOC | volatile organic compounds |
| $\mu g/m^3$ | micrograms per cubic meter |
| µm | micrometer |
| 4SLB | 4 stroke lean burn |

# 1.0 EXECUTIVE SUMMARY

Pursuant to the requirements specified in the Kansas Administrative Regulations (K.A.R) 28-19-350, TradeWind Energy Inc. (TradeWind) submits this Prevention of Significant Deterioration (PSD) construction permit application for the installation of up to ten reciprocating internal combustion engines (RICE) plus auxiliary equipment at the Lacey Randall Station (hereinafter referred to as the Project) to be located in Thomas County, Kansas approximately 3 miles northeast of Colby, Kansas. The Project will have a total nominal power output of approximately 94 megawatts (MW) and the RICE electric generating units (EGUs) will be fired solely by natural gas.

As required by the above-referenced rules, this permit application contains the following analyses/assessments regarding the emission of regulated pollutants associated with the construction and operation of the Project:

- Evaluation of ambient air quality in the area for each regulated pollutant for which the Project will cause a significant increase in net emissions
- Demonstration by air dispersion analysis that emissions from the Project will not cause or contribute to any exceedance of a National Ambient Air Quality Standard (NAAQS)
- Demonstration by air dispersion analysis that emissions from the Project will not exceed the remaining available PSD Class II increment consumption allowances
- Assessment of any adverse impacts on soils, vegetation, visibility, or growth in the area
- A Best Available Control Technology (BACT) analysis for each regulated pollutant for which the potential-to-emit (PTE) for the Project will result in a significant increase in net emissions

PTE from the Project are shown in Table 1-1. Start-up emissions for the engines are also included in Table 1-1. A full description of equipment associated with the Project is provided in Part 2 of the application.

**Table 1-1. Project Potential Emissions and PSD Significance Levels**

| Pollutant[A] | Preliminary Estimated Potential Emissions (Tons per Year [TPY])[B] | PSD Significance Levels (TPY) |
|---|---|---|
| $NO_x$ | **141.57** | 40 |
| $SO_2$ | 2.09 | 40 |
| CO | **169.78** | 100 |
| $PM/PM_{10}$[C] | **100.59** | 25/15 |
| $PM_{2.5}$[C] | **100.59** | 10 |
| VOC | **128.69** | 40 |
| Lead | 6.44E-06 | 0.6 |
| $H_2SO_4$ Mist | 0.32 | 7 |
| $CO_2e$ | **409,409** | 75,000 |

[A] $NO_x$ = nitrogen oxides; CO = carbon monoxide; $SO_2$ = sulfur dioxide;
VOC = volatile organic compounds; PM= total particulate matter;
$PM_{10}$ = particulate matter less than 10 microns in diameter; $PM_{2.5}$ = particulate matter less than 2.5 microns in diameter; $CO_2e$ = carbon dioxide equivalent (greenhouse gases);
$H_2SO_4$ Mist = sulfuric acid mist
[B] Numbers in **bold** indicate the PSD significance level is exceeded
[C] Filterable plus condensable

## 1.1 HAP Emissions

The Project will be a major source of hazardous air pollutants (HAPs) (greater than 25 tons per year of total HAPs and greater than 10 tons per year of any single HAP).[1] Therefore sections of 40 CFR Part 63-National Emission Standards for Hazardous Air Pollutants (NESHAP) will apply to the Project.

## 1.2 Project NAAQS Impact Analysis

The existing air quality in the Thomas County area is designated as attainment or unclassifiable with regard to the NAAQS for all criteria pollutants. A Project air dispersion modeling analysis was performed for the pollutants subject to PSD review to assess potential impacts on the NAAQS. The modeling was performed in accordance with relevant Kansas Department of Health and Environment (KDHE) and U.S. Environmental Protection Agency (EPA) modeling guidance. The air dispersion modeling protocol and Ozone Limiting Method (OLM) modeling protocol were submitted to both KDHE and EPA Region 7 for their review in April 2013.

The modeling analysis results (included in Part 6 of this application) demonstrate that the Project will not cause or contribute to a violation of any NAAQS. Further, the PSD Class II increment analysis demonstrates that Project impacts are less than the PSD Class II increments established for the area.

[1] All sources of HAPs that are not major sources are categorized as “area” sources.

Recent Federal Land Manager (FLM) guidance advises that a proposed major source, in the course of a PSD application, must perform an assessment of air quality impacts at Class I areas if these areas are located within approximately 300 kilometers of the proposed facility. As there are no Class I areas that are within 300 kilometers of the Project, an assessment of air quality impacts at Class I areas was not performed.

## 1.3 BACT for Reciprocating Internal Combustion Engines

A "top-down" BACT analysis was performed for each of the pollutants in Table 1-1 in which the PTE was above the associated PSD significance level: $NO_x$, CO, VOC, $PM/PM_{10}/PM_{2.5}$, and $CO_2e$ (greenhouse gases).

Pre-combustion and controlled combustion systems coupled with state-of-the-art pollution control equipment and consistently achievable emission limitations has been selected as BACT for this Project. Emissions of $NO_x$ from the RICE will be limited by lean burn combustion and further reduced and controlled by selective catalytic reduction (SCR) systems. Emissions of CO and VOC will be limited by good combustion practices and further reduced by oxidation catalysts (also referenced as a CO catalyst). Use of clean fuels and good combustion practices will control emissions of $PM/PM_{10}/PM_{2.5}$. Greenhouse gas emissions will be limited by the use of efficient lean-burn engines, and by use of natural gas as a fuel.

Table 1-2 displays the BACT results.

**Table 1-2. Summary of BACT Results: RICE**

| Pollutant | Systems and Controls | BACT Emission Limitation (lb/hr)[A] | Equivalent Emissions[B] (g/bhp-hr) | Averaging Period |
|---|---|---|---|---|
| $NO_x$ | Selective catalytic reduction (SCR) system | 1.45 | 0.0525 | 30-day |
| CO | Good combustion practices, oxidation catalyst | 2.67 | 0.0967 | 30-day |
| VOC | Good combustion practices, oxidation catalyst | 2.67 | 0.0967 | 30-day |
| $PM/PM_{10}/PM_{2.5}$ | Combustion controls and low ash fuels | 2.22 | NA | 3-hr |
| $CO_2e$ | Use of efficient lean-burn engines, use of natural gas as a fuel | 9,329.27 | 337.81 | Annual |

[A] Engine emission rate while operating at loads of 50 percent and greater under steady state conditions unless otherwise noted.

[B] Equivalent emissions in gram per brake horsepower hour (g/bhp-hr) for loads of 50% and higher are shown for comparison to the RACT/BACT/LAER Clearinghouse (RBLC) emission rates purposes only. These are not proposed as BACT emission limitations.

[C] Due to the testing methods and sources of PM in the emission exhaust, PM is only expressed in lb/hr and it is not appropriate to determine an equivalent g/bhp-hr. In addition, the RBLC limits are primarily expressed in lb/hr.

## 1.4 BACT Analysis for Auxiliary Equipment

The auxiliary equipment to be installed at the Project consists of a gas heater (using natural gas for fuel), an emergency diesel fire pump, an emergency diesel generator, and a fuel oil storage tank. A BACT analysis was performed for the pollutants in Table 1-1 that are emitted in total Project quantities above the PSD significance levels for the each of the auxiliary equipment. The following controls and operational practices have been established as applicable BACT requirements for the auxiliary equipment as shown in Table 1-3.

**Table 1-3. Summary of BACT Results: Auxiliary Equipment**

| Pollutant | Emissions Unit | Limiting Systems and Controls | BACT Emission Limitation |
|---|---|---|---|
| $NO_x$ | Gas Heater | Low $NO_x$ Burners and Combustion Control | 100 lb/MMcf |
| | Emergency Diesel-fired Generator | Combustion Control | 0.007 gm/hp-hr |
| | Emergency Fire Pump | Combustion Control | 3.00 gm/hp-hr |
| CO | Gas Heater | Good Combustion Practices | 84 lb/MMcf |
| | Emergency Diesel-fired Generator | Combustion Control | 2.61 gm/hp-hr |
| | Emergency Fire Pump | Combustion Control | 3.70 gm/hp-hr |
| VOC | Gas Heater | Good Combustion Practices | 5.5 lb/MMcf |
| | Emergency Diesel-fired Generator | Combustion Control | 0.007 gm/hp-hr |
| | Emergency Fire Pump | Combustion Control | 3.00 gm/hp-hr |
| | Fuel Oil Storage Tank | Submerged Fill Pipe | 0.156 tpy |
| $PM/PM_{10}/PM_{2.5}$ | Gas Heater | Combustion Control | 7.6 lb/MMcf |
| | Emergency Diesel-fired Generator | Combustion Control | 3.29E-04 gm/hp-hr |
| | Emergency Fire Pump | Combustion Controls and Low Ash Fuels | 2.20E-01 gm/hp-hr |
| $CO_2e$ | Gas Heater | Use of Clean Fuels, Maintaining and Tuning the Heater, Recordkeeping | 117.00 lb/MMBtu |
| | Emergency Diesel-fired Generator | Combustion Control | 164 lb/MMBtu |
| | Emergency Fire Pump | Selection of the Most Efficient Engines that Meet the Applicant's Project Needs | 164 lb/MMBtu |
| | Circuit Breakers | Enclosed-Pressure $SF_6$ Circuit Breakers | <0.5% leakage |

[A] g/hp-hr = gram per horsepower hour

## 1.5 Additional Impacts Analysis

The potential impacts of the Project on visibility, soils, vegetation, and growth are discussed in Section 8.0of this application. As shown by the analysis, the addition of the Project will not have a significant impact on visibility, soils, growth, or vegetation in the surrounding area.

# 2.0 INTRODUCTION

The Lacey Randall electric generation facility is located in western Kansas, in an area of the state that is experiencing significant expansion of both wind energy resources and oil/gas exploration. The Lacey Randall reciprocating gas engine facility is being developed to meet both of these demands while having little impact to water resources that are vital to the state's farming interests.

TradeWind Energy Inc. (TradeWind) proposes to install ten natural gas-fired stationary spark ignition reciprocating internal combustion engines (RICE) (Wartsila model 20V34SG) at the new Lacey Randall Station in Thomas County, Kansas. The ten engines will have a total nominal power output of approximately 94 megawatts (MW) and will be fired by natural gas. In addition to the engines, a gas heater, an emergency fire pump, an emergency diesel generator, circuit breakers, and a fuel oil storage tank will be part of this Project.

The Potential-To-Emit (PTE) calculations indicate that the Project will exceed the Prevention of Significant Deterioration (PSD) major-source threshold and therefore will be subject to PSD construction permit review for certain pollutants.

Table 2-1 identifies the PTE associated with the Project. Start-up emissions for the engines are included in the emissions estimate in Table 2-1 as well. The potential air emissions of the new units are based on unlimited hours per year of operation, including start-up. The start-up emissions are based on 14,600 start-up events per year total for all engines. The maximum emissions from each operating load and scenario for the RICE was used to demonstrate the maximum potential emissions for each pollutant. Table 2-1 also includes emissions from the auxiliary equipment proposed as part of this Project.

**Table 2-1. Project Potential Emissions and PSD Significance Levels**

| Pollutant[A] | Preliminary Estimated Potential Emissions (Tons per Year [TPY])[B] | PSD Significance Levels (TPY) |
|---|---|---|
| $NO_x$ | **141.57** | 40 |
| $SO_2$ | 2.09 | 40 |
| CO | **169.78** | 100 |
| $PM/PM_{10}$[C] | **100.59** | 25/15 |
| $PM_{2.5}$[C] | **100.59** | 10 |
| VOC | **128.69** | 40 |
| Lead | 6.44E-06 | 0.6 |
| $H_2SO_4$ Mist | 0.32 | 7 |
| $CO_2e$ | **409,409** | 75,000 |

[A] $NO_x$ = nitrogen oxides; CO = carbon monoxide; $SO_2$ = sulfur dioxide; VOC = volatile organic compound; PM= total particulate matter; $PM_{10}$ = particulate matter less than 10 microns in diameter; $PM_{2.5}$ = particulate matter less than 2.5 microns in diameter; $CO_2e$ = carbon dioxide equivalent (greenhouse gases); $H_2SO_4$ Mist = sulfuric acid mist
[B] Numbers in **bold** indicate the PSD significance level is exceeded
[C] Filterable plus condensable

As shown by the above table, the Project will result in emission increases above the significance level for $NO_x$, CO, VOC, $PM/PM_{10}/PM_{2.5}$, and $CO_2e$ (greenhouse gases or GHG). Therefore, these pollutants will be subject to PSD review.

The Project will be a major source of HAPs (greater than 25 tons per year of total HAPs and greater than 10 tons per year of any single HAP) and will be subject to National Emission Standards for Hazardous Air Pollutants (NESHAP) (40 CFR Part 63) to the degree they are applicable to the Project.

This construction permit application is divided into the following sections:

- Part 1 – Introduction
- Part 2 – Project Description
- Part 3 – Emissions Estimates
- Part 4 – Regulatory Review
- Part 5 – Best Available Control Technology (BACT) Analysis
- Part 6 – Air Dispersion Modeling (NAAQS and PSD Class II Increment analyses)
- Part 7 – Additional Impact Analysis

Construction permit application forms required by the Kansas Department of Health and Environment (KDHE) are included in Appendix A of this application.

# 3.0 PROJECT OVERVIEW AND OBJECTIVES

Lacey Randall Station will be located approximately 3 miles northeast of Colby, Kansas. Thomas County is currently designated as an attainment/unclassified area for all criteria pollutants. See 40 CFR Part 81. The location of Lacey Randall Station is shown in Figure 3-1 (Appendix B). A scaled site layout showing the plant and equipment is shown in Figure 3-2 (Appendix B). A second scaled site layout showing the plant and fence line is shown in Figure 3-3 (Appendix B).

## 3.1 Lacey Randall Station Project

The Project will consist of ten RICE with a nominal gross electrical output of up to 94 MW. TradeWind proposes that each of the RICE will operate without restriction on utilization. The gas heater will be permitted for 8,760 hours annually because it will be operational whenever gas is flowing to any of the engines. The emergency fire pump and emergency diesel generator are proposed to operate up to 100 annual hours, and their use will be limited primarily to testing and maintenance. The circuit breakers will have unlimited use. Table 3-1 displays each of the emission units along with maximum operating hours per year. The Project will be major for PSD based on potential emissions of greenhouse gasses ($CO_2e$) in excess of 100,000 tons per year. Maximum potential annual emissions from the Project are presented in Table 2-1.

**Table 3-1: Emission Units and Hours of Operation for the Project**

| Emissions Unit | Size | Number of Units | Fuel | Annual Hours of Operation |
|---|---|---|---|---|
| RICE | 9.34 MW | 10 | Natural Gas | 8,760 (each) |
| Gas Heater | 3 million British thermal units per hour (MMBtu/hr) | 1 | Natural Gas | 8,760 |
| Emergency Fire Pump | 150 horsepower (hp) | 1 | Diesel | 100 |
| Emergency Diesel Generator | 324 hp | 1 | Diesel | 100 |
| Diesel Storage Tank | 308,377 gal | 1 | Not applicable | 8,760 |
| Circuit Breakers | Not applicable | 4 | Not applicable | 8,760 |

### 3.1.1 Emission Unit Descriptions

The following subsections briefly describe the emission units that will be constructed as part of the Project.

#### 3.1.1.1 RICE Engines and Emission Controls

The RICE will be natural gas-fired 20V34SG Wärtsilä engines. This additional generating capacity is being constructed to provide ancillary support for substantial renewable energy resources proposed in the region. The ten engines are being permitted to operate unlimited hours annually.

To control emissions of $NO_x$, each engine will be equipped with selective catalytic reduction (SCR) systems and lean-burn combustion systems. To minimize the emissions of $SO_2$, $H_2SO_4$ mist and $PM/PM_{10}/PM_{2.5}$, the engines will be controlled through the use of low-sulfur/low ash fuels and good combustion practices. Emissions of CO and VOC will be controlled through the use of good combustion practices as well as an oxidation catalyst (also referred to as a CO catalyst). Greenhouse gas (GHG) emissions will be minimized with the use of efficient lean-burn engines and the use of natural gas fuel.

#### 3.1.1.2 Gas Heater

A 3-MMBtu/hr gas heater will be installed to maintain the temperature of the natural gas to the engines, in compliance with the manufacturer's recommendations for fuel quality parameters. Emissions estimated for the gas heater assume an annual operational schedule of 8,760 hours per year.

#### 3.1.1.3 Emergency Fire Pump

An emergency fire pump will be installed for use in case of fire. The emergency fire pump may be tested each week to confirm that it is working properly. The fire pump will have a maximum output of 150 hp and will be operated solely on ultra-low sulfur diesel (ULSD) fuel. TradeWind expects to operate the emergency fire pump for up to 100 hours annually for testing and maintenance purposes, and therefore requests an administrative limitation on its routine hours of operation.

#### 3.1.1.4 Emergency Diesel-fired Generator

An emergency diesel-fired generator will be built to support the plant safety and control features in case of a power interruption. The emergency generator will have a maximum power output of 324 hp and will be operated solely on natural gas fuel. TradeWind expects to operate the emergency generator for up to 100 hours annually for testing and maintenance purposes, and therefore requests an administrative limitation on routine hours of operation for this equipment.

#### 3.1.1.5 Fuel Oil Storage Tank

A fuel oil storage tank with approximately 308,377 gallons capacity will be installed at Lacey Randall Station to provide fuel to the emergency fire pump. The tank will be equipped with an exhaust vent system that minimizes vapor discharge to the atmosphere.

#### 3.1.1.6 Circuit Breakers

Four circuit breakers will be installed, each containing 61.2 pounds of SF6. A 0.5% leakage is assumed to occur.

# 4.0 EMISSIONS ESTIMATES

## 4.1 Introduction

Air pollution emissions result from the combustion of natural gas in the RICE. There will also be emissions generated from the gas heater, emergency fire pump, emergency diesel-fired generator, and fuel oil storage tank.

The potential annual emissions for the engines (including start-up emissions), gas heater, emergency fire pump, emergency diesel-fired generator, and fuel oil storage tank are listed in Table 2-1.

Based on the potential annual emissions, the Project is subject to PSD review for emissions of CO, $NO_x$, $PM/PM_{10}/PM_{2.5}$, VOC, and $CO_2e$ (greenhouse gases). PSD review is not required as to emissions of $SO_2$, lead, and $H_2SO_4$ mist, because the emissions of those pollutants will be below the PSD significance levels for those pollutants.

## 4.2 Emission Sources

Emissions from the Project will originate from the RICE and auxiliary equipment. Figure 4-1 and Figure 4-2 (Appendix G) present a RICE process flow diagram and auxiliary equipment flow diagram for the Project, respectively. Each emission point is discussed in more detail below. Procedures for estimating emissions are also discussed below. The emission calculations are included in Appendix C.

### 4.2.1 Engine Emissions

Emissions from the RICE are dependent on the ambient temperature conditions and the RICE's operating load. To account for representative seasonal climatic variations, the potential emissions from the RICE were analyzed at 50, 75, 90, and 100 percent load conditions. The projected emissions were based on data provided by the RICE manufacturer (Wärtsilä) and/or from AP-42 emission factors. Detailed calculations of the engines' emissions are provided in Appendix C.

The following conservative assumptions were used to determine potential emissions from the Project:

- Emissions are based on maximum-case emissions for 50 percent to 100 percent load with unlimited operation; maximum start-up emissions were accounted for in the total annual emissions estimates
- Start-up emissions are based on the start-up profiles (assumes 30 minutes per start-up) and 14,600` start-up events per year total for all engines

- CO emissions are based on the vendor's maximum guaranteed emissions rate with an oxidation catalyst of 2.67 pound per hour (lb/hr) per engine at 100 percent load
- $PM/PM_{10}/PM_{2.5}$ emissions are based on an estimated maximum emission rate of 2.22 lb/hr per engine; primary emissions from the combustion of natural gas fuel for PM, $PM_{10}$, and $PM_{2.5}$ are assumed to be the same.
- Filterable PM emissions will be no greater than 0.07 g/kWh
- $NO_x$ emissions are based on the manufacturer's maximum guaranteed emission rate of 1.45 lb/hr per engine equipped with SCR
- $SO_2$ emissions are based on the sulfur content of the pipeline quality natural gas and an estimated maximum emission rate of 0.05 lb/hr per engine
- VOC emissions are based on an estimated maximum emission rate of 2.67 lb/hr per engine
- $CO_2e$ emissions are based on vendor data for carbon dioxide ($CO_2$); methane ($CH_4$) and nitrous oxide ($N_2O$) were calculated using 40 CFR Part 98 emission factors, and ratioed with their appropriate $CO_2$ equivalency ratio and summed to obtain $CO_2e$

Based on these assumptions, the maximum expected hourly emission rates for each RICE engine are shown in Table 4-1.

**Table 4-1. RICE Maximum Expected Hourly Emission Rates**

| Pollutant | $NO_x$ | $SO_2$ | CO | PM/ $PM_{10}$ | $PM_{2.5}$ | VOC | $H_2SO_4$ Mist | $CO_2e$ |
|---|---|---|---|---|---|---|---|---|
| **Emission Rate Per Engine (lb/hr)**[A] | 1.45 | 0.05 | 2.67 | 2.22 | 2.22 | 2.67 | 7.11E-03 | 9,329 |

[A] Excludes start-up emissions

### 4.2.2 RICE Start-Up Emissions

Potential start-up emissions are based on the manufacturer's start-up profile and 14,600 start-up events total for all engines. Start-up events are assumed to take up to thirty minutes, after which control technologies will be fully functional. Potential start-up emissions for the combustion engines are shown in Table 4-2. Detailed calculations of the potential start-up emissions are provided in Appendix C.

**Table 4-2. Potential Combustion Engine Start-up Emissions**

| Pollutant | lb/Start-up per Engine | Start-up Emissions per Engine (TPY)[A] |
|---|---|---|
| $NO_x$ | 11.24 | 8.21 |
| $SO_2$ | 0.05 | 0.017 |
| CO | 8.38 | 6.12 |
| $PM/PM_{10}$ | 1.54 | 1.13 |
| $PM_{2.5}$ | 1.54 | 1.13 |
| VOC | 2.87 | 2.09 |
| $CO_2e$ | 9,329.27 | 3,405.19 |

[A] Based on 14,600 start-ups and 14,600 shutdowns per year total for all engines

Normal operation has higher emissions than shutdown. Therefore, total emissions on an annual basis include the maximum number of start-ups, with the remaining hours assumed to be full load operation, as both of those cases result in greater emissions than does a shutdown condition.

### 4.2.3 HAP Emissions

The Project will be a major source of HAPs (greater than 25 tons per year of total HAPs and greater than 10 tons per year of any single HAP).[2] The calculation of total HAP emissions from the RICE and associated equipment is provided in Appendix C.

### 4.2.4 Gas Heater Calculation Method

A 3-MMBtu/hr gas heater will be installed at the facility to regulate the temperature of natural gas fuel. Emissions for the gas heater are estimated using AP-42 emission factors[3] and an assumed annual operation schedule of 8,760 hours per year. Detailed calculations of the gas heater emissions are provided in Appendix C.

### 4.2.5 Emergency Fire Pump Calculation Method

A fire pump using ULSD fuel will be installed on-site to handle fire suppression for the facility. The fire pump will have a power output of 150 hp. An annual testing and maintenance schedule of 100 hours is assumed for the fire pump. Emissions for this unit are estimated based on NSPS emission rates.[4],The $CO_2e$ emission factors (for $CO_2$, $CH_4$, and $N_2O$) from the EPA Mandatory Greenhouse Gas Reporting

2 All sources of HAPs that are not major sources are categorized as “area” sources.
[3] AP-42 Section 1.4, *Natural Gas Combustion* (7/98)
[4] Generator limits (40 CFR 60.4202(a)(2) and 40 CFR 89.112)

Rule (40 CFR Part 98) are used to estimate $CO_2e$ emissions. Detailed calculations of the fire pump emissions are provided in Appendix C.

### 4.2.6 Emergency Diesel-fired Generator Calculation Method

One 324-hp emergency diesel-fired generator will be installed to support the engines in case of a power interruption; the generator will be fired solely with natural gas. An annual testing and maintenance schedule of 100 hours is assumed for the emergency diesel-fired generator. Emissions for this unit are estimated based on NSPS emission rates[5] for CO, VOC, $NO_x$, PM, $PM_{10}$, and $PM_{2.5}$, while $SO_2$ emissions are estimated using AP-42 emission factors[6]. The $CO_2e$ emission factors (for $CO_2$, $CH_4$, and $N_2O$) from the EPA Mandatory Greenhouse Gas Reporting Rule (40 CFR Part 98) are used to estimate $CO_2e$ emissions. Emissions for this unit were estimated assuming 100 hours of testing and maintenance per year. Detailed calculations of emergency diesel-fired generator emissions are provided in Appendix C.

### 4.2.7 Diesel Fuel Oil Tank Calculation Method

A 308,377 gallon fuel oil storage tank will be installed to store ULSD fuel oil as defined in Part 4. Emissions are estimated for the storage tank using the EPA TANKS emission software. Detailed calculations of the fuel oil storage tank emissions are provided in Appendix C.

### 4.2.8 Circuit Breakers

Four circuit breakers will be installed, each containing 61.2 pounds of SF6. A 0.5% leakage is assumed to occur.

[5] Generator limits (40 CFR 60.4202(a)(2) and 40 CFR 89.112)
[6] AP-42 Section 3.2, *Natural Gas-fired Reciprocating Engines* (7/00)

# 5.0 REGULATORY REVIEW

The Project at Lacey Randall Station is subject to various federal and state air regulations. This section contains a discussion of the PSD regulations, applicable New Source Performance Standards (NSPS), applicable NESHAPS for Source Categories, and applicable Kansas Administrative Code (K.A.R) provisions. Where applicable, reference to general limitations is provided when there is no specific requirement that applies to an emission source.

In certain instances there are multiple regulatory requirements. For instance, where a BACT emission limitation is established, it will be at least as stringent as a companion NSPS limitation. In each situation it is understood that compliance with the most restrictive requirement will demonstrate compliance with all other less stringent requirements.

## 5.1 PSD Regulations

PSD review is required for all criteria pollutants that will be emitted above significant levels in accordance with K.A.R 28-19-350 and 40 CFR 52.21 as revised on July 1, 2007. PSD review consists of the following:

- A BACT analysis
- An air quality analysis
- An analysis of additional impacts on visibility, soils, vegetation, and growth in the area of the Project

Three criteria were evaluated to determine PSD applicability:

1. Whether the Project is sufficiently large (in terms of its emissions) to be a “major” stationary source or “major” modification.

2. Whether the Project will be located in a region designated as “attainment” or “unclassified.”

3. Whether the pollutants to be emitted from the Project exceed the significant emission levels set forth at K.A.R 28-19-350 (f)(1).

The pollutants that may be subject to PSD requirements per Kansas rules are $NO_x$, $SO_2$, CO, PM, $PM_{10}$, $PM_{2.5}$, VOC, $CO_2e$, hydrogen sulfide, $H_2SO_4$ mist, fluorides, and lead. The definition of a “major stationary source” is established at K.A.R 28-19-16a. Lacey Randall Station is considered a major stationary source if the PTE of a PSD pollutant, not including $CO_2e$, exceeds 250 tons per year. Lacey

Randall Station emissions will exceed the PSD significance levels for a number of PSD pollutants; thus satisfying the first criteria for PSD applicability.

Lacey Randall Station is located in an attainment/unclassified area for all criteria pollutants and therefore is subject to PSD review.

The maximum potential emissions from the Project, including start-up emissions, are listed in Table 2-1.

PSD regulations require that the following issues be addressed:

- Determination of BACT on a case-by-case basis, taking into account capital and operating costs as well as energy, environmental, and economic impacts
- Demonstration that the potential increase in emissions will not cause or contribute to an exceedance of the National Ambient Air Quality Standards (NAAQS), or a PSD Class II increment
- Analysis of the impairment, if any, to visibility, soils, vegetation, and growth in the area

## 5.2 New Source Performance Standards

The Project will be subject to several applicable NSPS standards[7] that are identified below. A description of the TradeWind compliance plan to meet each standard is included. NSPS that may potentially be applicable but are not are also discussed below.

### 5.2.1 40 CFR Part 60, Subpart Kb

This NSPS regulation is not applicable because the fuel oil storage tank capacity is greater than or equal to 151 $m^3$ and will store a liquid with a maximum true vapor pressure less than 3.5 kilopascals (kPa).

### 5.2.2 40 CFR Part 60, Subpart IIII

Subpart IIII (§60. 4200 *et. seq.*) applies to stationary compression ignition internal combustion engines and the manufacturers and/or owners and operators of these engines. For purposes of this application, Subpart IIII is applicable to the emergency fire pump and emergency diesel generator. Both engines will meet the definition of “emergency stationary internal combustion engine” under this subpart. For purposes of estimating potential emissions associated with both engines, TradeWind proposes a 100-hour-per-year non-emergency use limitation for required testing and maintenance.

[7] 40 CFR Part 60 and K.A.R 28-19-720

#### 5.2.2.1 Emergency Fire Pump Emission Standards

The emergency fire pump will be certified in accordance with the limits in 40 CFR 60.4202(d), which refer to the emission standards of Table 4 of Subpart IIII. If the fire pump is model year 2010 or greater, then the limits are as follows for engines in the 100 to 175 hp range (Table 4 of Subpart IIII of Part 60):

- 3.0 gram per horsepower hour (g/hp-hr) for NMHC plus $NO_x$
- 3.7 g/hp-hr for CO
- 0.22 g/hp-hr for PM

#### 5.2.2.2 Emergency Generator Emission Standards

The generator will be certified in accordance with the limits in CFR 60.4202a(2), which refer to the emission standards of 40 CFR 89.112(a). If the generator is model year 2006 or greater, then the limits are as follows for engines in the 225 kW and 450 kW (302 hp and 603 hp) range:

- NMHC + $NO_x$ = 4.0 g/kW-hr
- CO = 3.5 g/kW-hr
- PM = 0.20 g/kW-hr

#### 5.2.2.3 Diesel Fuel Requirements

Pursuant to 40 CFR 60.4207(b), owners and operators of CI ICE subject to Subpart IIII with a displacement of less than 30 liters per cylinder that use diesel fuel must purchase diesel fuel that meets the requirements of 40 CFR 80.510(b) for non-road diesel fuel. As stated in 40 CFR 80.510(b), non-road diesel fuel must be limited to 15 parts per million (ppm) maximum sulfur content. The cetane index is limited to a minimum of 40 and the maximum aromatic content is limited to 35 volume percent. TradeWind will be subject to the applicable requirements of this rule for the emergency fire pump.

### 5.2.3 40 CFR Part 60, Subpart TTTT

This NSPS regulation, as proposed, is not applicable because the proposed standards apply only to individual electrical utility generating units with a nameplate capacity of 25 MW or more that commence construction after April 13, 2012.

## 5.3 National Emission Standards for Hazardous Air Pollutants (NESHAP) and Maximum Achievable Control Technology (MACT)

The NESHAP contained in 40 CFR Part 63 are adopted by reference in K.A.R 28-19-735. NESHAP are emissions standards set by EPA for particular source categories. The NESHAP require the maximum degree of emission reduction of certain HAP emissions that EPA determines to be achievable. These

Maximum Achievable Control Technology (MACT) standards are adopted by reference in K.A.R 28-19-750.

The following MACT standards are applicable to the Project.

### 5.3.1 Subpart ZZZZ

The Stationary RICE MACT is applicable to stationary RICE at both major and area sources of HAP emissions.

The RICE are spark ignition four-stroke-lean-burn (4SLB) stationary RICE and will be an affected source under Subpart ZZZZ. Based on the classification as 4SLB engines with a site rating of more than 500 hp which is located at a major source of HAP emissions pursuant to 40 CFR 63.6600(b), the engines must comply with the emission limitations in Table 2a of the subpart. The engines must reduce CO emissions by 93 percent or more or limit the concentration of formaldehyde in the exhaust to 14 ppmvd or less at 15 percent $O_2$. The engines will have CO catalysts installed that will achieve 93% reduction of CO.

The emergency diesel fired generator and the emergency fire pump will be affected sources under Subpart ZZZZ. The engines will only be subject to the requirements of 40 CFR 60 Subpart IIII based on their classifications as new emergency stationary RICE with a site ratings of less than or equal to 500 brake hp located at a major source of HAP emissions pursuant to 40 CFR 63.6590(c)(6).

The RICE, emergency diesel-fired generator, and emergency fire pump will comply with the applicable requirements of this rule.

### 5.3.2 Subpart DDDDD

The Boiler MACT is applicable to boilers at major sources of HAP emissions.

The indirect fuel-gas heater will be an affected source under Subpart DDDDD. The fuel-gas heater must comply with the work practice standards in Table 3 as required by 63.7500(a)(1). The heater must operate and maintain the fuel-gas heater in a manner consistent with safety and good air pollution control practices for minimizing emissions as required by 63.7500(a)(3).

## 5.4 Kansas Air Quality Standards and Regulations

This section describes the regulations which apply to the Project as set forth at K.A.R. 28-19.

### 5.4.1 K.A.R 28-19-20 Particulate Matter Emission Limitations

This regulation applies only to the transfer or processing of solid materials; it does not apply to gaseous fuels.

### 5.4.2 K.A.R 28-19-31 Emission Limitations for Indirect Heating Equipment

The gas heater will be subject to the emission limitation in K.A.R 28-19-31(a) and K.A.R 28-19-31(b)(2). Particulate emissions from the gas heater are limited to 0.6 lb PM/MMBtu (K.A.R. 28-19-31(a)). The visible contaminant emissions from the gas heater will be limited to 20 percent (K.A.R. 28-19-3(b)(2)). The gas heater will comply with the applicable requirements of this rule.

### 5.4.3 K.A.R 28-19-300 to 304 Volatile Organic Compounds (VOC) Liquid Storage in Permanent Fixed Roof Type Tanks

This regulation is not applicable because the fuel oil stored has a true vapor pressure of less than 1.5 psia.

### 5.4.4 K.A.R 28-19-300 to 304 Construction Permits and Approvals; Applicability

TradeWind will submit the required application and fees to obtain a construction permit from KDHE before commencing construction of the Project.

### 5.4.5 K.A.R 28-19-350 Prevention of Significant Deterioration of Air Quality

A PSD evaluation has been completed for all regulated NSR pollutants that will be emitted from the Project ($NO_x$, $SO_2$, CO, VOC, PM, $PM_{10}$, $PM_{2.5}$, $H_2SO_4$ mist, hydrogen sulfide, fluorides, total reduced sulfur, reduced sulfur compounds, $CO_2e$ and lead). Part 5 of this application contains BACT analyses for each pollutant that exceeds its PSD significance level (state or federal). Part 6 of this application contains air dispersion modeling analyses for each PSD-subject pollutant, and Part 7 of this application contains additional impacts analyses for the PSD-subject pollutants. Emissions of lead, $SO_2$, hydrogen sulfide, fluorides, and $H_2SO_4$ mist resulting from the Project will not exceed their respective significance levels; therefore, these pollutants are not subject to PSD review.

### 5.4.6 K.A.R 28-19-500 to 518 Operating Permit; Applicability

TradeWind will obtain a Class I (Title V) operating permit for Lacey Randall Station in accordance with the provisions of K.A.R 28-19-510.

### 5.4.7 K.A.R 28-19-645 Opening Burning Prohibited

TradeWind will not conduct open burning at Lacey Randall Station except for the limited purposes of providing fire training (K.A.R 28-19-647(c)(2)).

### 5.4.8 K.A.R 28-19-650 Emissions Opacity Limits

The opacity of visible emissions from the emission sources at the Lacey Randall Station may not exceed 20 percent opacity per K.A.R 28-19-650(a)(3). The Project's emission points will not cause greater than 20 percent opacity.

## 5.5 Mandatory Reporting of Greenhouse Gases – 40 CFR Part 98

40 CFR Part 98 requires facilities that emit 25,000 metric tons or more per year of greenhouse gases (GHG) to submit annual reports to EPA. Lacey Randall Station will exceed the reporting threshold. Therefore, TradeWind will report GHG emissions as required.

## 5.6 NAAQS

As noted above, Part 6 of this application discusses the ambient air quality analysis and dispersion modeling that has been performed for the Project. That analysis and modeling demonstrate that the Project will not cause or contribute to a violation of any NAAQS.

## 5.7 Other Ambient Air Quality Standards

Recent Federal Land Manager (FLM) proposed guidance advises, in the course of a PSD application, an assessment of air quality impacts at Class I areas if a proposed major source is located within a certain distance of the Class I area. The nearest Class I area to the Lacey Randall Station site is the Wichita Mountains Wilderness located approximately 600 kilometers southeast.

The maximum total emissions of the pollutants that contribute to visibility impairment are less than ten times the distance to the Wichita Mountains Wilderness. In accordance with proposed Federal Land Managers' Air Quality Related Values Work Group (FLAG) guidance, a Class I visibility analysis is not required. Nonetheless, a visibility analysis using VISCREEN has been performed on a Class II area and is presented in Part 8 of this application.

The PSD Class I and Class II Increment analyses can be found in Part 7 of this application.

## 5.8 Additional Impact Analysis

The potential impact of the Project on soils, vegetation, visibility, and growth has been considered as part of the PSD process. The construction and operation of the Project at Lacey Randall Station is not expected to have a detrimental effect on plants, soils, or industrial, commercial, or residential growth. A full analysis of these impacts is set forth in Part 8 of this application.

## 5.9 Acid Rain (40 CFR Part 75) – New Unit Utility Exemption

The RICE will not be subject to the 40 CFR Part 75 Acid Rain regulations because each affected engine meets the new unit utility exemption of 40 CFR 72.7(a). Therefore, in accordance with the applicable Acid Rain regulations, TradeWind will submit the new unit exemption application forms before operation commences.

# 6.0 BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

Per K.A.R. 28-19-350, an owner of a facility applying for a PSD construction permit must perform a Best Available Control Technology (BACT) analysis for each regulated NSR pollutant for which there would be a significant net emissions increase at the stationary source. This requirement applies to any proposed emissions unit at which a net emissions increase in the air pollutant would occur as a result of a physical change or change in the method of operation in the emissions unit.

As can be seen in Table 2-1., the Project is subject to PSD review for CO, $NO_x$, $PM/PM_{10}/PM_{2.5}$, VOC, and $CO_2e$ (greenhouse gases).

Therefore, a BACT analysis was performed for each of these pollutants. A summary of the selected control technologies and the associated BACT emission limitations for the RICE is presented in Table 6-1.

**Table 6-1. Summary of BACT Results: RICE**

| Pollutant | Control Technology | BACT Emission Limitation (lb/hr)[A] | Equivalent Emissions[B] (g/bhp-hr) | Averaging Time |
|---|---|---|---|---|
| $NO_x$ | Selective Catalytic Reduction (SCR) System | 1.45 | 0.053 | 30-day |
| CO | Good Combustion Practices, Oxidation Catalyst | 2.67 | 0.10 | 30-day |
| VOC | Good Combustion Practices, Oxidation Catalyst | 2.67 | 0.10 | 30-day |
| $PM_{10}/PM/PM_{2.5}$ | Combustion Controls and Low Ash Fuels | 2.22 | NA | 3-hr |
| $CO_2e$ | Use of Efficient Lean-Burn Engines, Use of Natural Gas, and Maintain Efficiency of Engines Through Maintenance Procedures | 9,329 | 338 | Annual |

[A] Maximum engine emission rate under steady state conditions unless otherwise noted.
[B] Equivalent emissions in gram per brake horsepower hour (g/bhp-hr) for loads of 50% and higher are shown for comparison to the RBLC emission rates purposes only. These are not proposed as BACT emission limitations.
[C] Due to the testing methods and sources of PM in the emission exhaust, PM is only expressed in lb/hr and it is not appropriate to determine an equivalent g/bhp-hr. In addition, the RBLC emission limitations are primarily expressed in lb/hr.

Table 6-2 displays the BACT results for the auxiliary equipment (gas heater, emergency fire pump and emergency diesel-fired generator).

**Table 6-2. Summary of BACT Results: Auxiliary Equipment**

| Pollutant | Emissions Unit | Limiting Systems and Controls | BACT Emission Limitation |
|---|---|---|---|
| $NO_x$ | Gas Heater | Low $NO_x$ Burners and Combustion Control | 100 lb/MMcf |
| | Emergency Diesel-fired Generator | Combustion Control | 0.007 gm/hp-hr |
| | Emergency Fire Pump | Combustion Control | 3.00 gm/hp-hr |
| CO | Gas Heater | Good Combustion Practices | 84 lb/MMcf |
| | Emergency Diesel-fired Generator | Combustion Control | 2.61 gm/hp-hr |
| | Emergency Fire Pump | Combustion Control | 3.70 gm/hp-hr |
| VOC | Gas Heater | Good Combustion Practices | 5.5 lb/MMcf |
| | Emergency Diesel-fired Generator | Combustion Control | 0.007 gm/hp-hr |
| | Emergency Fire Pump | Combustion Control | 3.00 gm/hp-hr |
| | Fuel Oil Storage Tank | Submerged Fill Pipe | 0.156 tpy |
| $PM/PM_{10}/PM_{2.5}$ | Gas Heater | Combustion Control | 7.6 lb/MMcf |
| | Emergency Diesel-fired Generator | Combustion Control | 3.29E-04 gm/hp-hr |
| | Emergency Fire Pump | Combustion Controls and Low Ash Fuels | 2.20E-01 gm/hp-hr |
| $CO_2e$ | Gas Heater | Use of Clean Fuels, Maintaining and Tuning the Heater, Recordkeeping | 117.00 lb/MMBtu |
| | Emergency Diesel-fired Generator | Combustion Control | 164 lb/MMBtu |
| | Emergency Fire Pump | Selection of the Most Efficient Engines that Meet the Applicant's Project Needs | 164 lb/MMBtu |
| | Circuit Breakers | Enclosed-Pressure $SF_6$ Circuit Breakers | <0.5% leakage |

## 6.1 PSD BACT Process

### 6.1.1 The "Top-Down" Process

As part of the permitting process, a major stationary source needs to prepare a BACT analysis in conjunction with a PSD permit application. While there is no legal requirement to perform the BACT analysis utilizing a specific criteria or process, EPA has developed guidance that establishes a five-step "top down" BACT process/methodology.[8]

For purposes of this application, TradeWind has conducted its BACT analysis consistent with EPA's top down approach, which consists of the following steps for each pollutant to be emitted from each source:

Step 1 – Identify all potential control technologies
Step 2 – Determine technical feasibility (of potential technologies)
Step 3 – Rank control technologies by control effectiveness
Step 4 – Evaluate most effective controls and document results
Step 5 – Select BACT

Each of these steps is discussed in further detail below.

Step 1 – Identify all potential control technologies. The first step in a "top-down" analysis is to identify, for all applicable emission units, all "available" control options. Available control options are defined as those air pollution control technologies or techniques that have a practical potential for application to the emissions unit and the regulated pollutant under evaluation and have been demonstrated in practice.

Step 2 – Determine technical feasibility (of potential options). In the second step, the technical feasibility of each control option identified in Step 1 is evaluated with respect to the source-specific factors. A demonstration of technical infeasibility should be documented and should show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review. Technically infeasible control options are then eliminated from further consideration in the BACT analysis.

Step 3 – Rank control technologies by control effectiveness. All remaining control alternatives not eliminated in Step 2 are ranked and then listed in order of overall control effectiveness for the pollutant

[8] U.S. Environmental Protection Agency. New Source Review Workshop Manual – Draft. North Carolina: Office of Air Quality Planning and Standards, 1990.

under review, with the most effective control alternative at the top. A list should be prepared for each pollutant and for each emissions unit (or grouping of similar units) subject to a BACT analysis.

Step 4 – Evaluate most effective controls and document results. After the identification of available and technically feasible control technology options, the energy, environmental, and economic impacts of each such option are taken into account and the technology for control of emissions of the pollutant is selected at Step 4. Section 6.1.2 describes the economic analyses used in this BACT analysis.

Step 5 – Select BACT. The BACT emission limitation determination is made at Step 5.

### 6.1.2 General Principles

The BACT analysis for the Project is also based on the following concepts:

- There is no single prescriptive approach to determining the appropriate control technology and emission limitation for a given project
- BACT does not redefine the facility as proposed (including fuels)
- The control technology must be available and feasible for this specific project
- Emission limitations are defined on a “case-by-case” analysis that considers site specific factors
- Emission limitations must be “achievable” on a long-term, day in and day out, basis

There is no prescriptive approach to performing a case-by-case control technology and emission limitation analysis. PSD permitting authorities determine emission limitations on a case-by-case basis. These case-by-case determinations must take into account source-specific and site-specific characteristics. This is not a “cookie-cutter” approach, and there is no single right answer to determining either the appropriate control technology or the appropriate emission limitation for a specific source or for a specific pollutant.

KDHE is not required to set any emission limitation at the most stringent emission limitation that has been demonstrated by a facility using similar emissions control technology. Similarly, an emission limitation does not need to be set at the most stringent emission limitation found in another permit. Rather, KDHE has the authority and the ability to evaluate and determine the proper control technologies and emissions limitations for a particular project based on project-specific factors, including location. The BACT process does not require that each determination establish an emission limitation that is equal to or more stringent than the most stringent previous determination.

Further, in establishing emission limitations, KDHE must confirm that those limitations are achievable by the specific facility that is subject to them: (1) over the life of the facility; and (2) during all operating conditions, not just ideal conditions. The use of a safety factor or margin is well-established in the air permitting context to appropriately account for the uncertainty and operational variability that will occur over the life of a facility. This safety factor must be sufficient to allow a permit holder to comply on a continuous basis. Emission limitations are not required to be based on the lowest emissions rate or highest control efficiency ever documented by a similar facility for a short-term period. The emission limitations must account for a full range of operating conditions and the inherent variability of complex fuel combustion and air pollution control systems.

In order to be considered in the BACT process, a control technology must be commercially available (*i.e.*, it must be offered for sale at commercial scale through commercial channels). Permit applicants are not required to explore Research &Development (R&D) projects to determine whether or not a particular technology is potentially feasible. In addition, in order to be considered feasible technology for purposes of inclusion in an analysis, a particular technology must have been previously demonstrated, on a long-term basis, at commercial scale.

In its March 2011 guidance, EPA affirmed that a BACT review for a project should not operate to redefine the project. “EPA has recognized that a Step 1 list of options need not necessarily include inherently lower polluting processes that would fundamentally redefine the nature of the source proposed by the permit applicant. BACT should generally not be applied to regulate the applicant’s purpose or objective for the proposed facility.” The March 2011 guidance continues, “The ‘redefining the source’ issue is ultimately a question of degree that is within the discretion of the permitting authority.” Similarly, EPA’s March 2011 “Guidance for Determining Best Available Control Technology for Reducing Carbon Dioxide Emissions from Bioenergy Production” states, “However, while Step 1 is intended to capture a broad array of potential options for pollution control, this step of the process is not without limits. EPA has recognized that a Step 1 list of options need not necessarily include inherently lower polluting processes that would fundamentally redefine the nature of the source proposed by the permit applicant. BACT should generally not be applied to regulate the applicant’s purpose or objective for the proposed facility.”

### 6.1.3 Economic Analyses

This section contains information regarding the economic analyses and how they were performed in Step 4 for each piece of equipment. Economic analyses were performed for add-on controls for auxiliary equipment and these tables are located in Appendix E.

For the controls that require an economic analysis, capital costs include the initial cost of components intrinsic to the complete control system. For both oxidation catalyst and SCR systems, these capital costs would include the catalyst modules, transition piece, support frame, piping, provisions for catalyst cleaning and removal, instrumentation, and installation costs. Additionally, the SCR system requires the installation of an ammonia injection system. Annual costs consist of the financial efficiency losses, parasitic loads, and revenue loss from operation of the control system; overhead, maintenance, labor, raw materials and utilities are included.

Capital and operating costs have been estimated in accordance with EPA guidance. The capital cost estimating technique used in this analysis is based on a factored method of determining direct and indirect installation costs. This technique is a modified version of the “Lang Method,” where installation costs are expressed as a function of known equipment costs. This method is consistent with the latest EPA guidance manual [Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual] on estimating control technology costs (EPA 2002).

Purchased equipment costs represent the delivered cost of the control equipment, auxiliary equipment, and instrumentation. Auxiliary equipment consists of all structural, mechanical, and electrical components required for continuous operation of the device. Depending on the control strategy that is used, these costs may include such items as reagent storage tanks, supply piping, the engine outlet transition piece, a catalyst removal crane, spare parts, and the catalyst and air dilution system. In this BACT evaluation, basic equipment costs were obtained from data provided by vendors and from recent projects with similar units. Instrumentation is usually not included in the basic equipment cost, so the OAQPS manual allows that instrumentation may be estimated to be 10 percent of the basic equipment cost.

Direct installation costs consist of the direct expenditures for materials and labor including site preparation, foundations, structural steel, insulation, erection, piping, electrical, painting, and enclosure structures. Indirect installation costs include engineering and supervision of contractors, construction and field expenses, construction fees, contingencies, and additional permits and licensing costs.

Direct installation costs are expressed as a function of the purchased equipment cost and are based on the average installation requirements of typical systems. Indirect installation costs are designated as a

percentage of the total direct cost (purchased equipment cost plus the direct installation cost) of the system. Other indirect costs include equipment start-up and performance testing, contingency funds, working capital and interest during construction.

Annualized costs are comprised of direct and indirect operation costs. Direct costs include electricity losses, labor, maintenance, replacement parts, raw materials, and utilities. Indirect operating costs include overhead, taxes, insurance, general administration, contingencies, and capital charges. Annualized cost factors used to estimate total annualized costs for the SCR and oxidation catalyst systems are presented in their respective discussions in the sections that follow. These tables are consistent with the EPA guidance on estimating control technology costs (EPA 2002).

Direct operating labor costs vary according to the system operating mode and operating time. Labor supervision is estimated as 15 percent of operating labor. Maintenance costs have been included and are itemized as appropriate. Replacement part costs, such as the cost to replace an aged or failed catalyst, have been included where appropriate. Reagent and utility costs are based upon estimated annual consumption. Based on the experience of other facilities, catalyst is assumed to require replacement at a minimum of every three years due to failure or aging.

Most indirect operating costs are calculated as a percentage of the total capital cost. The indirect capital costs are based on the capital recovery factor (CRF), defined as:

$$CRF = \frac{i \cdot (1+i)^n}{(1+i)^n - 1}$$

Where:

i = interest rate

n = equipment economic life (years)

A control system's economic life is typically 10 to 20 years. In this analysis, a 20-year equipment economic life (typical length of financing) was used. The average interest rate is assumed to be seven percent. The CRF is calculated to be 0.094.

The cost-effectiveness for each system is calculated by dividing the annualized cost of the available control technology by the annual emissions reduction. The annual emissions reduction is the difference between the baseline emission rate and the controlled emission. All BACT capital and annual cost tables are contained in Appendix E.

### 6.1.4 GHG BACT Process

Based on EPA GHG Guidance,[9] the GHG greenhouse gases BACT process is similar to the PSD BACT process summarized above. Potential control strategies are identified at Step 1 and technologically infeasible options are then eliminated at Step 2. The remaining technically feasible control technologies are ranked at Step 3. The most effective control technologies from an environmental, energy, and economic perspective are evaluated and the most appropriate control technology is selected at Step 4. Finally, the BACT emission limitation is made at Step 5. The general principles of PSD BACT analysis discussed above are equally applied to the GHG BACT process.

## 6.2 BACT Technology and Emission Limitations for Similar Units

The first step in the "top-down" BACT process is the identification of potentially available control technologies. A good source of information on such technologies is EPA's RACT/BACT/LAER Clearinghouse (RBLC) database maintained on EPA's Technology Transfer Network website at www.epa.gov/ttn/catc. This database includes recent BACT determinations for similar projects.

Advanced queries of the database were conducted to identify control technology determinations from January 2003 to April 2013 for sources similar to the RICE to be used for the Project. Queries were also made for the Project's auxiliary equipment for the same time period. The results of the RBLC queries can be found in Appendix D in Tables D1 to D7.

To identify previous control technology determinations for comparable sources, two types of queries were run for each set of operational modes. The first query was a "basic search" in which the RBLC database was searched for:

- Internal Combustion Engines (>500 hp), 17.130 – Natural gas combustion

In addition to the RBLC database search, other known RICE electric generating units (EGU) projects that are known by TradeWind and permitted (but filed under a different category in the RBLC) were located within the RBLC and included in the tables as well. All known projects that used natural gas engines of similar engine size (4-10 MW) and were subject to PSD review were included in the RBLC search. To the extent practicable, clearly non-applicable projects were removed from the RBLC tables presented in this application. For example, the following process types are incorrectly used in the RBLC to identify internal combustion engine projects; therefore, these categories were also examined:

[9] PSD and Title V Permitting Guidance for Greenhouse Gases, U.S. EPA, Office of Air Quality Planning and Standards, March 2011.

- Boilers (>250 MMBtu/hr), 11.310 - Natural gas combustion
- Combined Cycle Combustion Turbines (<25 MW), 15.210 - Natural gas combustion

Additionally, the most recent and relevant permit for comparison to this application is Mid-Kansas Electric, LLC's Rubart Station PSD air permit issued by KDHE in January 2013. Although Rubart Station proposed to use Caterpillar engines instead of Wärtsilä, the projects are very similar and Rubart Station BACT limits have been included in this BACT analysis.

Permitted BACT emission rates for other internal combustion engines have been compared to the RICE to be used in the Project. The best comparison is made to other turbo-charged, four-stroke, lean-burn machines (turbo charged, as opposed to naturally aspirated). However, differences in size (MW) and speed (rpm) of some other permitted engines makes such units dissimilar to the Project RICE. EPA's RBLC provides insufficient data to determine if other permitted machines are indeed turbo-charged, four-stroke, lean-burn engines. Most of the RBLC-listed machines are slow speed, gas-compression machines or higher speed, non-turbo machines. These differences must be taken into account when comparing the RICE to be used in this Project to other previously-permitted engines. Of the vendors and engines that are commercially available, Wärtsilä, Jenbacher, and Caterpillar manufacture and sell natural gas-fired reciprocating engines that are appropriate for this Project. However, only Wärtsilä has permitted and *operated* units of this size that are natural-gas fired. Permits for projects that include similar-sized Wärtsilä RICE and the Rubart CAT RICE have been collected by TradeWind. The Wärtsilä permitted emission rates are listed in Table 6-3, below. These projects represent the most applicable technology that is similar to this Project.

**Table 6-3. Emission Rates for Engines Similar to Project Engines at Full Load (g/bhp-hr)**

| Plant | State | $NO_x$[A] | CO[A] | VOC[A] | $PM_{10}$ total[A] |
|---|---|---|---|---|---|
| Western 102 | Nevada | 0.054 | 0.087 | 0.087 | 0.094 |
| Plains End 2 | Colorado | 0.059 | 4.000 | 1.000 | 0.102 |
| Goodman | Kansas | 0.097 | 0.097 | 0.097 | -- |
| Humboldt | California | 0.064 | 0.086 | 0.106 | 0.075 |
| Pearsall | Texas | 0.087 | 0.308 | 0.308 | 0.181 |
| Antelope | Texas | 0.052 | 0.096 | 0.157 | 0.075 |
| Lea County | New Mexico | 0.054 | 0.104 | 0.104 | 0.080 |
| Woodland 3 | California | 0.053 | 0.084 | 0.074 | 0.052 |
| Hutchinson | Minnesota | 0.030 | 0.746 | 0.299 | 0.082 |
| Quail Brush | California | 0.048 | 0.057 | 0.057 | 0.050 |
| Greenville Electric | Texas | 0.086 | 0.308 | 0.308 | 0.181 |
| Mid-Kansas Rubart Station (Caterpillar) | Kansas | 0.07 | 0.13 | 0.20 | 0.044 |

[A] The values are originally given in different units and here converted to similar units for comparison purposes (rounded to integral values). Also, many of these plants were not subject to PSD review. All units have CO catalysts and SCR, except for Hutchinson which does not have a CO catalyst. Note that emissions levels vary based on engine size, type and location.

## 6.3 New Source Performance Standards

### 6.3.1 Subpart JJJJ

Subpart JJJJ—Standards of Performance for Stationary Spark Ignition Internal Combustion Engines became effective March 18, 2008.[10] The RICE engines are subject to the NSPS Subpart JJJJ limits for non-emergency spark ignited (SI) natural gas engines greater than 500 HP manufactured after July 1, 2010. The applicable emission limitations are listed in Section 5.2.

All BACT emission limitations for the Project are more stringent than the applicable NSPS.

## 6.4 BACT For Nitrogen Oxides ($NO_x$) – RICE

### 6.4.1 STEP 1. Identify All Potential Control Technologies

$NO_x$ is primarily formed in combustion processes in three ways: 1) the combination of elemental nitrogen with oxygen in the combustion air within the high temperature environment of the combustor (thermal

[10] "Standards of Performance for Stationary Spark Ignition Internal Combustion Engines," Title 40 Code of Federal Regulations, Part 60, Subpart JJJJ. 2011 ed.

$NO_x$); 2) reactions of nitrogen with hydrocarbon radicals from the fuel (prompt $NO_x$); and 3) the oxidation of nitrogen contained in the fuel (fuel $NO_x$). Natural gas contains negligible amounts of fuel-bound nitrogen, although some molecular nitrogen is present. Therefore, it is assumed that essentially all $NO_x$ emissions from the engines originate as thermal $NO_x$. The rate of formation of thermal $NO_x$ is a function of residence time and free oxygen and is exponential with peak flame temperature. $NO_x$ control techniques are aimed at controlling one or more of these variables during combustion. Controlling the air-to-fuel ratio can reduce the amount of $NO_x$.[11]

The RICE for the Project will be lean-burn, 4-stroke engines, which can also be characterized as clean-burn engines. The term "clean-burn" technology refers to engines designed to reduce $NO_x$ by operating at high air-to-fuel ratios. The RICE will be equipped with turbo chargers which increase the volume of air in the combustion chamber. Lean-burn engines typically have lower oxides of nitrogen ($NO_x$) emissions than rich-burn engines.

Other control methods utilize add-on equipment to remove $NO_x$ from the exhaust gas stream after its formation. The most common control techniques involve the injection of ammonia or urea into the gas stream to reduce the $NO_x$ to molecular nitrogen and water. Ammonia is either injected into the engine combustion chamber (non-selective catalytic reduction [NSCR]) or injected with the use of a catalyst (selective catalytic reduction [SCR]). NSCR may be used for rich-burn engines, but is not feasible on lean-burn engines.

### 6.4.2 STEP 2. Identify Technically Feasible Control Technologies

#### 6.4.2.1 Non-Selective Catalytic Reduction (NSCR)

NSCR uses the residual hydrocarbons and CO in the rich-burn engine exhaust as a reducing agent for $NO_x$. In an NSCR, hydrocarbons and CO are oxidized by $O_2$ and $NO_x$. The excess hydrocarbons, CO, and $NO_x$ pass over a catalyst that reduces $NO_x$ to $N_2$.

The NSCR technique is effectively limited to engines with normal exhaust oxygen levels of 4 percent or less. This includes four-stroke rich-burn naturally-aspirated engines and some four-stroke rich- burn turbo-charged engines. Engines operating with NSCR require tight air-to-fuel control to maintain high reduction effectiveness without high hydrocarbon emissions. To achieve effective $NO_x$ reduction

[11] EPA. Compilation of Air Pollutant Emission Factors, Fifth Edition. (AP-42), Section 3.2 (7/00).

performance, the engine may need to be run with a richer fuel adjustment than normal. This exhaust excess oxygen level is usually closer to 1 percent.

Lean-burn engines cannot be retrofitted with NSCR control because of the reduced exhaust temperatures. **Because lean-burn engines cannot be fitted with NSCR, NSCR is not technically feasible for application to the RICE.**

#### 6.4.2.2 Selective Catalytic Reduction (SCR)

SCR is a post-combustion technology that employs ammonia in the presence of a catalyst to convert $NO_x$ to nitrogen and water. The function of the catalyst is to lower the activation energy of the $NO_x$ decomposition reaction. Technical factors related to this technology include the catalyst reactor design, optimum operating temperature, sulfur content of the fuel, deactivation due to aging, ammonia slip (ammonia that is left unreacted and exits out the stack) emissions, and the design of the ammonia injection system.

SCR represents state-of-the-art controls for lean-burn four-stroke engine $NO_x$ removal. This technology is also commonly used on natural gas-fired engines.

The temperature of the exhaust in an SCR dictates the type of catalyst that will be used. Typically, for exhaust gases on the higher end of the normal operating range (450 to 850 degrees Fahrenheit), a high-temperature catalyst such as vanadium or zeolite is required. **Because SCRs are commercially available and have been used on engines of this size, SCR is technically feasible for application to the RICE.**

#### 6.4.2.3 Lean-Burn Combustion

The Project's RICE will be lean-burn, four-stroke engines. Lean-burn engines may operate up to the lean flame extinction limit, with exhaust oxygen levels of 12 percent or greater. The air-to-fuel ratios of lean-burn engines range from 20:1 to 50:1 and are typically higher than 24:1. The Project's RICE lean-burn engines are also characterized as clean-burn engines. Engines operating at high air-to-fuel ratios (greater than 30:1) may require combustion modification to promote stable combustion with the high excess air. The RICE are designed with a turbo charger which is used to force more air than non-turbo charged engines into the combustion chamber. Lean-burn engines typically have lower oxides of nitrogen ($NO_x$) emissions than rich-burn engines.[12]

[12] EPA. Compilation of Air Pollutant Emission Factors, Fifth Edition. (AP-42), Section 3.2 (7/00).

Steady-state controlled $NO_x$ emissions using no control or only lean-burn combustion range from 0.19 to 20.2 g/bhp-hr according to the RBLC database (Table D-1). The $NO_x$ emissions are highly variable depending on the specific RICE and its use. Each vendor that offers RICE has different $NO_x$ emission levels, even though they all may use lean-burn technology.

**Because lean-burn combustion with clean-burn technology is standard on engines like those to be used for the Project, it is a technically feasible option for the RICE.**

#### 6.4.2.4 Summary of the Technically Feasible Control Options

The technical feasibility of the $NO_x$ control options for the engines is summarized in Table 6-4. The expected performance (steady state) has been determined considering the vendor guarantees.

**Table 6-4. Summary of Technically Feasible $NO_x$ Control Technologies for the RICE**

| Control System | | Expected Performance (lb/hr) | Technical Feasibility | Comments |
|---|---|---|---|---|
| Combustion Controls | Lean-burn Combustion | 34.70 | Feasible | Standard on the Project's RICE |
| Post Combustion Controls | Non-Selective Catalytic Reduction | N/A | Not Feasible | Only used on rich-burn engines |
| | Selective Catalytic Reduction | 1.45 | Feasible | SCR is part of standard package for the Project's RICE |

### 6.4.3 STEP 3. Rank the Technically Feasible Control Technologies

Add-on controls are a technically feasible option on the Project's RICE. The RICE will come as lean-burn engines and include SCR as part of the standard packages. Although the SCR is included with the RICE engines, it is an add-on control. Therefore, lean-burn combustion will be considered as baseline.

The technically feasible $NO_x$ control technologies for the RICE are ranked by control effectiveness in Table 6-5.

**Table 6-5: Ranking of Technically Feasible $NO_x$ Control Technologies for the RICE**

| Control Technology | Reduction (%) | Controlled Emission Level (lb/hr) |
|---|---|---|
| Lean-burn combustion/ with SCR | 96 | 1.45 |
| Lean-burn combustion | Baseline | 34.70 |

### 6.4.4 STEP 4. Evaluate the Most Effective Controls

#### 6.4.4.1 Environmental, Energy, and Economic Feasibility of Control Options

The next step in the top-down BACT analysis is to review each of the technically feasible control options for environmental, energy, and economic impacts. First, all technically feasible controls will be discussed for environmental and energy impacts. Next, if the top control is not chosen, an economic analysis to determine capital and annual control costs in terms of cost-effectiveness (i.e., dollars per ton of pollutant removed) of each control system will be conducted. Because TradeWind has selected the top control, the following information is presented for informational purposes only.

#### 6.4.4.2 Selective Catalytic Reduction (SCR)

Energy Impacts

As with all add-on controls, operation of an SCR system results in a loss of energy due to the pressure drop across the SCR catalyst. To compensate for the energy loss in the SCR system, additional natural gas combustion is required to maintain the net energy output, which also results in additional air pollutant emissions. However, the extra fuel required for the controls does not outweigh the benefit of reducing emissions of NOx.

Environmental Impacts

Urea, which is decomposed in an external reactor to form ammonia, will be used in the SCR. The SCR system consists of an ammonia injection system and a catalytic reactor. Unreacted ammonia may escape through to the exhaust gas. This is commonly called “ammonia slip.” It is estimated that ammonia slip from an SCR on this size of engine could be 10 ppm; this may be considered to be an environmental impact. The ammonia that is released may also react with other pollutants in the exhaust stream to create fine $PM_{10}$ in the form of ammonium salts. SCR catalysts must also be replaced on a routine basis. In some cases, these catalysts may be classified as hazardous waste. This typically requires either returning the material to the manufacturer for recycle and reuse or disposal in permitted landfills. None of this outweighs the benefit of reducing emissions of $NO_x$ because of the environmental and health benefits of reducing $NO_x$ emissions.

Economic Impacts

Engine manufacturers currently install SCRs as standard equipment on the RICE that combust natural gas for power generation in the United States. As SCR is the top control technology listed and because SCR is

standard equipment on the engines being considered, there is no need to calculate an annualized cost of the control for the purposes of this analysis.

#### 6.4.4.3 Lean-Burn Combustion

Energy Impacts

Lean-burn combustion and clean-burn technology are usually accompanied by an efficiency penalty (typically 2 to 3 percent) and an increase in power output (typically 5 to 6 percent). The increase in power output results from the increase in mass flow required to maintain engine inlet temperature at manufacturer's specifications. Because there is a power increase, no energy impacts are associated with lean-burn combustion and clean-burn technology.

Environmental Impacts

Lean-burn combustion may increase CO and VOC emissions. However, this increase does not outweigh the advantage of decreased $NO_x$ emissions because $NO_x$ emissions are considered to be more detrimental to the environment and human health.[13]

Economic Impacts

The RICE vendors under consideration currently install lean-burn combustion with clean-burn technology as standard on the engines. Because lean-burn combustion is standard equipment on the engines, there is no calculated annualized cost of the control for the economic impacts evaluation.

**The maximum technically feasible control applied to RICE is SCR with lean-burn combustion. Because this is the highest level of add-on control for engines of this size, BACT for control of $NO_x$ emissions from the RICE is lean-burn combustion with clean-burn technology with SCR.**

### 6.4.5 STEP 5. $NO_x$ BACT Emission Limitation

BACT determinations shown in the RBLC (Table D-1) for engines that are in the 4.5- to 9.3-MW size range located in attainment areas were in the range of 0.07 gram per brake horsepower-hour (g/bhp-hr) to 20.2 g/bhp-hr using either lean-burn combustion (or clean burn technology) or SCR for natural gas-fired engines.

The BACT emission limitation for $NO_x$ is 1.45 lb/hr for steady state loads of 50 percent and higher, based on vendor guarantees. This rate is equivalent to 0.053 g/hp-hr for loads of 50 percent and higher. This represents the lowest emission rates that can be achieved for these types of natural gas RICE EGUs.

[13] EPA. Compilation of Air Pollutant Emission Factors, Fifth Edition. (AP-42), Section 3.2 (7/00).

## 6.5 BACT FOR Carbon Monoxide (CO) – RICE

### 6.5.1 STEP 1. Identify Potential Control Strategies

CO results from incomplete combustion. Control of CO is typically accomplished by providing adequate fuel residence time and a high temperature in the combustion zone to ensure complete combustion. CO emissions may indicate early quenching of combustion gases on cylinder walls or valve surfaces. Lean-burn engines typically have higher CO emissions and lower $NO_x$ emissions due to the air-to-fuel ratios at which they both operate.

CO emissions from engines are a function of oxygen availability (excess air), flame temperature, residence time at flame temperature, combustion zone design, and turbulence. Front-end control involves controlling the combustion process to suppress CO formation. Post-combustion control involves the use of catalytic oxidation.

The technologies identified for reducing CO emissions from the engines are an oxidation catalyst (also referred to as a CO catalyst) and combustion controls. The standard technology for reducing CO emissions is to maintain “good combustion” through proper control and monitoring of the combustion process through the air-to-fuel ratio. A survey of the RBLC database (Table D-2) indicates that combustion controls is the most prevalent BACT control, with several oxidation catalysts listed as BACT.

### 6.5.2 STEP 2. Identify Technically Feasible Control Technologies

#### 6.5.2.1 Oxidation Catalyst

Oxidation catalysts are a post-combustion technology which does not rely on the introduction of additional chemicals, such as ammonia or urea with SCR, for a reaction to occur. The oxidation of CO to $CO_2$ utilizes excess air present in the engine exhaust; the activation energy required for the reaction to proceed is lowered in the presence of a catalyst. Products of combustion are introduced into a catalytic bed, with the optimum temperature range for these systems being between 700°F and 1,100°F. At higher temperatures, catalyst sintering may occur, potentially causing permanent damage to the catalyst. The addition of a catalyst bed onto the engine exhaust will create a pressure drop, resulting in back pressure to the engine. This has the effect of reducing the efficiency of the engine and the power generating capabilities.

**The use of oxidation catalysts is a technically feasible method for controlling CO emissions from the RICE.**

#### 6.5.2.2 Combustion Control

"Good combustion practices" include operational and incinerator design elements to control the amount and distribution of excess air in the flue gas to ensure that there is enough oxygen present for complete combustion (controlling the air-to-fuel ratio).

**Good combustion practices are a technically feasible method of controlling CO emissions from the RICE.**

#### 6.5.2.3 Summary of the Technically Feasible Control Options

The technical feasibility of the CO control options for the RICE being considered are summarized in Table 6-6. The expected performance has been determined considering the performance of existing systems, vendor guarantees, permitted emission limitations, and the design requirements for the engines.

**Table 6-6. Summary of Technically Feasible CO Control Technologies for the RICE**

| Control System | | Expected Performance (lb/hr) | Feasibility | Comments |
|---|---|---|---|---|
| Combustion Control | | 46.36 | Feasible | Standard on the RICE. Not an add-on control. |
| Post Combustion Controls | Oxidation Catalyst | 2.67 | Feasible | Produces $CO_2$ emissions. Standard on the RICE. |

### 6.5.3 STEP 3. Rank the Technically Feasible Control Technologies

The technically feasible CO control technologies for the RICE are ranked by control effectiveness in Table 6-7.

**Table 6-7. Ranking of Technically Feasible CO Control Technologies for the RICE**

| Control Technology | Reduction (%) | Controlled Emission Level (lb/hr) |
|---|---|---|
| Oxidation Catalyst | 94 | 2.67 |
| Combustion Control | Not applicable (baseline) | 46.36 |

### 6.5.4 STEP 4. Evaluate the Most Effective Control Technologies

#### 6.5.4.1 Environmental, Energy, and Economic Feasibility of Control Options

Because TradeWind has selected the top control, the following information is presented for informational purposes only.

#### 6.5.4.2 Oxidation Catalyst

Energy Impacts

The addition of a catalyst bed onto the engine exhaust for the oxidation catalyst will create additional pressure drop, resulting in increased back pressure to the engine. This has the effect of reducing the efficiency of the engine and the power generating capabilities. However, these effects are considered minor compared to the reduction in CO and VOC emissions from the use of an oxidation catalyst.

Environmental Impacts

The oxidation catalyst oxidizes CO and VOC to $CO_2$ which is released to the atmosphere and is now a regulated constituent of the atmosphere. In addition, as with all controls that utilize catalysts for removal of pollutants, the catalyst must be disposed of after it is spent. The catalyst may be considered hazardous waste and require special treatment or disposal; and even if it is not hazardous, it will add minor waste volume to landfills. The health and environmental benefits of reducing CO emissions outweigh these other environmental impacts.

Economic Impacts

The engine manufacturers being considered currently install oxidation catalysts as standard equipment on the RICE that combust natural gas. Since oxidation catalysts are standard equipment on the engine, there is no annualized cost of the control.

**Because the oxidation catalyst comes standard on the RICE and because oxidation catalysts represent the highest level of control for CO, oxidation catalysts are BACT for the RICE.**

#### 6.5.4.3 Combustion Control

Energy, Environmental, and Economic Impacts

Combustion controls are an inherent control designed to reduce pollution and increase efficiency of the engines. There are no energy, environmental, or economic impacts from this process. There is no “add-on” equipment associated with this control technology, and there is no capital cost associated with this control.

**Because there are no adverse energy, environmental, or economic impacts associated with this process, combustion controls are BACT for the RICE.**

### 6.5.5 STEP 5. CO BACT Emission Limitation

Recent BACT determinations indicate a level of 0.1 to 4.8 g/bhp-hr for CO emissions from engines firing natural gas (Table D-2). With good combustion controls and oxidation catalysts, these engines will

achieve CO emission rates of 2.67 lb/hr at loads of 50 percent and higher (which is equivalent to 0.13 g/bhp-hr at full load).

The use of good combustion practices that control the amount of excess air in the flue gas along with the added control of an oxidation catalyst are the practices that can meet a CO emission limitation of 2.67 lb/hr for steady state loads of 50 to 100 percent, based on RICE vendors guaranteed emission rate. This BACT emission limitation is equivalent to 0.10 g/hp-hr for loads of 50 percent and higher. This is the lowest-in-class emission rate that can be achieved for these types of natural gas RICE EGUs.

## 6.6 BACT for Volatile Organic Compounds (VOC) – RICE

### 6.6.1 STEP 1. Identify Potential Control Strategies

#### 6.6.1.1 Formation of VOC and Control Strategies

VOC results from incomplete combustion. VOC emissions occur when some gas remains unburned or is only partially burned during the combustion process. With natural gas, some organics are unreacted trace constituents of the gas, while others may be products of the heavier hydrocarbon constituents. Partially burned hydrocarbons result from inadequate air-to-fuel mixing before or during combustion or inefficient air-to-fuel ratios in the cylinder during combustion due to maladjustment of the engine fuel system. Lean-burn engines typically have higher VOC emissions than rich-burn engines due to the respective air-to-fuel ratios at which they operate.

VOC emissions from engines are a function of oxygen availability (excess air), flame temperature, residence time at flame temperature, and combustion zone design. Front-end control involves controlling the combustion process to suppress unburned VOC. Post-combustion control involves the use of catalytic oxidation.

The technologies identified for reducing VOC emissions from the RICE being considered are the same as those identified for CO control: an oxidation catalyst (also referred to as a CO catalyst) and combustion controls. The standard technology for reducing VOC emissions is to maintain “good combustion” through proper control and monitoring of the combustion process through the air-to-fuel ratio. A survey of the RBLC database (Table D-3) indicates that combustion controls is the most prevalent BACT control with several oxidation catalysts listed as BACT for VOC.

### 6.6.2 STEP 2. Identify Technically Feasible Control Technologies

#### 6.6.2.1 Oxidation Catalyst

Oxidation catalysts are a post-combustion technology that does not rely on the introduction of additional chemicals, such as ammonia or urea with SCR, for a reaction to occur. See Section 6.5.2.1 for a discussion oxidation catalyst process.

**The use of oxidation catalysts for VOC control is a technically feasible method for controlling VOC emissions from the RICE.**

#### 6.6.2.2 Combustion Control

"Good combustion practices" include operational and design elements to control the amount and distribution of excess air in the flue gas to ensure that there is enough oxygen present for complete combustion (controlling the air-to-fuel ratio). Such control practices applied to the Project's RICE can achieve VOC emission levels of 11.8 lb/hr without an oxidation catalyst.

**Good combustion practices are a technically feasible method of controlling VOC emissions from the RICE.**

#### 6.6.2.3 Summary of the Technically Feasible Control Options

The technical feasibility of the VOC control options for the RICE being considered is summarized in Table 6-8. The expected performance has been determined considering the performance of existing systems, vendor guarantees, permitted emission limitations, and the design requirements for the engines.

**Table 6-8. Summary of Technically Feasible VOC Control Technologies for the RICE**

| Control System | | Expected Performance (lb/hr) | Feasibility | Comments |
|---|---|---|---|---|
| Combustion Control | | 11.8 | Feasible | Standard on the RICE. Not an add-on control. |
| Post Combustion Controls | Oxidation Catalyst | 2.67 | Feasible | Standard on the RICE. |

### 6.6.3 STEP 3. Rank the Technically Feasible Control Technologies

The technically feasible VOC control technologies for the RICE are ranked by control effectiveness in Table 6-9.

**Table 6-9. Ranking of Technically Feasible VOC Control Technologies for the RICE**

| Control Technology | Reduction (%) | Controlled Emission Level (lb/hr) |
|---|---|---|
| Oxidation Catalyst | 77 | 2.67 |
| Combustion Control | Not applicable (baseline) | 11.8 |

## 6.6.4 STEP 4. Evaluate the Most Effective Control Technologies

### 6.6.4.1 Environmental, Energy, and Economic Feasibility of Control Options

Because TradeWind has selected the top control, the following information is presented for informational purposes only.

### 6.6.4.2 Oxidation Catalyst

Energy Impacts

The addition of a catalyst bed onto the engine exhaust for the oxidation catalyst will create additional pressure drop, resulting in increased back pressure to the engine. This has the effect of reducing the efficiency of the engine and the power generating capabilities. The reduction in energy efficiency is considered negligible when compared to the benefit of reducing emissions.

Environmental Impacts

The oxidation catalyst oxidizes CO and VOC to $CO_2$ which is released to the atmosphere and is now a regulated constituent of the atmosphere. In addition, as with all controls that utilize catalysts for removal of pollutants, the catalyst must be disposed of after it is spent. The catalyst may be considered hazardous waste and require special treatment or disposal; and even if it is not hazardous, it will add to the use of landfills.

Economic Impacts

The engine manufacturers being considered currently install oxidation catalysts as standard equipment on the RICE that combust natural gas. Since oxidation catalysts are standard equipment on the engine, there is no annualized cost of the control.

**Because the oxidation catalyst comes standard on the RICE and because oxidation catalysts represent the highest level of control for VOC, oxidation catalysts are BACT for the RICE.**

#### 6.6.4.3 Combustion Control

Energy, Environmental, and Economic Impacts

Combustion controls are an inherent control designed to reduce pollution and increase efficiency of the engines. There are no energy, environmental, or economic impacts from this process. There is no "add-on" equipment associated with this control technology, and there is no capital cost associated with this control.

**Because there are no adverse energy, environmental, or economic impacts associated with this process, combustion controls are BACT for the RICE.**

### 6.6.5 STEP 5. VOC BACT Emission Limitation

With the good combustion controls and oxidation catalysts, these engines will achieve VOC emission rates of 2.67 lb/hr at loads of 50 percent and higher (which is equivalent to 0.10 g/bhp-hr at full load).

The use of good combustion practices that control the amount of excess air in the flue gas along with the added control of an oxidation catalyst will meet a VOC emission limitation of 2.67 lb/hr for steady state operation, based on RICE vendors guaranteed emission rate. This BACT emission limitation is equivalent to 0.10 g/hp-hr for loads of 50 percent and higher. This is the lowest-in-class emission rate that can be achieved for these types of natural gas RICE EGUs.

## 6.7 BACT for Particulate Matter ($PM/PM_{10}/PM_{2.5}$) – RICE

### 6.7.1 STEP 1. Identify Potential Control Strategies

$PM/PM_{10}/PM_{2.5}$ emissions from natural gas combustion sources consist of several components: a) inert contaminants in natural gas; b) sulfates from fuel sulfur or mercaptans used as odorants, c) dust drawn in from the ambient air, and d) particulate of carbon and hydrocarbons resulting from incomplete combustion. Therefore, units firing fuels with low ash content and high combustion efficiency exhibit correspondingly low particulate emissions.

Because of their extremely low particulate concentrations and resulting large costs per ton of particulate matter removed, post-combustion controls, such as electrostatic precipitators (ESPs) or baghouses, have not been applied to commercial gas-fired engines. In addition, no vendors of the RICE to be used for the Project have identified any similar engines that have particulate control devices. Therefore, the use of ESPs and baghouse filters are both technically infeasible and do not represent an available control technology.

In the absence of add-on controls, the most effective control method demonstrated for gas engines is the use of low ash fuel, such as natural gas, and combustion controls. This was confirmed by a survey of the RBLC database (Table D-4) which disclosed no add-on $PM/PM_{10}/PM_{2.5}$ control technologies for the RICE to be used for this Project. **Because proper combustion control and the firing of fuels with negligible or zero ash content (such as natural gas) are the only control methods, they are BACT for the RICE. Further control technology is not necessary or appropriate.**

### 6.7.2 STEP 5. $PM/PM_{10}/PM_{2.5}$ BACT Emission Limitation

The use of low ash fuels and good combustion control will limit steady state $PM/PM_{10}/PM_{2.5}$emissions to 2.22 lb/hr, based on the guarantees from RICE engine vendors. **Therefore, the BACT emission limitation for $PM/PM_{10}/PM_{2.5}$ emissions from the RICE is 2.22 lb/hr. This limitation includes both filterable and condensable $PM/PM_{10}/PM_{2.5}$ emissions. Filterable PM emissions will not exceed 0.07 g/kWh.**

## 6.8 BACT For Greenhouse Gases (GHG) – RICE

### 6.8.1 Introduction

As of January 2, 2011, EPA required the States to begin permitting GHG emissions from major sources in concert with EPA's June 3, 2010 Tailoring Rule.

In March 2011, EPA finalized guidance to assist permit writers and permit applicants in addressing the PSD and Title V permitting requirements for GHGs.[14] This guidance document: (1) describes, in general terms and through examples, the requirements of the PSD and Title V permit regulations; (2) reiterates and emphasizes relevant past EPA guidance on the PSD and Title V review processes for other regulated air pollutants; and (3) provides additional recommendations and suggested methods for meeting the permitting requirements for GHGs to be considered by the States, which are illustrated by examples.

### 6.8.2 Summary of GHG BACT – RICE

The following is BACT for GHG emissions from the RICE:

1. Use of lean-burn, four-stroke, internal combustion engine generating technology to generate up to 94 MW while maximizing the greatest amount of "economic dispatch" power from each unit of fuel combusted

[14] See PSD and Title V Permitting Guidance for Greenhouse Gases, U.S. EPA, Office of Air Quality Planning and Standards, March 2011.

2. Use of natural gas as the only fuel in the RICE

### 6.8.3 STEP 1 and STEP 2. Identify Potential Control Strategies and Eliminate Technologically Infeasible Options

Steps 1 and 2 of the top-down method are presented together in this analysis. Table 6-10 summarizes the potentially available control technologies for GHG and those that have been eliminated and/or included for consideration as BACT for the project.

**Table 6-10. Summary of Potential GHG Control Technologies**

| GHG Technology | Evaluation Status |
|---|---|
| Add-on GHG controls | Considered (Not Feasible) |
| Good combustion design | Considered and Applied |
| **VOLUNTARY CONSIDERATIONS** | |
| Inherently lower-emitting GHG processes, practices, or designs | Considered and Applied |
| Renewable energy technology (solar or wind) | Considered (Not Feasible) |
| Alternative generating technologies | Considered (Not Feasible) |
| Alternative fuels | Considered (Not Feasible) |
| Energy efficiency | Considered and Applied |
| Carbon capture and sequestration (CCS) | Considered (Not Feasible) |

Unlike other regulated air pollutants, which can be reduced by controlling the combustion process or through addition of add-on controls, there is at this time no corresponding way to reduce the amount of $CO_2$ generated during combustion, as $CO_2$ is an inherent product of the chemical reaction between the fuel and oxygen in which it burns. As such, the only way to reduce the amount of $CO_2$ generated by a fuel-burning power plant is to design and operate it through the use of the most efficient generating technologies for the anticipated load requirement.

Emissions of $CO_2$ during fossil fueled combustion are strongly correlated to the amount of carbon in the fuel stream. As stated above, a fundamental objective of the Project is to utilize pipeline quality natural gas. Thus, specification of any other fuel would take away a Project objective. That said, in comparison to all other potential fuels, natural gas will achieve the lowest emissions of $CO_2$ and other GHG. Natural gas combustion produces only about half as much $CO_2$ as coal and substantially less emissions of both criteria

and toxic air pollutants (see EPA's AP-42 for emission rates for coal (Section 1.1) and natural gas (Section 1.4) for a comparison on emissions).[15] Based on the Project design size and objectives and the analysis presented herein, TradeWind has determined that reciprocating engine technology (firing natural gas and with RICE sizes between 4 to 10 MW)) constitutes the most efficient electric generating technology available for the Project.

TradeWind considered both renewable energy technologies (hydroelectric processes, geothermal power processes, energy from biomass, solar energy, wind energy) and other fossil-fuel energy technologies (conventional boiler and steam turbine, conventional simple-cycle combustion turbine, conventional combined-cycle power plant and advanced combustion turbine designs). In every case, however, these alternative generating technologies fail to meet fundamental Project objectives and/or were not technically feasible at the proposed scale (up to 94 MW) and were therefore eliminated from consideration.

A comparison of emissions rate factors for the various fuels as presented in Table 6-11 shows that natural gas, when used as a fuel in stationary sources, typically produces less $CO_2$ than other fuels.

**Table 6-11. $CO_2$ Emission Factors for Various Fuels**

| Fuel | Stationary Source Factors | |
|---|---|---|
| | CCAR (lb/gal) | CCAR [pound per million British thermal units (lb/MMBtu)] |
| Nat Gas | 15.12 | 116.98 |
| LNG | 9.63 | - |
| LPG | 13.11 | 139.24 |
| Diesel #2 | 22.38 | 161.27 |
| Gasoline | 19.55 | - |
| Residual Oil | 25.99 | 173.72 |
| Propane | 12.57 | 139.04 |
| Biodiesel | 20.99 | - |
| Wood-Biomass | - | 200.49 |
| Kerosene | 21.54 | 159.41 |
| Coal | - | 206.04 |

Source: California Climate Action Registry (CCAR), General Protocol, V3.1, 1/2009, and Power Sector Protocol, V1.1, May 2009.

[15] EPA. Compilation of Air Pollutant Emission Factors, Fifth Edition. (AP-42), Section 3.2 (7/00).

#### 6.8.3.1 Carbon Capture and Sequestration

Carbon capture, compression, transport, and storage are the terms typically used to describe a series of technologies designed to capture $CO_2$ emitted from industrial and energy-related sources before it enters the atmosphere, compressing it to supercritical pressures, injecting it deep underground in secure geological formations, and then ensuring it remains stored there indefinitely.[16] The EPA generally considers CCS to be an "available" add-on pollution control technology for facilities emitting $CO_2$ in large amounts and industrial facilities with high-purity $CO_2$ streams.[17] However, EPA also recognizes that CCS may not be an available option in all cases.[18]

The RICE units proposed for Lacey Randall are such a source where CCS is not an available technology. Current post-combustion $CO_2$ capture processes (e.g., amine systems) that may potentially be applicable to the Lacey Randall RICE are complicated chemical processes that do not lend themselves to the rapid cycling and ramp rates associated with the Lacey Randall facility, which is discussed above. Additionally, they have never been demonstrated on the exhaust of a natural gas fired RICE at any scale. There is not a single reference plant design that describes exactly what such systems might include for such a source, nor to our knowledge has one been conceived. The BACT process does not require a source to consider unavailable technology that would require research and development before it can be designed, tested and deployed.

Unlike the sources where EPA has concluded that CCS is technically available, the exhaust gases from the individual RICE sources at Lacey Randall will neither be continuous, of large amounts, nor of a high-purity $CO_2$ concentration. The full load PTE of each of the ten individual RICE sources would be less than 41,000 tons per year, and the $CO_2$ concentration will be only about 6% of the gas stream. Further, even if the individual RICE exhaust gas streams were combined, the $CO_2$ concentration in such streams would be expected to vary from less than 4.7 tons/hour (1 RICE) to as much as 47 tons/hour (ten RICE), making it difficult to design a system to handle such a wide range.

[16] In the alternative, $CO_2$ injected into oil-bearing formations at supercritical pressures is useful in tertiary oil recovery operations. $CO_2$ has been used for these purposes, primarily in the Permian basin of Texas, for over two decades. Studies for similar utilization have been suggested to the U.S. Department of Energy for Kansas oil fields, but decisions for funding this research have been declined in favor of those in central Oklahoma. While EOR has been in use for many years, its purpose has not been the indefinite storage of $CO_2$ and therefore it is unknown whether current EOR practices result in the actual removal of the $CO_2$ from the atmosphere or simply transfers the release to a different location. EPA has raised these very issues in their evaluation of EOR as CCS.

[17] EPA. PSD and Title V Permitting Guidance for Greenhouse Gases (EPA-457/B-11-001). March 2011. Page 35.

[18] EPA. PSD and Title V Permitting Guidance for Greenhouse Gases (EPA-457/B-11-001). March 2011. Page 36.

Nonetheless, TradeWind has attempted to identify the type and components of such as system. TradeWind has been unable to find a chilled-ammonia capture system that would have applicability at Lacey Randall. None of these have been particularly successful and none are currently being operated in the U.S. A $CO_2$ capture plant for Lacey Randall might be more like an amine system such as those that have been used in stripping small amounts of very-low concentration $CO_2$ in natural gas cryogenic processing plants. These types of systems have never been installed experimentally in any power application. Further these unproven, untried systems would have to be deployed ten times at Lacey Randall, once for each engine, just as the $NO_x$, CO, and VOC control technologies that are being deployed on each of the ten units.

An amine plant would require several additional plant systems, including the provision of relatively large amounts of steam. Since simple Otto-cycle engines like the proposed RICE do not produce steam, the cycle would either need to be augmented with auxiliary boilers or combined with substantial heat recovery systems, duct burners, or other regenerative-type heaters. It takes 6 to 12 hours to place a typical amine system in service. In addition, relatively large amounts of cooling water, associated water and wastewater treatment systems, a very large cooling tower system (not unlike that found in a typical steam plant for recirculation of the cooling water), an exhaust gas amine-based $CO_2$-absorber to strip the $CO_2$ from the engine exhaust, a chemical $CO_2$-desorber to regenerate amine for reuse, as well as substantial amounts of piping and mass and heat transfer systems between the various pieces of equipment would at a minimum be required for a $CO_2$ amine-based capture system.

Furthermore, once the $CO_2$ is captured, large compressors, including variable speed compressors to account for the variable $CO_2$ capture rates, must be used to compress $CO_2$ to supercritical pressure conditions before discharging it into a special high-pressure pipeline for reuse in enhanced oil recovery operations or disposal in deep injection wells for sequestration. But, as previously stated, such a system has not been demonstrated for a source like the proposed Lacey Randall Station and would require considerable research and development with no guarantee that it would be successful.

But for the analysis above, in which TradeWind found that CCS is not an available technology, TradeWind would have reached the same conclusion that was reached by every other proposed project for which it was evaluated under BACT. No other power production facility – peaking or otherwise (including natural gas combined-cycle), no natural gas compressor station or processing facility, nor any ethanol-producing facility or other major source sector has concluded that CCS is feasible (Step 2) or affordable (Step 4) in any BACT analysis prepared for this purpose.

For all the reasons provided above, CCS is not an available control technology for the Project.

### 6.8.4 STEP 3. Rank the Technically Feasible Control Technologies

The amount of $CO_2$ and other GHGs emitted during combustion of fossil fuels is directly correlative to the amount of fuel consumed, which in turn is correlative to the specific types of electrical and auxiliary demands being met by the technology. Thus, the only available means of reducing emissions of $CO_2$ from the generation of power is to reduce the amount of fuel consumed per unit of energy or auxiliary service generated. Accordingly, a comparison of various generating technologies' relative efficiency – or operational design, expressed in terms of "heat rate" – provides an appropriate basis for comparing and ranking the control efficiency of such technologies. For the Project, the only fuel to be used in the power generation cycle will be natural gas. In addition, the efficient use of that fuel in a 94-MW plant meeting the Project design objectives needs to be factored into that initial control efficiency ranking. The Project therefore will minimize GHG emissions in its generation of firm, quick, start and stop, dispatchable power by using natural gas and highly efficient RICE technology with a low heat rate and high efficiency across the Project's entire load range. The high efficiency and operational design aspects of the RICE technology includes the following; lean-burn four-stroke combustion configuration employing spark ignition in the Otto process, use of clean fuels, air-to-fuel ratio control, turbocharger technology, open interface cooling system, and a lube oil cooling system designed as an integral part of the engine.

Table 6-12 presents a generalized ranking of the identified generation technologies based on their known ranges of heat rates, as considered in the BACT analysis for this Project.

**Table 6-12. Ranking of Potential Generating Technologies by Heat Rate**

| Technology | Heat Rate Range (HHV basis) | Technologically Feasible for This Project? |
|---|---|---|
| Renewable energy sources | n/a | No |
| Nuclear power | n/a | No |
| Biomass and other biofuels | n/a | No |
| CCS | n/a | No |
| Combined cycle turbines | ~7000-8000 Btu/Kw-hr | Yes |
| Reciprocating IC engines | ~7500-8600 Btu /Kw-hr | Yes |
| Simple cycle turbines | ~8500-10000 Btu /Kw-hr | Yes |
| Boilers | >10000 Btu /Kw-hr | No |

Notably, simple-cycle combustion turbine technology generally has a higher heat rate than reciprocating engine technology. Table 6-13 presents a comparison of various power plant facility heat rates and GHG performance.

**Table 6-13. Power Plant Heat Rates and GHG Performance**

| Facility | Heat Rate, Btu/kWh | Est. Energy Output, GWh[A] | GHG Performance, $MTCO_2/MWh$ |
|---|---|---|---|
| TradeWind Lacey Randall | 8,386 | 818 | ~0.499 |
| Mid-Kansas Rubart Project (RICE) | 7,860 | ~2,100 | ~0.484 |
| Quail Brush (RICE) | 8,600 | ~412 | ~0.464 |
| Lea County (RICE) | 8,596 | 350 | 0.484 |
| EME Walnut (SC) | 8,595 | 2,000 | 0.481 |
| Mariposa Energy (SC) | 9,450 | 800 | 0.541 |
| Fremont Energy (CC) | 7,161 | 3,000 | 0.381 |
| SMEPA – Moselle (CC) | 8,410 | 2,628 | 0.379 |
| Gateway GS (CC) | 7,123 | 2,490 | 0.378 |
| Los Medanos EC (CC) | 7,184 | 3,395 | 0.381 |
| Delta EC (CC) | 7,308 | 5,014 | 0.387 |
| CCPP #6 (Boiler) | 13,499 | 21 | 0.716 |
| CCPP #7 (Boiler) | 11,182 | 177 | 0.593 |

RICE-reciprocating internal combustion engine(s), CC – combined cycle combustion turbine, SC – simple cycle combustion turbine, Boiler – gas-fired boiler

[A] Dependent upon purchase power agreement and actual facility dispatch. Values represent operations as limited by permit conditions.

At the present time, combined cycle plants utilizing efficient turbines, HRSGs, and clean fuels represent the highest efficiencies with respect to fuel burned versus power produced for large scale, firm base load, and moderate cycling power resources. However, because a 500-700 MW combined cycle plant does not meet the Project design objectives (quick start and stop, up to 94 MW, low water use for cooling, partial and full load operation) and the site space, fuel and electric interconnection limitations, a combined cycle plant does not meet the Project's objectives.

As previously discussed, fast-start capabilities are currently only available for much larger turbines than would be needed to meet the Project's proposed capacity of up to 94 MW (the 300 MW Siemens SCC6-500F and GE 7FA Response System). Operation of a larger turbine at only a fraction of its capacity would result in significant losses in efficiency, such that the efficiency of the combined-cycle plant would likely be even less than a smaller simple-cycle plant. Further, although once-through steam generators (OTSG) might be used in-lieu-of conventional HSRG technology, the addition of a steam cycle to a plant only intended only for economic dispatch generation likely would provide only marginal-to-no-efficiency

gains, in comparison to a simple-cycle operation. Thus, for an economic dispatch plant that will undergo multiple daily start-ups, the steam cycle would likely provide no to marginal benefit while not meeting the Project's objectives regarding fast start and cycling capability.

For peaking and economic dispatch power production, simple cycle turbines and RICE typically represent the systems of choice due to the flexibility in overall operations, *i.e.*, fast start-up times, fast power ramp-up times, ability of air pollution control systems to reach optimum performance levels within short periods of time, and ability to vary loads versus demand. This last attribute — the ability to change load swiftly in response to demand — is more characteristic of RICE than simple-cycle turbines. Thus, a compelling advantage to the Project design in using several RICE, as opposed to one or two combustion turbines, is the wide range of dispatch scenarios that the Project can achieve.

Table 6-14 shows the flexibility of the system for a set of some selected operational loads between 5 and 94 MW. Note that any number of engines may operate from loads of 50 to 100% and from one to ten engines may be operating at any time. This provides a significantly wide range of load levels available for the Project.

**Table 6-14. Power Supply Sample Scenarios**

| # Engines | Load vs. MW | | | | # of Engines Operating |
|---|---|---|---|---|---|
| | 50% | 75% | 85% | 100% | |
| 1 Engine | | | | | |
| MWs | 4.7 | 7.0 | 7.9 | 9.3 | 1 |
| 3 Engines | | | | | |
| MWs | 14.0 | 21.0 | 23.8 | 28.0 | 3 |
| 5 Engines | | | | | |
| MWs | 23.4 | 35.0 | 39.7 | 46.7 | 5 |
| 7 Engines | | | | | |
| MWs | 32.7 | 49.0 | 55.6 | 65.4 | 7 |
| 10 Engines | | | | | |
| MWs | 46.7 | 70.1 | 79.4 | 93.4 | 10 |

The flexibility of the engines to produce a wide range of power output is evident from the above basic load vs. MW table. The lowest typical load is 50% for any single engine. Each engine can be run at numerous load levels above 50%. The engines will be dispatched per the power purchase agreement or contract which may differ in load scenarios from the above noted values in the table.

In comparison, use of simple-cycle gas turbines to meet the Project's demand, such as a single one-frame-size 94-MW combustion turbine or several aeroderivatives (50 MW size) would not afford the same degree of flexibility as the multiple dispatch scenarios noted above for the reciprocating engines by . Moreover, as indicated by Table 6-12, RICE, such as those proposed for this Project, have a lower heat

rate than simple-cycle combustion turbines. For these reasons the use of a simple-cycle gas turbine was rejected from further consideration.

As indicated above, a critical component of GHG BACT for the Project includes the use of clean fuels. The Project will use pipeline quality natural gas as the only fuel for power generation. Thus, the use of clean fuels, *i.e.*, fuels which inherently have lower $CO_2e$ emissions, becomes an integral part of the overall GHG BACT applied to the Project.

Beyond consideration of the power generation, another critical component of the GHG BACT analysis is the efficiency of load-consuming elements of the overall plant design. The more efficiently the plant consumes energy, the more energy that can be provided to the grid, resulting in lower emissions of GHGs per MWh of energy provided to the grid. As a consequence, TradeWind will also consider the efficiency of other major components through prudent engineering and design protocol for the Project design.

Table 6-15 presents the ranking of the GHG technologies deemed feasible for the Project. While these three technologies are "ranked" in order of their presentation, they are more appropriately considered as a suite of measures that will be implemented to assure that the Project generates and consumes power in the most efficient manner and thereby achieves BACT for GHGs.

**Table 6-15. GHG Technology Ranking for the Project**

| Technology | Ranking | Applied to Project |
|---|---|---|
| Reciprocating Engines (employing state-of-the-art design) | 1 | Yes |
| Clean Fuels | 2 | Yes |
| Energy Efficiency/Operational Design | 3 | Yes |

**For the reasons discussed above, the RICE power generation system utilizing efficient engine designs and firing natural gas is the most efficient system in terms of GHG emissions for the Project and therefore is BACT for those emissions.**

## 6.8.5 STEP 4. Evaluate the Most Effective Control Technologies

### 6.8.5.1 Environmental, Energy, and Economic Feasibility of Control Options

Because the Project will utilize all three of the feasible technologies for reducing GHGs from the generation of power, no detailed analysis is provided to compare the available control technologies' relative environmental, energy and economic impacts.

### 6.8.6 STEP 5. GHG BACT Emission Limitation

The technology selected as BACT at Step 4 must be translated into an enforceable emissions limitation by KDHE. In its March 2011 Guidance, EPA encouraged permitting authorities to consider establishing output-based limits or a combination of both output- and input-based limits.[19] EPA noted that, because the environmental concern related to GHG emissions is their cumulative impacts, the focus in establishing limits should be on longer-term averages, e.g., 12-month or 365-day rolling average, rather than short-term averages. For the purposes of this BACT analysis, TradeWind has determined that a $CO_2$ emission limitation of 9,330 lb/hr is BACT for the RICE.

## 6.9 BACT for Start-Up and Shut-down Emissions – RICE

### 6.9.1 STEP 1. Identify Potential Control Strategies

Start-up emissions on a lb/hr basis will be higher than during normal steady-state operation because the SCR and oxidation catalysts cannot operate until they reach certain minimum temperatures. Shut-down emissions, though, occur when catalysts are at proper operating temperature.

TradeWind is proposing a limitation of 14,600 start-up/shut-down events total for all engines per year based on long range dispatch model runs for their electrical system. For the purposes of this permit application, it is assumed that all start-ups are “cold start-ups.” This is a very conservative approach as a “cold start-up” has more emissions than a “warm start-up” and TradeWind expects to have many “warm start-ups” due to the expected daily fluctuations in electrical demand. A “cold start-up” is one which requires about 30 minutes of fired-operation for the SCR and CO catalysts to reach their respective minimum operating temperatures and has higher emissions than a “warm start-up” because it takes more time to reach the proper operating temperature required for the catalyst systems.

### 6.9.2 STEP 2. Identify Technically Feasible Control Technologies

Controls that are functional during normal operation are not available to control start-up and shut-down emissions. SCR and CO catalysts require minimum operating temperatures to control emissions (for the catalytic reactions to occur for removal of $NO_x$, CO, and VOC). This temperature is not reached until approximately 30 minutes after the unit is turned on. In addition, the air-to-fuel ratio is highly variable until approximately 20 percent load for the lean-burn combustion. **Therefore, there are no technically feasible control technologies for start-up and shut-down emissions from the RICE.**

[19] PSD and Title V Permitting Guidance for Greenhouse Gases, U.S. EPA, Office of Air Quality Planning and Standards, March 2011, Page 46.

### 6.9.3 STEP 3. Rank the Technically Feasible Control Technologies

Because there are no technically feasible control technologies for start-up and shut-down emissions, Step 3 is not applicable.

### 6.9.4 STEP 4. Evaluate the Most Effective Control Technologies

#### 6.9.4.1 Energy, Environmental, and Economic Feasibility of Control Options

Because there are no technically feasible control technologies for start-up and shut-down emissions; Step 4 is not required.

### 6.9.5 STEP 5. Start-up and Shut-down BACT Determination

Table 6-16 sets forth the BACT levels for start-up and shut-down emissions. These units start-up quickly and will come into compliance with full load /controlled emission rates quickly compared to other types of technologies. The emission rates presented are based on vendor information regarding start-up and shut-down emissions and are consistent with the emission limitations for units similar to the Project's RICE. The RICE will take up to 30 minutes for the engines to reach the proper temperatures for the SCR and CO catalysts to operate to their full potential.

**Table 6-16. Start-up Emissions Per RICE**

| Pollutant | lb/Start-up per Engine | Start-up Emissions per Engine (TPY)[A] |
|---|---|---|
| $NO_x$ | 11.24 | 8.21 |
| CO | 0.05 | 0.017 |
| $PM/PM_{10}/PM_{2.5}$ | 8.38 | 6.12 |
| VOC | 1.54 | 1.13 |
| $SO_2$ | 1.54 | 1.13 |
| $H_2SO_4$ Mist | 2.87 | 2.09 |
| $CO_2e$ | 9,329.27 | 3,405.19 |

[A] Based on 14,600 start-ups and 14,600 shut-downs per year total for all engines.

## 6.10 BACT for the Gas Heater

The gas heater which heats the gas before it enters the engines will be fired by natural gas. The gas heater is a 3.0 MMBtu/hr heater that will operate 8,760 hours per year. The RBLC has limited BACT information for gas heaters (Table D-5). The RBLC tables also show high variability for emission

limitations for each pollutant. No add-on controls are listed for any pollutant because gas heaters are so small.

### 6.10.1 BACT for Nitrogen Oxides ($NO_x$) – Gas Heater

#### 6.10.1.1 STEP 1. Identify Potential Control Strategies

The only add-on $NO_x$ control technique available for a unit this size is an SCR system. The SCR process for removal of $NO_x$ is described in Section 6.4.2.2. Dry low-$NO_x$ burners are available and are standard on most gas heaters. Dry low-$NO_x$ burners, along with combustion controls, are identified as BACT in the RBLC for the gas heaters that were identified. $NO_x$ emission limitations listed in the RBLC range from 0.01 to 0.37 lb/MMBtu for similar sized gas heaters utilizing dry low-$NO_x$ burners and combustion controls.

#### 6.10.1.2 STEP 2. Identify Technically Feasible Control Technologies

##### 6.10.1.2.1 SCR

Although the RBLC did not identify any add-on control devices as BACT for gas heaters, one SCR vendor said that they could provide an SCR for this size engine. The vendor's guaranteed $NO_x$ removal efficiency for this size unit is 90 percent.

**Based on this vendor information, an SCR system is technically feasible for the gas heater.**

##### 6.10.1.2.2 Dry Low-$NO_x$ Burners

Dry, low-$NO_x$ burners are currently available from most gas heater manufacturers. This technology reduces combustion temperatures, thereby reducing $NO_x$. In a conventional combustor, the air and fuel are introduced at an approximately stoichiometric ratio, and air/fuel mixing occurs at the flame front where diffusion of fuel and air reaches the combustible limit. A dry low-$NO_x$ burner is designed to premix the fuel and air prior to combustion. Premixing results in a homogenous air/fuel mixture, which minimizes localized fuel-rich pockets that produce elevated combustion temperatures and resulting higher $NO_x$ emissions. A lean air-to-fuel ratio approaching the lean flammability limit is maintained, and the excess air serves as a heat sink to lower combustion temperatures, which lowers $NO_x$ formation. A pilot flame is used to maintain combustion stability in this fuel-lean environment.

**Because dry low-$NO_x$ burners are standard on gas heaters, they are considered both baseline and technically feasible for the gas heater and therefore are BACT.**

#### 6.10.1.2.3 Combustion Control

"Good combustion practices" include operational and design elements to control the amount and distribution of excess air in the flue gas to ensure that there is enough oxygen present for complete combustion.

**Therefore, combustion control is both considered baseline and technically feasible for the gas heater, and is BACT.**

### 6.10.1.3 STEP 3. Rank the Technically Feasible Control Technologies

The technically feasible $NO_x$ control technologies for the 3-MMBtu/hr gas heater are ranked by control effectiveness in Table 6-17.

**Table 6-17. Ranking of $NO_x$ Control Technologies for the Gas Heater**

| Control Technology | Reduction (%) | Controlled Emission Level (lb/MMBtu [lb/hr]) |
|---|---|---|
| SCR | 90 | 0.01 [0.02] |
| Dry Low-$NO_x$ Burners and Combustion Control[A] | Not applicable (baseline) | 0.10 [0.20] |

[A]Based on vendor data.

### 6.10.1.4 STEP 4. Evaluate the Most Effective Control Technologies

Each technically feasible control technology was evaluated for energy, environmental, and economic impacts. These impacts are discussed below for each control technology.

#### 6.10.1.4.1 SCR

Energy and Environmental Impacts

Energy and environmental impacts for an SCR system are discussed in Section 6.4.4.2.

Economic Impacts

The capital costs associated with an SCR system for the gas heater are shown in Table E-1. The overall initial capital cost of installing an SCR system on the gas heater is approximately $39,921. The annualized costs associated with an SCR system on the gas heater are shown in Table E-2. On an annual basis, the SCR system would cost $88,251, which results in a cost per ton of $NO_x$ removed of $77,197 while removing only 1.1 tons of $NO_x$ per year. Therefore, any control of $NO_x$ by add-on controls would result in costs that would not be economical.

**An SCR for the gas heater is not economically feasible.**

#### 6.10.1.4.2 Dry Low-$NO_x$ Burners and Combustion Control

Energy, Environmental, and Economic Impacts

Because dry low-$NO_x$ burners are standard on most gas heaters and combustion control is accomplished through operation of the gas heater, there are no incremental energy, environmental, or economic impacts associated with these controls.

**Low-$NO_x$ burners and combustion control is BACT for the gas heater.**

### 6.10.1.5 STEP 5. $NO_x$ BACT Emission Limitation

The low $NO_x$ burners of the gas heater can achieve an emission rate of 0.29 lb/hr during steady state operation. **Therefore, 0.29 lb/hr is the BACT emission limitation for $NO_x$ emissions from the gas heater.**

## 6.10.2 BACT for Carbon Monoxide (CO) – Gas Heater

### 6.10.2.1 STEP 1. Identify Potential Control Strategies

The RBLC does not list add-on controls in the BACT determinations for control of CO emissions from gas heaters. However, one control vendor has indicated that a CO catalyst system may be used on a gas heater this size. Good combustion control will help control emissions of CO from the gas heater. Therefore a CO catalyst system and good combustion control are available technologies.

### 6.10.2.2 STEP 2. Identify Technically Feasible Control Technologies

#### 6.10.2.2.1 Oxidation Catalyst System

One control vendor has indicated that a CO catalyst system may be used on a gas heater this size. The CO catalyst system is an add-on control that converts VOC and CO to $CO_2$ by use of a catalyst. Section 6.5.2.1 describes the CO catalyst system for gas-fired units.

**Because one vendor has provided a quote for such a system, an oxidation catalyst system is technically feasible for the gas heater.**

#### 6.10.2.2.2 Combustion Control

“Good combustion practices” include operational and design elements to control the amount and distribution of excess air in the flue gas to ensure that there is enough oxygen present for complete combustion.

**Good combustion practices are a technically feasible method of controlling CO emissions from the gas heater and therefore are BACT for the gas heater.**

### 6.10.2.3 STEP 3. Rank the Technically Feasible Control Technologies

The technically feasible CO control technologies for the 3.0 MMBtu/hr gas heater are ranked by control effectiveness in Table 6-18.

**Table 6-18. Ranking of CO Control Technologies for the Gas Heater**

| Control Technology | Reduction (%) | Controlled Emission Level (lb/MMBtu [lb/hr]) |
|---|---|---|
| Oxidation Catalyst | 90 | 0.008 [0.025] |
| Combustion Control[A] | Not applicable (baseline) | 0.08 [0.25] |

[A]Based on vendor data.

### 6.10.2.4 STEP 4. Evaluate the Most Effective Control Technologies

Each technically feasible add-on control technology was evaluated for energy, environmental, and economic impacts. These impacts are discussed below for each control technology.

#### 6.10.2.4.1 Oxidation Catalyst

Energy and Environmental Impacts

Energy and environmental impacts of an oxidation catalyst are discussed in Section 6.5.4.2.

Economic Impacts

The control cost analysis for an oxidation catalyst system for the gas heater is shown in Tables E-3 and E-4. An oxidation catalyst system for this size unit would require an initial capital cost of $9,484. The annual costs of operating this CO catalyst system would be $29,478. On an annual basis, only 0.99 tons per year (at 90 percent removal) of CO would be removed (along with only 0.04 tons per year of VOC removed) at a cost of almost $28,874 per ton of pollutants removed.

**An oxidation catalyst for control of CO emissions from the gas heater is not economically feasible. Therefore, as noted at Step 2, BACT for the gas heater is the use of good combustion practices.**

### 6.10.2.5 STEP 5. CO BACT Emission Limitation

Good combustion practices will achieve an emission rate of 0.16 lb/hr during steady state operation of the gas heater. **Therefore, the BACT emission limitation for CO emissions from the gas heater is 0.16 lb/hr.**

### 6.10.3 BACT for Volatile Organic Compounds (VOC) – Gas Heater

#### 6.10.3.1 STEP 1. Identify Potential Control Strategies

The RBLC does not list add-on controls for gas heaters in the BACT determinations for control of VOC emissions from gas heaters. However, one control vendor has indicated that a CO catalyst system may be used on a gas heater this size. As with CO, good combustion control will help control emissions of VOC from the gas heater. Therefore, a CO catalyst system and good combustion control are available technologies.

#### 6.10.3.2 STEP 2. Identify Technically Feasible Control Technologies

##### 6.10.3.2.1 Oxidation Catalyst System

One control vendor has indicated that a CO catalyst system may be used on a gas heater this size. The CO catalyst system is an add-on control that converts VOC and CO to $CO_2$ by use of a catalyst. Section 6.3.2.1 describes the CO catalyst system for gas-fired units.

**Because one vendor has provided a quote for this system, an oxidation catalyst system is technically feasible for the gas heater.**

##### 6.10.3.2.2 Combustion Control

"Good combustion practices" include operational and design elements to control the amount and distribution of excess air in the flue gas to ensure that there is enough oxygen present for complete combustion.

**Good combustion practices are a technically feasible method of controlling VOC emissions from the gas heater and are therefore BACT for the gas heater.**

#### 6.10.3.3 STEP 3. Rank the Technically Feasible Control Technologies

The technically feasible VOC control technologies for the 3.0 MMBtu/hr gas heater are ranked by control effectiveness in Table 6-19.

**Table 6-19. Ranking of VOC Control Technologies for the Gas Heater**

| Control Technology | Reduction (%) | Controlled Emission Level (lb/MMBtu [lb/hr]) |
|---|---|---|
| Oxidation Catalyst | 50 | 0.003 [0.008] |
| Combustion Control[A] | Not applicable (baseline) | 0.005 [0.016] |

[A] Based on vendor data.

#### 6.10.3.4 STEP 4. Evaluate the Most Effective Control Technologies

Each technically feasible add-on control technology was evaluated for energy, environmental, and economic impacts. These impacts are discussed below for each control technology.

##### 6.10.3.4.1 Oxidation Catalyst

Energy and Environmental Impacts

Energy and environmental impacts of an oxidation catalyst are discussed in Section 6.5.4.2.

Economic Impacts

The control cost analysis for an oxidation catalyst system for the gas heater is shown in Tables E-3 and E-4 and discussed in Section 6.10.2.4.1. The cost per ton of pollutant removed is almost $28,874.

**An oxidation catalyst for control of VOC emissions from the gas heater is not economically feasible. Therefore, as noted at Step 2, BACT for the gas heater is good combustion practices.**

#### 6.10.3.5 STEP 5. VOC BACT Emission Limitation

Good combustion practices will achieve an emission rate of 0.016 lb/hr during steady state operation of the gas heater. **Therefore, the BACT emission limitation for VOC emissions from the gas heater is 0.016 lb/hr.**

### 6.10.4 BACT for Particulate Matter ($PM/PM_{10}/PM_{2.5}$) – Gas Heater

#### 6.10.4.1 STEP 1. Identify Potential Control Strategies

The RBLC does not list any control strategies other than good combustion practices and low ash fuel (natural gas). No add-on controls were identified for significant removal of these pollutants from the gas heater exhaust.

#### 6.10.4.2 STEP 2. Identify Technically Feasible Control Technologies

The only technically feasible control option for $PM/PM_{10}/PM_{2.5}$, is good combustion practices and low ash fuel. **As these control measures are technically feasible, they are BACT for the gas heater**.

#### 6.10.4.3 STEPS 3-5. $PM/PM_{10}/PM_{2.5}$ BACT Emission Limitation

Good combustion control practices the gas heater can attain an emission rate of 0.022 lb/hr**. Therefore, the BACT emission limitation for $PM/PM_{10}/PM_{2.5}$ emissions from the gas heater is 0.022 lb/hr.**

### 6.10.5 BACT for Greenhouse Gases (GHG) – Gas Heater

The gas heater will be fired exclusively on natural gas and is used to pre-heat that fuel to facilitate rapid starts and meet RICE engine manufacturer requirements. The unit is rated at approximately 3.0 MMBtu/hr, and will be fired a total of 8,760 hours per year. GHG emissions from this unit are estimated to be on the order of 1,537 tons $CO_2e$/yr. These GHG emissions are also *de minimis*, when compared to the RICE engine GHG emissions or the Project total GHG emissions. The basic GHG BACT reasoning presented for the RICE applies to the gas heater as well. GHG BACT for the heater is the following:

- Using clean fuels (exclusive use of natural gas)
- Operating the unit in the most efficient manner possible, i.e. good combustion practices.
- Tuning the unit every two years according to the manufacturer's specifications.
- Recording the annual hours of operation and annual fuel use and reporting GHG emissions annually. GHG emissions from this unit will be included in the facility-wide annual GHG limitation.

## 6.11 BACT for the Emergency Fire Pump

The emergency fire pump (150 hp) will be limited to 100 hours per year of operation and will utilize ULSD fuel oil, with a sulfur content of no more than 0.0015 weight percent. The emergency fire pump will comply with the applicable NSPS (Section 5.2). The RBLC has limited information on BACT determinations for small engines such as the emergency fire pump (Table D-6). The RBLC tables also demonstrate high variability for emission rates for each pollutant. No add-on controls were listed in the RBLC for all pollutants, because the fire pump is emergency and is so small.

### 6.11.1 BACT for Nitrogen Oxides ($NO_x$) – Emergency Fire Pump

#### 6.11.1.1 STEP 1. Identify Potential Control Strategies

The RBLC does not list any control strategies other than good combustion practices for control of NOx emissions from diesel fire pump engines.

#### 6.11.1.2 STEP 2. Identify Technically Feasible Control Technologies

"Good combustion practices" include operational and design elements to control the amount and distribution of excess air in the flue gas to ensure that there is enough oxygen present for complete combustion.

**Combustion control is the only technically feasible control and therefore is BACT for the emergency fire pump.**

#### 6.11.1.3 STEP 5. $NO_x$ BACT Emission Limitation

The fire pump is able to achieve an emission limit of 3.0 g/hp-hr of NOx emissions on an on-going basis. **Therefore, the BACT emission limitation for NOx emissions from the emergency fire pump is 3.0 g/hp-hr.**

### 6.11.2 BACT for Carbon Monoxide (CO) – Emergency Fire Pump

#### 6.11.2.1 STEP 1. Identify Potential Control Strategies

The RBLC does not identify any add-on controls for the fire pump for CO emissions. Therefore, good combustion practices are the only feasible control for the fire pump.

#### 6.11.2.2 STEP 2. Identify Technically Feasible Control Technologies

"Good combustion practices" include operational design elements to control the amount and distribution of excess air in the flue gas to ensure that there is enough oxygen present for complete combustion. **Good combustion practices are a technically feasible method of controlling CO emissions from the fire pump and are considered BACT.**

#### 6.11.2.3 STEPS 3-5. CO BACT Emission Limitation

The fire pump will attain an emission level of 3.7 g/hp-hr for CO with good combustion control. **Therefore, the BACT emissions limitation for CO emissions from the emergency fire pump is 3.7 g/hp-hr.**

### 6.11.3 BACT for Volatile Organic Compounds – Emergency Fire Pump

#### 6.11.3.1 STEP 1. Identify Potential Control Strategies

The RBLC does not identify any add-on controls for the emergency fire pump for VOC emissions. Therefore, good combustion practices are the only feasible control for the fire pump.

#### 6.11.3.2 STEP 2. Identify Technically Feasible Control Technologies

"Good combustion practices" include operational design elements to control the amount and distribution of excess air in the flue gas to ensure that there is enough oxygen present for complete combustion. **Good combustion practices are a technically feasible method of controlling VOC emissions from the fire pump and are BACT.**

#### 6.11.3.3 STEPS 3-5. VOC BACT Emission Limitation

The emergency fire pump is capable of limiting emissions to 3.0 g/hp-hr for VOC. **Therefore, the BACT emissions limitation for VOC emissions from the emergency fire pump is 3.0 g/hp-hr.**

### 6.11.4 BACT for Particulate Matter ($PM/PM_{10}/PM_{2.5}$) – Emergency Fire Pump

#### 6.11.4.1 STEP 1. Identify Potential Control Strategies

The RBLC does not identify any control strategy other than good combustion practices and low ash fuel (natural gas) for the emergency fire pump. No add-on controls were identified for significant removal of these pollutants from the RICE exhaust.

#### 6.11.4.2 STEP 2. Identify Technically Feasible Control Technologies

The only technically feasible control option for $PM/PM_{10}/PM_{2.5}$, is good combustion practices and low ash fuel. **As these control measures are technically feasible, they are BACT for the emergency fire pump**.

#### 6.11.4.3 STEPS 3-5. $PM/PM_{10}/PM_{2.5}$BACT Emission Limitation

The fire pump can limit its emissions to a rate of 0.22 g/hp-hr. **Therefore, the BACT emission limitation for the emergency fire pump is 0.22 g/hp-hr.**

### 6.11.5 BACT for Greenhouse Gases (GHG) – Emergency Fire Pump

The emergency fire pump will be used for no more than 100 hours per year. The design of the diesel fire pump is dictated by the manufacturer, not by TradeWind. As such, TradeWind is limited to commercially available options, which include those engines meeting EPA Tier 3 requirements.

Consistent with the rationale for the BACT determination for GHG emissions from the RICE engines, TradeWind believes that BACT for this source involves selection of the most efficient stationary fire pump engine that can meet the Project's needs. TradeWind has provided information on the emissions from the specified diesel engine in the agency permitting documents. TradeWind has estimated total GHG emissions from the emergency fire pump at 4 tons of $CO_2e$ per year. These GHG emissions also are *de minimi*s when compared to the RICE GHG emissions or the Project total GHG emissions.

TradeWind is unaware of any more fuel efficient alternative to a Tier 3-certified engine for these purposes.

Additionally, operation of this source will be limited to reliability-related activities and TradeWind will be required to keep records of the operation of this source and its fuel usage. Therefore, no additional conditions are required to enforce this GHG BACT determination.

## 6.12 BACT for Emergency Diesel-fired Generator

The emergency diesel-fired generator (324 hp) will be limited to 100 hours per year of operation and will comply with the applicable NSPS. The RBLC has limited information on BACT determinations for small engines such as the emergency diesel-fired generator (Table D-6). The RBLC tables also show high variability for emission rates for each pollutant. No add-on controls for emissions of any pollutant from the emergency generator were listed because generator is so small and has only emergency use.

### 6.12.1 BACT for Nitrogen Oxides ($NO_x$) – Emergency Diesel-fired Generator

#### 6.12.1.1 STEP 1. Identify Potential Control Strategies

The RBLC does not identify any add-on controls for the emergency diesel-fired generator for $NO_x$ emissions. It is assumed that an SCR system is technically feasible, as vendors say that they can provide SCR systems for this small engine.

#### 6.12.1.2 STEP 2. Identify Technically Feasible Control Technologies

##### 6.12.1.2.1 SCR

Although the RBLC did not identify any add-on control devices as BACT for the emergency diesel-fired generator, an SCR vendor has indicated that an SCR system is available for this small engine.

**An SCR system is technically feasible for the emergency diesel-fired generator.**

##### 6.12.1.2.2 Combustion Control

"Good combustion practices" include operational and design elements to control the amount and distribution of excess air in the flue gas to ensure that there is enough oxygen present for complete combustion. **Combustion control is considered baseline for the emergency diesel-fired generator and is technically feasible; therefore, it is BACT.**

#### 6.12.1.3 STEP 3. Rank the Technically Feasible Control Technologies

The technically feasible $NO_x$ control technologies for the emergency diesel-fired generator are ranked by control effectiveness in Table 6-20.

**Table 6-20. Ranking of $NO_x$ Control Technologies for the Emergency Diesel-fired Generator**

| Control Technology | Reduction (%) | Controlled Emission Level (g/hp-hr) |
|---|---|---|
| SCR | 85 | 0.41 |
| Combustion Control | Not applicable (baseline) | 2.7 |

### 6.12.1.4 STEP 4. Evaluate the Most Effective Control Technologies

The technically feasible control technology was evaluated for energy, environmental, and economic impacts. These impacts are discussed below for each control technology.

#### 6.12.1.4.1 SCR

Energy and Environmental Impacts

Energy and environmental impacts for an SCR system are discussed in Section 6.4.4.2.

Economic Impacts

The capital costs associated with an SCR system for the emergency diesel-fired generator are shown in Table E-5. The overall initial capital cost of installing an SCR system on the fire pump is approximately $18,744. The annualized costs associated with an SCR system on the emergency diesel-fired generator are shown in Table E-6. On an annual basis, the SCR system would cost $31,338, which results in a cost per ton of $NO_x$ removed of $247,440 while removing only 0.1 tons of $NO_x$ per year. Therefore, any control of $NO_x$ by add-on controls would result in costs that would not be economical.

A**n SCR for the emergency diesel-fired generator is not economically feasible.**

#### 6.12.1.4.2 Combustion Control

Energy, Environmental, and Economic Impacts

Combustion control is accomplished through operation of the generator. Therefore, there are no energy, environmental, or economic impacts associated with these controls.

### 6.12.1.5 STEP 5. $NO_x$ BACT Emission Limitation

The generator is capable of achieving 2.98 g/hp-hr of $NO_x$ emissions on an on-going basis. **Therefore, the BACT emissions limitation for $NO_x$ emissions from the emergency diesel-fired generator is 2.98 g/hp-hr.**

### 6.12.2 BACT for Carbon Monoxide– Emergency Diesel-fired Generator

#### 6.12.2.1 STEP 1. Identify Potential Control Strategies

The RBLC does not identify any add-on controls for the emergency diesel-fired generator for CO emissions. However, oxidation catalyst vendors have indicated that an oxidation catalyst system is available for small engines, such as the emergency diesel generator, but often foul fast when applied to diesel fired units. Available control technologies include good combustion control and oxidation catalysts for the emergency diesel-fired generator.

#### 6.12.2.2 STEP 2. Identify Technically Feasible Control Technologies

##### 6.12.2.2.1 Oxidation Catalyst System

One control vendor has indicated that a CO catalyst system may be used on an emergency diesel-fired generator this size. The CO catalyst system is an add-on control that converts VOC and CO to $CO_2$ by use of a catalyst. Section 6.5.2.1 describes the CO catalyst system for gas-fired units.

**Because a vendor has provided a quote for such a system, an oxidation catalyst system is considered technically feasible for the emergency diesel-fired generator.**

##### 6.12.2.2.2 Combustion Control

"Good combustion practices" include operational and design elements to control the amount and distribution of excess air in the flue gas to ensure that there is enough oxygen present for complete combustion.

**Good combustion practices are a technically feasible method of controlling CO emissions from the emergency diesel-fired generator and therefore are BACT for the emergency diesel-fired generator.**

#### 6.12.2.3 STEP 3. Rank the Technically Feasible Control Technologies

The technically feasible CO control technologies for the emergency diesel-fired generator are ranked by control effectiveness in Table 6-21.

**Table 6-21. Ranking of CO Control Technologies for the Emergency Diesel-fired Generator**

| Control Technology | Reduction (%) | Controlled Emission Level (g/hp-hr) |
|---|---|---|
| Oxidation Catalyst | 80 | 0.14 |
| Combustion Control | Not applicable (baseline) | 0.7 |

### 6.12.2.4 STEP 4. Evaluate the Most Effective Control Technologies

Each technically feasible add-on control technology was evaluated for energy, environmental, and economic impacts. These impacts are discussed below for each control technology.

#### 6.12.2.4.1 Oxidation Catalyst

Energy and Environmental Impacts

Energy and environmental impacts of an oxidation catalyst are discussed in Section 6.5.4.2.

Economic Impacts

The control cost analysis for an oxidation catalyst system for the emergency diesel-fired generator is shown in Tables E-7 and E-8. An oxidation catalyst system for this size unit would require an initial capital cost of $4,598. The annual costs of operating this CO catalyst system would be $2,441. On an annual basis, only 0.02 tons per year (at 80 percent removal) of CO would be removed (along with only 0.01 tons per year of VOC removed) at a cost of $96,678 per ton of pollutants removed.

**An oxidation catalyst for control of CO emissions from the emergency diesel-fired generator is not economically feasible. Therefore, as noted at Step 2, BACT for the emergency diesel-fired generator is the use of good combustion practices.**

### 6.12.2.5 STEP 5. CO BACT Emission Limitation

Good combustion practices will achieve an emission rate of 2.61 g/hp-hr during steady state operation of the emergency diesel-fired generator. **Therefore the BACT emission limitation for CO emissions from the emergency diesel-fired generator is 2.61 g/hp-hr.**

### 6.12.3 BACT for Volatile Organic Compounds – Emergency Diesel-fired Generator

#### 6.12.3.1 STEP 1. Identify Potential Control Strategies

The RBLC does not identify any add-on controls for the emergency diesel-fired generator for VOC emissions. An oxidation catalyst, however, is available for this size engine according to vendors. Good combustion control will help control emissions of VOC from the generator.

#### 6.12.3.2 STEP 2. Identify Technically Feasible Control Technologies

##### 6.12.3.2.1 Oxidation Catalyst System

One control vendor has indicated that a CO catalyst system may be used on an emergency diesel-fired generator this size. The CO catalyst system is an add-on control that converts VOC and CO to $CO_2$ by use of a catalyst. Section 6.5.2.1 describes the CO catalyst system for gas-fired units.

**Because a vendor has provided a quote for such a system, an oxidation catalyst system is considered technically feasible for the emergency diesel-fired generator.**

##### 6.12.3.2.2 Combustion Control

"Good combustion practices" include operational and design elements to control the amount and distribution of excess air in the flue gas to ensure that there is enough oxygen present for complete combustion.

**Good combustion practices are a technically feasible method of controlling VOC emissions from the emergency diesel-fired generator and therefore are BACT for the generator.**

#### 6.12.3.3 STEP 3. Rank the Technically Feasible Control Technologies

The technically feasible VOC control technologies for the emergency diesel-fired generator are ranked by control effectiveness in Table 6-22.

**Table 6-22. Ranking of VOC Control Technologies for the Emergency Diesel-fired Generator**

| Control Technology | Reduction (%) | Controlled Emission Level (g/hp-hr) |
|---|---|---|
| Oxidation Catalyst | 50 | 1.5 |
| Combustion Control | Not applicable (baseline) | 3.0 |

#### 6.12.3.4 STEP 4. Evaluate the Most Effective Control Technologies

Each technically feasible add-on control technology was evaluated for energy, environmental, and economic impacts. These impacts are discussed below for each control technology.

##### 6.12.3.4.1 Oxidation Catalyst

Energy and Environmental Impacts

Energy and environmental impacts of an oxidation catalyst are discussed in Section 6.5.4.2.

Economic Impacts

The control cost analysis for an oxidation catalyst system for the emergency diesel-fired generator is shown in Tables E-7 and E-8. An oxidation catalyst system for this size unit would require an initial capital cost of $4,598. The annual costs of operating this CO catalyst system would be $2,441. On an annual basis, only 0.02 tons per year (at 80 percent removal) of CO would be removed (along with only 0.01 tons per year of VOC removed) at a cost of $96,678 per ton of pollutants removed.

**An oxidation catalyst for control of VOC emissions from the emergency diesel-fired generator is not economically feasible. Therefore, as noted at Step 2, the use of good combustion practices is BACT for the emergency diesel-fired generator.**

#### 6.12.3.5 STEP 5. VOC BACT Emission Limitation

Good combustion practices will achieve a VOC emission rate of 3 g/hp-hr during steady state operation of the emergency diesel-fired generator. Therefore, **the BACT emission limitation for VOC emissions from the emergency diesel-fired generator is 3 g/hp-hr.**

### 6.12.4 BACT for Particulate Matter ($PM/PM_{10}/PM_{2.5}$) – Emergency Diesel-fired Generator

#### 6.12.4.1 STEP 1. Identify Potential Control Strategies

The RBLC does not identify any control strategies other than good combustion practices and low ash fuel (natural gas) for the emergency diesel-fired generator. No add-on controls were identified for significant removal of these pollutants from the engine's exhaust.

#### 6.12.4.2 STEP 2. Identify Technically Feasible Control Technologies

The only technically feasible control options for $PM/PM_{10}/PM_{2.5}$, are good combustion practices and use of low ash fuel. **As these control measures are technically feasible, they are BACT for the emergency diesel-fired generator**.

#### 6.12.4.3 STEP 5. $PM/PM_{10}/PM_{2.5}$ BACT Emission Limitation

The emergency diesel-fired generator is cable of limiting emissions to 0.15 g/hp-hr. **Therefore, the BACT emission limitation for $PM/PM_{10}/PM_{2.5}$ from the emergency diesel-fired generator is 0.15 g/hp-hr.**

### 6.12.5 BACT for Greenhouse Gases (GHG) – Emergency Diesel-fired Generator

Consistent with the rationale for the BACT determination for GHG emissions from the RICE, BACT for this source involves selection of the most efficient stationary emergency generator engine that can meet the Project's needs. TradeWind has provided information on the emissions from the specified engine in the agency permitting documents. TradeWind has estimated total greenhouse gas emissions from the emergency diesel-fired generator at 15.6 tons of $CO_2e$ per year. These GHG emissions also are *de minimis*, when compared to the RICE GHG emissions or the Project total GHG emissions.

TradeWind is unaware of any more fuel-efficient alternative NSPS-certified engine for these purposes. Further, because emissions of GHG are directly correlative to operation of the unit, BACT requires that the engine shall be operated only for readiness testing, during emergencies, and other periods authorized by KDHE.

Because operation of this source will be limited by permit conditions for reliability-related activities and TradeWind will be required to keep records of the operation of this source and its fuel usage, no additional conditions are required to enforce this GHG BACT determination.

## 6.13 BACT FOR Greenhouse Gases (GHG) – Circuit Breakers

#### 6.13.1.1 Introduction

Sulfur hexafluoride ($SF_6$) is a very potent greenhouse gas (GHG) with a global warming potential of 22,800, which means that it is 22,800 times more potent as a greenhouse gas than $CO_2$. $SF_6$ is a gaseous dielectric used in circuit breakers. The Project will have a maximum of four circuit breakers that will contain small amounts of $SF_6$. Leakage is expected to be minimal, and is expected to occur only as a result of circuit interruption and at extremely low temperatures. The following presents the GHG BACT analysis for the $SF_6$ emissions from the $SF_6$-containing circuit breakers that are part of this project.

#### 6.13.1.2 Emissions of Greenhouse Gas Emissions – Circuit Breakers

Emissions of $SF_6$ from the circuit breakers are calculated in Table 6-23. Emissions are based on a maximum leakage rate of 0.5% per year, based on vendor guarantees, to calculate the annual PTE emissions. Based on the calculations for all four circuit breakers, the maximum greenhouse gas emissions as $CO_2e$ are 13.95 tons per year.

**Table 6-23. Emissions of Greenhouse Gases from Circuit Breakers for Lacey Randall Station**

| | Number of Units | Quantity of $SF_6$ per Breaker (lbs) | Emissions of $SF_6$ Per Breaker (lbs/yr) | Total $SF_6$ Emissions (lbs/yr) | Global Warming Potential of $SF_6$ | Total $CO_2e$ Emissions (tons/yr) |
|---|---|---|---|---|---|---|
| **Circuit Breakers** | 4 | 61.2 | 0.306 | 1.22 | 22,800 | 13.95 |

*Based on a maximum $SF_6$ leakage rate of 0.5% per year.

#### 6.13.1.3 STEP 1 and STEP 2. Identify Potential Control Strategies and Eliminate Technologically Infeasible Options

The first steps in a top-down BACT analysis are to determine the potential control strategies and then determine if the control strategy is technically feasible for the project. There are no add-on control technologies for $SF_6$; only inherent controls are available. The following control strategies have been identified and considered in determining BACT for $SF_6$ emissions from circuit breakers:

1. **Use state-of-the-art $SF_6$ technology with leak detection systems to limit fugitive emissions.**

   The use of state-of-the-art gas-filled circuit breakers using $SF_6$ with leak detection to limit fugitive emissions is the proposed control option. Modern circuit breakers and switchers are designed as a totally enclosed-pressure system with far lower potential for $SF_6$ emissions than older circuit breakers. The International Electrotechnical Commission (IEC) recommends that new equipment be built to low leakage limits (standard for new equipment leakage is 0.5% per year).[20] Therefore, the newest modern equipment can be guaranteed to leak at a rate of no more than 0.5% per year by weight. In addition, the effectiveness of leak-tight closed systems can be enhanced by equipping them with a density alarm (weight change) that provides a warning when

[20] U.S. EPA, J. Blackman (U.S. EPA, Program Manager, $SF_6$ Emission Reduction Partnership for Electric Power Systems), M. Averyt (ICF Consulting), and Z. Taylor (ICF Consulting), *$SF_6$ Leak Rates from High Voltage Circuit Breakers – U.S. EPA Investigates Potential Greenhouse Gas Emissions Source*, June 2006, first published in Proceedings of the 2006 IEEE Power Engineering Society General Meeting, Montreal, Quebec, Canada, June 2006 (available at: www.epa.gov/electricpower-sf6/documents/leakrates_circuitbreakers.pdf).

$SF_6$ has leaked from the breaker. Therefore, this type of technology is available to limit emissions, is feasible for use, and is the baseline established for this BACT analysis.

2. **Substitution of another, non-greenhouse-gas substance for $SF_6$ such as the use of a different dielectric oil or compressed air (air-blast) circuit breaker as the dielectric material in the breakers.**

One alternative to $SF_6$ would be the use of a dielectric oil or compressed air (air-blast) circuit breaker, which historically were used in high-voltage installations prior to the development of $SF_6$ breakers. $SF_6$ has become the predominant insulator and arc-quenching substance in circuit breakers today because of its superior capabilities over oil and air-blast circuit breakers and switchers. The main drawback to oil and air-blast breakers are that these type of breakers require significantly larger equipment to replicate the same insulating and arc-quenching capabilities of the $SF_6$ breakers and air-blast breakers can have significant noise impacts to nearby residences. This type of technology is not feasible for use here, however, because oil breakers are no longer available from vendors, other than as used equipment and air-blast breakers are no longer made for this size voltage (145 kV). According to vendors, air-blast breakers are available only up to 69 kV currently. Therefore, oil and air-blast breakers and switchers are not available control technology for circuit breakers.

3. **Use an emerging technology to replace $SF_6$ with a material that has similar dielectric and arc-quenching properties, but without the drawbacks of oil and air-blast breakers.**

The availability of emerging technologies to serve as an alternative to $SF_6$ was researched. According to the most recent report released by the EPA $SF_6$ Partnership, "no clear alternative exists for this gas that is used extensively in circuit breakers, gas-insulated substations, and switch gear, due to its inertness and dielectric properties."[21] Research and development efforts have been focused on finding substitutions for $SF_6$ that have comparable insulating and arc-quenching properties in high-voltage applications.[22] Most studies have concluded, "there is no replacement gas immediately available to use as an $SF_6$ substitute"[23] for high-voltage applications. Therefore,

[21] U.S. EPA, *$SF_6$ Emission Reduction Partnership for Electric Power Systems 2007 Annual Report*, December 2008, Page 1 (available at http://www.epa.gov/electricpower-sf6/documents/sf6_2007_ann_report.pdf).

[22] U.S. Climate Change Technology Program, Technology Options for the Near and Long Term, 4.3.5, *Electric Power System and Magnesium: Substitutes for $SF_6$*, November 2003, Page 185 (available at: www.climatetechnology.gov/library/2003/tech-options/tech-options-4-3-5.pdf)

[23] Siemens Power Transmissions & Distribution, Inc., Siemens TechTopics No. 53, *Use of $SF_6$ Gas in Medium Voltage Switchgear*, June 3, 2005, Page 3 (available at:

the alternative to use an emerging technology to replace $SF_6$ is not an available control technology.

4. **Develop and implement a Leak Detection and Repair (LDAR) program, similar to NSPS, Subpart Wa (40 CFR 60.480a through 60.489a).**

   A written LDAR program similar to the requirements of 40 CFR Part 60, Subpart Wa, Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry, is a control technology proposed by other facilities to control $SF_6$ emissions from circuit breakers. Under a normal LDAR program, documentation regarding observations and/or repairs made in accordance with the LDAR program is provided to KDHE for a demonstration of compliance with this control. A similar program would be developed specifically for $SF_6$. Leak detection and repair is an available control technology for this project and are technically feasible.

Table 6-24 displays the control options and feasibility for $SF_6$.

**Table 6-24. Summary of Potential GHG Control Technologies**

| GHG Technology | Evaluation Status |
|---|---|
| State-of-the-art $SF_6$ technology with leak detection systems | Considered and Applied |
| Oil/air-blast circuit breakers | Considered (Not Feasible) |
| Use of emerging technology to replace $SF_6$ | Considered (Not Feasible) |
| LDAR | Considered and Applied |

### 6.13.1.4 STEP 3. Rank the Technically Feasible Control Technologies

Table 6-25 presents the ranked technically feasible control options.

**Table 6-25. GHG Technology Rankings for Circuit Breakers Equipment Leaks**

| Rank | Control Technology | Emission Rate (short tons $CO_2e$/year) | Emissions Reduction (short tons $CO_2e$/year) |
|---|---|---|---|
| 1 | State-of-the-art $SF_6$ technology with leak detection systems | 13.95 | N/A |
| 2 | LDAR* | N/A | N/A |

*Implementation of the LDAR program will not generate emissions, nor will it control emissions beyond the baseline. The LDAR program is used to monitor equipment leaks for repair.

www.energy.siemens.com/cms/us/US_Products/CustomerSupport/TechTopicsApplicaionNotes/Documents/TechTopics53.Rev0.pdf).

#### 6.13.1.5 STEP 4. Evaluate the Most Effective Control Technologies

##### 6.13.1.5.1 Environmental, Energy, and Economic Feasibility of Control Options

##### 6.13.1.5.2 LDAR

A LDAR program is a technically feasible control option for the $SF_6$-containing circuit breakers and does not have any environmental or energy considerations. There will be very minor economic costs associated with implementation of a LDAR program. However, these costs are considered minimal for this project.

#### 6.13.1.6 STEP 5. GHG BACT Emission Limitation

Based on this top-down analysis, TradeWind has determined that GHG BACT for the onsite circuit breakers consists of the following:

- State-of-the-art enclosed-pressure $SF_6$ circuit breakers with a guaranteed loss rate of 0.5% by weight or less by year
- Density monitor alarm system
- Develop and implement a written LDAR program

The recently issued (2011) Abengoa Bioenergy Biomass of Kansas, LLC PSD permit contained a BACT analysis for a similar source of $SF_6$. The KDHE issued this permit with a similar BACT determination as the BACT proposed here. In addition, recent permits for power plants (most of them combined-cycle plants) have been issued in other states that have a similar or the same BACT determination. The Russell City Energy Center (Bay Area Air Quality Management District), Calpine Deer Creek plant (Texas, EPA Region VI), and Moxie Liberty Generation Plant (Pennsylvania) were also issued PSD permits with very similar BACT for $SF_6$ emissions from similar sources in 2010 and 2011. All of these plants are similar in that they combust natural gas to produce power and have circuit breakers that are assumed to be of similar size to the circuit breakers to be used at Lacey Randall Station.

#### 6.13.1.7 Compliance with GHG BACT for Circuit Breakers

Any $SF_6$ emissions from these sources will be fugitive emissions. Fugitive emissions are, by their nature, very difficult to monitor directly, as they are not emitted from a discrete emission point. Fugitive $SF_6$ emissions can be estimated very accurately, however, by measuring “top-ups,” i.e., the replacement of

lost $SF_6$ with new product.[24] It is conservatively assumed that the amount of $SF_6$ that has leaked and entered the atmosphere is the amount that has to be topped up to maintain a full $SF_6$ level. Therefore, TradeWind proposes that no direct monitoring of $SF_6$ fugitive emissions be required. In place of direct monitoring, TradeWind proposes surrogate monitoring through measuring the amount of $SF_6$ lost and using a conversion factor to assess annual $SF_6$ fugitive emissions in terms of $CO_2$e.

The overall effectiveness of the leak-tight closed systems will be enhanced by equipping them with a density alarm that provides a warning when $SF_6$ has leaked from the breaker. BACT was determined for the Abengoa Bioenergy Biomass facility, Russell City Energy Center, Moxie Liberty plant, and the Calpine Deer Creek plant projects to be state-of-the-art enclosed-pressure $SF_6$ circuit breakers with leak detection and the use of an alarm system to alert controllers when a circuit breaker loses10 percent of its $SF_6$. As established in various EPA publications,[25] an $SF_6$ circuit breaker is classified as leaking if it had documented "top-ups" of $SF_6$, which occurred after a density alarm sounded, indicating that 10 percent of the circuit breaker gas volume has been emitted. Some recent industry studies[26] have indicated that the leak monitoring set point of the density alarm may be lowered with a reasonable degree of certainty.

A density monitor is used to monitor for and determine $SF_6$ leaks by measuring the circuit breaker and circuit switcher internal pressure and temperature. The monitor then "compensates" for the difference between the measured temperature and the reference standard of a fully charged breaker defined at installation and calculates the temperature compensated pressure. Because $SF_6$ is a real gas, not an ideal gas, it has a pressure-temperature-density relationship described by a curved equation while an ideal gas functions on a straight equation. Because of the pressure-temperature-density relationship, the accuracy of the mechanical monitoring device (density alarm) proposed is impacted by both pressure and temperature changes. The accuracy of most density monitors is plus or minus 2.5 percent (or 2 psi).[27]

TradeWind will implement a density alarm threshold of 10 percent, based on the data available for review. According to circuit breaker vendors, a 10 percent alarm is standard on most $SF_6$-containing circuit breakers. In the event of an alarm, TradeWind will investigate the event and take any necessary corrective action to address any problems. This is consistent with the previous BACT determinations identified above.

[24] *SF6 Leak Rates from High Voltage Circuit Breakers – U.S. EPA Investigates Potential Greenhouse Gas Emissions Source,* supra note 2, Page 1.
[25] *SF6 Leak Rates from High Voltage Circuit Breakers – U.S. EPA Investigates Potential Greenhouse Gas Emissions Source,* supra note 2, Page 1.
[26] Thesen, Sven. Pacific Gas & Electric Co, *PG&E and the New Breaker SF6 Leak Study,* Page 2 (available at http://www.epa.gov/electricpower-sf6/documents/conf04_thesen_paper/pdf).
[27] *PG&E and the New Breaker $SF_6$ Leak Study,* Page 3

TradeWind also proposes to develop and implement a written LDAR program similar to the requirements of 40 CFR Part 60, Subpart Wa, Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry, but modified for this source and pollutant. TradeWind will provide a copy of the LDAR program and documentation regarding observations and/or repairs made in accordance with the LDAR program to KDHE upon request to demonstrate compliance with BACT.

# 7.0 AIR DISPERSION MODELING

Because the Project is subject to PSD review, an air dispersion modeling analysis is required for each regulated NSR pollutant that exceeds its PSD significance level, i.e. $NO_x$, CO, VOC, $PM/PM_{10}/PM_{2.5}$ and $CO_2e$. Accordingly, an air quality analysis has been performed for $NO_x$, CO, and $PM_{10}/PM_{2.5}$ using the EPA-approved AMS/EPA Regulatory Model (AERMOD). However, in accordance with guidance, modeling of PM, VOCs, and $CO_2e$ has not been carried out, because there are no modeling thresholds for these pollutants.

A pre-project meeting with KDHE was held to discuss the modeling protocol to be used for this Project. The air dispersion modeling protocol and Ozone Limiting Method (OLM) modeling protocol submitted to the KDHE in April 2013 are presented in Appendix F.

A summary of the model, modeling techniques, and modeling results for the Project are discussed in the following sections.

## 7.1 Air Dispersion Model

Air dispersion modeling has been performed using the latest version of the AERMOD model (Version 12345). AERMOD is an EPA-approved, steady-state, Gaussian air dispersion model that is designed to estimate downwind ground-level concentrations from single or multiple sources using detailed meteorological data. AERMOD is a model currently approved for industrial sources and PSD permits. KDHE requested that TradeWind demonstrate regulatory compliance through its use.

Major features of AERMOD are as follows:

- Plume rise, in stable conditions, is calculated using Briggs equations that consider wind and temperature gradients at stack top and half the distance to plume rise; in unstable conditions, plume rise is superimposed on the displacements by random convective velocities, accounting for updrafts and downdrafts due to momentum and buoyancy as a function of downwind distance for stack emissions
- Plume dispersion receives Gaussian treatment in horizontal and vertical directions for stable conditions and non-Gaussian probability density function in vertical direction only for unstable conditions
- AERMOD creates profiles of wind, temperature, and turbulence, using all available measurement levels and accounts for meteorological data throughout the plume depth

- Surface characteristics, such as Bowen ratio, albedo, and surface roughness length, may be specified to better simulate the modeling domain
- Planetary Boundary Layers (PBL) such as friction velocity, Monin-Obukhov length, convective velocity scale, mechanical and convective height, and sensible heat flux may be specified
- AERMOD uses a convective (based upon hourly accumulation of sensible heat flux) and a mechanical mixed layer height
- AERMOD's terrain pre-processor (AERMAP) provides information for the advanced critical dividing streamline height algorithms and uses National Elevation Dataset (NED) to obtain elevations
- AERMOD uses vertical and horizontal turbulence-based plume growth (from measurements and/or PBL theory) that varies with height and uses continuous growth functions
- AERMOD uses convective updrafts and downdrafts in a probability density function to predict plume interaction with the mixing lid in convective conditions while using a mechanically mixed layer near the ground
- Plume reflection above the lid is considered
- AERMOD models impacts that occur within the cavity regions of building downwash via the use of the plume rise model enhancements (PRIME) algorithm, and then uses the standard AERMOD algorithms for areas without downwash

Details of the modeling algorithms contained in the AERMOD model are set forth in the User's Guide for AERMOD. The regulatory default option was selected for this analysis because it meets the EPA guideline requirements and KDHE modeling guidance requirements, with the exception of the 1-hour and annual nitrogen dioxide ($NO_2$) modeling. The 1-hour and annual $NO_2$ modeling options selected are detailed in the OLM modeling protocol in Appendix F.

The following default model options, which are discussed in the air dispersion modeling protocol, were used:

- Gradual Plume Rise
- Stack-tip Downwash
- Buoyancy-induced Dispersion
- Calms and Missing Data Processing Routine
- Calculate Wind Profiles
- Calculate Vertical Potential Temperature Gradient

- Rural Dispersion

Further specifications, detailed in the air dispersion modeling protocol and OLM protocol submitted to the KDHE in February 2012, are set forth in Appendix F of this application.

## 7.2 Model Parameters

Modeling runs were conducted at full load and partial loads to confirm that operation of the Project will not result in exceedances of any NAAQS or PSD Class II increment consumption allowance. The expected hourly emission rates and modeling parameters for a single combustion engine are shown in Table 7-1. These emission rates represent projected worst-case ambient conditions under various operating loads including start-up emissions. The annual emissions are based on 8,760 hours per year.

**Table 7-1. Combustion Engine Emissions and Modeling Parameters**

| Parameter | 100% Load | 90% Load | 75% Load | 50% Load | Start-up |
|---|---|---|---|---|---|
| $NO_x$ (lb/hr) | 1.45 | 1.31 | 1.33 | 1.02 | 11.97 (3.20) [A] |
| CO (lb/hr) | 2.67 | 2.59 | 2.31 | 2.25 | 9.71 |
| $PM_{10}/PM_{2.5}$ (lb/hr) | 2.67 | 2.00 | 1.88 | 2.02 | 2.65 (2.29)[A] |
| Stack Temperature (F) | 627 | 654 | 690 | 771 | 539.5 |
| Exit Velocity (ft/s) | 83.87 | 77.59 | 67.08 | 50.05 | 81.06 |
| Stack Height (f) | 100 | 100 | 100 | 100 | 100 |
| Stack Diameter (ft) | 4 | 4 | 4 | 4 | 4 |

[A] Maximum annual emissions including 1,460 start-ups averaged over 8,760 hours per year

The expected hourly emission rates and modeling parameters for the gas heater, emergency fire pump, and emergency diesel-fired generator are shown in Table 7-2. Annual emissions for the emergency fire pump and emergency diesel-fired generator are based on 100 hours per year of operation.

**Table 7-2. Gas Heater, Emergency Fire Pump and Emergency Diesel-fired Generator Emissions and Modeling Parameters**

| Parameter | Gas Heater | Emergency Diesel-Fired Generator | Emergency Fire Pump |
|---|---|---|---|
| $NO_x$ (lb/hr) | 0.29 | 2.13 (0.02) [A] | 0.99 (0.01) [A] |
| CO (lb/hr) | 0.25 | 1.86 | 1.22 |
| $PM_{10}/PM_{2.5}$ (lb/hr) | 0.022 | 0.11 (0.001) [A] | 0.073 (0.001) [A] |
| Stack Temperature (F) | 500 | 949 | 840 |
| Exit Velocity (ft/s) | 44.33 | 89.05 | 66.37 |
| Stack Height (ft) | 19 | 20 | 30 |
| Stack Diameter (ft) | 0.83 | 0.58 | 0.67 |

[A] Equivalent lb/hr emissions averaged over 8,760 hours per year, based on operation of 100 hours.

### 7.2.1 Good Engineering Practice

Sources included in a PSD permit application are subject to Good Engineering Practice (GEP) stack height requirements established by K.A.R 28-19-18a through K.A.R 28-19-18f. As defined by the regulations, GEP height is calculated as the greater of 65 meters (measured from the ground level elevation at the base of the stack) or the height resulting from the following formula:

$$GEP = H + 1.5L$$

Where

H = the height of nearby structure(s) measured from the ground level elevation at the base of the stack; and

L = the lesser dimension (height or projected width) of nearby structure(s) (i.e., building height or the greatest crosswind distance of the building - also known as maximum projected width).

To meet stack height requirements, each point source was evaluated in terms of its proximity to nearby structures. The purpose of this evaluation was to determine if the discharge from the stack will become caught in the turbulent wake of a building or other structure, resulting in downwash of the plume. Downwash of the plume can result in elevated ground-level concentrations. The KDHE provides guidance for determining whether building downwash will occur in K.A.R 28-19-18. The downwash analysis was performed in accordance with the methods prescribed in K.A.R 28-19-18c.

Calculations for determining the direction-specific downwash parameters were performed using the most current version of EPA's Building Profile Input Program – Plume Rise Model Enhancements (Version

04274), otherwise referred to as the BPIP-PRIME downwash algorithm. The BPIP-PRIME algorithm provides direction-specific building dimensions to evaluate downwash conditions. Lacey Randall Station is located in a rural area, and the only buildings that could potentially affect emissions from the Project are the on-site structures.

According to the BPIP-PRIME model results, it was determined that the GEP stack height for the RICE will not exceed 65 meters. A stack height of 100 feet (30.48 meters) was used in the AERMOD modeling.

## 7.3 Modeling Methodology and Parameters

### 7.3.1 Receptor Grid

The purpose of the modeling analysis was to quantify the potential ground-level concentrations from the Project to determine if they will cause or contribute to an exceedance of a NAAQS and/or a PSD Class II increment consumption allowance. The modeling runs were conducted using the AERMOD model in simple and complex terrain mode within a 10-by-10-kilometer Cartesian grid to determine the significant impact area for each pollutant. The grid incorporates the following spacing between receptors: 50 meters out to 1 kilometer, 100 meters out to two kilometers, and 250 meters out to 10 kilometers (Figure 7-1, Appendix G). Receptors also were placed along the fence line boundary at a spacing of 50 meters. Because the significant impact area exceeded 10 kilometers for the 1-hour $NO_2$ averaging period, the grid was extended to a 50-by-50 kilometer grid (Figure 7-2, Appendix G). The significant impact area did not exceed 10 kilometers for any other pollutant or averaging period, so the receptor grid was not extended otherwise.

The appropriate U.S. Geological Survey (USGS) Digital Elevation Model (DEM) terrain files were used to obtain the necessary receptor elevations. North American Datum of 1983 (NAD 83) was used to develop the Universal Transverse Mercator (UTM) coordinates for this project.

AERMOD has a terrain preprocessor (AERMAP) which uses gridded terrain data for the modeling domain to calculate not only a XYZ coordinate, but a representative terrain-influence height associated with each receptor location selected. This terrain-influenced height is called the height scale and is separate for each individual receptor. AERMAP (Version 11103) utilized the electronic DEM terrain data to populate the model with receptor elevations.

### 7.3.2 Meteorological Data

Meteorological data obtained from KDHE was used for the modeling analysis. Integrated Surface Hourly meteorological data from the Goodland Municipal Airport (station # 23065) and upper air data from the

Dodge City Regional Airport (station #13985) was used in the analysis. A profile base elevation value of 3,687 feet was used. The most recent five-year data set available covers the period of 2007 to 2011. One-minute meteorological data is included in the meteorological files.

The dominant wind direction is shown in Figure 7-3 in Appendix G.

### 7.3.3 Model Parameters

Based on the Auer scheme, the existing land use for a three-kilometer area surrounding the Project is more than 50 percent rural, and the population density is less than 750 people per square kilometer for the same area. Therefore, rural dispersion coefficients were used in the AERMOD model.

### 7.3.4 Significant Impact Area Determination

The AERMOD model used the worst-case impact scenario for the RICE and auxiliary equipment. If any modeled pollutant was predicted to cause impacts only below the significance levels for each averaging period, no further modeling for that pollutant and averaging period was required in relation to either the NAAQS or PSD Class II increment consumption allowances. However, if the model predicted impacts at or above the modeling significance level for any pollutant, a cumulative analysis including all point sources within the radius of impact (ROI) was carried out for that pollutant and averaging period.

### 7.3.1 NAAQS and PSD Class II Increment Analysis

For the NAAQS and PSD Class II increment analysis, all major stationary sources that emit pollutants subject to this analysis and located within the ROI of the Lacey Randall Station were addressed. KDHE provided the inventory of sources located in the ROI. The inventory sources provided by KDHE are located in Appendix H. Background concentrations were included for NAAQS modeling compliance determinations. The background concentrations provided by KDHE are shown in Table 7-3.

**Table 7-3. Background Level**

| Pollutant | Averaging Period | Background Concentration (micrograms per cubic meter (µg/m$^3$)) | Air Quality System Monitor ID |
|---|---|---|---|
| $NO_2$ | Annual | 7.5 | 20-191-0002 (Peck) |
| | 1-hour | 49.0 | 20-191-0002 (Peck) |
| $PM_{10}$ | 24-hour | 89.0 | 20-181-0001 (Goodland) |
| $PM_{2.5}$ | Annual | 7 | 20-195-0001 (Cedar Bluff) |
| | 24-hour | 17 | 20-195-0001 (Cedar Bluff) |

### 7.3.2 Ambient Monitoring

The modeling analysis for emission sources at Lacey Randall Station addresses the pre-construction monitoring provision of the PSD regulations. The regulations specify significant monitoring levels for each PSD pollutant that triggers the requirement to perform one year of pre-construction ambient air monitoring. For any impacts predicted to be below the monitoring *de minimis* levels, TradeWind requests pre-construction ambient air monitoring not be required. For any predicted concentrations reaching or exceeding the monitoring *de minimis* levels, TradeWind will satisfy all pre-construction monitoring requirements stated in the EPA "Ambient Monitoring Guidelines for Prevention of Significant Deterioration" (EPA). The NAAQS, modeling/monitoring significance levels, and PSD Class II Increment thresholds for the modeled pollutants are shown in Table 7-4.[28]

[28] The pollutants that are allowed one NAAQS exceedance per year and one PSD Class II increment consumption allowance exceedance per year are: 1-hour and 8-hour CO and 24-hour $PM_{10}$.

**Table 7-4. NAAQS, Significance, and Monitoring Levels and PSD Class II Increment ($\mu g/m^3$)**

| Pollutant | Averaging Period | NAAQS | Modeling Significance Level | Monitoring Significance Level | PSD Class II Increment |
|---|---|---|---|---|---|
| $NO_2$ | annual | 100 | 1 | 14 | 25 |
| | 1-hour | 188.7 | 7.5 | NA | NA |
| CO | 8-hour | 10,000 | 500 | 575 | NA |
| | 1-hour | 40,000 | 2,000 | NA | NA |
| $PM_{10}$ | annual | NA | 1 | NA | 17 |
| | 24-hour | 150 | 5 | 10 | 30 |
| $PM_{2.5}$ | annual | 12 | 0.3[A] | NA | 4 |
| | 24-hour | 35 | 1.2[A] | 4[B] | 9 |

[A]United States Court of Appeals for the District of Columbia Circuit on January 22, 2013 vacated and remanded portions of the U.S. EPA rule establishing significant impact levels (SILs) and vacated the rule establishing the significant monitoring concentration (SMC) for particulate matter less than 2.5 micrometers ($PM_{2.5}$), however the $PM_{2.}$5 SILs are still valid in Kansas per guidance from KDHE.

[B]The $PM_{2.5}$ 24-hour Significant Monitoring Concentration vacated by the United States Court of Appeals for the District of Columbia on January 22, 2013 is not considered valid in Kansas. However, representative local monitoring data is available for use.

### 7.3.3 $NO_2$ Modeling – Multi-Tiered Screening Approach

The AERMOD model predicts ground-level concentrations of any generic pollutant without chemical transformations. Thus, the modeled $NO_x$ emission rate will give ground-level modeled concentrations of $NO_x$. NAAQS values are presented as $NO_2$.

EPA has a three-tier approach to modeling $NO_2$ concentrations.

- Tier I – total conversion, or all $NO_x = NO_2$
- Tier II – use a default $NO_2/NO_x$ ratio
- Tier III – case-by-case detailed screening methods, such as OLM and Plume Volume Molar Ratio Method (PVMRM)

Initial modeling was performed using both Tier I and Tier II methodologies. These modeling iterations demonstrate that less conservative methods for determining 1-hour and annual $NO_2$ compliance would be needed for this project. Therefore, the ambient impact of 1-hour and annual $NO_x$ predicted by the model was screened using the Tier III – OLM. An OLM modeling protocol, which discussed the proposed model to be used and the OLM methodology was submitted to KDHE in April 2013 and is shown in Appendix F for reference. The OLM protocol was also submitted to EPA Region VII.

## 7.4 Significance Model Results

### 7.4.1 $NO_2$ Results

The model predicts that impacts greater than the 1-hour and annual $NO_2$ modeling significance levels can occur, so refined modeling is required. The predicted impacts were lower than the annual ambient air monitoring *de minimis* level and no pre-construction monitoring will be required.

The maximum modeled concentration for the $NO_2$ 1-hour and annual average period are shown in Table 7-5.

### 7.4.2 CO Results

The model predicts that no exceedances of the 1- or 8-hour CO significance level will occur, and that no further modeling is required. Also, the 8-hour predicted impacts were lower than the ambient air monitoring *de minimis* level and no pre-construction monitoring will be required. The maximum modeled concentrations for CO are shown in Table 7-5.

### 7.4.3 $PM_{2.5}$/$PM_{10}$ Results

The model also predicts that impacts greater than the annual $PM_{10}$, annual $PM_{2.5}$, 24-hour $PM_{2.5}$, and 24-hour $PM_{10}$ significance levels will occur, and refined modeling is required. The 24-hour modeling impacts for $PM_{2.5}$ is greater than the ambient air monitoring de minimis levels. However, TradeWind requests that existing monitoring data (provided by KDHE) from the Cedar Bluff monitor (monitor number 20-195-0001) be used for existing ambient levels of $PM_{2.5}$. The maximum modeled concentrations for $PM_{2.5}$ and $PM_{10}$ are shown in Table 7-5.

**Table 7-5. Maximum Modeled Concentrations**

| Pollutant | Averaging Period | UTM Coordinates | | Year | Predicted Concentration ($\mu g/m^3$) | Modeling Significance Level ($\mu g/m^3$) | Monitoring Significance ($\mu g/m^3$) | Radius of Impact (km) |
|---|---|---|---|---|---|---|---|---|
| | | Easting[A] (meters) | Northing[A] (meters) | | | | | |
| $NO_2$ | Annual[B] | 325096.6 | 4368115.4 | 2007 | 1.11 | **1** | 14 | 0.5 |
| | 1-hour | 324800.9 | 4367779.3 | NA | 59.15 | **7.5** | -- | |
| CO | 1-hour | 325286 | 4368110.7 | 2009 | 86.01 | 2000 | -- | insignificant |
| | 8-hour | 325001.9 | 4368117.7 | 2009 | 48.97 | 500 | 575 | insignificant |
| $PM_{10}$ | Annual | 325143.9 | 4368114.2 | 2007 | 1.09 | **1** | -- | 1.3 |
| | 24-hour | 325370 | 4367323.5 | 2008 | 8.80 | **5** | 10 | 1.3 |
| $PM_{2.5}$ | Annual | 325143.9 | 4368114.2 | 2007 | 1.09 | **0.3** | -- | 1.6 |
| | 24-hour | 325370 | 4367323.5 | 2008 | 8.80 | **1.2** | **4** | 4.3 |

[A]NAD 83
[B]ARM of 0.75 applied.

The modeling results demonstrate that the impacts of the 1-hour CO and 8-hour CO emissions from the Project will not result in a significant impact at any location. Therefore, no further modeling is required for CO.

The modeling analyses indicate that the Project's emissions will exceed the PSD modeling significance thresholds for $NO_2$ 1-hour, $NO_2$ annual, $PM_{10}$ 24-hour, $PM_{10}$ annual, $PM_{2.5}$ annual, and $PM_{2.5}$ 24-hour averaging periods. Therefore, a refined modeling analysis was conducted to demonstrate compliance with the NAAQS and PSD Class II increment consumption allowances.

Model input and output files for each pollutant are provided in Appendix H on CD-ROM. In addition, area plots with concentration contour plots of each pollutant are shown in Figures 7-4 to 7-11 in Appendix G.

## 7.5 PSD Class II Increment Modeling

A refined modeling analysis was conducted for the $PM_{10}$ 24-hour, $PM_{10}$ annual, $PM_{2.5}$ annual and 24-hour, and $NO_2$ annual averaging periods to demonstrate compliance with the PSD Class II increment.

An inventory of sources within the expected ROI was used in the refined analysis. This inventory of sources and modeled parameters are provided in Appendix H.

There were no modeled PSD increment consumption allowance exceedances for the pollutants and averaging periods modeled. Therefore, there are sufficient available $NO_2$, $PM_{10}$, and $PM_{2.5}$ PSD Class II increment allowances to construct and operate the Project. The results of the PSD Class II Increment analysis are shown below in Table 7-6. The second highest high was used for the 24-hour averaging periods.

**Table 7-6. Increment Modeling Results**

| Pollutant | Averaging Period | UTM Coordinates | | Year | Predicted Concentration ($\mu g/m^3$) | PSD Class II Increment ($\mu g/m^3$) |
|---|---|---|---|---|---|---|
| | | Easting[A] (meters) | Northing[A] (meters) | | | |
| $NO_2$ | Annual[C] | 325096.6 | 4368115.4 | 2007 | 1.11 | 25 |
| $PM_{10}$ | Annual | 325143.9 | 4368114.2 | 2007 | 1.09 | 17 |
| | 24-hour | 325143.9 | 4368114.2 | 2011 | 7.76[B] | 30 |
| $PM_{2.5}$ | Annual | 325143.9 | 4368114.2 | 2007 | 1.09 | 4 |
| | 24-hour | 325143.9 | 4368114.2 | 2011 | 7.76[B] | 9 |

[A] NAD 83
[B] Value is 2nd highest high
[C] ARM of 0.75 applied

The model input and output files are provided on CD-ROM in Appendix H. In addition, area plots with concentration contour plots are provided in Figures 7-12 to 7-15 in Appendix G.

## 7.6 NAAQS Modeling

A refined modeling analysis was conducted for the annual and 1-hour $NO_2$ averaging periods, 24-hour $PM_{10}$ averaging period, and the annual and 24-hour $PM_{2.5}$ averaging periods to demonstrate compliance with the NAAQS.

There were modeled NAAQS exceedances for the $PM_{10}$ 24-hour averaging period, the $PM_{2.5}$ annual and 24-hour averaging periods, and the $NO_2$ annual and 1-hour averaging periods. Further analysis demonstrated that the Project is not a significant contributor at the receptors that exceed the NAAQS. Details of the further analysis are provided in Appendix H. In summary, the Project will not cause or significantly contribute to a violation of any NAAQS. The NAAQS analysis modeling results are provided in Table 7-7.

**Table 7-7. NAAQS Modeling Results**

| Pollutant and Averaging Period | | UTM Coordinates | | Year | Predicted Concentration ($\mu g/m^3$) | Background Concentration ($\mu g/m^3$) | Total Concentration ($\mu g/m^3$) | NAAQS ($\mu g/m^3$) |
|---|---|---|---|---|---|---|---|---|
| | | Easting[A] (meters) | Northing[A] (meters) | | | | | |
| $NO_2$ | Annual[C] | 322750 | 4362500 | 2008 | 590.54 | 7.5 | 598.04 | **100** |
| | 1-hour | 322750 | 4362500 | NA | 1,095.68 | 49 | 1,144.68 | **188.0** |
| $PM_{10}$ | 24-hour | 322750 | 4362500 | NA | 150.31 | 89 | 239.31 | **150** |
| $PM_{2.5}$ | Annual | 322750 | 4362500 | 2008 | 20.35 | 7 | 27.35 | **12** |
| | 24-hour | 322750 | 4362500 | NA | 156.37 | 17 | 173.37 | **35** |

[A] NAD 83
[B] The Project, is not a significant contributor at any modeled exceedance.
[C] ARM of 0.75 applied

The modeled impacts for the NAAQS analysis were compared to the following highs shown in Table 7-8 for each averaging period.

**Table 7-8. Modeled Highs**

| Pollutant | Averaging Period | Modeled High |
|---|---|---|
| $NO_2$ | Annual | Annual Mean |
| | 1-hour | 98th Percentile |
| $PM_{10}$ | 24-hour | Sixth High |
| $PM_{2.5}$ | Annual | Highest First High |
| | 24-hour | Highest First High |

The model input and output files (including the additional analysis) are provided on CD-ROM in Appendix H. In addition area plots with concentration contour plots are provided in Figures 7-16 to 7-20 in Appendix G.

## 7.7 PSD Class I Analysis

Recent FLM guidance advises that a proposed major source, in the course of a PSD application, should perform an assessment of air quality impacts at Class I areas located within approximately 300 kilometers of the proposed facility. Because there are no Class I areas that are within 300 kilometers of Lacey Randall Station, no assessment of air quality impacts at Class I areas was performed for the Project.

## 7.8 Conclusion

The modeling results provided in Table 7-5 demonstrate that no exceedances of the 1-hour CO or 8-hour CO significant impact levels are predicted. Therefore, no further modeling is required. A refined modeling analysis was conducted to demonstrate compliance with the PSD Class II increment consumption allowances and NAAQS. There were no modeled Class II PSD increment consumption allowance exceedances for $PM_{10}$ 24-hour, $NO_2$ annual, or $PM_{2.5}$ annual and 24-hour averaging periods as shown in Table 7-6. As shown in Table 7-7, there were modeled NAAQS exceedances for the $PM_{10}$ 24-hour averaging period, the $PM_{2.5}$ annual and 24-hour averaging periods, and the $NO_2$ annual and 1-hour averaging periods. However, the Project is not a significant contributor to any of the modeled exceedances.

In short, the modeling requirements for CO, $NO_2$, and $PM_{10}$/$PM_{2.5}$ have been fulfilled, and no further modeling is required. The modeling carried out demonstrates that the operation of the Project will not cause or contribute to a significant degradation of ambient air quality.

## 7.9 Analysis of Secondary $PM_{2.5}$ Formation

In addition to direct emissions of $PM_{2.5}$, other pollutants, chiefly $NO_x$ and $SO_2$, can lead to formation of $PM_{2.5}$ further downwind. The photochemical reactions that transform these pollutants into nitrates and sulfates, which become the major species of $PM_{2.5}$, take place over hours or days. Potentials to emit after controls for the Project are 141.57 tpy $NO_x$ and 2.09 tpy $SO_2$.

The modeling for $NO_x$ shows that receptor concentrations are below the NAAQS and further diminish within the modeling domain out to 50 km to ensure the maximum concentrations are modeled. $SO_2$ was not modeled since the project's emissions are below the PSD threshold for $SO_2$.

Since the $NO_2$ and $SO_2$ standards are extremely restrictive, being below the PSD significance levels and PSD major project thresholds would likely prevent the pollutants from impacting secondary formation significantly enough to result in a violation of the $PM_{2.5}$ standards.

However, it is possible that some transformation into nitrates and sulfates from this source may occur and be transported downwind. No peer-reviewed regulatory model presently exists to examine the impacts of an individual source of $SO_2$ or $NO_x$. All photochemical models are regional scale and a source of this size would not show any measurable impact. Therefore, other available information from emissions inventories, meteorological analyses, and other modeling projects can be used to estimate the impact from this source.

The wind rose in Figure 7-3 Appendix G shows the general directions that emissions from this source would impact.

Design values from 2007 – 2011 at all Kansas $PM_{2.5}$ monitors in the area meet the annual and 24-hour NAAQS.

Because of the well-established relationship between $NO_x$ and $SO_2$, regional transport, and the formation of $PM_{2.5}$, to assist states to meet the $PM_{2.5}$ NAAQS, U.S. EPA finalized the Cross State Air Pollution Rule (CSAPR). Although CSAPR was vacated in August 2012, the rule included extensive modeling to support the emissions reductions necessary in each state to achieve the $PM_{2.5}$ NAAQS in the eastern U.S. that is still relevant to this analysis. The source category responsible for these reductions is EGU.

U.S. EPA used a regional model, CAMx, and the Air Quality Assessment Tool (AQAT) to determine levels of reduction from EGUs necessary to achieve the NAAQS at every site. The documentation includes extensive tables showing impacts at all $PM_{2.5}$ monitoring sites in the eastern U.S. and emission reduction levels necessary to achieve those results.

To examine the possible impact of the Project, the modeling U.S. EPA used to establish the final 2014 budgets in CSAPR is used for this analysis. The CSAPR website is located at http://www.epa.gov/airtransport/.

Tables showing projected base case 2014 $PM_{2.5}$ concentrations at existing monitoring sites versus control strategy $PM_{2.5}$ concentrations are located in AQModeling.pdf,[29] Appendix B, pages B-43 and B-44 for annual design values and pages B-72 and B-73 for 24-hour design values.

Information regarding $SO_2$ emission reductions necessary to achieve the future year modeled design values can be found in the "Final June Revisions Rule Significant Contribution Assessment TSD,"[30] Table 1, page 7. This table shows the base case annual $SO_2$ emissions for Kansas by 2014 were projected to be 69,818.75 tons, and remedy control scenario annual $SO_2$ emissions by 2014 to be 45,740.27 tons. The difference between these is 24,078.48 tons. All surrounding states make similar significant reductions. The $NO_x$ values are found in the excel workbook "TransportRuleFinal_EmissionsSummaries" in docket EPA-HQ-OAR-2009-0491-4206 on www.regulations.gov.[31] See Table 7-9.

**Table 7-9: EPA's Cross-State Air Pollution Rule Emission Summary for Kansas**

| State | Pollutant | 2014 Base (tons) | 2014 Remedy (tons) | EGU Reduction (tons) |
|---|---|---|---|---|
| Kansas | $SO_2$ | 69,818.75 | 45,740.27 | 24,078.48 |
| Kansas | $NO_x$ | 248,692.75 | 240,383.63 | 8,308.12 |
| | | | Total | 32,386.60 |

As an example, the maximum annual modeled concentrations for Sedgwick County (the closest county to Thomas that has data available) are 9.57 $\mu g/m^3$ for the 2014 base case and 8.89 $\mu g/m^3$ for the 2014 control scenario. This is a reduction of 0.68 $\mu g/m^3$. In order for this modeled annual concentration reduction to occur, Kansas EGUs modeled annual $SO_2$ emissions by 2014 were reduced by 24,078.48 tons and annual $NO_x$ emissions by 2014 were reduced by 8,308.12 for a total of 32,386.60 tons of $SO_2$ and $NO_x$.

This particular monitoring site is not necessarily impacted by every EGU in Kansas, but in the surrounding states, hundreds of thousands of tons of annual $SO_2$ emission reductions have also occurred by 2014, many of which would impact this site. Therefore, to estimate the impact of the Project on modeled concentrations, the ratio of the Project $SO_2$ and $NO_x$ emissions / 32,386.60 tons of $SO_2$ and $NO_x$ can be compared to the ratio of the Project $PM_{2.5}$ impact / 0.68 $\mu g/m^3$ of $PM_{2.5}$. See Table 7-10.

[29] http://www.epa.gov/airtransport/pdfs/AQModeling.pdf, accessed on June 28, 2013.
[30] http://www.epa.gov/airtransport/pdfs/FinalJuneRevisionsRuleSignificantContributionssessmentTSD.pdf, dated June 2012 and accessed on June 28, 2013.
[31] http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2009-0491-4206, accessed on June 28, 2013.

The calculation to estimate secondary formation is as follows:

$$\frac{(tons\ SO2\ \&NOx\ from\ Project)}{(tons\ SO2\ \&NOx\ from\ State)} = \frac{(Project's\ impact\ \mu g/m^3\ )}{(State\ reduction\ target\ \mu g/m^3\ )}$$

Project $PM_{2.5}$ impact = (143.66 tons / 32,386.60 tons) x (0.68 μg/m$^3$ of $PM_{2.5}$) = 0.00302 μg/m$^3$ of $PM_{2.5}$

**Table 7-10. EPA's Cross-State Air Pollution Rule Modeling Results & Estimated Project Impact**

| Monitor ID | County | 2014 Base | 2014 Remedy | 2014 Base-Remedy (μg/m$^3$) | Source Impact (μg/m$^3$) | Source Impact (%) |
|---|---|---|---|---|---|---|
| 201730008 | Sedgwick | 5.69 | 5.41 | 0.28 | 0.00124 | 0.124% |

Since this concentration is well below measurable values, there would be no change in projected modeled $PM_{2.5}$ concentrations at this site.

As seen in Figure 7-21, when comparing the dominant wind directions from Figure 7-3 Appendix G to other monitor locations, the other monitor that should be evaluated for impacts from the Project is located in Sumner county. This comparison is done in Table 7-11 and shows that the concentration is well below measurable values, and that there would be no change in projected modeled $PM_{2.5}$ concentrations at this site.

**Figure 7-21. Counties in Kansas.**

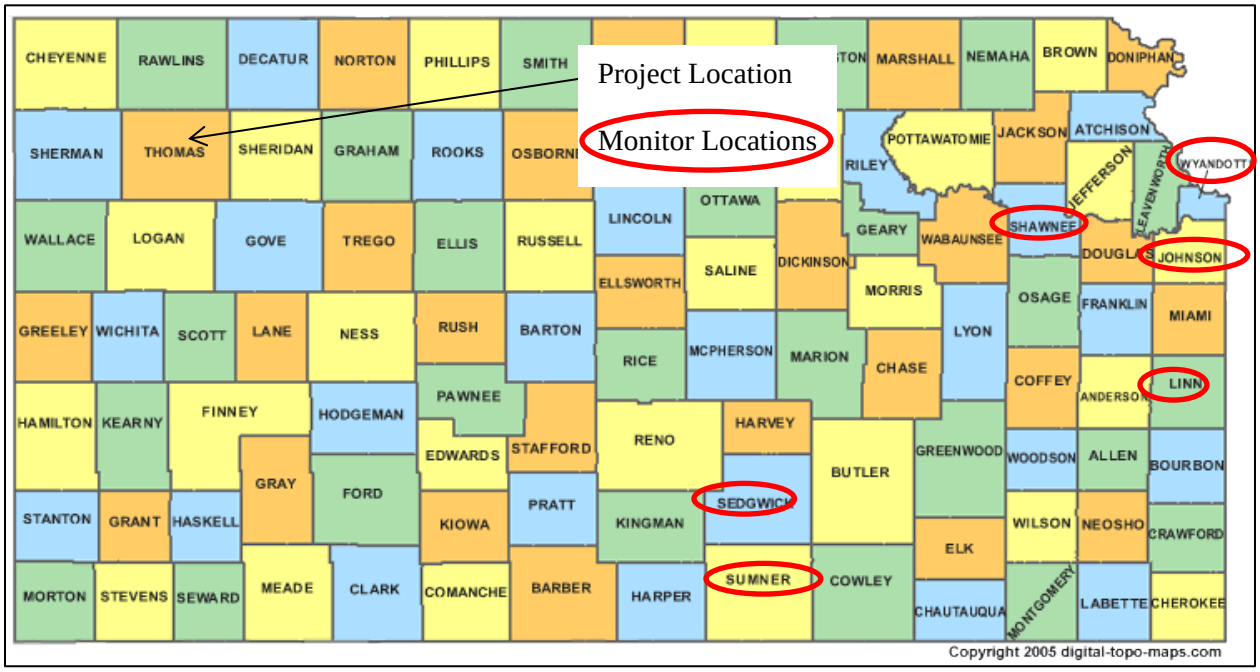



**Table 7-11. EPA's Cross-State Air Pollution Rule Annual $PM_{2.5}$ Modeling Results & Estimated Project Impact**

| Monitor ID | County | 2014 Base | 2014 Remedy | 2014 Base-Remedy (µg/m$^3$) | Source Impact (µg/m$^3$) | Source Impact (%) |
|---|---|---|---|---|---|---|
| 201910002 | Sumner | 9.17 | 8.47 | 0.7 | 0.00310 | 0.31% |

## 7.10 Scheffe Ozone Analysis

Project emissions include $NO_x$ and VOC which are precursors to ozone. Ozone is formed in the atmosphere due to a series of complex chemical reactions primarily involving VOC and $NO_x$ in the presence of sunlight. The highest ozone concentrations typically occur on hot stagnant sunny days.

Since VOCs are photoreactive pollutants and are generally regional in nature in terms of their contribution to ozone formation, no reactive-pollutant modeling of VOCs is proposed at this point. In addition, Power Ventures requests that a pre-construction ambient ozone monitoring study not be required.

VOC is not limited directly by NAAQS. Rather, VOC is regulated by the U.S. EPA as a precursor to tropospheric ozone formation. Ozone is unique because the U.S. EPA has not established a PSD modeling

significance level [an ambient concentration expressed in either micrograms per cubic meter [$\mu g/m^3$] or parts per million by volume (ppmv)] for ozone. U.S. EPA has also established an ambient monitoring *de minimis* level, which is different from other criteria pollutants because it is based on a mass emission rate (100 tpy) instead of an ambient concentration (in units of $\mu g/m^3$ or ppmv). Since the project VOC emissions increase exceeds the 40 tpy significant mass emission rate, an air quality analysis was performed using the Scheffe method to demonstrate compliance with the currently enforced 1-hour NAAQS standard for ozone.

Ozone impacts due to proposed new sources can be evaluated using the "Scheffe Tables." [32] The Scheffe method is a screening procedure used to calculate the ambient ozone concentration resulting from a VOC-dominated point source. A series of lookup tables, based on the Reactive Plume Model-II, are used to conservatively estimate the ozone concentration increase. Use of the Scheffe method requires knowledge of the ratio of maximum annual non-methane volatile organic compounds (NMVOC) to $NO_x$ emissions from the facility. The lookup tables have been validated for NMVOC/$NO_x$ values ranging from 1 to 30. The user is cautioned against interpolating from the tables for values outside this range. In addition, it is generally accepted that NMVOC/$NO_x$ ratios less than 2:1 result in no significant increase in ozone.

The Scheffe NMOC/ $NO_x$ Point Source Screening Tables were used to calculate the ozone increment. Non-methane organic carbons (NMOC) are conservatively assumed to be equal to VOC for the purposes of this analysis. Given that NMOC = 128.69 tpy and $NO_x$ =141.57 tpy, the post-project facility-wide NMVOC/$NO_x$ ratio is 0.91. Since the NMVOC/$NO_x$ ratio is less than 1, the source is considered $NO_x$-dominated, and a Scheffe method analysis is infeasible to run. Additionally, the NMVOC/$NO_x$ ratio is not conducive to ozone formation and no significant increase in ozone can be expected.

## 7.11 Representative Monitors

For the Lacey Randall project, representative monitoring data was used for ozone, $PM_{2.5}$, and $PM_{10}$. This paper discusses each of these pollutant monitors and how they are representative of the project site. Table 1 below displays the selected representative monitors and their locations for each pollutant.

[32] http://ndep.nv.gov/bapc/download/model/scheffe.pdf

**Table 7-12. Selected Monitors for Background Concentrations**

| Pollutant | Air Quality System Monitor ID |
|---|---|
| $PM_{10}$ | Monitor 20-181-0001 (Goodland) |
| $PM_{2.5}$ | Monitor 20-195-0001 (Cedar Bluff) |
| Ozone | Monitor 20-195-0001 (Cedar Bluff) |

In accordance with EPA documentation[33], there are three criteria that should be considered when selecting a representative existing ambient air monitor to represent ambient air concentrations for a project. These three criteria include the following: monitor location, data quality and currentness of data. Further discussion on these three criteria is presented below.

Monitor Location

The selected monitors are located in Figure 7-22 Appendix G and are all located in Kansas. For each pollutant, the closest and most current monitor was selected. Land use was considered in the selection of representative monitors for the proposed Project. Monitored concentrations should represent the land use within the immediate vicinity of the site, as much as is practicable. The land use surrounding the Project and each selected monitor are shown in Figures 7-23, 7-24, and 7-25. As shown in the figures, the selected monitors are located in grasslands and open water for Cedar Bluff and cultivated crops/low to medium intensity developed for Goodland. The Project will be located in cultivated cropland, three miles northeast of Colby, Kansas and is just over two km from the developed industrial/urban area of the city.

Another criteria used to show that the monitors are representative of the Project site is to show that the air emission sources near the monitors are similar to the proposed Project site. Figures 7-26 through 7-33 display the pollutant sources near the MGS site as well as the pollutant sources near each of the selected monitors. In all cases, the selected monitors are either closer to or comparably located near larger sources

[33] U.S EPA. Ambient Air Monitoring Guidelines for Prevention of Significant Deterioration (PSD). EPA-450/4-87-007. May 1987.

of emissions than the Project. The facility data shown in the figures were obtained from the actual emissions reported in the National Emissions Inventory Database (2008 data),[34] as this data was readily available and is based on actual emissions. Therefore, the selection of the proposed monitors are representative of the Project or would likely provide more conservative ambient concentrations due to the more industrialized locations of the monitors.

Additionally, the monitor base elevations are representative of the Project elevation as shown below:

- Project Elevation = 962 meters
- Monitor 20-195-0001 (Cedar Bluff) = 670 meters
- Monitor 20-181-0001 (Goodland) = 1117 meters

Data Quality

Data quality was a factor in the selection of the proposed monitors. The selected monitors were reviewed for completeness and it was determined that all data years for each pollutant and selected monitor are more than 80 percent complete (Goodland – $PM_{10}$- 80%+, Cedar Bluff – Ozone – 99%+).

Currentness of Data

Each monitor has data from at least 2000 to 2013 and therefore fulfills the currentness requirement.

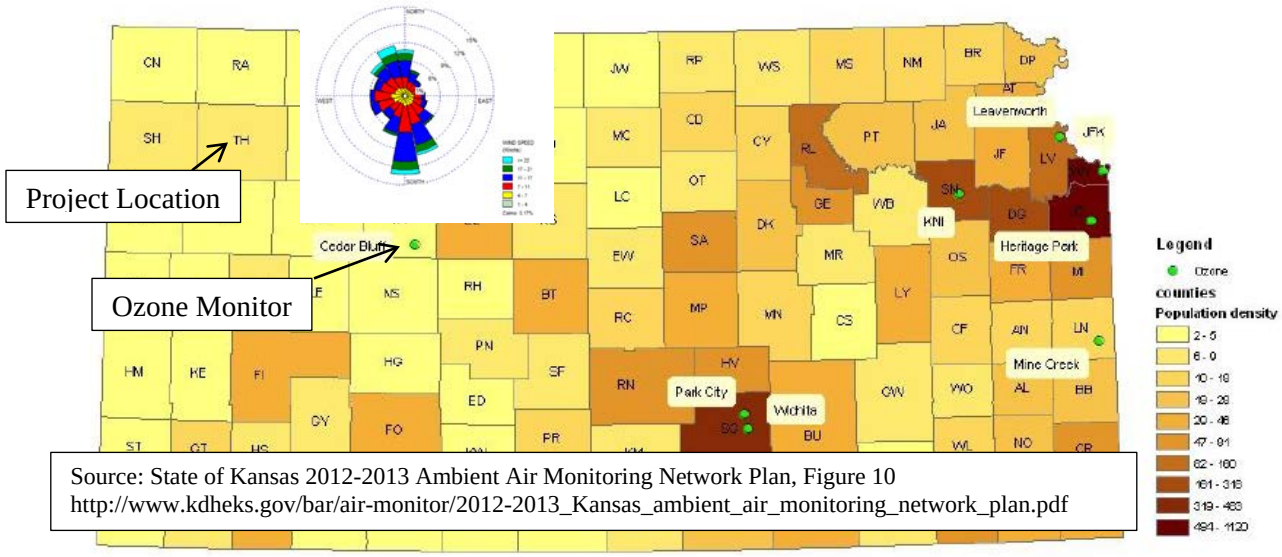
Monitor Recommendations

The nearest monitor to the Project that measures ozone and $PM_{2.5}$ concentrations is the Cedar Bluff site (AIRS No 20-195-0001), located at the Cedar Bluff Reservoir in Trego county. This monitor is 83 miles southwest from the Project in a generally downwind direction. See Figures 7-34 and 7-35. This station is operated by the KDHE and measure ozone and $PM_{2.5}$ concentrations according to EPA procedures.

When comparing the population density and the location of the Cedar Bluff monitor in relation to the Project site, Cedar Bluff is appropriately representative for use as preconstruction monitoring for both ozone and $PM_{2.5}$.

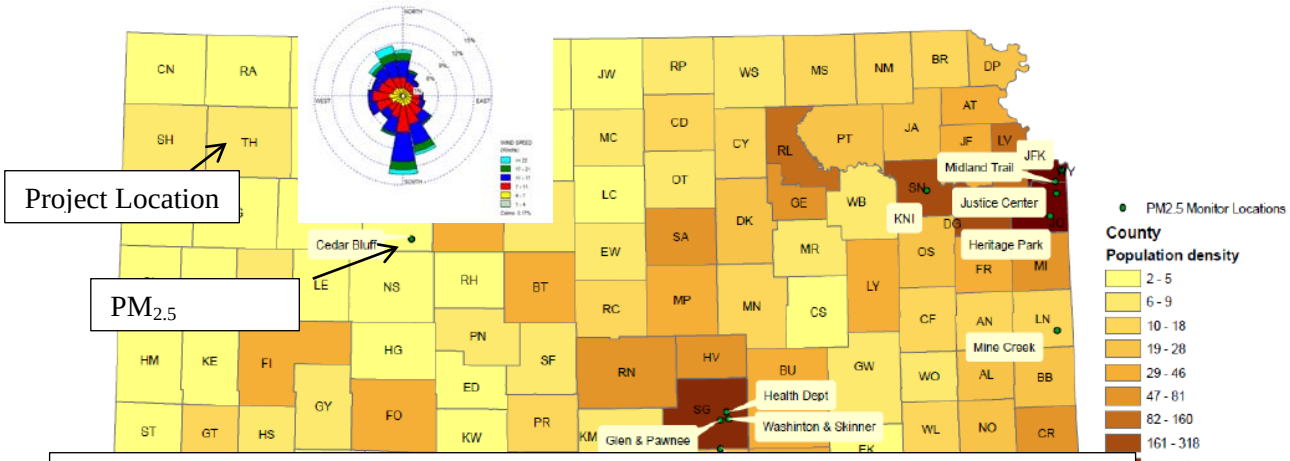
[34] The National Emissions Inventory: http://www.epa.gov/ttn/chief/net/2008inventory.html

**Figure 7-34. State of Kansas Population Density Map and the Location of $O_3$ Monitors Compared to Project Site.**




Source: State of Kansas 2012-2013 Ambient Air Monitoring Network Plan, Figure 10
http://www.kdheks.gov/bar/air-monitor/2012-2013_Kansas_ambient_air_monitoring_network_plan.pdf

**Figure 7-35. State of Kansas Population Density Map and the Location of $PM_{2.5}$ Monitors Compared to Project Site.**

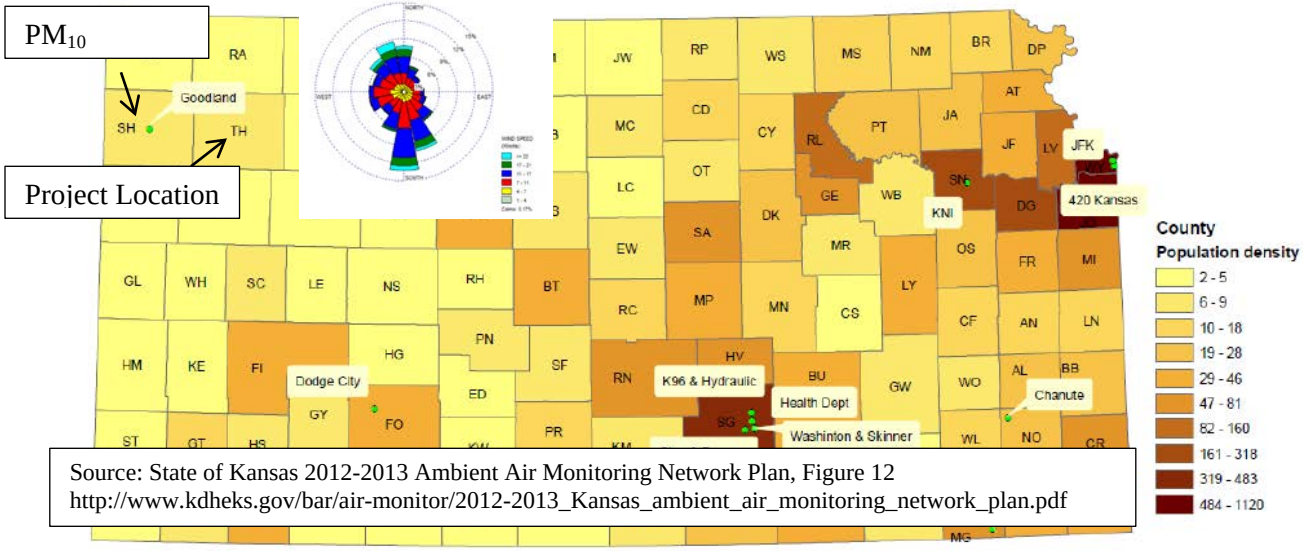



Source: State of Kansas 2012-2013 Ambient Air Monitoring Network Plan, Figure 11
http://www.kdheks.gov/bar/air-monitor/2012-2013_Kansas_ambient_air_monitoring_network_plan.pdf

The nearest monitor to the Project that measures $PM_{10}$ concentrations is the Goodland site (AIRS No 20-181-0001), located at the city fire station in the city of Goodland in Sherman county. This monitor is 37 miles west from the Project. See Figure 7-36. This station is operated by the KDHE and measure $PM_{10}$ concentrations according to EPA procedures.

When comparing the population density and the location of the Goodland monitor in relation to the Project site, Goodland is appropriately representative for use as preconstruction monitoring for both ozone and $PM_{2.5}$.

**Figure 7-36. State of Kansas Population Density Map and the Location of $PM_{10}$ Monitors Compared to Project Site.**




Source: State of Kansas 2012-2013 Ambient Air Monitoring Network Plan, Figure 12
http://www.kdheks.gov/bar/air-monitor/2012-2013_Kansas_ambient_air_monitoring_network_plan.pdf

Tradewind requests that preconstruction monitoring be fulfilled with existing KDHE monitors, specifically that Goodland (20-181-0001) be used for $PM_{10}$ and that Cedar Bluff (20-195-0001) be used for ozone and $PM_{2.5}$.

# 8.0 ADDITIONAL IMPACT ANALYSIS

The additional impacts analysis requirement under K.A.R 28-19-50 includes the ambient air quality impact analysis, soils and vegetation impacts, visibility impairment, and growth analysis for the Project.

## 8.1 Construction Impacts

Construction at Lacey Randall Station has the potential for short-term adverse effects on air quality in the immediate area around the site. Diesel fumes from construction vehicles and dust from site preparation and construction vehicle operation can affect local air quality during certain meteorological conditions. However, these instances are limited in time and area of effect.

The Thomas County area is in attainment or is unclassified for all criteria pollutants. Low sulfur fuel will be used for construction vehicles that use diesel fuel. Operation of these vehicles is not expected to significantly affect ambient air quality. Emissions will be minimized as much as practicable by reducing engine idling, operating vehicles as little as possible and employing vehicles with highly efficient engines. Fugitive dust will be minimized through the application of water to on-site roads used by construction equipment.

## 8.2 Vegetation Impacts

The general land use in the vicinity of Lacey Randall Station is irrigated row cropland and dry-land farming. Common crops produced in this area include wheat (*Triticum aestivum*), corn (*Zea mays*), grain sorghum (*Sorghum bicolor*), alfalfa (*Medicago sativa*), and sunflower (*Helianthus annuus*).[35,36] Trees are generally uncommon but may occur in hedgerows and along riparian corridors. These species include Siberian elm (*Ulmus pumila*), hackberry (*Celtis occidentalis*), honey locust (*Gleditsia triancanthous*), plum (*Prunus* spp.), black willow (*Salix nigra*), sandbar willow (*Salix interior*), eastern red cedar (*Juniperus virginiana*), cottonwood (*Populus deltoides*), and, mulberry (*Morus* sp.).[37] Remnants of native shortgrass prairie may occur near Lacey Randall Station. Common grasses in this community include blue-grama (*Bouteloua gracilis*), buffalograss (*Bouteloua dactyloides*), alkali sacaton (*Sporobolus airoides*), and western wheatgrass (*Pascopyrum smithii*).[38]

The following sections briefly describe the potential effects of $NO_2$, CO, $PM/PM_{10}/PM_{2.5}$, and $CO_2e$ produced by the Project on the nearby vegetation. The potential effects of these air emissions on

[35] Kansas State University Extension, 2012.
[36] Barker et al. 1980.
[37] Stephens, 1969.
[38] Chapman et al. 2001.

vegetation within the immediate vicinity of Lacey Randall Station were compared to scientific research examining the effects of pollution on vegetation. Damage to vegetation often results from acute exposure to pollution, but may also occur after prolonged or chronic exposures. Acute exposures are typically manifested by internal physical damage to leaf tissues, while chronic exposures are more associated with the inhibition of physiological processes such as photosynthesis, carbon allocation, and stomatal functioning.[39]

### 8.2.1 Nitrogen Oxides

During fuel combustion, atmospheric and fuel-bound nitrogen is oxidized to nitrogen oxide (NO) and small amounts of $NO_2$.[40] The NO is photochemically oxidized to $NO_2$, which is then subsequently consumed during the production of ozone and peroxyacetyl nitrates (PANs). As with $SO_2$ emission research, $NO_2$ has been shown to deleteriously impact vegetation.[41] Typical leaf injury responses include interveinal necrotic blotches similar to $SO_2$ injury for angiosperms and red-brown distal necrosis in gymnosperms.[42] Injury threshold concentrations vary by species and dose, but are much higher than that of $SO_2$ as described above. In general, short-term, high concentrations of $NO_2$ are required for deleterious impacts on plants.[43] The injury threshold concentration for plants that are grown in Kansas is 7,380 $\mu g/m^3$ for tomato (*Lycopersicon esculentum*) and annual sunflower (*Helianthus annuus*). Lamb's quarters (*Chenopodium album),*a common weedy plant found in disturbed areas in Kansas, was not injured for two hours at concentrations of 1.9 $\mu g/m^3$ $NO_2$. Furthermore, short-term fumigations of approximately 1-hour, 20-hours, and 48-hours at $NO_2$ concentrations of 940 to 38,000 $\mu g/m^3$, 470 $\mu g/m^3$, and 3,000 to 5,000 $\mu g/m^3$, respectively, have been shown to impair photosynthesis in a number of herbaceous [tomato, oats (*Avena sativa*), alfalfa] and woody plants.[44] Moreover, Taylor and McLean (1970),[45] in their review of $NO_2$ effects on vegetation, noted that long-term exposures of phytotoxic doses of $NO_2$ ranged from 280 to 560 $\mu g/m^3$. The maximum annual and 1-hour $NO_2$ modeled values for the Project are 1.11 and 59.15 $\mu g/m^3$, respectively. These levels are low, so it is highly unlikely that $NO_2$ emissions will impact vegetation adjacent to or surrounding Lacey Randall Station.

[39] Hallgren, 1984; Hill and Littlefield, 1969; Mansfield and Freer-Smith, 1984.
[40] Chang 1981
[41] Taylor et al. 1975; Heath 1980; Kozlowski and Constantinidou 1986; Darrall 1989
[42] Kozlowski and Constantinidou 1986
[43] Prinz and Brandt 1985
[44] Hill and Bennett 1970; Capron and Mansfield 1976; Smith 1981
[45] Taylor and McLean, 1970.

### 8.2.2 Synergistic Effects of Pollutants

Air pollutants are known to act in concert to cause injury to or decrease the functioning of plants.[46] Synergistic refers to the combined effects of pollutants when they are greater than is expected from the additive effect of the compounds. Inhibitory effects of $SO_2$ and $NO_2$,[47] $NO_2$ and NO,[48] $NO_2$ and ozone,[49] and ozone and $SO_2$[50] have been reported in various short-term studies for crop and woody plants (e.g., soybean, broad bean (*Vicia faba*), annual sunflower, tomato, and eastern cottonwood). Concentrations of pollutants (80 to 981 $\mu g/m^3$) in these studies are higher than the concentrations predicted to occur near Lacey Randall Station. Consequently, no synergistic effects of the air pollutants are expected to inhibit vegetation at or near Lacey Randall Station.

### 8.2.3 Particulate Matter

Particulates have been typically shown to be detrimental to vegetation within the immediate vicinity of the source. The most obvious effect of particle deposition on vegetation is a physical smothering of the leaf surface. This will reduce light transmission to the plant and cause a decrease in photosynthesis. The maximum $PM_{10}$ and $PM_{2.5}$ 24-hour modeled values for the Project are 8.8 $\mu g/m^3$ and 8.8 $\mu g/m^3$, respectively. This level is low, so it is highly unlikely that $PM_{10}$ and $PM_{2.5}$ emissions will impact vegetation adjacent to Lacey Randall Station.

### 8.2.4 Carbon Monoxide

CO is not known to injure plants, nor has it been shown to be taken up by plants. Consequently, no adverse impacts to vegetation at or near Lacey Randall Station are expected from CO stack emissions from the Project.

### 8.2.5 Carbon Dioxide

$CO_2$ is not known to injure plants. Long-term exposure to elevated $CO_2$ levels has shown to improve the efficiency of nutrient, water, and photosynthesis in some plants.[51] However, the improved efficiencies that result from elevated $CO_2$ levels may not necessarily result in greater yields for crop plants.[52] No adverse impacts to vegetation at or near Lacey Randall Station are expected from $CO_2$ stack emissions from the Project.

[46] *See* reviews of Reinert et al. 1975; Omrod 1982
[47] White et al. 1974; Wright et al. 1986
[48] Capron and Mansfield 1976
[49] Furakawa et al. 1984; Okana et al. 1985
[50] Costonis 1970, Carlson 1979; Jensen 1981; Omrod et al. 1981
[51] Drake, Gonzalez-Meler, and Long 1997; Leakey, Ainsworth, Bernacchi, Rogers, Long, and Ort 2009
[52] Morgan, Bollero, Nelson, Dohleman, and Long 2005

## 8.3 Soil Impacts

Four soil types are mapped at, or in the immediate vicinity of, the Project site.[53] They include:

- Keith silt loam, 0 to 1 percent slopes
- Keith silt loam, 1 to 3 percent slopes
- Ulysses silt loam, 1 to 3 percent slopes
- Ulysses silt loam, 3 to 6 percent slopes

Sulfates and nitrates resulting from $SO_2$ and $NO_2$ deposition on soil can be both beneficial and detrimental to soils depending on their composition. However, given that the expected impacts from the project are considerably lower than the NAAQS or any other standard found in the regulations, the levels of pollution from the project will likely have negligible effects on soils on-site or in the immediate vicinity.

## 8.4 Industrial, Residential, and Commercial Growth Impacts

The Project is expected to increase employment in the area. The building phase will last approximately one year. Construction employment is expected to peak at approximately 150 skilled construction jobs. Projected employment, reflecting full-time jobs directly tied to the operation of Lacey Randall Station is estimated to be 5 people at the facility. This will result in moderate amounts of secondary employment being created by the economic activity of the facility. In the immediate vicinity of the facility and as a result of the Project at Lacey Randall Station, increased vehicular traffic is expected. However, these activities are not expected to significantly impact air quality.

The construction work at Lacey Randall Station may temporarily increase the number of people residing in the area. After construction is completed, many of the new employees are expected to already live in the area. However, some new employees are expected to move into the area, with only a slight increase in the residential growth in the area. This small increase in new residences is not expected to have an impact on the air quality in the area.

Adding additional electricity to the grid in this area may increase industrial growth. However, it is unknown how increasing available electrical power in this area may affect future industrial growth.

[53] Barker et al., 1980; Natural Resources Conservation Service. 2013.

## 8.5 Visibility and Deposition Analysis

### 8.5.1 Class I Area Analysis

Recent FLM guidance advises that a proposed major source, in the course of a PSD application, should perform an assessment of air quality impacts at Class I areas if these areas are located within approximately 300 kilometers of the proposed facility. Because there are no Class I areas that are within 300 kilometers of the Project, no assessment of air quality impacts at Class I areas will be performed for this Project.

### 8.5.2 Class II Area Analysis

Lacey Randall Station is located in a Class II area. With respect to visibility conditions around the facility, there are no known Class II screening visibility criteria that have been recommended at this time. A visibility analysis was performed for Scott State Park located approximately 80 kilometers south of the Project near Scott City, Kansas.

The visibility analysis was performed in accordance with the guidelines set forth in EPA-450/4-88-015, Workbook for Plume Visual Impact Screening and Analysis. Within the document, the model VISCREEN is recommended for plume visibility analysis. Several refinement levels of VISCREEN are described. The first-level VISCREEN analysis uses worst-case meteorological conditions (F-class stability, one meter per second wind speed). This level of screening results in the most conservative (worst-case) visibility results. If the plume visibility against the sky and terrain is below a level perceivable to the human eye, the visibility modeling is complete. Otherwise, a second-level VISCREEN analysis using actual meteorological data and refined particle characteristics can be performed. The second-level model will result in a more realistic visibility analysis. If this plume visibility still does not meet sky and terrain contrast levels, a third-level model may be required which adds more statistical analysis.

The first-level VISCREEN model was performed for the Project at Lacey Randall Station. The inputs into the model included particulate matter, $NO_x$, primary $NO_2$, soot, and primary sulfate ($SO_4$). Annual particulate and $NO_x$ emissions were calculated for each operating scenario. The maximum annual particulate emission rate of 100.59 tons per year occurs when the units operate 8,760 hours per year and the maximum $NO_x$ emission rate of 141.57 tons per year occur when the units operate for 8,760 hours per year. These maximum rates were used in the VISCREEN analysis.

According to the workbook, primary $NO_2$, soot, and primary $SO_4$ can be assumed to be zero except for very specific sources. Since the facility is not one of the specified sources, the emissions for the last three

pollutants (primary $NO_2$, soot, and primary $SO_4$) are assumed to be zero. The next set of inputs into the first-level VISCREEN model considers the distance between the source, observer, and area, and the background visual range. The distance between the source and observer at Scott State Park is 80 kilometers. Background visibility was determined from the VISCREEN manual to be 60 kilometers.

The last inputs into the model are particle sizes, background ozone, plume-source-observer angle, stability, and wind speed. All of these inputs are automatically set if the default option is chosen. For the first-level analysis, the workbook tells the analyst to choose the default option, which sets the following particle sizes:

- background fine = 0.3 micrometer (μm) diameter, 1.5 gram per cubic centimeter ($g/cm^3$) density,
- background course = 6 μm diameter, 2.5 $g/cm^3$ density,
- plume particulate = 2 μm diameter, 2.5 $g/cm^3$ density,
- plume soot = 0.1 μm diameter, 2 $g/cm^3$ density, and
- plume primary sulfate = 0.5 μm diameter, 1.5 $g/cm^3$.

The background ozone is 0.04 ppm, the plume-source-observer angle is 11.25 degrees, the worst case atmospheric stability is an F stability class, and the worst-case wind speed is one meter per second.

The VISCREEN model output compares the calculated Delta E and contrast from the plume to present default comparison values. Delta E is the color difference parameter used to characterize the perceptibility of the plume on a color difference between the plume and a viewing background such as the sky, a cloud, or a terrain feature. Color differences are due to differences in three dimensions: brightness (L*), color hue (a*), and saturation (b*). Delta E is calculated for several lines of sight. A green contrast analysis is also performed for various lines of sight using a green wavelength and contrasting the plume with the terrain and sky backgrounds. The critical E value is 2.0 and the green contrast value is 0.05 for Class I areas. However, there are currently no Class II screening visibility criteria for the state of Kansas.

The results of the first-level VISCREEN model are provided in Appendix H. The visual results pass the Class II screening criteria for Scott State Park located approximately 80 kilometers from Lacey Randall Station.

## 8.6 Conclusion

As shown by the results presented in this section of the application and additional supplemental information, the Project will not have a significant adverse impact on the air quality, soils, vegetation, visibility and or growth in the surrounding area.

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# APPENDIX A - FORMS

# Kansas Department of Health and Environment
# Bureau of Air and Radiation
# Phone (785) 296-1570 Fax (785) 291-3953

# Notification of Construction or Modification

**(K.A.R. 28-19-300 Construction permits and approvals; applicability)**

**Check one: ☒Applying for a Permit under K.A.R. 28-19-300(a) GApplying for an Approval under K.A.R. 28-19-300(b)***

1) Source ID Number: 1930036

2) Mailing Information:
Company Name: Lacey Randall Generation Facility, LLC
Address: 16105 W. 113th Street, Suite 105
City, State, Zip: Lenexa, KS 66219

3) Source Location:
Street Address: Southwest ¼ Section 17, Township 7S, Range 33W – 3.5 miles northeast of Colby, Kansas
City, County, State, Zip: Colby, Thomas County, Kansas 67701
Section, Township, Range: Southwest ¼ Section 17, Township 7S, Range 33W
Latitude & Longitude Coordinates: North 39° 26'29.54" West 101° 01'51.47"

4) NAICSC/SIC Code (Primary): 221112, Fossil Fuel Power Generation/ SIC 4911

5) Primary Product Produced at the Source: Electricity

6) Would this modification require a change in the current operating permit for your facility? 9 Yes ☒No

If no, please explain: Not Applicable – New Facility

7) Is a permit fee being submitted? ☒ Yes ☐ No

If yes, please include the facility=s federal employee identification number (FEIN #) 46-1018545

8) Person to Contact at the Site: Brice Barton Phone: (785-443-3434)
Title: Development Manager

9) Person to Contact Concerning Permit: Jennifer A. Dean Phone: (913) 219-5004
Title: Director of Environmental Studies and Permitting
Email: jdean@tradewindenergy.com Fax: (913) 888-0390

Please read before signing:

Reporting forms provided may not adequately describe some processes. Modify the forms if necessary. Include a written description of the activity being proposed, a description of where the air emissions are generated and exhausted and how they are controlled. A simple diagram showing the proposed activity addressed in this notification which produces air pollutants at the facility (process flow diagrams, plot plan, etc.) with emission points labeled must be submitted with reporting forms. Information that, if made public, would divulge methods or processes entitled to protection as trade secrets may be held confidential. See the reverse side of this page for the procedure to request information be held confidential. A copy of the Kansas Air Quality Statutes and Regulations will be provided upon request.

Name and Title: Robert H. Freeman, CEO

Address: 16105 W. 113th Street, Suite 105
Lenexa, KS 66219

Signature: _____ Date: ___/___/_____ Phone: (913) 322-7415

* If you do not know whether to apply for a permit or an approval, follow approval application procedures.

# Procedures For Requesting Information To Be Held Confidential

An applicant may request that information submitted to the Department, other than emission data or information in any air quality permit or approval, be treated as confidential if the information would divulge methods or processes entitled to protection as trade secrets.

A request to designate information within the Department's air quality files as confidential must include:

(1) An uncensored copy of the document clearly marked as confidential;

(2) A copy of the document, or copies if more than one is required to be filed with the Department, with the confidential information masked;

(3) Specification of the type of information to be held as confidential (i.e., product formulations, process rates);

(4) Specification and justification of the reason the information is qualified by statute to be treated as confidential (competitive advantage, company developed secret formulation, trade secret); and

(5) A reference at each place in the document or documents where information is masked referring to the specification of the type of information masked and the specification and justification the information is qualified by statute to be treated as confidential.

ONLY THE CONFIDENTIAL INFORMATION ON ANY DOCUM ENT MAY BE MASKED. ALL INFORMATION ON ANY DOCUMENT WHICH IS NOT CONFIDENTIAL MUST REMAIN LEGIBLE.

The information will be treated as confidential until the secretary has acted upon the request and the owner or operator has had the opportunity to exhaust any available remedies if the secretary determines the information is not confidential.

Complete this and all reporting forms and submit to:

Kansas Department of Health and Environment
Bureau of Air and Radiation
1000 SW Jackson, Suite 310
Topeka, KS 66612-1366
(785) 296-1570

Sources located in Wyandotte County should obtain forms from, and submit forms to:

Unified Government of Wyandotte County
Department of Air Quality
619 Ann Avenue
Kansas City, KS 66101
(913) 573-6700

# CALCULATING THE CONSTRUCTION PERMIT APPLICATION FEE

[These requirements are found at K.A.R. 28-19-304(b).]

Calculate the construction permit application fee as follows:

| | | |
|---|---|---|
| Estimated capital cost of the proposed activity for which the application is made, including the total cost of equipment and services to be capitalized. | **Line 1** $ | 47,000,000 |
| Multiply by .05% (.0005) | **x** | .0005 |
| Total | **Line 2** $ | 23,500 |
| **If Line 2 is less than $100, enter $100 on Line 3.** If Line 2 is greater than $4,000, enter $4,000 on Line 3. | | |
| Otherwise, copy Line 2 to Line 3. | | |
| **Construction permit application fee.** | **Line 3** $ | 5,500* Minimum fee is $100 *Includes $1500 PSD fee |

Certifier of Capital Cost

_____
(Print)

_____ _____
(Signature) Date

K.A.R. 28-19-350 is a complex regulation pertaining to prevention of significant deterioration (PSD). An additional fee of $1,500 will be required if a PSD review is necessary. If you believe the proposed activity in this Notification of Construction or Modification will be subject to the requirements of K.A.R. 28-19-350, contact the Department for further evaluation.

For purposes of construction permit or approval applications, the following are not considered modifications:

1. Routine maintenance or parts replacement.
2. An increase or decrease in operating hours or production rates if:
   a. production rate increases do not exceed the originally approved design capacity of the stationary source or emissions unit; and
   b. the increased potential-to-emit resulting from the change in operating hours or production rates do not exceed any emission or operating limitations imposed as a permit condition.

**Kansas Department of Health and Environment**
**Division of Environment**
**Bureau of Air and Radiation**

# STATIONARY INTERNAL COMBUSTION ENGINES

1) Source ID Number :__1930036_____ Emission Point Number:___10 Engines (ENG_1 to ENG_10)____

2) Company/Source Name:__TradeWind Energy, Inc./Lacey Randall Station

3) Type of Engine: Turbine_____ ; Reciprocating__X__; Other__ _____

4) Engine Manufacturer :____Wartsila
   Model No.:_____20V34SG
   Date of Manufacture:_____TBD
   Serial No.:_____TBD

5) Use of Engine: Electric power generation __X__; Compressor ___ ; Pump___ ; Other - describe_____

6) Maximum Brake horsepower at continuous rating: _____ BHP
   Normal operating engine speed: _____ RPM
   Rated Brake Horsepower at normal operating RPM: _____ BHP
   or
   Maximum Generator Nameplate Capacity:_____9341_____kW
   Maximum design heat input rate: ___78.93_____ MMBTU/hr

7) Operating schedule: 8,760___hrs per year

8) Date of Installation: ____1st Quarter 2014
   Date of Last modification: ___not applicable

**TURBINES**

9) Type of Gas Turbine: Simple cycle _____ ; Co-generation _____ ; Regenerative _____ ; Combined cycle_____

10) Fuel data for all the different types of fuel to be used :
    a) Fuel Type _____ ; Sulfur content % by weight _____ ;
       Lower heating value _____ BTU per cu ft; **or** _____ BTU per lb; **or** _____ BTU per gallon
    b) Fuel Type _____ ; Sulfur content % by weight _____ ;
       Lower heating value _____ BTU per cu ft; **or** _____ BTU per lb; **or** _____ BTU per gallon
    c) Fuel Type _____ ; Sulfur content % by weight _____ ;
       Lower heating value _____ BTU per cu ft; **or** _____ BTU per lb; **or** _____ BTU per gallon

## STATIONARY INTERNAL COMBUSTION ENGINES
## (cont.)

11) Heat recovery unit or steam generator unit installed? Yes _____; No _____
Supplementary fired ? Yes _____; No _____ If yes, type of fuel used: _____
Capacity of the burner _____ gals per hr
Fuel heating value _____ BTU per cu ft or gal
Sulfur content of fuel by weight _____ %; Please attach complete supplementary fuel oil/distillate analysis.

12) Emission control system(s) used: Water injection_____ ; Steam injection_____ ;
Selective Catalytic reduction with Water injection _____ ; Selective catalytic reduction _____ ;
Describe Selective Catalytic emission reduction control installed:_____
Manufacturer's name:_____ Model No.: _____

| POLLUTANT | MANUFACTURER'S REDUCTION EFFICIENCY % |
|---|---|
| | |
| | |
| | |

13) Did construction, modification, or reconstruction commence after October 3, 1977? Yes_____; No _____
If yes, this facility may be subject to NSPS, 40 CFR 60, Subpart GG.

**RECIPROCATING ENGINES**

14) Engine design details:
Number of cylinders _20___
Aspiration: Normal _____ ; Turbo charged ___X___
Ignition: Spark__X__; Compression _____
Design class 2 cycle lean burn _____ ; 4 cycle lean burn __X__; 4 cycle rich burn _____

15) 2 or 4 cycle lean burn with combustion modification, increased air/fuel ratio and intercooling?
Yes _____; No__X___ Engines are 4 cycle, lean burn, with intercooled prechamber using Miller cycle (modified Otto cycle)
If yes, attach the guaranteed performance of the conversion supplier **or** the actual monitored performance, and the engine operating conditions for the guarantee of performance.

16) Type of integral emission control: Selective Catalytic Reduction___X____;
Non Selective Catalytic Reduction _____ ; Combustion Reduction Oxidation Catalyst__X_; None

17) Fuel(s): Gasoline _____ ; Diesel _____ ; Natural Gas___X____; Dual fuel _____

## STATIONARY INTERNAL COMBUSTION ENGINES
## (cont.)

18) Fuel Heating Value: Gasoline _____ BTU per gal; Diesel _____ BTU per gal;
Natural Gas __1,020__BTU per cu ft ; Dual fuel mix _ ____ % diesel _____ % natural gas
Sulfur content of diesel by weight _____ %

APPLICABLE TO ALL STATIONARY INTERNAL COMBUSTION ENGINES

19) Enclose available engine manufacturer′s emissions data.

20) For emission control equipment, use the appropriate CONTROL EQUIPMENT form and duplicate as needed. Be sure to indicate the emission unit that the control equipment is affecting.

**Kansas Department of Health and Environment**
**Division of Environment**
**Bureau of Air and Radiation**

# CATALYTIC CONVERTER
## (Stationary Internal Combustion Engine)

1) Source ID Number: __1930036_____

2) Company/Source Name: __Lacey Randall Generation Facility, LLC / Lacey Randall Generation Facility___

3) Catalytic Converter identification number or designation: __SCR_1 to SCR_10_____

4) What emission unit(s) or source(s) of emissions is(are) vented to the catalytic converter?
   a. _ENG_1 to ENG_10 are vented to SCR_1 to SCR_10, respectively____
   b. _____
   c. _____
   d. _____

5) Description of pollutant(s) collected: __NOx_____

6) Engine:
   Manufacturer:__Wartsila_____ Model No._20V34SG_____ Serial No. ___TBD_____
   Maximum HP:___12,526_____

7) Catalytic Converter:
   Manufacturer:___TBD_____ Model No.____TBD_____ Serial No. ____TBD_____
   Operating temperature range of catalyst: __635___°F to __842___°F
   Temperature at which over temperature protection switch activates: ___842___°F
   Describe any situations that could render the catalyst ineffective:
   - Operation at low engine loads (< 40% of maximum engine output) à risk to destroy catalyst elements
   - It is an unavoidable fact that the catalytic material loses activity over time. The actual ageing process is difficult to predict but after a certain point the activity of the catalyst has reached its design point and needs to be replaced.

   List the parameters and ranges that will define the proper operation of the catalytic converter:
   (e.g.: Output: __ to __ HP; $O_2$ Sensor: __ to __ volts; Exhaust temperature into the converter: __ to __°F)
   ___The Selective Catalytic Reduction (SCR) systems will work at operating loads of 50% to 100% load, except periods of unit start-up (30-min) and shutdown. The exhaust temperature must reach 635 degrees Fahrenheit for the catalyst temperature to reach the minimum temperature for maximum reduction of NOx.

8) Air/Fuel Ratio Controller:
   Manufacturer:_____ Model No._____ Serial No. _____

# CATALYTIC CONVERTER
# (cont.)

| 9) Emissions Reduced | Emission Factor (after converter) in grams/hp-hr |
|---|---|
| NOx | _____0.0525___ |
| CO | _____ |
| Nonmethane Hydrocarbons | _____ |
| Other: _____ | _____ |

**Kansas Department of Health and Environment**
**Division of Environment**
**Bureau of Air and Radiation**

# CATALYTIC CONVERTER
## (Stationary Internal Combustion Engine)

1) Source ID Number: _1930036_____

2) Company/Source Name: ___Lacey Randall Generation Facility, LLC / Lacey Randall Generation Facility___

3) Catalytic Converter identification number or designation: _OxCat_1 to OxCat_10_____

4) What emission unit(s) or source(s) of emissions is(are) vented to the catalytic converter?
   a. _ENG_1 to ENG_10 are vented to OxCat_1 to OxCat_10, respectively__
   b. _____
   c. _____
   d. _____

5) Description of pollutant(s) collected: __CO and VOC emissions_____

6) Engine:
   Manufacturer:___Wartsila_____ Model No.____20V34SG_____ Serial No. _____TBD_____
   Maximum HP:__12,526_____

7) Catalytic Converter:
   Manufacturer:___TBD_____ Model No.____TBD_____ Serial No. ____TBD_____
   Operating temperature range of catalyst: __635___°F to __842___°F
   Temperature at which over temperature protection switch activates: ___842___°F
   Describe any situations that could render the catalyst ineffective:
   - Operation at low engine loads (< 40% of maximum engine output) à risk to destroy catalyst elements
   - It is an unavoidable fact that the catalytic material loses activity over time. The actual ageing process is difficult to predict but after a certain point the activity of the catalyst has reached its design point and needs to be replaced.

   List the parameters and ranges that will define the proper operation of the catalytic converter:
   (e.g.: Output: __ to __ HP; $O_2$ Sensor: __ to __ volts; Exhaust temperature into the converter: __ to __°F)
   ___The Selective Catalytic Reduction (SCR) systems will work at operating loads of 50% to 100% load, except periods of unit start-up (30-min) and shutdown. The exhaust temperature must reach 635 degrees Fahrenheit for the catalyst temperature to reach the minimum temperature for maximum reduction of NOx.

8) Air/Fuel Ratio Controller:
   Manufacturer:_____ Model No._____ Serial No. _____

# CATALYTIC CONVERTER
# (cont.)

| 9) Emissions Reduced | Emission Factor (after converter) in grams/hp-hr |
|---|---|
| NOx | _____ |
| CO | ____0.0967____ |
| Nonmethane Hydrocarbons | ____0.0967____ |
| Other: _____ | _____ |

**Kansas Department of Health and Environment**
**Division of Environment**
**Bureau of Air and Radiation**

# STATIONARY INTERNAL COMBUSTION ENGINES

1) Source ID Number :____TBD_____Emission Point Number: __FP_1_____

2) Company/Source Name:__Lacey Randall Generation Facility, LLC / Lacey Randall Generation Facility_____

3) Type of Engine: Turbine_____ ; Reciprocating __X__ ; Other_____

4) Engine Manufacturer :____TBD____
   Model No.:_____ _TBD_____
   Date of Manufacture: _____TBD_____
   Serial No.: _____TBD_____

5) Use of Engine: Electric power generation ___ ; Compressor ___ ; Pump_X_; Other - describe_____

6) Maximum Brake horsepower at continuous rating: ___150_____ BHP
   Normal operating engine speed: _____ RPM
   Rated Brake Horsepower at normal operating RPM: ____150____ BHP
   or
   Maximum Generator Nameplate Capacity: ___111.9_____kW
   Maximum design heat input rate: ___881,028_____ BTU/hr

7) Operating schedule:__100__hrs per year

8) Date of Installation:_____1st Quarter 2014_____
   Date of Last modification: __not applicable_____

**TURBINES**

9) Type of Gas Turbine: Simple cycle _____ ; Co-generation _____ ; Regenerative _____ ; Combined cycle_____

10) Fuel data for all the different types of fuel to be used :
    a) Fuel Type _____ ; Sulfur content % by weight _____ ;
       Lower heating value _____ BTU per cu ft; **or** _____ BTU per lb; **or** _____ BTU per gallon
    b) Fuel Type _____ ; Sulfur content % by weight _____ ;
       Lower heating value _____ BTU per cu ft; **or** _____ BTU per lb; **or** _____ BTU per gallon
    c) Fuel Type _____ ; Sulfur content % by weight _____ ;
       Lower heating value _____ BTU per cu ft; **or** _____ BTU per lb; **or** _____ BTU per gallon

## STATIONARY INTERNAL COMBUSTION ENGINES
## (cont.)

11) Heat recovery unit or steam generator unit installed? Yes _____; No _____
Supplementary fired ? Yes _____; No _____ If yes, type of fuel used: _____
Capacity of the burner _____ gals per hr
Fuel heating value _____ BTU per cu ft or gal
Sulfur content of fuel by weight _____ %; Please attach complete supplementary fuel oil/distillate analysis.

12) Emission control system(s) used: Water injection_____ ; Steam injection_____ ;
Selective Catalytic reduction with Water injection _____ ; Selective catalytic reduction _____ ;
Describe Selective Catalytic emission reduction control installed:_____
Manufacturer's name:_____ Model No.: _____

| POLLUTANT | MANUFACTURER'S REDUCTION EFFICIENCY % |
|---|---|
| | |
| | |
| | |

13) Did construction, modification, or reconstruction commence after October 3, 1977? Yes_____; No _____
If yes, this facility may be subject to NSPS, 40 CFR 60, Subpart GG.

**RECIPROCATING ENGINES**

14) Engine design details: TBD
Number of cylinders _____
Aspiration: Normal _____ ; Turbo charged _____
Ignition: Spark _____ ; Compression _____
Design class 2 cycle lean burn _____ ; 4 cycle lean burn _ _____ ; 4 cycle rich burn _____

15) 2 or 4 cycle lean burn with combustion modification, increased air/fuel ratio and intercooling ? TBD
Yes _____; No_____
If yes, attach the guaranteed performance of the conversion supplier **or** the actual monitored performance, and the engine operating conditions for the guarantee of performance.

16) Type of integral emission control: Selective Catalytic Reduction _____ ;
Non Selective Catalytic Reduction _____ ; Combustion Reduction _____(Describe)_____; None __X__

17) Fuel(s): Gasoline _____ ; Diesel __X__ ; Natural Gas _____ ; Dual fuel _____

## STATIONARY INTERNAL COMBUSTION ENGINES
## (cont.)

18) Fuel Heating Value: Gasoline _____ BTU per gal; Diesel _140,000_____ BTU per gal;
Natural Gas _____ BTU per cu ft ; Dual fuel mix _ ____ % diesel _____ % natural gas
Sulfur content of diesel by weight __0.0015____ %

APPLICABLE TO ALL STATIONARY INTERNAL COMBUSTION ENGINES

19) Enclose available engine manufacturer=s emissions data.

20) For emission control equipment, use the appropriate CONTROL EQUIPMENT form and duplicate as needed. Be sure to indicate the emission unit that the control equipment is affecting.

**Kansas Department of Health and Environment**
**Division of Environment**
**Bureau of Air and Radiation**

# STATIONARY INTERNAL COMBUSTION ENGINES

1) Source ID Number : 1930036 Emission Point Number: GEN_1

2) Company/Source Name: Lacey Randall Generation Facility, LLC / Lacey Randall Generation Facility

3) Type of Engine: Turbine_____ ; Reciprocating ___X___ ; Other_____

4) Engine Manufacturer : Cummins
   Model No.: QSB7-G5 NR3
   Date of Manufacture: TBD
   Serial No.: TBD

5) Use of Engine: Electric power generation _X__ ; Compressor ___ ; Pump___ ; Other - describe_____

6) Maximum Brake horsepower at continuous rating: 324 BHP
   Normal operating engine speed: 1800 RPM
   Rated Brake Horsepower at normal operating RPM: _____ BHP
   or
   Maximum Generator Nameplate Capacity: _____kW
   Maximum design heat input rate: _1,903,020__ BTU/hr

7) Operating schedule: 100 hrs per year

8) Date of Installation: 1st Quarter 2014
   Date of Last modification: not applicable

**TURBINES**

9) Type of Gas Turbine: Simple cycle _____ ; Co-generation _____ ; Regenerative _____ ; Combined cycle_____

10) Fuel data for all the different types of fuel to be used :
    a) Fuel Type _____ ; Sulfur content % by weight _____ ;
       Lower heating value _____ BTU per cu ft; **or** _____ BTU per lb; **or** _____ BTU per gallon
    b) Fuel Type _____ ; Sulfur content % by weight _____ ;
       Lower heating value _____ BTU per cu ft; **or** _____ BTU per lb; **or** _____ BTU per gallon
    c) Fuel Type _____ ; Sulfur content % by weight _____ ;
       Lower heating value _____ BTU per cu ft; **or** _____ BTU per lb; **or** _____ BTU per gallon

## STATIONARY INTERNAL COMBUSTION ENGINES
## (cont.)

11) Heat recovery unit or steam generator unit installed? Yes _____; No _____
Supplementary fired ? Yes _____; No _____ If yes, type of fuel used: _____
Capacity of the burner _____ gals per hr
Fuel heating value _____ BTU per cu ft or gal
Sulfur content of fuel by weight _____ %; Please attach complete supplementary fuel oil/distillate analysis.

12) Emission control system(s) used: Water injection_____ ; Steam injection_____ ;
Selective Catalytic reduction with Water injection _____ ; Selective catalytic reduction _____ ;
Describe Selective Catalytic emission reduction control installed:_____
Manufacturer's name:_____ Model No.: _____

| POLLUTANT | MANUFACTURER'S REDUCTION EFFICIENCY % |
|---|---|
| | |
| | |
| | |

13) Did construction, modification, or reconstruction commence after October 3, 1977? Yes_____; No _____
If yes, this facility may be subject to NSPS, 40 CFR 60, Subpart GG.

**RECIPROCATING ENGINES**

14) Engine design details: TBD
Number of cylinders ____
Aspiration: Normal _____ ; Turbo charged _____
Ignition: Spark _____ ; Compression _____
Design class 2 cycle lean burn _____ ; 4 cycle lean burn _____ ; 4 cycle rich burn _____

15) 2 or 4 cycle lean burn with combustion modification, increased air/fuel ratio and intercooling ? TBD
Yes _____; No_____
If yes, attach the guaranteed performance of the conversion supplier **or** the actual monitored performance, and the engine operating conditions for the guarantee of performance.

16) Type of integral emission control: Selective Catalytic Reduction _____ ;
Non Selective Catalytic Reduction _____ ; Combustion Reduction _____(Describe)_____; None __X___

17) Fuel(s): Gasoline _____ ; Diesel __X ____ ; Natural Gas __ __ ; Dual fuel _____

## STATIONARY INTERNAL COMBUSTION ENGINES
## (cont.)

18) Fuel Heating Value: Gasoline _____ BTU per gal; Diesel ___140,000_____ BTU per gal;
Natural Gas _____ BTU per cu ft ; Dual fuel mix _ ____ % diesel _____ % natural gas
Sulfur content of diesel by weight _0.0015_%

APPLICABLE TO ALL STATIONARY INTERNAL COMBUSTION ENGINES

19) Enclose available engine manufacturer=s emissions data.

20) For emission control equipment, use the appropriate CONTROL EQUIPMENT form and duplicate as needed. Be sure to indicate the emission unit that the control equipment is affecting.

**Kansas Department of Health and Environment**
**Division of Environment**
**Bureau of Air and Radiation**

# INDIRECT HEATING UNIT (BOILER)

1) Source ID Number: __1930036_____

2) Company/Source Name:__Lacey Randall Generation Facility, LLC / Lacey Randall Generation Facility_____

3) Emission Unit Identification:_____HTR_1_____

4) Manufacturer:_____TBD_____Model No.:____TBD_____

5) Maximum design heat-input rate:____3,000,000___BTU/hr
   Heat-release Rate:__1,020__BTU/hr/cu. ft. of furnace volume
   Annual load factor: _100%_____
   Heater design: Cyclone _____; Underfeed stoker _____; Spreader stoker _____;
   Pulverized (dry-tangential or normal/wet)_____; Other (specify) _____
   Normal Operating Schedule:__8760__hours/year
   Date of latest modification: ___not applicable_____

6) Primary Fuel Type:
   Natural Gas __X__ Oil ____Coal ____ Other (specify) _____
   Secondary Fuel Type: N/A
   Natural Gas ____ Oil ____ Coal ____ Other (specify) _____

7) If other fuel is waste liquid:
   What is the source of the waste? _____
   Will the waste be pretreated to remove any of the contaminants? Yes ____; No ____ If yes, describe method of pretreatment:
   _____
   _____
   If waste liquid is used in combination with fuel oil:
   Specify the volume percent of waste liquid:_____ %
   Specify the anticipated annual operating hours during which the fuel and waste combination will be used: _____ hrs.
   Fill in the data below for the fuel oil.

Include the chemical and physical characteristics of the waste liquid. Also, include any source emissions test data that is available from testing similar facilities that have disposed of this type liquid waste.

# INDIRECT HEATING UNIT (BOILER)
# (cont.)

8) Fuel Specific Data: (if other is specified, give appropriate data)
   Natural Gas:
   Heating value: 1,020 BTU/cu. ft.
   (If fuel gas is used, also specify %Sulfur: _____)
   Coal:
   Fuel Parameters: %Sulfur: _____ % Ash: _____
   Heating value: _____ BTU/lb.
   Fuel Oil:
   Fuel Parameters: %Sulfur: ____ Grade: _____
   Heating value: _____ BTU/gal.
   Density: _____ lb./gal.

9) Air Emissions Control Technology: NOx __X__ SOx ____ CO ____ Particulate ____
   If yes, breakdown of Control Technology: Dry Low NOx Burners

10) Soot blowing (if applicable): frequency: _____ duration: _____

11) Has boiler been derated because of:
   Fuel change _____ Equip. limitations _____ Regulatory compliance _____

12) Emissions discharge to atmosphere 19 ft. above grade through stack or duct 0.83 ft. diameter at 500 E F temperature, with 1,439 cfm flow rate and 44.33 fps velocity.

13) For emission control equipment, use the appropriate CONTROL EQUIPMENT form and duplicate as needed. Be sure to indicate the emission unit that the control equipment is affecting

14) Did construction, modification, or reconstruction commence after August 17, 1971 and on or before September 18, 1978 and does the indirect heating unit have a maximum design heat-input capacity to combust more than 250 million BTU/hour? Yes _____; No __X_
   If yes, this plant may be subject to NSPS, 40 CFR Part 60, Subpart D.

15) Did construction, modification, or reconstruction commence after September 18, 1978 and does the indirect heating unit have a maximum design heat-input capacity to combust more than 250 million BTU/hour? Yes _____; No__X__
   If yes, this plant may be subject to NSPS, 40 CFR Part 60, Subpart Da.

16) Did construction, modification, or reconstruction commence after June 19, 1984 and does the indirect heating unit have a maximum design heat-input capacity to combust more than 100 million BTU/hour but less than 250 million BTU/hour? Yes___; No__X____
   If yes, this plant may be subject to NSPS, 40 CFR Part 60, Subpart Db.

# INDIRECT HEATING UNIT (BOILER)
# (cont.)

17) Did construction, modification, or reconstruction commence after June 9, 1989 and does the indirect heating unit have a maximum design heat-input capacity to combust 10 million or more BTU/hour but less than 100 million BTU/hour? Yes _____; No __X__
If yes, this plant may be subject to NSPS, 40 CFR Part 60, Subpart Dc. **(Not applicable because the gas heater does not produce steam.)**

**Kansas Department of Health and Environment**
**Division of Environment**
**Bureau of Air and Radiation**

# LIQUID STORAGE TANKS/VESSELS

1) Source ID Number: ___1930036_____

2) Company/Source Name:__Lacey Randall Generation Facility, LLC / Lacey Randall Generation Facility_____

3) Emission Unit Identification and Number: _____TANK1_____

4) Type of Tank:
   1. External Floating Roof (E) _____
   2. Internal Floating Roof (I) _____
   3. Horizontal Fixed Roof (H) _____
   4. Vertical Fixed Roof (V) _X_____
   5. Domed External Floating Roof (D) _____

5) Complete the following table:

| Measurement, Physical State, etc. | External | Internal | Horizontal | Vertical | Domed |
|---|---|---|---|---|---|
| Shell height (ft) | | | | 32’ | |
| Diameter (ft) | | | | 40.5’ | |
| Shell length (ft) | | | | | |
| Maximum liquid height (ft) | | | | 32’ | |
| Average liquid height (ft) | | | | 16’ | |
| Working volume / tank volume (gal) | | | | 308,377 | |
| Turnovers per year | | | | 100 | |
| Net throughput (gal/yr) | | | | 30,837,780 | |
| Tank heated (yes/no) | | | | no | |
| Tank underground (yes/no) | | | | | |
| Self-supported roof? (yes/no) | | | | | |
| Number of columns | | | | | |
| Column diameter (ft) | | | | | |
| Shell color/shade | | | | White/white | |
| Shell condition (good/poor) | | | | Good | |
| Shell paint condition (good/poor) | | | | | |
| Roof color/shade | | | | White/white | |
| Roof paint condition (good/poor) | | | | good | |

# LIQUID STORAGE TANKS/VESSELS
## (cont.)

| Measurement, Physical State, etc. | External | Internal | Horizontal | Vertical | Domed |
|---|---|---|---|---|---|
| Roof type (cone, dome, pontoon, doubledeck) | | | | cone | |
| Roof height (ft) | | | | 0 | |
| Dome roof radius (ft) | | | | 0 | |
| Cone roof slope (ft/ft) | | | | 0 | |
| Tank construction (welded, riveted) | | | | | |
| Primary seal (vapor-mounted, liquid-mounted, mechanical shoe) | | | | | |
| Secondary seal (weather shield, rim-mounted, none) | | | | | |
| Fitting category (typical, controlled, detail) | | | | | |
| Vacuum setting (psig) | | | | -0.03 | |
| Pressure setting (psig) | | | | 0.03 | |
| Deck type (bolted, welded) | | | | | |
| If bolted, deck construction | | | | | |
| If bolted, deck seam length (ft) | | | | | |
| Deck fitting (typical, controlled, detail) | | | | | |
| Chemical category of liquid (crude oil, petroleum distillate, organic liquid) | | | | petroleum distillate | |
| Single or multiple component mixture | | | | single | |
| Chemical name | | | | Distillate fuel oil no. 2 | |
| CAS number | | | | | |
| Vapor pressure of tank if different than ambient (psig) | | | | | |
| Temperature of tank if different than ambient ($^{o}$F) | | | | | |

## LIQUID STORAGE TANKS/VESSELS
## (cont.)

6) Tank shape: cylindrical _____ spherical _____other, describe _____

7) Tank material: steel _____ fiberglass _____ other, describe _____

8) If tank is fixed roof, check the type of vapor recovery system:

Liquid absorption _____ Vapor compression _____ Carbon absorption _____
None_____ Other, describe _____

9) Tank filling source: pipeline _____ railcar _____ truck ___X__ other, specify _____

10) Type of filling: submerged ___X___ splash _____

11) Maximum rate at which tank can be emptied _____gpm filled ____500____gpm

**Is this storage vessel subject to any of the following NSPS (40 CFR 60) subparts?**

12) (Subpart K - Petroleum Liquid Storage Vessels) Does the storage vessel have a capacity greater than 151,416 liters (40,000 gallons) but not exceeding 246,052 liters (65,000 gallons), and commenced construction or modification after March 8, 1974 and prior to May 19, 1978?
Yes ____ No ____ Exempt __X___

13) (Subpart K - Petroleum Liquid Storage Vessels) Does the storage vessel have a capacity greater than 246,052 liters (65,000 gallons) and commenced construction or modification after June 11, 1973 and prior to May 19, 1978?
Yes ____ No ____ Exempt __X___

14) (Subpart Ka - Petroleum Liquid Storage Vessels) Does the storage vessel have a capacity greater than 151,416 liters (40,000 gallons) and for which construction commenced after May 18, 1978 and prior to July 23, 1984?
Yes ____ No ____ Exempt __X___

15) (Subpart Kb - Volatile Organic Liquid Storage Vessels) Does the storage vessel have a capacity greater than or equal to 75 $m^3$ (19,813 gallons) and is used to store volatile organic liquids in which construction, reconstruction, or modification commenced after July 23, 1984?
Yes __X__ No ____ Exempt _____

16) (Subpart XX - Bulk Gasoline Terminals) Does the facility have a bulk gasoline terminal site?
Yes ____ No __X__
Have the loading racks at the bulk gasoline terminal been constructed or modified after December 17, 1980?
Yes ____ No ____ Exempt __X__

# LIQUID STORAGE TANKS/VESSELS
# (cont.)

17) (Subpart UU – Asphalt Processing and Asphalt Roofing Manufacturing) Is the tank an asphalt storage facility at a petroleum refinery or an asphalt roofing plant; or a mineral storage tank at an asphalt roofing plant; and
did the equipment commence construction or modification after November 18, 1980?

Yes _____ No _____ Exempt ____X____

Is the equipment an asphalt storage tank or blowing still at an asphalt processing plant, petroleum refinery, or asphalt roofing plant; and
does the asphalt storage tank or blowing still process and/or store asphalt used for roofing only or for roofing and other purposes; and
did the equipment commence construction or modification after November 18, 1980?

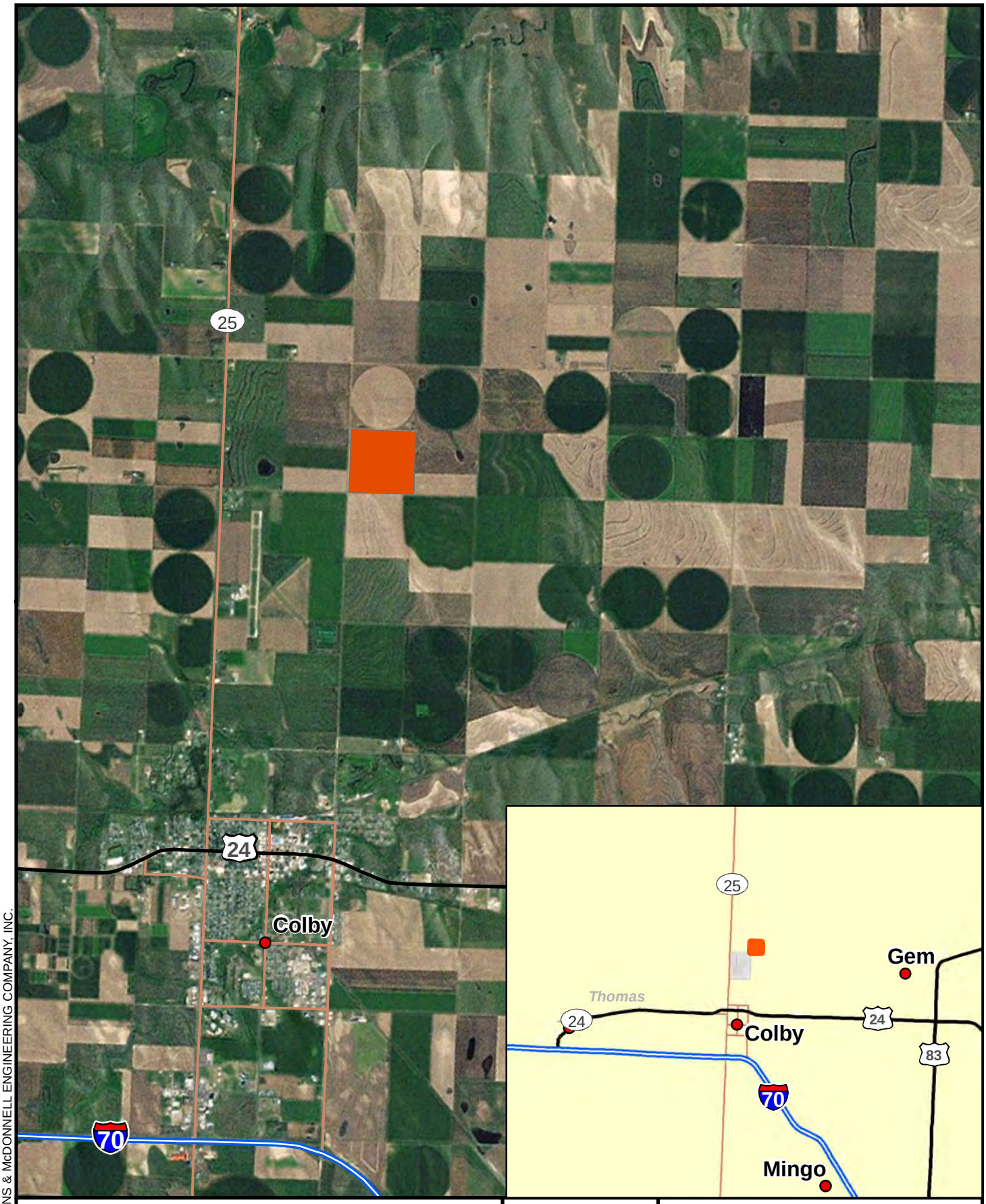
Yes _____ No _____ Exempt ____X_____

Is the equipment an asphalt storage tank or blowing still at an asphalt processing plant, petroleum refinery, or asphalt roofing plant; and
does the asphalt storage tank or blowing still process and/or store only nonroofing asphalts; and
did the equipment commence construction or modification after May 26, 1981?

Yes _____ No _____ Exempt ____X_____

18) Reason for any exemptions:_____
_____
_____
_____

# APPENDIX B - LAYOUTS




City

Project Location

NORTH

1 0.5 0 1

Miles

Burns & McDonnell SINCE 1898

Figure 3-1:
Proposed Lacey Randall Station
Site Location

Source: Esri, DigitalGlobe, GeoEye, i-cubed, USDA, USGS, AEX, Getmapping, Aerogrid, IGN, IGP, and the GIS User Community

Issued: 5/10/2013

Path: \\espsrv\data\Data2\Projects\Tradewind Energy\72125-Lacey_Randall\GIS\DataFiles\ArcDocs\LocationFigure.mxd cronchetti 5/10/2013

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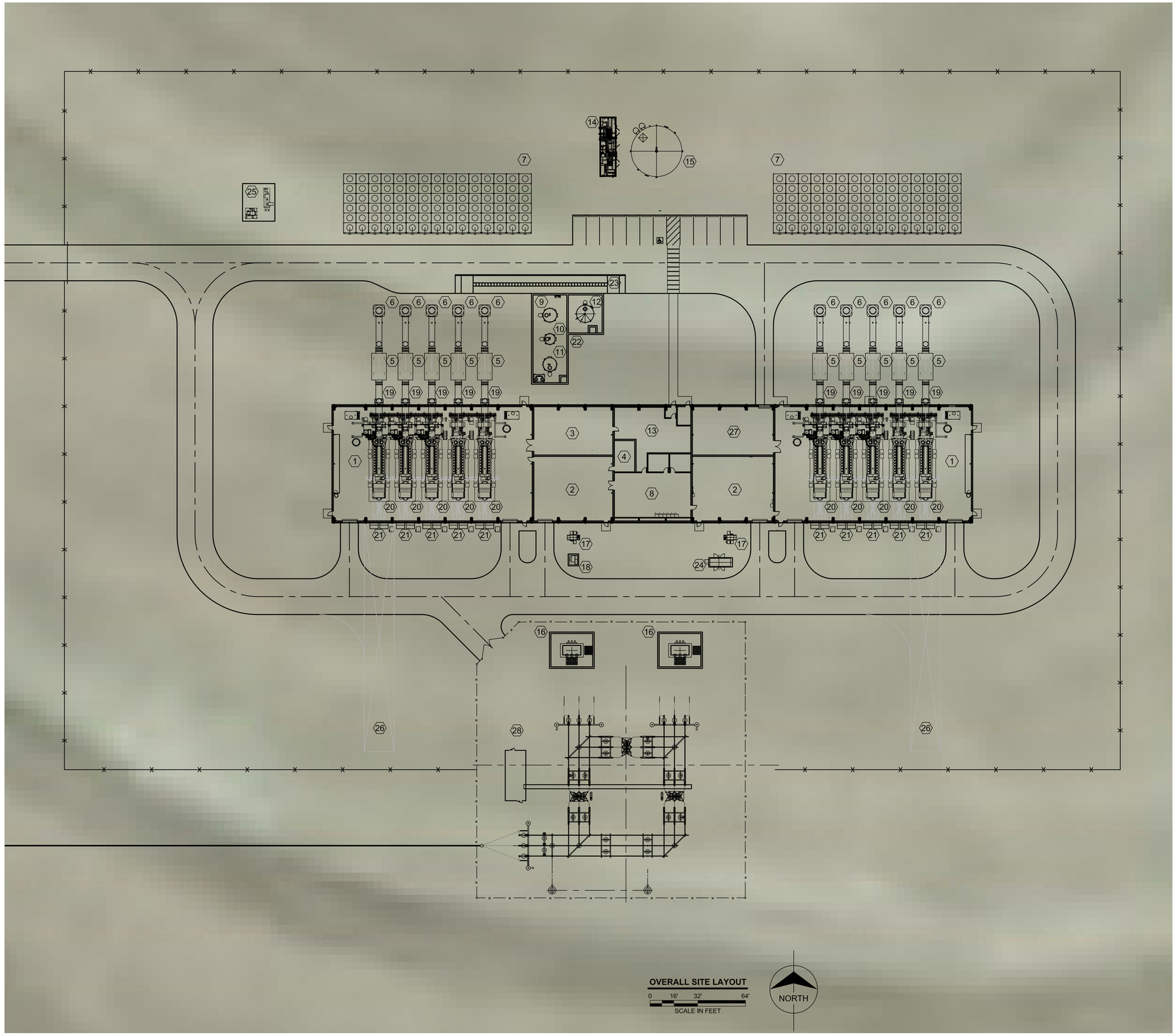
| no. | date | by | ckd | description |
|---|---|---|---|---|
| A | 02/28/13 | WRL | CJM | PRELIMINARY LAYOUT |




## SITE KEY

| | |
|---|---|
| 1 | RECIPROCATING ENGINE HALLS |
| 2 | SWITCHGEAR ROOM |
| 3 | MECHANICAL ROOM |
| 4 | BATTERY ROOM |
| 5 | SELECTIVE CATALYTIC REDUCERS |
| 6 | SILENCERS / STACKS |
| 7 | RADIATORS |
| 8 | CONTROL ROOM |
| 9 | NEW LUBE OIL TANK |
| 10 | SERVICE LUBE OIL TANK |
| 11 | USED LUBE OIL TANK |
| 12 | UREA TANK |
| 13 | ADMINISTRATIVE AREA |
| 14 | FIRE WATER PUMP HOUSE |
| 15 | FIRE WATER TANK |
| 16 | STEP-UP TRANSFORMER |
| 17 | STATION TRANSFORMERS |
| 18 | STAND-BY TRANSFORMER |
| 19 | CHARGE AIR FILTERS |
| 20 | GAS ENGINE |
| 21 | VENTILATION FANS |
| 22 | OIL/UREA CONTAINMENT |
| 23 | OIL/UREA UNLOADING STATION |
| 24 | AUXILARY GENERATOR |
| 25 | GAS CONDITIONING |
| 26 | HEAVY HAUL ROAD |
| 27 | MAINTENANCE |
| 28 | SWITCHYARD |

**CONFIDENTIAL**

Burns & McDonnell SINCE 1898

| | |
|---|---|
| date February 15, 2013 | detailed W. LESNIAK |
| designed | checked V. RANALLETTA |

TRADEWIND ENERGY® At the heart of power®

Figure 3-2: Site Layout

**PLANT GENERAL CONSTRUCTION**
WARTSILA 20V34SG
OVERALL SITE ARRANGEMENT

| | |
|---|---|
| project 69814 | contract |
| drawing **GA101** | rev. **A** |
| sheet | of sheets |
| file 69814_GA100.DWG | |

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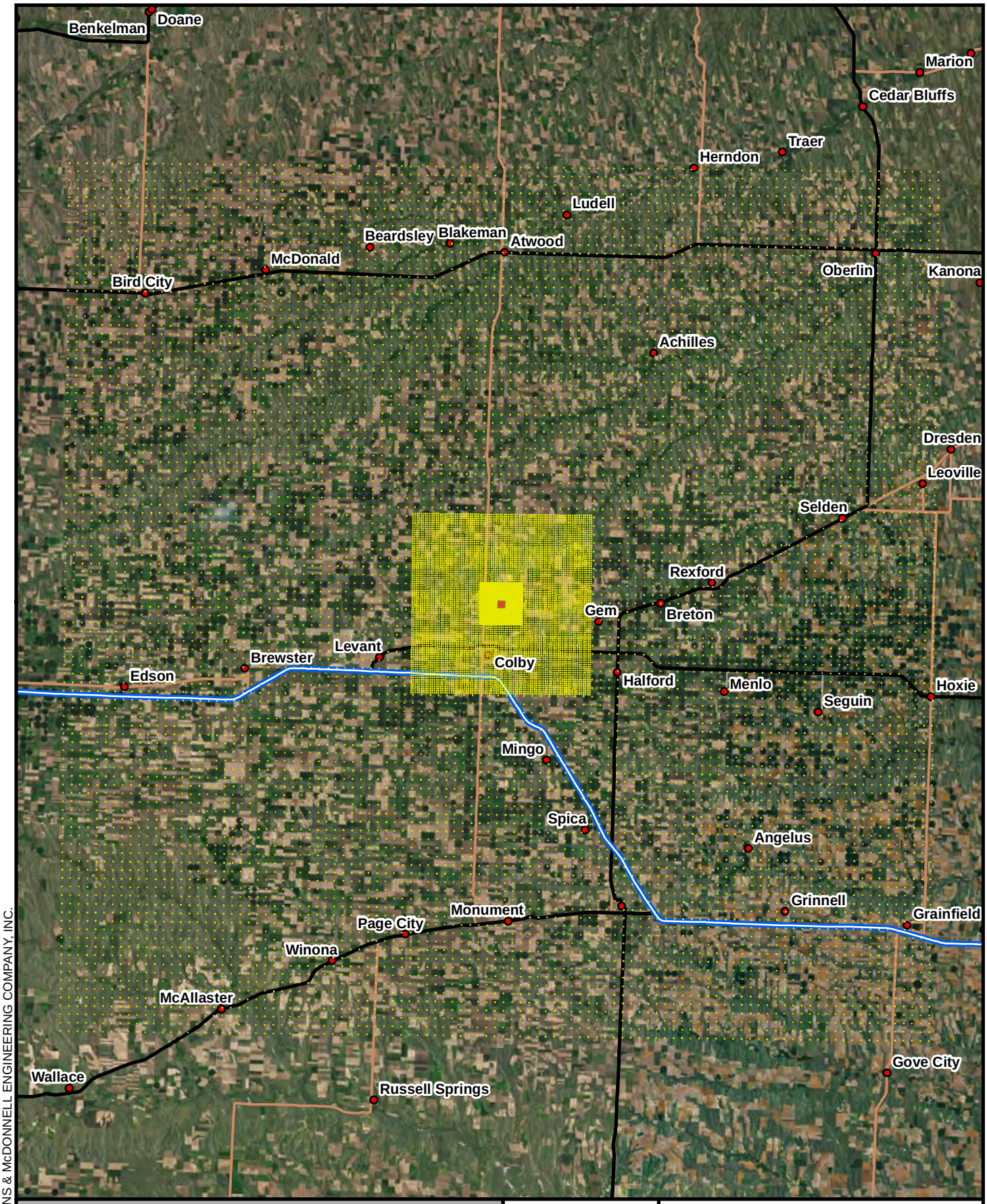
Scale For Microfilming: Millimeters / Inches

J:\ENR PRACTICE\ENGINE PROJECTS\TRADEWINDS\69814\CADD\MECH\69814_GA100.DWG WLESNIAK May 10, 2013




Project Location

Receptor Grid Location

City

NORTH

8 4 0 8

Scale in Miles

Burns & McDonnell SINCE 1898

Figure 3-3:
Proposed Lacey Randall Station
Receptor Grid

Source: Esri, DigitalGlobe, GeoEye, i-cubed, USDA, USGS, AEX, Getmapping, Aerogrid, IGN, IGP, and the GIS User Community

Issued: 7/1/2013

Path: V:\Tradewind Energy\72125-Lacey_Randall\GIS\DataFiles\ArcDocs\ReceptorGrid.mxd jdringman 7/1/2013

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# APPENDIX C - EMISSION CALCULATIONS

# Lacey Randall Energy Facility
# Internal Combustion Engine Emissions Calculations

## Engine Information

| | | | |
|---|---|---|---|
| # engines= | 10 | Heating Value (BTU/cf) | 138,000 |
| Hours of full load (each) | 8,760 | Total hours of operation (all | 87,600 |

| | 100% | 90% | 75% | 50% | |
|---|---|---|---|---|---|
| Fuel input | 78.93 | 71.67 | 61.05 | 43.12 | mmBTU/hr HHV |

| | |
|---|---|
| Total MW | 93.41 |

## Stack Information

| | 100% | 90% | 75% | 50% | Start-up | |
|---|---|---|---|---|---|---|
| Flue gas exit temperature | 331 | | | | | °C |
| | 627 | 654 | 690 | 771 | 539.50 | °F |
| Flue gas exit velocity | | | | | | m/s |
| | 83.87 | 77.59 | 67.08 | 50.05 | 81.06 | ft/s |

## Startup

20V34SG-D

The estimated cumulative flue gas emissions expressed as kg per a start period (30 min) of one (1) Wärtsilä® 20V34SG engine are given in the table below for cold startup. Pound per hour values assume 30 minutes of startup and 30 minutes of 100% load (in table below for modeling).

| Component | Cold catalyst emissions per start | | |
|---|---|---|---|
| | kg* | lb | |
| NOx as NO2 | 5.10 | 11.24 | |
| CO | 3.80 | 8.38 | |
| VOC as CH4 equivalent | 1.30 | 2.87 | |
| PM10/PM (total) | 0.70 | 1.54 | |
| PM2.5 | - | 1.54 | |
| CO2 | | 9090.12 | |
| CH4 | | 2.96 | |

| Time | Flue gas temperature at stack outlet Cold start | | |
|---|---|---|---|
| [ min ] | [ C ] | [ C ] | F |
| 0 | 25 | | |
| 10 | 100.0 | 281.9 | 539.50 |
| 10 | 270.0 | = weighted average temp | = weighted average temp |
| 10 | 330.0 | | |
| 10 | 330.6 | | |
| 10 | 330.6 | | |
| 10 | 330.6 | | |

**Start up Assumptions**

| | | |
|---|---|---|
| No. Startups Per Year (avg per engine) | 1460 | |
| Max. Hours of Startup Per Year | 730 | 8030 |
| Startup duration (Hours) | 0.5 | |

| Percent Load Ratio | |
|---|---|
| 90% | 0.90 |
| 75% | 0.85 |
| 50% | 0.91 |

## Global Warming Potentials

| Greenhouse Gas | | | Global Warming Potential* |
|---|---|---|---|
| Carbon Dioxide | 124-38-9 | $CO_2$ | 1 |
| Methane | 74-82-8 | $CH_4$ | 25 |
| Nitrous Oxide | 10024-97-2 | $N_2O$ | 298 |
| Hydrofluorocarbons | Various | CHF (various) | 12 - 11700 |
| Perfluor0carbons | Various | CF (various) | 6500 - 17340 |
| Sulfur Hexafluoride | 2551-62-4 | $SF_6$ | 22800 |
| Chlorofluorocarbons | Various | CClF (various) | Not Available |

* Based on Intergovernmental Panel on Climate Change (IPCC) for the Fourth Assessment Report (AR4), Published in 2007.

## Emission Calculations

| | 100% | 90% | 75% | 50% | 100% | 90% | 75% | 50% | Startup[1] | Startup | 100%[2] | 100% + Startup[2] | All Engines[3] |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | gm/bhp hr - requested permit limits | | | | lb/hr per engine | | | | | tpy per engine | | | tpy |
| NOx | | | | | 1.45 | 1.31 | 1.33 | 1.02 | 11.97 | 8.21 | 6.33 | 14.01 | 140.12 |
| SO2 (AP-42) | 5.88E-04 | lb/mmBTU HHV | | | 0.05 | 0.04 | 0.04 | 0.03 | 0.05 | 0.0169 | 0.20 | 0.20 | 2.03 |
| CO | | | | | 2.67 | 2.59 | 2.31 | 2.25 | 9.71 | 6.12 | 11.72 | 16.85 | 168.54 |
| PM10/PM (total) | | | | | 2.22 | 2.00 | 1.88 | 2.02 | 2.65 | 1.13 | 9.73 | 10.05 | 100.48 |
| PM2.5 | | | | | 2.22 | 2.00 | 1.88 | 2.02 | 2.65 | 1.13 | 9.73 | 10.05 | 100.48 |
| VOC | | | | | 2.67 | 2.59 | 2.47 | 2.25 | 4.20 | 2.09 | 11.72 | 12.83 | 128.31 |
| H2SO4 | | | | | 7.11E-03 | 6.45E-03 | 5.50E-03 | 3.88E-03 | 7.11E-03 | 0.0026 | 0.03 | 0.03 | 0.31 |
| Ammonia | | | | | 1.07 | 0.98 | 0.83 | 0.62 | 1.07 | 0.39 | 4.69 | 4.69 | 46.86 |
| CO2 | | | | | 9,320.23 | 8,458.79 | 7,214.21 | 5,025.07 | 9,090.12 | 3,317.89 | 40,822.61 | 40,738.62 | 407,386.17 |
| CH4 | 2.20E-03 | 1.98E-03 | 1.87E-03 | 2.00E-03 | 0.17 | 0.14 | 0.11 | 0.09 | 0.17 | 0.06 | 0.74 | 0.74 | 7.45 |
| NO2 | 2.20E-04 | 1.98E-04 | 1.87E-04 | 2.00E-04 | 0.02 | 0.01 | 0.01 | 0.01 | 0.02 | 0.007 | 0.09 | 0.09 | 0.88 |
| CO2e | | | | | 9,330 | 8,467 | 7,220 | 5,030 | 9,100 | 3,321.62 | 40,867 | 40,783.34 | 407,833 |

[1]assumes startup lasts for 30 minutes and other 30 minutes is 100% load for one hour total (used for modeling only)

[2]based on each engine operating 8,760 hours per year

[3]based on total operation of 87,600 hours per year for all 10 engines combined

## $H_2SO_4$ Calculations

| | 100% | 90% | 75% | 50% | |
|---|---|---|---|---|---|
| SO2 (AP-42) | 5.88E-04 | 5.88E-04 | 5.88E-04 | 5.88E-04 | lb/mmBTU HHV |

$SO_2 + ½ O_2 = SO_3$ $SO_3 + H_2O = H_2SO_4$

Sulfur Dioxide
SO2
MW = 64.0638

→ 10% converted →

Sulfur Trioxide
SO3 Created
MW=80.0632

→ 100% converted →

Sulfuric Acid Mist H2SO4 Created
MW=98.07848

assumed that only 10 percent of the $SC_2$ is available to convert to $SO_3$

| | | |
|---|---|---|
| 1 lb/hr SO2 = | 0.153 | lb/hr H2SO4 |

9.341 MW
0.498408316

From Matther Fisher 3-21-2013

**Expected Emissions (Controlled)**

| **Applicable to One 20V34SG unit (steady state)** | | | | | |
|---|---|---|---|---|---|
| **Treated Emission Summary & Conversion Tables** | | 100% | 90% | 75% | 50% |
| NOx (as NO2) | **ppm-v, 15 % O2, dry** | 5 | 5 | 6 | 7 |
| CO | **ppm-v, 15 % O2, dry** | 15 | 16 | 17 | 23 |
| VOC (as CH4) | **ppm-v, 15 % O2, dry** | 25 | 27 | 31 | 40 |
| PM10 (total) | **mg/Nm3, 15 % O2, dry** | 16 | 16 | 19 | 27 |
| CO2 | **ppm-v, 15 % O2, dry** | 34765 | 34752 | 34799 | 34878 |
| Ammonia | **ppm-v, 15 % O2, dry** | 10 | 10 | 10 | 11 |
| | | 100% | 90% | 75% | 50% |
| NOx (as NO2) | **g/kWhe** | 0.070 | 0.071 | 0.086 | 0.100 |
| CO | **g/kWhe** | 0.130 | 0.140 | 0.150 | 0.220 |
| VOC (as CH4) | **g/kWhe** | 0.130 | 0.140 | 0.160 | 0.220 |
| PM10 | **g/kWhe** | 0.108 | 0.108 | 0.122 | 0.197 |
| CO2 | **g/kWhe** | 453 | 457 | 468 | 491 |
| Ammonia | **g/kWhe** | 0.052 | 0.053 | 0.054 | 0.061 |
| | **kWe defined at alternator** | | | | |
| | | 100% | 90% | 75% | 50% |
| NOx (as NO2) | **lb/h** | 1.45 | 1.31 | 1.33 | 1.02 |
| CO | **lb/h** | 2.67 | 2.59 | 2.31 | 2.25 |
| VOC (as CH4) | **lb/h** | 2.67 | 2.59 | 2.47 | 2.25 |
| PM10 | **lb/h** | 2.22 | 2.00 | 1.88 | 2.02 |
| CO2 | **lb/h** | 9320 | 8459 | 7214 | 5025 |
| Ammonia | **lb/h** | 1.07 | 0.98 | 0.83 | 0.62 |
| | pounds per hour per engine | | | | |
| Gross heat rate | **Btu/kWh LHV** | 7623 | 7694 | 7870 | 8372 |
| Fuel use | mmBTU/h HHV | 78.93 | 71.67 | 61.05 | 43.12 |
| Output | kWe-gross | 9341 | 8403 | 6998 | 4646 |
| | | 8385.63 | | | |

EXHAUST

| 32F | 100% | 90% | 75% | 50% | |
|---|---|---|---|---|---|
| Flow | 1059 | 980 | 847 | 632 | acfs - wet |
| temp | 640 | 667 | 703 | 784 | F |

| 70F | 100% | 90% | 75% | 50% | |
|---|---|---|---|---|---|
| Flow | 1054 | 976 | 843 | 630 | acfs - wet |
| temp | 632 | 659 | 695 | 776 | F |

| 95F | 100% | 90% | 75% | 50% | |
|---|---|---|---|---|---|
| Flow | 1054 | 975 | 943 | 629 | acfs - wet |
| temp | 627 | 654 | 690 | 771 | F |

WORST CASE

| | 100% | 90% | 75% | 50% | |
|---|---|---|---|---|---|
| Flow | 1054 | 975 | 843 | 629 | acfs - wet |
| Velocity | 83.87 | 77.59 | 67.08 | 50.05 | ft/sec |
| temp | 627 | 654 | 690 | 771 | F |

Stack Diameter (ft): 4.0 updated from Matthew 5/3/13
Stack Area (ft^2): 12.6

| | | | | | |
|---|---|---|---|---|---|
| Formaldehyde | **lb/h** | 0.22 | 0.22 | 0.21 | 0.19 |
| Acetaldehyde | **lb/h** | 0.36 | 0.36 | 0.36 | 0.36 |
| Acrolein | **lb/h** | 0.32 | 0.31 | 0.28 | 0.27 |
| Methanol | **lb/h** | 0.20 | 0.20 | 0.20 | 0.18 |
| | pounds per hour per engine | | | | |

Uncontrolled emissions

| Load | | 100% | 90% | 75% | 50% |
|---|---|---|---|---|---|
| Nox as NO2 | ppm-v, 15 % $O_2$, dry | 120 | 120 | 110 | 100 |
| CO | ppm-v, 15 % $O_2$, dry | 260 | 260 | 300 | 400 |
| VOC as CH4 | ppm-v, 15 % $O_2$, dry | 110 | 110 | 140 | 170 |
| $PM_{10}$ (total) | mg/$Nm^3$, 15 % $O_2$, dry | 16 | 16 | 19 | 27 |

| | | 100% | 90% | 75% | 50% | |
|---|---|---|---|---|---|---|
| NOx (as NO2) | **g/kWhe** | 1.686 | 1.702 | 1.581 | 1.429 | |
| CO | **g/kWhe** | 2.253 | 2.275 | 2.647 | 3.826 | |
| VOC (as CH4) | **g/kWhe** | 0.572 | 0.570 | 0.723 | 0.935 | 96% |
| PM10 | **g/kWhe** | 0.108 | 0.108 | 0.122 | 0.197 | 94% |
| | | | | | | 77% |

| | | 100% | 90% | 75% | 50% |
|---|---|---|---|---|---|
| NOx (as NO2) | **lb/h** | 34.70 | 31.51 | 24.37 | 14.62 |
| CO | **lb/h** | 46.36 | 42.11 | 40.80 | 39.16 |
| VOC (as CH4) | **lb/h** | 11.77 | 10.56 | 11.14 | 9.57 |
| PM10 | **lb/h** | 2.22 | 2.00 | 1.88 | 2.02 |

from matthew fisher

| **Pollutant** | **BACT Emission Limitation (lb/hr)[A]** | **Equivalent Emissions[B] (g/bhp hr)** |
|---|---|---|
| $NO_x$ | 1.45 | 0.0525 |
| CO | 2.67 | 0.0967 |
| VOC | 2.67 | 0.0967 |
| $CO_2e$ | 9329.27 | 337.81 |

## Lacey Randall Energy Facility
## Auxiliary Equipment Emissions Calculations

**Stack Parameters**

| ID | Description | Size | Size Units | Size | Size Units | Size | Size Units | Height (ft) | Temp. (F) | Velocity (ft/sec) | Diameter (ft) | ACFM | Discharge Type[A] | Fuel |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| GH1 | Natural Gas Heater | 3.00 | MMBtu/hr | -- | -- | -- | -- | 19 | 500 | 44.33 | 0.83 | 1,439 | V | Natural Gas |
| EG1 | Emergency Diesel Generator | 324.0 | HP | 1.90 | MMBtu/hr | 13.79 | gal/hr | 15 | 949 | 89.05 | 0.58 | 1,428.0 | V | Fuel Oil |
| FP1 | Emergency Fire Pump | 150.0 | HP | 0.88 | MMBtu/hr | -- | -- | 20 | 840 | 66.37 | 0.67 | 1,404 | V | Fuel Oil |

[A]Discharge Type- horizontal stack (H), Raincap (C), or Vertical (V)

**Emissions**

| ID | Description | Emissions (lb/hr) | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | NOx | CO | VOC | PM/PM10/PM2.5 | SO2 | H2SO4 | CO2 | CH4 | NO2 | CO2e |
| GH1 | Natural Gas Heater | 0.29 | 0.25 | 0.016 | 0.02 | 1.8E-03 | 2.7E-04 | 351 | 6.61E-03 | 6.61E-04 | 351.36 |
| EG1 | Emergency Diesel Generator | 2.1 | 1.86 | 2.1 | 0.11 | 0.66 | 1.0E-01 | 310 | 1.26E-02 | 2.52E-03 | 311.07 |
| FP1 | Emergency Fire Pump | 1.0 | 1.22 | 1.0 | 0.07 | 0.31 | 4.7E-02 | 144 | 5.83E-03 | 1.17E-03 | 144.49 |

| ID | Description | Emissions (tpy) | | | | | | | | | | Hours of Operation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | NOx | CO | VOC | PM/PM10/PM2.5 | SO2 | H2SO4 | CO2 | CH4 | NO2 | CO2e | |
| GH1 | Natural Gas Heater | 1.29 | 1.08 | 7.1E-02 | 9.8E-02 | 8E-03 | 1.2E-03 | 1,537.38 | 0.029 | 0.003 | 1,539 | 8,760 |
| EG1 | Emergency Diesel Generator | 0.1 | 9.3E-02 | 1.1E-01 | 5.3E-03 | 3.3E-02 | 5.1E-03 | 15.50 | 0.0006 | 0.0001 | 15.6 | 100 |
| FP1 | Emergency Fire Pump | 0.0 | 6.1E-02 | 5.0E-02 | 3.6E-03 | 1.5E-02 | 2.4E-03 | 7.20 | 0.0003 | 0.0001 | 7.2 | 100 |

**Emission Factors**

| ID | Description | Emission Factors | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | NOx | | CO | | VOC | | PM/PM10/PM2.5 | | SO2 | | CO2 lb/MMBtu | CH4 lb/MMBtu | NO2 lb/MMBtu | CO2e lb/MMBtu |
| GH1 | Natural Gas Heater | 100 | lb/MMcf | 84 | lb/MMcf | 5.5 | lb/MMcf | 7.6 | lb/MMcf | 0.60 | lb/MMcf | 116.89 | 0.002204623 | 0.000220462 | 117.0099248 |
| EG1 | Emergency Diesel Generator | 2.98 | gm/hp-hr | 2.61 | gm/hp-hr | 2.98 | gm/hp-hr | 0.15 | gm/hp-hr | 2.05E-03 | lb/hp-hr | 163.05 | 0.006613869 | 0.001322774 | 163.6134504 |
| FP1 | Emergency Fire Pump | 3.000 | gm/hp-hr | 3.70 | gm/hp-hr | 3.00 | gm/hp-hr | 0.22 | gm/hp-hr | 2.05E-03 | lb/hp-hr | 163.05 | 0.006613869 | 0.001322774 | 163.61 |

| | | | | | |
|---|---|---|---|---|---|
| Heating Value - Natural Gas | 1,020 | Btu/cf | Heating Value - Fuel Oil | 138,000 | Btu/gal |

**Emission Factor References**

| ID | Description | Emission Factors | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | NOx | CO | VOC | PM/PM10/PM2.5 | SO2 | H2SO4 | CO2 | CH4 | NO2 |
| GH1 | Natural Gas Heater | AP-42 Section 1.4 7/98 | | | | | | Federal Register - Subpart C of Part 98 | | |
| EG1 | Emergency Diesel Generator | Cummins Data Sheet | | | | AP-42 Section 3.3 10/96 | | Federal Register - Subpart C of Part 98 | | |
| FP1 | Emergency Fire Pump | AP-42 Section 3.3 10/96 | | | NSPS | AP-42 Section 3.3 10/96 | | Federal Register - Subpart C of Part 98 | | |

### Global Warming Potentials

| Greenhouse Gas | | | Global Warming |
|---|---|---|---|
| Carbon Dioxide | 124-38-9 | $CO_2$ | 1 |
| Methane | 74-82-8 | $CH_4$ | 25 |
| Nitrous Oxide | 10024-97-2 | $N_2O$ | 298 |
| Hydrofluorocarbons | Various | CHF (various) | 12 - 11700 |
| Perfluorocarbons | Various | CF (various) | 6500 - 17340 |
| Sulfur Hexafluoride | 2551-62-4 | $SF_6$ | 22800 |
| Chlorofluorocarbons | Various | CClF (various) | Not Available |

* Based on Intergovernmental Panel on Climate Change (IPCC) for the Fourth Assessment Report (AR4), Published in 2007.

| NSPS Limits for Generator 40 CFR 89.112(a) | | |
|---|---|---|
| | g/kW-hr | g/hp-hr |
| NMHC+NOx | 4 | 2.98 |
| CO | 3.5 | 2.61 |
| PM | 0.2 | 0.15 |

### Sulfuric Acid Mist

| | Conversion Percent | |
|---|---|---|
| Assume 10% of SO2 is converted to SO3 | 10 | SO2 + 1/2 O2 = SO3 |
| Assume 100% of SO3 is converted to H2SO4 | 100 | SO3 + H2O = H2SO4 |

| Name | lb/hr SO2 | lb/hr SO2 converted to SO3 | lb/hr SO3 created | lb/hr H2SO4 created | tons / year H2SO4 |
|---|---|---|---|---|---|
| Natural Gas Heater | 1.8E-03 | 1.8E-04 | 2.2E-04 | 2.7E-04 | 1.2E-03 |
| Emergency Diesel Generator | 6.6E-01 | 6.6E-02 | 8.3E-02 | 1.0E-01 | 5.1E-03 |
| Emergency Fire Pump | 3.1E-01 | 3.1E-02 | 3.8E-02 | 4.7E-02 | 2.4E-03 |

| Molecular Weights | |
|---|---|
| SO2 | 64.1 |
| SO3 | 80.1 |
| H2SO4 | 98.1 |

# HAPS Calculations

## Lacey Randall Energy Facility
## Wartsila Engine: Hazardous Air Pollutants Emissions

Total Hours of Operation (all engines) = 87,600 hrs/yr
Hours of Operation = 8,760 hrs/yr
Heater Fuel Input Capacity = 78.93 MMBtu/hr
Number of Units: 10
Control Efficiency = 77%

| Pollutant | CAS. No. | Emission Factors lb/MMBTU | Control Efficiency % | Emissions from 1 Turbine lb/hr | Emissions from 1 Turbine tpy | Emissions from 1 Turbine lb/year | Emissions from All Turbines lb/hr | Emissions from All Turbines tpy | Emissions from All Turbines lb/year |
|---|---|---|---|---|---|---|---|---|---|
| 1,1,2,2-Tetrachloroethane | 79-34-5 | 4.00E-05 | 77% | 7.26E-04 | 3.18E-03 | 6.36E+00 | 7.26E-03 | 3.18E-02 | 6.36E+01 |
| 1,1,2-Trichloroethane | 79-00-5 | 3.18E-05 | 77% | 5.77E-04 | 2.53E-03 | 5.06E+00 | 5.77E-03 | 2.53E-02 | 5.06E+01 |
| 1,3-Butadiene | 106-99-0 | 2.67E-04 | 77% | 4.85E-03 | 2.12E-02 | 4.25E+01 | 4.85E-02 | 2.12E-01 | 4.25E+02 |
| 1,3-Dichloropropene | 542-75-6 | 2.64E-05 | 77% | 4.79E-04 | 2.10E-03 | 4.20E+00 | 4.79E-03 | 2.10E-02 | 4.20E+01 |
| 2-Methylnaphthalene | 91-57-6 | 3.32E-05 | 77% | 6.03E-04 | 2.64E-03 | 5.28E+00 | 6.03E-03 | 2.64E-02 | 5.28E+01 |
| 2,2,4-Trimethylpentane | 540-84-1 | 2.50E-04 | 77% | 4.54E-03 | 1.99E-02 | 3.98E+01 | 4.54E-02 | 1.99E-01 | 3.98E+02 |
| 3-Methylchloranthrene | 56-49-5 | | | | | | | | |
| 7,12-Dimethylbenz(a)anthracene | 57-97-6 | | | | | | | | |
| Acenaphthene | 83-32-9 | 1.25E-06 | 77% | 2.27E-05 | 9.94E-05 | 1.99E-01 | 2.27E-04 | 9.94E-04 | 1.99E+00 |
| Acenaphthylene | 203-96-8 | 5.53E-06 | 77% | 1.00E-04 | 4.40E-04 | 8.79E-01 | 1.00E-03 | 4.40E-03 | 8.79E+00 |
| Acetaldehyde | 75-07-0 | Vendor Factor | | 3.55E-01 | 1.56E+00 | 3.11E+03 | 3.55E+00 | 1.56E+01 | 3.11E+04 |
| Acrolein | 107-028 | Vendor Factor | | 3.22E-01 | 1.41E+00 | 2.82E+03 | 3.22E+00 | 1.41E+01 | 2.82E+04 |
| Anthracene | 120-12-7 | | | | | | | | |
| Arsenic | 7440-38-2 | | | | | | | | |
| Benz(a)anthracene | 56-55-3 | | | | | | | | |
| Benzene | 71-43-2 | 4.40E-04 | 77% | 7.99E-03 | 3.50E-02 | 7.00E+01 | 7.99E-02 | 3.50E-01 | 7.00E+02 |
| Benzo(b)fluoranthene | 205-99-2 | 1.66E-07 | 77% | 3.01E-06 | 1.32E-05 | 2.64E-02 | 3.01E-05 | 1.32E-04 | 2.64E-01 |
| Benzo(e)pyrene | 50-32-8 | 4.15E-07 | 77% | 7.53E-06 | 3.30E-05 | 6.60E-02 | 7.53E-05 | 3.30E-04 | 6.60E-01 |
| Benzo(g,h,i)perylene | 191-24-2 | 4.14E-07 | 77% | 7.52E-06 | 3.29E-05 | 6.58E-02 | 7.52E-05 | 3.29E-04 | 6.58E-01 |
| Benzo(k)fluoranthene | 205-82-3 | | | | | | | | |
| Beryllium | 7440-41-7 | | | | | | | | |
| Biphenyl | 92-51-3 | 2.12E-04 | 77% | 3.85E-03 | 1.69E-02 | 3.37E+01 | 3.85E-02 | 1.69E-01 | 3.37E+02 |
| Cadmium | 7440-43-9 | | | | | | | | |
| Carbon Tetrachloride | 56-23-5 | 3.67E-05 | 77% | 6.66E-04 | 2.92E-03 | 5.84E+00 | 6.66E-03 | 2.92E-02 | 5.84E+01 |
| Chlorobenzene | 108-90-7 | 3.04E-05 | 77% | 5.52E-04 | 2.42E-03 | 4.83E+00 | 5.52E-03 | 2.42E-02 | 4.83E+01 |
| Chloroform | 67-66-3 | 2.85E-05 | 77% | 5.17E-04 | 2.27E-03 | 4.53E+00 | 5.17E-03 | 2.27E-02 | 4.53E+01 |
| Chromium | 7440-47-3 | | | | | | | | |
| Chrysene | 218-01-9 | 6.93E-07 | 77% | 1.26E-05 | 5.51E-05 | 1.10E-01 | 1.26E-04 | 5.51E-04 | 1.10E+00 |
| Cobalt | 7440-48-4 | | | | | | | | |
| Dibenzo(a,h)anthracene | 53-70-3 | | | | | | | | |
| Dichlorobenzene | 25321-22-6 | | | | | | | | |
| Ethylbenzene | 100-41-4 | 3.97E-05 | 77% | 7.21E-04 | 3.16E-03 | 6.31E+00 | 7.21E-03 | 3.16E-02 | 6.31E+01 |
| Ethylene Dibromide | 106-93-4 | 4.43E-05 | 77% | 8.04E-04 | 3.52E-03 | 7.05E+00 | 8.04E-03 | 3.52E-02 | 7.05E+01 |
| Fluoranthene | 206-44-0 | 1.11E-06 | 77% | 2.02E-05 | 8.83E-05 | 1.77E-01 | 2.02E-04 | 8.83E-04 | 1.77E+00 |
| Fluorene | 86-73-7 | 5.67E-06 | 77% | 1.03E-04 | 4.51E-04 | 9.02E-01 | 1.03E-03 | 4.51E-03 | 9.02E+00 |
| Formaldehyde | 50-00-0 | Vendor Factor | | 2.22E-01 | 9.72E-01 | 1.94E+03 | 2.22E+00 | 9.72E+00 | 1.94E+04 |
| Hexane | 110-54-3 | 1.11E-03 | 77% | 2.02E-02 | 8.83E-02 | 1.77E+02 | 2.02E-01 | 8.83E-01 | 1.77E+03 |
| Indeno(1,2,3-cd)pyrene | 193-39-5 | | | | | | | | |
| Lead | 7439-92-1 | | | | | | | | |
| Manganese | 7439-96-5 | | | | | | | | |
| Methanol | 67-56-1 | Vendor Factor | | 2.00E-01 | 8.75E-01 | 1.75E+03 | 2.00E+00 | 8.75E+00 | 1.75E+04 |
| Methylene Chloride | 75-09-2 | 2.00E-05 | 77% | 3.63E-04 | 1.59E-03 | 3.18E+00 | 3.63E-03 | 1.59E-02 | 3.18E+01 |
| Mercury | 7439-97-6 | | | | | | | | |
| Naphthalene | 91-20-3 | 7.44E-05 | 77% | 1.35E-03 | 5.92E-03 | 1.18E+01 | 1.35E-02 | 5.92E-02 | 1.18E+02 |
| Nickel | 7440-02-0 | | | | | | | | |
| PAH | - | 2.69E-05 | 77% | 4.88E-04 | 2.14E-03 | 4.28E+00 | 4.88E-03 | 2.14E-02 | 4.28E+01 |
| Phenanthrene | 85-01-8 | 1.04E-05 | 77% | 1.89E-04 | 8.27E-04 | 1.65E+00 | 1.89E-03 | 8.27E-03 | 1.65E+01 |
| Phenol | 108-95-2 | 2.40E-05 | 77% | 4.36E-04 | 1.91E-03 | 3.82E+00 | 4.36E-03 | 1.91E-02 | 3.82E+01 |
| Propylene | 115-07-1 | | | | | | | | |
| Pyrene | 129-00-0 | 1.36E-06 | 77% | 2.47E-05 | 1.08E-04 | 2.16E-01 | 2.47E-04 | 1.08E-03 | 2.16E+00 |
| Selenium | 7782-49-2 | | | | | | | | |
| Styrene | 100-42-5 | 2.36E-05 | 77% | 4.28E-04 | 1.88E-03 | 3.75E+00 | 4.28E-03 | 1.88E-02 | 3.75E+01 |
| Tetrachloroethane | 25322-20-7 | 2.48E-06 | 77% | 4.50E-05 | 1.97E-04 | 3.94E-01 | 4.50E-04 | 1.97E-03 | 3.94E+00 |
| Toluene | 108-88-3 | | | | | | | | |
| Vinyl Chloride | 75-01-4 | 1.49E-05 | 77% | 2.71E-04 | 1.18E-03 | 2.37E+00 | 2.71E-03 | 1.18E-02 | 2.37E+01 |
| Xylene | 1330-20-7 | 1.84E-04 | 77% | 3.34E-03 | 1.46E-02 | 2.93E+01 | 3.34E-02 | 1.46E-01 | 2.93E+02 |
| All HAPs | | | | | | | 11.53 | 50.51 | 101,014 |

Emission factors from AP-42, Section 3.2, 7/00, except where note

## Total Facility: Hazardous Air Pollutants Emissions

| HAP | HAP | Maximum Potential Emissions tpy |
|---|---|---|
| 1st maxium - | Acetaldehyde | 15.56 |
| 2nd maxium - | Acrolein | 14.10 |
| 3rd maxium - | Formaldehyde | 9.72 |
| All HAPs | | 50.53 |

## HAPS Calculations

### Lacey Randall Energy Facility
### Gas Heater: Hazardous Air Pollutants Emissions

Hours of Operation = 8,760 hrs/yr
Heater Fuel Input Capacity = 3.00 MMBtu/hr
Number of Units: 1
Natural gas heating value = 1,020 BTU/scf

| Emission Factors lb/10^6 scf | Emission Factors lb/MMBTU | Emissions lb/hr | Emissions tpy | Emissions lb/year |
|---|---|---|---|---|
| | | | | |
| | | | | |
| | | | | |
| | | | | |
| 2.40E-05 | 2.35E-08 | 7.06E-08 | 3.09E-07 | 6.18E-04 |
| | | | | |
| 1.80E-06 | 1.76E-09 | 5.29E-09 | 2.32E-08 | 4.64E-05 |
| 1.60E-05 | 1.57E-08 | 4.71E-08 | 2.06E-07 | 4.12E-04 |
| 1.80E-06 | 1.76E-09 | 5.29E-09 | 2.32E-08 | 4.64E-05 |
| 1.80E-06 | 1.76E-09 | 5.29E-09 | 2.32E-08 | 4.64E-05 |
| | | | | |
| | | | | |
| 2.40E-06 | 2.35E-09 | 7.06E-09 | 3.09E-08 | 6.18E-05 |
| 2.00E-04 | 1.96E-07 | 5.88E-07 | 2.58E-06 | 5.15E-03 |
| 1.80E-06 | 1.76E-09 | 5.29E-09 | 2.32E-08 | 4.64E-05 |
| 2.10E-03 | 2.06E-06 | 6.18E-06 | 2.71E-05 | 5.41E-02 |
| 1.80E-06 | 1.76E-09 | 5.29E-09 | 2.32E-08 | 4.64E-05 |
| 1.20E-06 | 1.18E-09 | 3.53E-09 | 1.55E-08 | 3.09E-05 |
| 1.20E-06 | 1.18E-09 | 3.53E-09 | 1.55E-08 | 3.09E-05 |
| 1.80E-06 | 1.76E-09 | 5.29E-09 | 2.32E-08 | 4.64E-05 |
| 1.20E-05 | 1.18E-08 | 3.53E-08 | 1.55E-07 | 3.09E-04 |
| | | | | |
| 1.10E-03 | 1.08E-06 | 3.24E-06 | 1.42E-05 | 2.83E-02 |
| | | | | |
| | | | | |
| | | | | |
| 1.40E-03 | 1.37E-06 | 4.12E-06 | 1.80E-05 | 3.61E-02 |
| 1.80E-06 | 1.76E-09 | 5.29E-09 | 2.32E-08 | 4.64E-05 |
| 8.40E-05 | 8.24E-08 | 2.47E-07 | 1.08E-06 | 2.16E-03 |
| 1.20E-06 | 1.18E-09 | 3.53E-09 | 1.55E-08 | 3.09E-05 |
| 1.20E-03 | 1.18E-06 | 3.53E-06 | 1.55E-05 | 3.09E-02 |
| | | | | |
| | | | | |
| 3.00E-06 | 2.94E-09 | 8.82E-09 | 3.86E-08 | 7.73E-05 |
| 2.80E-06 | 2.75E-09 | 8.24E-09 | 3.61E-08 | 7.21E-05 |
| 7.50E-02 | 7.35E-05 | 2.21E-04 | 9.66E-04 | 1.93E+00 |
| 1.80E+00 | 1.76E-03 | 5.29E-03 | 2.32E-02 | 4.64E+01 |
| 1.80E-06 | 1.76E-09 | 5.29E-09 | 2.32E-08 | 4.64E-05 |
| 5.00E-04 | 4.90E-07 | 1.47E-06 | 6.44E-06 | 1.29E-02 |
| 3.80E-04 | 3.73E-07 | 1.12E-06 | 4.90E-06 | 9.79E-03 |
| | | | | |
| | | | | |
| 2.60E-04 | 2.55E-07 | 7.65E-07 | 3.35E-06 | 6.70E-03 |
| 6.10E-04 | 5.98E-07 | 1.79E-06 | 7.86E-06 | 1.57E-02 |
| 2.10E-03 | 2.06E-06 | 6.18E-06 | 2.71E-05 | 5.41E-02 |
| | | | | |
| 1.70E-05 | 1.67E-08 | 5.00E-08 | 2.19E-07 | 4.38E-04 |
| | | | | |
| | | | | |
| 5.00E-06 | 4.90E-09 | 1.47E-08 | 6.44E-08 | 1.29E-04 |
| 2.40E-05 | 2.35E-08 | 7.06E-08 | 3.09E-07 | 6.18E-04 |
| | | | | |
| | | | | |
| 3.40E-03 | 3.33E-06 | 1.00E-05 | 4.38E-05 | 8.76E-02 |
| | | | | |
| | | | | |
| | | 5.55E-03 | 2.43E-02 | 48.66 |

Emission factors from AP-42, Section 1.4, 3/9

## HAPS Calculations

### Lacey Randall Energy Facility
### Diesel Fire Pump: Hazardous Air Pollutants Emissions

Hours of Operation = 100 hrs/yr
Estimated Fuel Input Capacity = 0.88 MMBtu/hr
Number of Units: 1

| Emission Factors lb/MMBtu | Emissions lb/hr | Emissions tpy | Emissions lb/year |
|---|---|---|---|
| | | | |
| | | | |
| 3.91E-05 | 3.44E-05 | 1.72E-06 | 3.44E-03 |
| | | | |
| | | | |
| | | | |
| | | | |
| | | | |
| 1.42E-06 | 1.25E-06 | 6.26E-08 | 1.25E-04 |
| 5.06E-06 | 4.46E-06 | 2.23E-07 | 4.46E-04 |
| 7.67E-04 | 6.76E-04 | 3.38E-05 | 6.76E-02 |
| 9.25E-05 | 8.15E-05 | 4.07E-06 | 8.15E-03 |
| 1.87E-06 | 1.65E-06 | 8.24E-08 | 1.65E-04 |
| | | | |
| 1.68E-06 | 1.48E-06 | 7.40E-08 | 1.48E-04 |
| 9.33E-04 | 8.22E-04 | 4.11E-05 | 8.22E-02 |
| 9.91E-08 | 8.73E-08 | 4.37E-09 | 8.73E-06 |
| 1.88E-07 | 1.66E-07 | 8.28E-09 | 1.66E-05 |
| 4.89E-07 | 4.31E-07 | 2.15E-08 | 4.31E-05 |
| 1.55E-07 | 1.37E-07 | 6.83E-09 | 1.37E-05 |
| | | | |
| | | | |
| | | | |
| | | | |
| | | | |
| | | | |
| | | | |
| 3.53E-07 | 3.11E-07 | 1.56E-08 | 3.11E-05 |
| | | | |
| 5.83E-07 | 5.14E-07 | 2.57E-08 | 5.14E-05 |
| | | | |
| | | | |
| | | | |
| 7.61E-06 | 6.70E-06 | 3.35E-07 | 6.70E-04 |
| 2.92E-05 | 2.57E-05 | 1.29E-06 | 2.57E-03 |
| 1.18E-03 | 1.04E-03 | 5.20E-05 | 1.04E-01 |
| | | | |
| 3.75E-07 | 3.30E-07 | 1.65E-08 | 3.30E-05 |
| | | | |
| | | | |
| | | | |
| | | | |
| | | | |
| 8.48E-05 | 7.47E-05 | 3.74E-06 | 7.47E-03 |
| | | | |
| 1.68E-04 | 1.48E-04 | 7.40E-06 | 1.48E-02 |
| 2.94E-05 | 2.59E-05 | 1.30E-06 | 2.59E-03 |
| | | | |
| 2.58E-03 | 2.27E-03 | 1.14E-04 | 2.27E-01 |
| 4.78E-06 | 4.21E-06 | 2.11E-07 | 4.21E-04 |
| | | | |
| | | | |
| | | | |
| 4.09E-04 | 3.60E-04 | 1.80E-05 | 3.60E-02 |
| | | | |
| 2.85E-04 | 2.51E-04 | 1.26E-05 | 2.51E-02 |
| | 5.83E-03 | 2.92E-04 | 5.83E-01 |

Emission factors from AP-42, Section 3.3, 10/9

# HAPS Calculations

## Lacey Randall Energy Facility
## Diesel Emergency Generator: Hazardous Air Pollutants Emissions

Hours of Operation = 100 hrs/yr
Estimated Fuel Input Capacity = 1.90 MMBtu/hr
Number of Units: 1

| Emission Factors lb/MMBtu | Emissions lb/hr | Emissions tpy | Emissions lb/year | Total Emissions (all equipment) tpy |
|---|---|---|---|---|
| | | | | 3.18E-02 |
| | | | | 2.53E-02 |
| 3.91E-05 | 7.44E-05 | 3.72E-06 | 7.44E-03 | 2.12E-01 |
| | | | | 2.10E-02 |
| | | | | 2.64E-02 |
| | | | | 1.99E-01 |
| | | | | 2.32E-08 |
| | | | | 2.06E-07 |
| 1.42E-06 | 2.70E-06 | 1.35E-07 | 2.70E-04 | 9.94E-04 |
| 5.06E-06 | 9.63E-06 | 4.81E-07 | 9.63E-04 | 4.40E-03 |
| 7.67E-04 | 1.46E-03 | 7.30E-05 | 1.46E-01 | 1.56E+01 |
| 9.25E-05 | 1.76E-04 | 8.80E-06 | 1.76E-02 | 1.41E+01 |
| 1.87E-06 | 3.56E-06 | 1.78E-07 | 3.56E-04 | 2.91E-07 |
| | | | | 2.58E-06 |
| 1.68E-06 | 3.20E-06 | 1.60E-07 | 3.20E-04 | 2.57E-07 |
| 9.33E-04 | 1.78E-03 | 8.88E-05 | 1.78E-01 | 3.50E-01 |
| 9.91E-08 | 1.89E-07 | 9.43E-09 | 1.89E-05 | 1.32E-04 |
| 1.88E-07 | 3.58E-07 | 1.79E-08 | 3.58E-05 | 3.30E-04 |
| 4.89E-07 | 9.31E-07 | 4.65E-08 | 9.31E-05 | 3.29E-04 |
| 1.55E-07 | 2.95E-07 | 1.47E-08 | 2.95E-05 | 4.48E-08 |
| | | | | 1.55E-07 |
| | | | | 1.69E-01 |
| | | | | 1.42E-05 |
| | | | | 2.92E-02 |
| | | | | 2.42E-02 |
| | | | | 2.27E-02 |
| | | | | 1.80E-05 |
| 3.53E-07 | 6.72E-07 | 3.36E-08 | 6.72E-05 | 5.51E-04 |
| | | | | 1.08E-06 |
| 5.83E-07 | 1.11E-06 | 5.55E-08 | 1.11E-04 | 9.66E-08 |
| | | | | 1.55E-05 |
| | | | | 3.16E-02 |
| | | | | 3.52E-02 |
| 7.61E-06 | 1.45E-05 | 7.24E-07 | 1.45E-03 | 8.84E-04 |
| 2.92E-05 | 5.56E-05 | 2.78E-06 | 5.56E-03 | 4.51E-03 |
| 1.18E-03 | 2.25E-03 | 1.12E-04 | 2.25E-01 | 9.72E+00 |
| | | | | 9.06E-01 |
| 3.75E-07 | 7.14E-07 | 3.57E-08 | 7.14E-05 | 7.54E-08 |
| | | | | 6.44E-06 |
| | | | | 4.90E-06 |
| | | | | 8.75E+00 |
| | | | | 1.59E-02 |
| | | | | 3.35E-06 |
| 8.48E-05 | 1.61E-04 | 8.07E-06 | 1.61E-02 | 5.92E-02 |
| | | | | 2.71E-05 |
| 1.68E-04 | 3.20E-04 | 1.60E-05 | 3.20E-02 | 2.14E-02 |
| 2.94E-05 | 5.59E-05 | 2.80E-06 | 5.59E-03 | 8.27E-03 |
| | | | | 1.91E-02 |
| 2.58E-03 | 4.91E-03 | 2.45E-04 | 4.91E-01 | 3.59E-04 |
| 4.78E-06 | 9.10E-06 | 4.55E-07 | 9.10E-04 | 1.08E-03 |
| | | | | 3.09E-07 |
| | | | | 1.88E-02 |
| | | | | 1.97E-03 |
| 4.09E-04 | 7.78E-04 | 3.89E-05 | 7.78E-02 | 1.01E-04 |
| | | | | 1.18E-02 |
| 2.85E-04 | 5.42E-04 | 2.71E-05 | 5.42E-02 | 1.46E-01 |
| | 1.26E-02 | 6.30E-04 | 1.26E+00 | **50.53** |

Emission factors from AP-42, Section 3.3, 10/96

| Inputs | |
|---|---|
| Number of Breakers | 4 |
| Quantity of SF6 in each Breaker (lbs) | 61.2 |
| Number of Circuit Switchers | 0 |
| Quantity of SF6 in each Circuit Switcher (lbs) | 3.3 |
| Global Warming Potential of SF6 (100yr) | 22,800 |

## Fugitive Emissions of SF6 due to leakage

| | Number of Units | Quantity of SF6 per Breaker or Switcher (lbs) | Emissions of SF6 Per Breaker or Switcher* (lbs/yr) | Total SF6 Emissions (lbs/yr) | Global Warming Potential | Total CO2e Emissions (tons/yr) |
|---|---|---|---|---|---|---|
| Breakers | 4 | 61.2 | 0.306 | 1.22 | 22,800 | 13.95 |
| Circuit Switchers | 0 | 3.3 | 0.0165 | 0.00 | 22,800 | 0.00 |
| **Total** | | | | **1.22** | | **13.95** |

*Assuming 0.5% leakage

# APPENDIX D - RBLC

**Table D-1 - RBLC Results for $NO_X$ Emissions for RICE (Natural Gas) (In Order of Lowest to Highest Emission Limits)**

| RBLCID | Permit Date | Facility Name | Corporation | State | Throughput | Units | Control Device | Emission Limit 1 | Units | Type |
|---|---|---|---|---|---|---|---|---|---|---|
| CA-0959 | 4/9/2001 | NEO CALIFORNIA POWER - RED BLUFF | NEO CALIFORNIA POWER | CA | 3928 | BHP | SELECTIVE CATALYTIC REDUCTION | 0.07 | G/B-HP-H | LAER |
| TX-0541 | 5/18/2009 | POWER LANE STEAM PLANT | GEUS | TX | 8.44 | MW EACH | SELECTIVE CATALYTIC REDUCTION | 0.084 | G/B-HP-H | BACT-PSD |
| TX-0542 | 1/23/2009 | PEARSALL POWER PLANT | SOUTH TEXAS ELECTRIC COOPERATIVE INC. | TX | 8.44 | MW EACH | SELECTIVE CATALYTIC REDUCTION | 0.084 | G/B-HP-H | BACT-PSD |
| TX-0364 | 1/31/2003 | SALT CREEK GAS PLANT | EXXON MOBIL CORPORATION | TX | 2400 | HP | NONE INDICATED | 0.19 | G/B-HP-H | BACT-PSD |
| MS-0056 | 8/26/2003 | SOUTHERN NATURAL GAS CO. - ENTERPRISE COMPRESSOR | SOUTHERN NATURAL GAS CO. | MS | 4730 | HP | USE OF LOW EMISSION (OR CLEAN BURN) TECHNOLOGY | 0.7 | G/B-HP-H | BACT-PSD |
| GA-0104 | 10/11/2002 | THOMASTON COMPRESSOR STATION | SOUTHERN NATURAL GAS COMPANY | GA | 4730 | HP | CLEAN BURN TECHNOLOGY | 0.7 | G/B-HP-H | BACT-PSD |
| PA-0230 | 10/23/2001 | EASTERN SHORE NAT. GAS /DALEVILLE | EASTERN SHORE NAT. GAS CO | PA | 1665 | BHP | GOOD COMBUSTION PRACTICE | 0.7 | G/B-HP-H | Other Case-by-Case |
| CO-0058 | 6/12/2004 | CHEYENNE STATION | CHEYENNE PLAINS GAS PIPELINE COMPANY | CO | 1775 | HP | LEAN BURN COMBUSTION TECHNOLOGY | 0.8 | G/B-HP-H | BACT-PSD |
| CO-0058 | 6/12/2004 | CHEYENNE STATION | CHEYENNE PLAINS GAS PIPELINE COMPANY | CO | 2,443 | HP | LEAN BURN TECHNOLOGY | 0.8 | G/B-HP-H | BACT-PSD |
| IA-0077 | 6/8/2005 | STATION 204 | NATURAL GAS PIPELINE OF AMERICA | IA | 4735 | HP | | 1.0 | G/B-HP-H | Other Case-by-Case |
| AZ-0047 | 12/1/2004 | WELLTON MOHAWK GENERATING STATION | DOME VALLEY ENERGY PARTNERS | AZ | 6 | MW | | 1.5 | G/B-HP-H | BACT-PSD |
| PA-0209 | 11/8/2002 | ORCHARD PARK GENERATING STATION | BOROUGH OF CHAMBERSBURG | PA | 1088 | MMCF | LEAN BURN, SCR, LOW EMISSION COMBUSTION CONTROL | 1.5 | G/B-HP-H | Other Case-by-Case |
| IL-0083 | 2/8/2002 | PANHANDLE EASTERN PIPELINE COMPANY | PANHANDLE EASTERN PIPELINE COMPANY | IL | 2070 | HP | CLEAN BURN TECHNOLOGY, GOOD COMBUSTION PRACTICE | 2 | G/B-HP-H | BACT-PSD |
| IL-0083 | 2/8/2002 | PANHANDLE EASTERN PIPELINE COMPANY | PANHANDLE EASTERN PIPELINE COMPANY | IL | 4000 | HP | CLEAN BURN TECHNOLOGY, GOOD COMBUSTION PRACTICE | 2 | G/B-HP-H | BACT-PSD |
| OK-0109 | 1/21/2005 | MOORELAND CRYOGENIC PLT | DUKE ENERGY FIELD SVS LP | OK | 2200 | hp | LEAN BURN CONVERSION | 2 | G/B-HP-H | BACT-PSD |
| TX-0408 | 11/22/2002 | INDIAN ROCK GATHERING COMPANY LP | INDIAN ROCK GATHERING COMPANY LP | TX | 800 | HP | GOOD COMBUSTION PRACTICE | 2 | G/B-HP-H | BACT-PSD |
| WV 0019 +0020 | 2/14/2003 | COLUMBIA GAS TRANSMISSIONS LOST RIVER | COLUMBIA GAS TRANSMISSIONS LOST RIVER | WV | 4640 | HP | CLEAN BURN; TECHNOLOGY OF LEAN-BURN ENGINES | 2 | G/B-HP-H | BACT-PSD |
| LA-0257 | 12/6/2011 | SABINE PASS LNG TERMINAL | SABINE PASS LNG, LP & SABINE PASS LIQUEFACTION, LL | LA | 2012 | hp | Comply with 40 CFR 60 Subpart JJJJ | 2 | G/B-HP-H | BACT-PSD |
| AL-0189 | 6/19/2001 | GALLION COMPRESSOR STATION | SOUTHERN NATURAL GAS COMPANY | AL | 4000 | HP | | 2.2 | G/B-HP-H | BACT-PSD |
| OK-0109 | 1/21/2005 | MOORELAND CRYOGENIC PLT | DUKE ENERGY FIELD SVS LP | OK | 842 | hp | CATALYTIC CONVERTERS | 3 | G/B-HP-H | BACT-PSD |
| PA-0201 | 8/6/2002 | ROYSTONE COMPRESSOR STATION | NATIONAL FUEL GAS SUPPLY CORP. | PA | 800 | HP | CLEAN BURN TECHNOLOGY | 3 | G/B-HP-H | Other Case-by-Case |
| TX-0501 | 7/11/2006 | TEXSTAR GAS PROCESS FACILITY | TEXSTAR FS LP | TX | 875 | HP | | 3.0 | G/B-HP-H | BACT-PSD |
| TX-0364 | 1/31/2003 | SALT CREEK GAS PLANT | EXXON MOBIL CORPORATION | TX | 3105 | HP | NONE INDICATED | 3.2 | G/B-HP-H | BACT-PSD |
| WA-0289 | 2/22/2002 | TRANSALTA CENTRALIA GENERATION LLC | TRANSALTA | WA | 1448 | HP | | 10.1 | G/B-HP-H | BACT-PSD |
| TX-0364 | 1/31/2003 | SALT CREEK GAS PLANT | EXXON MOBIL CORPORATION | TX | 2000 | HP EACH | NONE INDICATED | 19.2 | G/B-HP-H | BACT-PSD |
| TX-0364 | 1/31/2003 | SALT CREEK GAS PLANT | EXXON MOBIL CORPORATION | TX | 1330 | HP | NONE INDICATED | 20.2 | G/B-HP-H | BACT-PSD |
| CA-1137 | 8/3/2001 | BEAR VALLEY ELECTRIC | BEAR VALLEY ELECTRIC | CA | 1695 | BHP | THREE-WAY CATALYST WITH AIR/FUEL RATIO CONTROLLER | 7.3 | PPMVD@15%O2 | BACT-PSD |
| CA-1068 | 4/17/2001 | NEO CALIFORNIA POWER, LLC | NEO CALIFORNIA POWER, LLC | CA | 3870 | HP | SCR | 9 | PPMVD @ 15% O2 | BACT-PSD |

**Table D-2 - RBLC Results for CO Emissions for RICE (Natural Gas) (In Order of Lowest to Highest Emission Limits)**

| RBLCID | Permit Date | Facility Name | Corporation | State | Throughput | Units | Control Device | Emission Limit 1 | Units | Type |
|---|---|---|---|---|---|---|---|---|---|---|
| CA-0959 | 4/9/2001 | NEO CALIFORNIA POWER - RED BLUFF | NEO CALIFORNIA POWER | CA | 3928 | BHP | OXIDATION CATALYST | 0.1 | G/B-HP-H | LAER |
| GA-0104 | 10/11/2002 | THOMASTON COMPRESSOR STATION | SOUTHERN NATURAL GAS COMPANY | GA | 4730 | HP | OXIDATION CATALYST | 0.175 | G/B-HP-H | BACT-PSD |
| IA-0077 | 6/8/2005 | STATION 204 | NATURAL GAS PIPELINE OF AMERICA | IA | 4735 | HP | OXIDATIVE CATALYST | 0.18 | G/B-HP-H | MACT |
| CO-0058 | 6/12/2004 | CHEYENNE STATION | CHEYENNE PLAINS GAS PIPELINE COMPANY | CO | 1775 | HP | OXIDATION CATALYST | 0.21 | G/B-HP-H | BACT-PSD |
| CO-0058 | 6/12/2004 | CHEYENNE STATION | CHEYENNE PLAINS GAS PIPELINE COMPANY | CO | 2,443 | HP | OXIDATION CATALYST | 0.21 | G/B-HP-H | BACT-PSD |
| TX-0541 | 5/18/2009 | POWER LANE STEAM PLANT | GEUS | TX | 8.44 | MW EACH | OXIDATION CATALYST | 0.3 | G/B-HP-H | BACT-PSD |
| TX-0542 | 1/23/2009 | PEARSALL POWER PLANT | SOUTH TEXAS ELECTRIC COOPERATIVE INC. | TX | 8.44 | MW EACH | OXIDATION CATALYST | 0.3 | G/B-HP-H | BACT-PSD |
| TX-0364 | 1/31/2003 | SALT CREEK GAS PLANT | EXXON MOBIL CORPORATION | TX | 1330 | HP | NONE INDICATED | 1.19 | G/B-HP-H | Other Case-by-Case |
| TX-0364 | 1/31/2003 | SALT CREEK GAS PLANT | EXXON MOBIL CORPORATION | TX | 2400 | HP | NONE INDICATED | 1.2 | G/B-HP-H | Other Case-by-Case |
| IL-0083 | 2/8/2002 | PANHANDLE EASTERN PIPELINE COMPANY | PANHANDLE EASTERN PIPELINE COMPANY | IL | 2070 | HP | GOOD COMBUSTION PRACTICE. | 2 | G/B-HP-H | BACT-PSD |
| TX-0364 | 1/31/2003 | SALT CREEK GAS PLANT | EXXON MOBIL CORPORATION | TX | 2000 | HP EACH | NONE INDICATED | 2.04 | G/B-HP-H | Other Case-by-Case |
| WV-0020 | 2/14/2003 | COLUMBIA GAS TRANSMISSIONS LOST RIVER | COLUMBIA GAS TRANSMISSIONS LOST RIVER | WV | 4640 | HP | | 2.1 | G/B-HP-H | BACT-PSD |
| IL-0083 | 2/8/2002 | PANHANDLE EASTERN PIPELINE COMPANY | PANHANDLE EASTERN PIPELINE COMPANY | IL | 4000 | HP | GOOD COMBUSTION PRACTICE | 2.2 | G/B-HP-H | BACT-PSD |
| AZ-0047 | 12/1/2004 | WELLTON MOHAWK GENERATING STATION | DOME VALLEY ENERGY PARTNERS | AZ | 6 | MW | | 2.3 | G/B-HP-H | BACT-PSD |
| AL-0189 | 6/19/2001 | GALLION COMPRESSOR STATION | SOUTHERN NATURAL GAS COMPANY | AL | 4000 | HP | | 2.68 | G/B-HP-H | BACT-PSD |
| LA-0141 | 1/24/2002 | DUKE ENERGY FIELD SERVICES - MINDEN | DUKE ENERGY FIELD SERVICES - MINDEN | LA | 1478 | HP | | 3 | G/B-HP-H | Other Case-by-Case |
| TX-0408 | 11/22/2002 | INDIAN ROCK GATHERING COMPANY LP | INDIAN ROCK GATHERING COMPANY LP | TX | 800 | HP | GOOD COMBUSTION PRACTICE | 3 | G/B-HP-H | BACT-PSD |
| LA-0257 | 12/6/2011 | SABINE PASS LNG TERMINAL | SABINE PASS LNG, LP & SABINE PASS LIQUEFACTION, LL | LA | 2012 | hp | Comply with 40 CFR 60 Subpart JJJJ | 4 | G/B-HP-H (corrected from RBLC typo of lb/b-hp-h) | BACT-PSD |
| TX-0364 | 1/31/2003 | SALT CREEK GAS PLANT | EXXON MOBIL CORPORATION | TX | 3105 | HP | NONE INDICATED | 4.8 | G/B-HP-H | Other Case-by-Case |
| CA-1137 | 8/3/2001 | BEAR VALLEY ELECTRIC | BEAR VALLEY ELECTRIC | CA | 1695 | BHP | THREE-WAY CATALYST WITH AIR/FUEL RATIO CONTROLLER | 36 | PPMVD@15%O2 | BACT-PSD |
| CA-1068 | 4/17/2001 | NEO CALIFORNIA POWER, LLC | NEO CALIFORNIA POWER, LLC | CA | 3870 | HP | OXIDATION CATALYST | 56 | PPMVD @ 15% O2 | BACT-PSD |

**Table D-3 - RBLC Results for VOC Emissions for RICE (Natural Gas) (In Order of Lowest to Highest Emission Limits)**

| RBLCID | Permit Date | Facility Name | Corporation | State | Throughput | Units | Control Device | Emission Limit 1 | Units | Type |
|---|---|---|---|---|---|---|---|---|---|---|
| CA-0959 | 4/9/2001 | NEO CALIFORNIA POWER - RED BLUFF | NEO CALIFORNIA POWER | CA | 3928 | BHP | OXIDATION CATALYST | 0.15 | G/B-HP-H | LAER |
| TX-0364 | 1/31/2003 | SALT CREEK GAS PLANT | EXXON MOBIL CORPORATION | TX | 2000 | HP EACH | NONE INDICATED | 0.3 | G/B-HP-H | Other Case-by-Case |
| CO-0058 | 6/12/2004 | CHEYENNE STATION | CHEYENNE PLAINS GAS PIPELINE COMPANY | CO | 1775 | HP | OXIDATION CATALYST | 0.3 | G/B-HP-H | BACT-PSD |
| CO-0058 | 6/12/2004 | CHEYENNE STATION | CHEYENNE PLAINS GAS PIPELINE COMPANY | CO | 2,443 | HP | OXIDATION CATATLYST | 0.3 | G/B-HP-H | BACT-PSD |
| GA-0104 | 10/11/2002 | THOMASTON COMPRESSOR STATION | SOUTHERN NATURAL GAS COMPANY | GA | 4730 | HP | OXIDATION CATALYST | 0.3 | G/B-HP-H | Other Case-by-Case |
| TX-0541 | 5/18/2009 | POWER LANE STEAM PLANT | GEUS | TX | 8.44 | MW EACH | TCEQ'S CURRENT BACT GUIDELINES FOR GAS-FIRED, | 0.3 | G/B-HP-H | BACT-PSD |
| TX-0542 | 1/23/2009 | PEARSALL POWER PLANT | SOUTH TEXAS ELECTRIC COOPERATIVE INC. | TX | 8.44 | MW EACH | TCEQ'S CURRENT BACT GUIDELINES THIS TYPE OF ENGINE | 0.3 | G/B-HP-H | BACT-PSD |
| IL-0083 | 2/8/2002 | PANHANDLE EASTERN PIPELINE COMPANY | PANHANDLE EASTERN PIPELINE COMPANY | IL | 2070 | HP | GOOD COMBUSTION PRACTICE | 0.43 | G/B-HP-H | BACT-PSD |
| IL-0083 | 2/8/2002 | PANHANDLE EASTERN PIPELINE COMPANY | PANHANDLE EASTERN PIPELINE COMPANY | IL | 4000 | HP | GOOD COMBUSTION PRACTICE | 0.43 | G/B-HP-H | BACT-PSD |
| LA-0141 | 1/24/2002 | DUKE ENERGY FIELD SERVICES - MINDEN | DUKE ENERGY FIELD SERVICES - MINDEN | LA | 1478 | HP | | 0.50 | G/B-HP-H | Other Case-by-Case |
| TX-0364 | 1/31/2003 | SALT CREEK GAS PLANT | EXXON MOBIL CORPORATION | TX | 1330 | HP | NONE INDICATED | 0.6 | G/B-HP-H | Other Case-by-Case |
| IA-0077 | 6/8/2005 | STATION 204 | NATURAL GAS PIPELINE OF AMERICA | IA | 4735 | HP | OXIDATIVE CATALYST | 0.68 | G/B-HP-H | BACT-PSD |
| WV-0020 | 2/14/2003 | COLUMBIA GAS TRANSMISSIONS LOST RIVER | COLUMBIA GAS TRANSMISSIONS LOST RIVER | WV | 4640 | HP | | 0.7 | G/B-HP-H | BACT-PSD |
| PA-0230 | 10/23/2001 | EASTERN SHORE NAT. GAS /DALEVILLE | EASTERN SHORE NAT. GAS CO | PA | 1665 | BHP | | 0.9 | G/B-HP-H | Other Case-by-Case |
| LA-0257 | 12/6/2011 | SABINE PASS LNG TERMINAL | SABINE PASS LNG, LP & SABINE PASS LIQUEFACTION, LL | LA | 2012 | hp | Comply with 40 CFR 60 Subpart JJJJ | 1 | G/B-HP-H | BACT-PSD |
| TX-0408 | 11/22/2002 | INDIAN ROCK GATHERING COMPANY LP | INDIAN ROCK GATHERING COMPANY LP | TX | 800 | HP | GOOD COMBUSTION PRACTICE | 1.2 | G/B-HP-H | BACT-PSD |
| TX-0364 | 1/31/2003 | SALT CREEK GAS PLANT | EXXON MOBIL CORPORATION | TX | 2400 | HP | NONE INDICATED | 1.2 | G/B-HP-H | Other Case-by-Case |
| TX-0501 | 7/11/2006 | TEXSTAR GAS PROCESS FACILITY | TEXSTAR FS LP | TX | 875 | HP | | 1.4 | G/B-HP-H | BACT-PSD |
| AL-0189 | 6/19/2001 | GALLION COMPRESSOR STATION | SOUTHERN NATURAL GAS COMPANY | AL | 4000 | HP | | 1.52 | G/HP-H | BACT-PSD |
| TX-0364 | 1/31/2003 | SALT CREEK GAS PLANT | EXXON MOBIL CORPORATION | TX | 3105 | HP | NONE INDICATED | 1.6 | G/B-HP-H | Other Case-by-Case |
| CA-1137 | 8/3/2001 | BEAR VALLEY ELECTRIC | BEAR VALLEY ELECTRIC | CA | 1695 | BHP | THREE-WAY CATALYST WITH AIR/FUEL RATIO CONTROLLER | 11 | PPMVD@15%O2 | BACT-PSD |
| CA-1068 | 4/17/2001 | NEO CALIFORNIA POWER, LLC | NEO CALIFORNIA POWER, LLC | CA | 3870 | HP | OXIDATION CATALYST | 25 | PPMVD @ 15% O2 | BACT-PSD |

**Table D-4 - RBLC Results for PM/$PM_{10}$ Emissions for RICE (Natural Gas) (In Order of Lowest to Highest Emission Limits)**

| RBLCID | Permit Date | Facility Name | Corporation | State | Throughput | Units | Control Device | Emission Limit 1 | Units | Type |
|---|---|---|---|---|---|---|---|---|---|---|
| TX-0364 | 1/31/2003 | SALT CREEK GAS PLANT | EXXON MOBIL CORPORATION | TX | 1330 | HP | NONE INDICATED | 0.12 | LB/H | Other Case-by-Case |
| CA-1068 | 4/17/2001 | NEO CALIFORNIA POWER, LLC | NEO CALIFORNIA POWER, LLC | CA | 3870 | HP | | 0.17 | LB/H | BACT-PSD |
| TX-0408 | 11/22/2002 | INDIAN ROCK GATHERING COMPANY LP | INDIAN ROCK GATHERING COMPANY LP | TX | 800 | HP | GOOD COMBUSTION PRACTICE | 0.3 | LB/H | BACT-PSD |
| IA-0077 | 6/8/2005 | STATION 204 | NATURAL GAS PIPELINE OF AMERICA | IA | 4735 | HP | | 0.36 | LB/H | Other Case-by-Case |
| TX-0364 | 1/31/2003 | SALT CREEK GAS PLANT | EXXON MOBIL CORPORATION | TX | 2000 | HP EACH | NONE INDICATED | 0.53 | LB/H | Other Case-by-Case |
| TX-0364 | 1/31/2003 | SALT CREEK GAS PLANT | EXXON MOBIL CORPORATION | TX | 2400 | HP | NONE INDICATED | 0.62 | LB/H | Other Case-by-Case |
| LA-0257 | 12/6/2011 | SABINE PASS LNG TERMINAL | SABINE PASS LNG, LP & SABINE PASS LIQUEFACTION, LL | LA | 2012 | hp | fueled by natural gas | 0.75 | LB/H | BACT-PSD |
| WA-0289 | 2/22/2002 | TRANSALTA CENTRALIA GENERATION LLC | TRANSALTA | WA | 1448 | HP | | 0.94 | LB/H | BACT-PSD |
| WA-0289 | 2/22/2002 | TRANSALTA CENTRALIA GENERATION LLC | TRANSALTA | WA | 1448 | HP | | 0.94 | LB/H | BACT-PSD |
| WV-0020 | 2/14/2003 | COLUMBIA GAS TRANSMISSIONS LOST RIVER | COLUMBIA GAS TRANSMISSIONS LOST RIVER | WV | 4640 | HP | | 1 | LB/H | BACT-PSD |
| TX-0364 | 1/31/2003 | SALT CREEK GAS PLANT | EXXON MOBIL CORPORATION | TX | 3105 | HP | NONE INDICATED | 1.09 | LB/H | Other Case-by-Case |
| TX-0541 | 5/18/2009 | POWER LANE STEAM PLANT | GEUS | TX | 8.44 | MW EACH | TCEQ EMISSION LIMITS WERE NOT VERY COMPARABLE TO THE PROCESS GEUS IS USING. SO GEUS PROPOSES THE USE OF CLEAN FUELS AND GOOD | 4.5 | LB/H | BACT-PSD |
| TX-0542 | 1/23/2009 | PEARSALL POWER PLANT | SOUTH TEXAS ELECTRIC COOPERATIVE INC. | TX | 8.44 | MW EACH | TCEQ'S CURRENT BACT GUIDELINES PROVIDE NO GUIDANCE FOR PM EMISSIONS FOR THIS TYPE OF ENGINE. LOW ASH FUEL AND COMBUSTION | 4.5 | LB/H | BACT-PSD |

**Table D-5 - RBLC Results for Emissions for the Gas Heater**

| RBLCID | Permit Date | Facility Name | Corporation | State | Throughput | Units | Pollutant | Control Device | Emission Limit | Units | Type |
|---|---|---|---|---|---|---|---|---|---|---|---|
| NV-0050 | 11/30/2009 | MGM MIRAGE | MGM MIRAGE | NV | 2 | MMBTU/H | Nitrogen Oxides (NOx) | LOW-NOX BURNERS AND GOOD COMBUSTION PRACTICES | 0.025 | LB/MMBTU | Other Case-by-Case |
| IA-0058 | 4/10/2002 | GREATER DES MOINES ENERGY CENTER | MIDAMERICAN ENERGY | IA | | | Nitrogen Oxides (NOx) | | 0.036 | LB/MMBTU | BACT-PSD |
| LA-0237 | 5/20/2010 | ST. ROSE TERMINAL | INTERNATIONAL MATEX TANK TERMINAL (IMTT) | LA | 37.8 | MMBTU/H | Nitrogen Oxides (NOx) | LOW NOX BURNERS | 0.036 | LB/MMBTU | BACT-PSD |
| IA-0058 | 4/10/2002 | GREATER DES MOINES ENERGY CENTER | MIDAMERICAN ENERGY | IA | | | Nitrogen Oxides (NOx) | | 0.041 | LB/MMBTU | BACT-PSD |
| *FL-0286 | 1/10/2007 | FPL WEST COUNTY ENERGY CENTER | FLORIDA POWER AND LIGHT COMPANY | FL | 10 | MMBTU/H | Nitrogen Oxides (NOx) | | 0.095 | LB/MMBTU | BACT-PSD |
| MD-0040 | 11/12/2008 | CPV ST CHARLES | VENTURES, INC./CPV MARYLAND, LLC | MD | 1.7 | MMBTU/H | Nitrogen Oxides (NOx) | | 0.1 | LB/MMBTU | BACT-PSD |
| NJ-0036 | 10/24/2001 | AES RED OAK LLC | AES RED OAK LLC | NJ | 16 | MMBTU/H | Nitrogen Oxides (NOx) | GAS HEATER HAS FAR LOWER HEAT INPUT RATE AND SUCH NOX | 0.12 | LB/MMBTU | LAER |
| NV-0035 | 8/16/2005 | TRACY SUBSTATION EXPANSION PROJECT | SIERRA PACIFIC POWER COMPANY | NV | 4 | MMBTU/H | Nitrogen Oxides (NOx) | BEST COMBUSTION PRACTICES | 0.14 | LB/MMBTU | BACT-PSD |
| NV-0035 | 8/16/2005 | TRACY SUBSTATION EXPANSION PROJECT | SIERRA PACIFIC POWER COMPANY | NV | 4 | MMBTU/H | Nitrogen Oxides (NOx) | BEST COMBUSTION PRACTICES | 0.14 | LB/MMBTU | BACT-PSD |
| IA-0064 | 1/31/2003 | ROQUETTE AMERICA | ROQUETTE AMERICA | IA | 1.6 | MMBTU/H | Nitrogen Oxides (NOx) | GOOD COMBUSTION PRACTICES | 0.15 | LB/MMBTU | BACT-PSD |
| OH-0264 | 5/23/2002 | NORTON ENERGY STORAGE, LLC | NORTON ENERGY | OH | 11.45 | MMBTU/H | Nitrogen Oxides (NOx) | | 1.076 | LB/H | BACT-PSD |
| LA-0192 | 6/6/2005 | CRESCENT CITY POWER | CRESENT CITY POWER, LLC | LA | 19 | MMBTU/H | Nitrogen Oxides (NOx) | LOW NOX BURNERS AND GOOD COMBUSTION PRACTICES | 1.81 | LB/H | BACT-PSD |
| LA-0244 | 11/29/2010 | COMPLEX - LAB UNIT | SASOL NORTH AMERICA, INC. | LA | 21 | MMBTU/H | (NOx) | low nox burners | 2.71 | LB/H | BACT-PSD |
| LA-0244 | 11/29/2010 | LAKE CHARLES CHEMICAL COMPLEX - LAB UNIT | SASOL NORTH AMERICA, INC. | LA | 87.3 | MMBTU/H | Nitrogen Oxides (NOx) | Low NOX Burners | 7.15 | LB/H | BACT-PSD |
| LA-0244 | 11/29/2010 | LAKE CHARLES CHEMICAL COMPLEX - LAB UNIT | SASOL NORTH AMERICA, INC. | LA | 170 | MMBTU/H | Nitrogen Oxides (NOx) | low nox burners | 19.69 | LB/H | BACT-PSD |
| GA-0105 | 4/17/2003 | MCINTOSH COMBINED CYCLE FACILITY | SAVANNAH ELECTRIC AND POWER CO | GA | 5 | MMBTU/H | Nitrogen Oxides (NOx) | | 99 | PPM @ 15% O2 | BACT-PSD |
| | | | | | | | | | | | |
| **RBLCID** | **Permit Date** | **Facility Name** | **Corporation** | **State** | **Throughput** | **Units** | **Pollutant** | **Control Device** | **Emission Limit** | **Units** | **Type** |
| NV-0035 | 8/16/2005 | TRACY SUBSTATION EXPANSION PROJECT | SIERRA PACIFIC POWER COMPANY | NV | 4 | MMBTU/H | Carbon Monoxide | BEST COMBUSTION PRACTICES | 0.03 | LB/MMBTU | BACT-PSD |
| NV-0035 | 8/16/2005 | TRACY SUBSTATION EXPANSION PROJECT | SIERRA PACIFIC POWER COMPANY | NV | 4 | MMBTU/H | Carbon Monoxide | BEST COMBUSTION PRACTICES | 0.03 | LB/MMBTU | BACT-PSD |
| NV-0050 | 11/30/2009 | MGM MIRAGE | MGM MIRAGE | NV | 2 | MMBTU/H | Carbon Monoxide | GAS ONLY AND GOOD COMBUSTION PRACTICES | 0.035 | LB/MMBTU | LAER |
| IA-0058 | 4/10/2002 | GREATER DES MOINES ENERGY CENTER | MIDAMERICAN ENERGY | IA | | | Carbon Monoxide | | 0.036 | LB/MMBTU | BACT-PSD |
| IA-0058 | 4/10/2002 | GREATER DES MOINES ENERGY CENTER | MIDAMERICAN ENERGY | IA | | | Carbon Monoxide | | 0.036 | LB/MMBTU | BACT-PSD |
| MD-0040 | 11/12/2008 | CPV ST CHARLES | VENTURES, INC./CPV MARYLAND, LLC | MD | 1.7 | MMBTU/H | Carbon Monoxide | | 0.08 | LB/MMBTU | BACT-PSD |
| FL-0285 | 1/26/2007 | PROGRESS BARTOW POWER PLANT | PROGRESS ENERGY FLORIDA (PEF) | FL | 3 | MMBTU/H | Carbon Monoxide | | 0.08 | LB/MMBTU | BACT-PSD |
| *FL-0286 | 1/10/2007 | FPL WEST COUNTY ENERGY CENTER | FLORIDA POWER AND LIGHT COMPANY | FL | 10 | MMBTU/H | Carbon Monoxide | | 0.08 | LB/MMBTU | BACT-PSD |
| NJ-0036 | 10/24/2001 | AES RED OAK LLC | AES RED OAK LLC | NJ | 16 | MMBTU/H | Carbon Monoxide | GOOD COMBUSTION PRACTICE | 0.86 | LB/H | BACT-PSD |
| OH-0264 | 5/23/2002 | NORTON ENERGY STORAGE, LLC | NORTON ENERGY | OH | 11.45 | MMBTU/H | Carbon Monoxide | | 0.96 | LB/H | BACT-PSD |
| LA-0192 | 6/6/2005 | CRESCENT CITY POWER | CRESENT CITY POWER, LLC | LA | 19 | MMBTU/H | Carbon Monoxide | GOOD COMBUSTION PRACTICES | 1.52 | LB/H | BACT-PSD |
| GA-0105 | 4/17/2003 | MCINTOSH COMBINED CYCLE FACILITY | SAVANNAH ELECTRIC AND POWER CO | GA | 5 | MMBTU/H | Carbon Monoxide | | 37 | PPM @ 15% O2 | BACT-PSD |
| | | | | | | | | | | | |

**Table D-5 - RBLC Results for Emissions for the Gas Heater**

| RBLCID | Permit Date | Facility Name | Corporation | State | Throughput | Units | Pollutant | Control Device | Emission Limit | Units | Type |
|---|---|---|---|---|---|---|---|---|---|---|---|
| MD-0040 | 11/12/2008 | CPV ST CHARLES | COMPETITIVE POWER VENTURES, INC./CPV MARYLAND, LLC | MD | 1.7 | MMBTU/H | Volatile Organic Compounds (VOC) | | 0.005 | LB/MMBTU | LAER |
| NV-0050 | 11/30/2009 | MGM MIRAGE | MGM MIRAGE | NV | 2 | MMBTU/H | Volatile Organic Compounds (VOC) | GAS ONLY AND GOOD COMBUSTION PRACTICES | 0.0054 | LB/MMBTU | Other Case-by-Case |
| LA-0237 | 5/20/2010 | ST. ROSE TERMINAL | INTERNATIONAL MATEX TANK TERMINAL (IMTT) | LA | 37.8 | MMBTU/H | Volatile Organic Compounds (VOC) | GOOD COMBUSTION PRACTICES | 0.0055 | LB/MMBTU | BACT-PSD |
| OH-0264 | 5/23/2002 | NORTON ENERGY STORAGE, LLC | NORTON ENERGY | OH | 11.45 | MMBTU/H | Volatile Organic Compounds (VOC) | | 0.063 | LB/H | BACT-PSD |
| NV-0035 | 8/16/2005 | TRACY SUBSTATION EXPANSION PROJECT | SIERRA PACIFIC POWER COMPANY | NV | 4 | MMBTU/H | Volatile Organic Compounds (VOC) | BEST COMBUSTION PRACTICES | 0.08 | LB/MMBTU | BACT-PSD |
| NV-0035 | 8/16/2005 | TRACY SUBSTATION EXPANSION PROJECT | SIERRA PACIFIC POWER COMPANY | NV | 4 | MMBTU/H | Volatile Organic Compounds (VOC) | BEST COMBUSTION PRACTICES | 0.08 | LB/MMBTU | BACT-PSD |
| LA-0192 | 6/6/2005 | CRESCENT CITY POWER | CRESENT CITY POWER, LLC | LA | 19 | MMBTU/H | Volatile Organic Compounds (VOC) | GOOD COMBUSTION PRACTICES | 0.1 | LB/H | BACT-PSD |
| NJ-0036 | 10/24/2001 | AES RED OAK LLC | AES RED OAK LLC | NJ | 16 | MMBTU/H | Volatile Organic Compounds (VOC) | GOOD COMBUSTION PRACTICES | 0.11 | LB/H | LAER |
| FL-0285 | 1/26/2007 | PROGRESS BARTOW POWER PLANT | PROGRESS ENERGY FLORIDA (PEF) | FL | 3 | MMBTU/H | Volatile Organic Compounds (VOC) | | 2 | GR S /100 SCF GAS | BACT-PSD |
| *FL-0286 | 1/10/2007 | FPL WEST COUNTY ENERGY CENTER | FLORIDA POWER AND LIGHT COMPANY | FL | 10 | MMBTU/H | Volatile Organic Compounds (VOC) | | 2 | GR S/ 100 SCF GAS | BACT-PSD |
| | | | | | | | | | | | |
| **RBLCID** | **Permit Date** | **Facility Name** | **Corporation** | **State** | **Throughput** | **Units** | **Pollutant** | **Control Device** | **Emission Limit** | **Units** | **Type** |
| IA-0058 | 4/10/2002 | GREATER DES MOINES ENERGY CENTER | MIDAMERICAN ENERGY | IA | | | filterable < 10 µ (FPM10) | | 0.0045 | LB/MMBTU | BACT-PSD |
| MD-0040 | 11/12/2008 | CPV ST CHARLES | VENTURES, INC./CPV MARYLAND, LLC | MD | 1.7 | MMBTU/H | Particulate Matter (PM) | | 0.007 | LB/MMBTU | BACT-PSD |
| MD-0040 | 11/12/2008 | CPV ST CHARLES | VENTURES, INC./CPV MARYLAND, LLC | MD | 1.7 | MMBTU/H | filterable < 10 µ (FPM10) | | 0.007 | LB/MMBTU | BACT-PSD |
| MD-0040 | 11/12/2008 | CPV ST CHARLES | VENTURES, INC./CPV MARYLAND, LLC | MD | 1.7 | MMBTU/H | filterable < 2.5 µ (FPM2.5) | | 0.007 | LB/MMBTU | LAER |
| NV-0050 | 11/30/2009 | MGM MIRAGE | MGM MIRAGE | NV | 2 | MMBTU/H | filterable; 10 µ (FPM10) | GAS ONLY AND GOOD COMBUSTION PRACTICES | 0.0075 | LB/MMBTU | Other Case-by-Case |
| IA-0064 | 1/31/2003 | ROQUETTE AMERICA | ROQUETTE AMERICA | IA | 1.6 | MMBTU/H | Particulate Matter (PM) | GOOD COMBUSTION PRACTICES | 0.008 | LB/MMBTU | BACT-PSD |
| NV-0035 | 8/16/2005 | TRACY SUBSTATION EXPANSION PROJECT | SIERRA PACIFIC POWER COMPANY | NV | 4 | MMBTU/H | Particulate Matter < 10 µ (PM10) | BEST COMBUSTION PRACTICES. | 0.02 | LB/MMBTU | BACT-PSD |
| NV-0035 | 8/16/2005 | TRACY SUBSTATION EXPANSION PROJECT | SIERRA PACIFIC POWER COMPANY | NV | 4 | MMBTU/H | Particulate Matter < 10 µ (PM10) | BEST COMBUSTION PRACTICES | 0.02 | LB/MMBTU | BACT-PSD |
| OH-0264 | 5/23/2002 | NORTON ENERGY STORAGE, LLC | NORTON ENERGY | OH | 11.45 | MMBTU/H | filterable < 10 µ (FPM10) | | 0.087 | LB/H | BACT-PSD |
| NJ-0036 | 10/24/2001 | AES RED OAK LLC | AES RED OAK LLC | NJ | 16 | MMBTU/H | Particulate Matter (PM) | NONE- PM EMISSIONS ALREADY VERY LOW | 0.12 | LB/H | BACT-PSD |
| LA-0192 | 6/6/2005 | CRESCENT CITY POWER | CRESENT CITY POWER, LLC | LA | 19 | MMBTU/H | Particulate Matter < 10 µ (PM10) | NATURAL GAS AND GOOD COMBUSTION PRACTICES | 0.14 | LB/H | BACT-PSD |
| LA-0244 | 11/29/2010 | LAKE CHARLES CHEMICAL COMPLEX - LAB UNIT | SASOL NORTH AMERICA, INC. | LA | 21 | MMBTU/H | Particulate matter, total; 10 µ (TPM10) | No additional Control | 0.21 | LB/H | BACT-PSD |
| LA-0244 | 11/29/2010 | LAKE CHARLES CHEMICAL COMPLEX - LAB UNIT | SASOL NORTH AMERICA, INC. | LA | 87.3 | MMBTU/H | Particulate matter, total; 10 µ (TPM10) | | 0.86 | LB/H | BACT-PSD |
| LA-0244 | 11/29/2010 | LAKE CHARLES CHEMICAL COMPLEX - LAB UNIT | SASOL NORTH AMERICA, INC. | LA | 170 | MMBTU/H | Particulate matter, total; 10 µ (TPM10) | No additional control | 1.71 | LB/H | BACT-PSD |
| *FL-0286 | 1/10/2007 | FPL WEST COUNTY ENERGY CENTER | FLORIDA POWER AND LIGHT COMPANY | FL | 10 | MMBTU/H | Particulate Matter < 10 µ (PM10) | | 2 | GR S/100 SCF GAS | BACT-PSD |

**Table D-6 - RBLC Results for Emissions for Emergency Fire Pump and Generator**

| RBLCID | Permit Date | Facility Name | Corporation | State | Throughput | Units | Pollutant | Control Device | Emission Limit 1 | Units | Type |
|---|---|---|---|---|---|---|---|---|---|---|---|
| OH-0255 | 3/29/2001 | AEP WATERFORD ENERGY LLC | AMERICAN ELECTRIC POWER | OH | 290 | KW | Nitrogen Oxides (NOx) | | 0.24 | T/YR | BACT-PSD |
| TX-0350 | 1/31/2002 | ENNIS TRACTEBEL POWER | ENNIS-TRACTEBEL II LP | TX | | | Nitrogen Oxides (NOx) | NONE INDICATED | 1.91 | LB/H | Other Case-by-Case |
| IA-0058 | 4/10/2002 | GREATER DES MOINES ENERGY CENTER | MIDAMERICAN ENERGY | IA | 235 | BHP | Nitrogen Oxides (NOx) | RETARDED IGNITION TIMING (3-4) DEGREES | 2.55 | LB/H | BACT-PSD |
| MD-0040 | 11/12/2008 | CPV ST CHARLES | VENTURES, INC./CPV MARYLAND, LLC | MD | 300 | HP | Nitrogen Oxides (NOx) | | 3 | G/HP-H | BACT-PSD |
| FL-0322 | 12/23/2010 | SWEET SORGHUM-TO-ETHANOL ADVANCED BIOREFINERY | SOUTHEAST RENEWABLE FUELS (SRF), LLC | FL | 0 | | Nitrogen Dioxide (NO2) | | 3 | G/HP-H | BACT-PSD |
| NJ-0044 | 6/26/2001 | MANTUA CREEK GENERATING FACILITY | MANTUA CREEK GENERATING FACILITY | NJ | 1.5 | MMBTU/H | Nitrogen Oxides (NOx) | NONE | 3.35 | LB/H | N/A |
| LA-0194 | 11/24/2004 | SABINE PASS LNG IMPORT TERMINAL | SABINE PASS LNG, LP | LA | 300 | HP EA. | Nitrogen Oxides (NOx) | GOOD ENGINE DESIGN & PROPER OPERATING PRACTICES | 3.44 | LB/H | BACT-PSD |
| TX-0343 | 6/27/2001 | MONTGOMERY COUNTY POWER PROJECT | MC ENERGY PARTNERS LP | TX | | | Nitrogen Oxides (NOx) | NONE INDICATED | 3.79 | LB/H | Other Case-by-Case |
| ID-0018 | 6/25/2010 | LANGLEY GULCH POWER PLANT | IDAHO POWER COMPANY | ID | 235 | KW | Nitrogen Oxides (NOx) | TIER 3 ENGINE-BASED GOOD COMBUSTION PRACTICES (GCP) | 4 | G/KW-H | BACT-PSD |
| MN-0053 | 7/15/2004 | FAIRBAULT ENERGY PARK | MN MUNICIPAL POWER AGENCY | MN | 250 | HP | Nitrogen Dioxide (NO2) | GOOD COMBUSTION. | 4.41 | LB/MMBTU | BACT-PSD |
| OK-0090 | 3/21/2003 | DUKE ENERGY STEPHENS, LLC STEPHENS ENERGY | DUKE ENERGY | OK | 265 | BHP | Nitrogen Oxides (NOx) | ENGINE DESIGN AND HOURS LIMIT (<100 H/YR) | 4.41 | LB/MMBTU | BACT-PSD |
| OK-0070 | 6/13/2002 | GENOVA OK I POWER PROJECT | GENOVA OKLAHOMA LLC | OK | 200 | BHP | Nitrogen Oxides (NOx) | ENGINE DESIGN AND LIMITATION OF HOURS | 4.41 | LB/MMBTU | BACT-PSD |
| OK-0056 | 2/12/2002 | HORSESHOE ENERGY PROJECT | MUSTANG POWER LLC | OK | 250 | HP | Nitrogen Oxides (NOx) | ENGINE DESIGN | 4.41 | LB/MMBTU | BACT-PSD |
| CO-0052 | 8/11/2002 | ROCKY MOUNTAIN ENERGY CENTER, LLC. | ROCKY MOUNTAIN ENERGY CENTER, LLC. | CO | | | Nitrogen Oxides (NOx) | | 4.6 | T/YR | Other Case-by-Case |
| MD-0040 | 11/12/2008 | CPV ST CHARLES | VENTURES, INC./CPV MARYLAND, LLC | MD | | | Nitrogen Oxides (NOx) | | 4.8 | G/HP-H | BACT-PSD |
| MN-0054 | 12/4/2003 | MANKATO ENERGY CENTER | | MN | 290 | HP | Nitrogen Oxides (NOx) | GOOD COMBUSTION | 5.7 | G/B-HP-H | BACT-PSD |
| *LA-0251 | 4/26/2011 | FLOPAM INC. FACILITY | FLOPAM INC. | LA | 444 | hp | Nitrogen Oxides (NOx) | no additional control | 5.82 | LB/HR | BACT-PSD |
| *CA-1144 | 4/25/2007 | BLYTHE ENERGY PROJECT II | CAITHNESS BLYTHE II, LLC | CA | 303 | HP | Nitrogen Oxides (NOx) | | 7.5 | LB/H | BACT-PSD |
| FL-0285 | 1/26/2007 | PROGRESS BARTOW POWER PLANT | PROGRESS ENERGY FLORIDA (PEF) | FL | | | Nitrogen Oxides (NOx) | | 7.8 | G/B-HP-H | BACT-PSD |
| *FL-0286 | 1/10/2007 | FPL WEST COUNTY ENERGY CENTER | FLORIDA POWER AND LIGHT COMPANY | FL | | | Nitrogen Oxides (NOx) | | 7.8 | GM/B-HP | BACT-PSD |
| OH-0252 | 12/28/2004 | DUKE ENERGY HANGING ROCK ENERGY FACILITY | DUKE ENERGY HANGING ROCK, LLC | OH | 265 | HP | Nitrogen Oxides (NOx) | | 8.2 | LB/H | BACT-PSD |
| LA-0192 | 6/6/2005 | CRESCENT CITY POWER | CRESENT CITY POWER, LLC | LA | | | Nitrogen Oxides (NOx) | GOOD ENGINE DESIGN AND PROPER OPERATING PRACTICES | 8.9 | LB/H | BACT-PSD |
| TX-0352 | 12/31/2002 | BRAZOS VALLEY ELECTRIC GENERATING FACILITY | BRAZOS VALLEY ENERGY LP | TX | 300 | HP | Nitrogen Oxides (NOx) | NONE INDICATED | 9.3 | LB/H | BACT-PSD |
| TX-0407 | 12/6/2002 | STERNE ELECTRIC GENERATING FACILITY | STEAG POWER LLC | TX | 300 | HP | Nitrogen Oxides (NOx) | | 9.3 | LB/H | BACT-PSD |
| LA-0224 | 3/20/2008 | ARSENAL HILL POWER PLANT | SOUTHWEST ELECTRIC POWER COMPANY (SWEPCO) | LA | 310 | HORSEPOWER | Nitrogen Oxides (NOx) | OPERATING HOURS AND PROPER ENGINE MAINTENANCE | 9.61 | LB/H | BACT-PSD |
| LA-0224 | 3/20/2008 | ARSENAL HILL POWER PLANT | SOUTHWEST ELECTRIC POWER COMPANY (SWEPCO) | LA | 310 | HORSEPOWER | Nitrogen Oxides (NOx) | OPERATING HOURS AND PROPER ENGINE MAINTENANCE | 9.61 | LB/H | BACT-PSD |
| *AK-0072 | 7/14/2011 | DUTCH HARBOR POWER PLANT | CITY OF UNALASKA | AK | 4400 | KW | Nitrogen Oxides (NOx) | Engine has turbo charger and after cooler installed as part of the design | 9.8 | G/KW-H | BACT-PSD |
| LA-0194 | 11/24/2004 | SABINE PASS LNG IMPORT TERMINAL | SABINE PASS LNG, LP | LA | 660 | HP EA. | Nitrogen Oxides (NOx) | GOOD ENGINE DESIGN AND PROPER OPERATING PRACTICES | 12.2 | LB/H | BACT-PSD |
| OH-0254 | 8/14/2003 | DUKE ENERGY WASHINGTON COUNTY LLC | DUKE ENERGY NORTH AMERICA | OH | 400 | HP | Nitrogen Oxides (NOx) | LOW SULFUR FUEL, COMBUSTION CONTROL | 12.8 | LB/H | BACT-PSD |
| NJ-0043 | 3/28/2002 | LIBERTY GENERATING STATION | LIBERTY GENERATING STATION | NJ | 3.5 | MMBTU/H | Nitrogen Oxides (NOx) | NONE | 15.5 | LB/H | Other Case-by-Case |
| NJ-0043 | 3/28/2002 | LIBERTY GENERATING STATION | LIBERTY GENERATING STATION | NJ | 14.1 | MMBTU/H | Nitrogen Oxides (NOx) | NONE | 26.2 | LB/H | Other Case-by-Case |
| NC-0101 | 9/29/2005 | FORSYTH ENERGY PLANT | FORSYTH ENERGY PROJECTS, LLC | NC | 11.4 | MMBTU/H | Nitrogen Oxides (NOx) | | 36.48 | LB/H | BACT-PSD |
| MD-0033 | 9/27/2001 | KELSON RIDGE | FREE STATE ELECTRIC, LLC | MD | 700 | KW | Nitrogen Oxides (NOx) | GOOD COMBUSTION CONTROLS OPERATIONAL LIMITATION | | | LAER |
| MD-0033 | 9/27/2001 | KELSON RIDGE | FREE STATE ELECTRIC, LLC | MD | 200 | HP | Nitrogen Oxides (NOx) | GOOD COMBUSTION CONTROLS OPERATIONAL LIMITATION | | | LAER |

**Table D-6 - RBLC Results for Emissions for Emergency Fire Pump and Generator**

| RBLCID | Permit Date | Facility Name | Corporation | State | Throughput | Units | Pollutant | Control Device | Emission Limit 1 | Units | Type |
|---|---|---|---|---|---|---|---|---|---|---|---|
| LA-0224 | 3/20/2008 | ARSENAL HILL POWER PLANT | SOUTHWEST ELECTRIC POWER COMPANY (SWEPCO) | LA | 310 | HORSEPOWER | Carbon Monoxide | USE OF LOW-SULFUR FUELS, LIMITING OPERATING HOURS AND PROPER ENGINE MAINTENANCE | 2.07 | LB/H | BACT-PSD |
| *CA-1144 | 4/25/2007 | BLYTHE ENERGY PROJECT II | CAITHNESS BLYTHE II, LLC | CA | 303 | HP | Carbon Monoxide | | 0.7 | LB/H | BACT-PSD |
| FL-0285 | 1/26/2007 | PROGRESS BARTOW POWER PLANT | PROGRESS ENERGY FLORIDA (PEF) | FL | | | Carbon Monoxide | | 2.6 | G/B-HP-H | BACT-PSD |
| *FL-0286 | 1/10/2007 | FPL WEST COUNTY ENERGY CENTER | FLORIDA POWER AND LIGHT COMPANY | FL | | | Carbon Monoxide | | 2.6 | GM/B-HP-H | BACT-PSD |
| NC-0101 | 9/29/2005 | FORSYTH ENERGY PLANT | FORSYTH ENERGY PROJECTS, LLC | NC | 11.4 | MMBTU/H | Carbon Monoxide | | 9.69 | LB/H | BACT-PSD |
| LA-0192 | 6/6/2005 | CRESCENT CITY POWER | CRESENT CITY POWER, LLC | LA | | | Carbon Monoxide | GOOD ENGINE DESIGN AND PROPER OPERATING PRACTICES | 1.88 | LB/H | BACT-PSD |
| OH-0252 | 12/28/2004 | DUKE ENERGY HANGING ROCK ENERGY FACILITY | DUKE ENERGY HANGING ROCK, LLC | OH | 265 | HP | Carbon Monoxide | | 1.8 | LB/H | BACT-PSD |
| LA-0194 | 11/24/2004 | SABINE PASS LNG IMPORT TERMINAL | SABINE PASS LNG, LP | LA | 660 | HP EA. | Carbon Monoxide | GOOD ENGINE DESIGN AMD PROPER OPERATING PRACTICES | 0.55 | LB/H | BACT-PSD |
| LA-0194 | 11/24/2004 | SABINE PASS LNG IMPORT TERMINAL | SABINE PASS LNG, LP | LA | 300 | HP EA. | Carbon Monoxide | GOOD ENGINE DESIGN & PROPER OPERATING PRACTICES | 0.18 | LB/H | BACT-PSD |
| MN-0053 | 7/15/2004 | FAIRBAULT ENERGY PARK | MN MUNICIPAL POWER AGENCY | MN | 250 | HP | Carbon Monoxide | GOOD COMBUSTION. | 0.95 | LB/MMBTU | BACT-PSD |
| MN-0054 | 12/4/2003 | MANKATO ENERGY CENTER | | MN | 290 | HP | Carbon Monoxide | GOOD COMBUSTION | 0.25 | G/B-HP-H | N/A |
| OH-0254 | 8/14/2003 | DUKE ENERGY WASHINGTON COUNTY LLC | DUKE ENERGY NORTH AMERICA | OH | 400 | HP | Carbon Monoxide | LOW SULFUR FUEL, COMBUSTION CONTROL | 2.76 | LB/H | BACT-PSD |
| OK-0090 | 3/21/2003 | DUKE ENERGY STEPHENS, LLC STEPHENS ENERGY | DUKE ENERGY | OK | 265 | BHP | Carbon Monoxide | ENGINE DESIGN AND GOOD COMBUSTION PRACTICES | 0.95 | LB/MMBTU | BACT-PSD |
| MD-0040 | 11/12/2008 | CPV ST CHARLES | VENTURES, INC./CPV MARYLAND, LLC | MD | 300 | HP | Carbon Monoxide | | 2.6 | G/HP-H | BACT-PSD |
| MD-0040 | 11/12/2008 | CPV ST CHARLES | VENTURES, INC./CPV MARYLAND, LLC | MD | | | Carbon Monoxide | | 2.6 | G/HP-H | BACT-PSD |
| LA-0224 | 3/20/2008 | ARSENAL HILL POWER PLANT | SOUTHWEST ELECTRIC POWER COMPANY (SWEPCO) | LA | 310 | HORSEPOWER | Carbon Monoxide | OPERATING HOURS AND PROPER ENGINE MAINTENANCE | 2.07 | LB/H | BACT-PSD |
| TX-0352 | 12/31/2002 | BRAZOS VALLEY ELECTRIC GENERATING FACILITY | BRAZOS VALLEY ENERGY LP | TX | 300 | HP | Carbon Monoxide | NONE INDICATED | 2 | LB/H | Other Case-by-Case |
| TX-0407 | 12/6/2002 | STERNE ELECTRIC GENERATING FACILITY | STEAG POWER LLC | TX | 300 | HP | Carbon Monoxide | | 2 | LB/H | BACT-PSD |
| OK-0070 | 6/13/2002 | GENOVA OK I POWER PROJECT | GENOVA OKLAHOMA LLC | OK | 200 | BHP | Carbon Monoxide | GOOD ENGINE DESIGN | 0.95 | LB/MMBTU | BACT-PSD |
| IA-0058 | 4/10/2002 | GREATER DES MOINES ENERGY CENTER | MIDAMERICAN ENERGY | IA | 235 | BHP | Carbon Monoxide | | 2.21 | LB/H | BACT-PSD |
| NJ-0043 | 3/28/2002 | LIBERTY GENERATING STATION | LIBERTY GENERATING STATION | NJ | 14.1 | MMBTU/H | Carbon Monoxide | NONE | 11.1 | LB/H | Other Case-by-Case |
| NJ-0043 | 3/28/2002 | LIBERTY GENERATING STATION | LIBERTY GENERATING STATION | NJ | 3.5 | MMBTU/H | Carbon Monoxide | NONE | 3.3 | LB/H | Other Case-by-Case |
| OK-0056 | 2/12/2002 | HORSESHOE ENERGY PROJECT | MUSTANG POWER LLC | OK | 250 | HP | Carbon Monoxide | GOOD COMBUSTION PRACTICES AND DESIGN | 0.95 | LB/MMBTU | BACT-PSD |
| MD-0033 | 9/27/2001 | KELSON RIDGE | FREE STATE ELECTRIC, LLC | MD | 700 | KW | Carbon Monoxide | GOOD COMBUSTION CONTROLS OPERATIONAL LIMITATION | | | BACT-PSD |
| MD-0033 | 9/27/2001 | KELSON RIDGE | FREE STATE ELECTRIC, LLC | MD | 200 | HP | Carbon Monoxide | GOOD COMBUSTION CONTROLS OPERATIONAL LIMITATION | | | BACT-PSD |
| NJ-0044 | 6/26/2001 | MANTUA CREEK GENERATING FACILITY | MANTUA CREEK GENERATING FACILITY | NJ | 1.5 | MMBTU/H | Carbon Monoxide | NONE | 1.2 | LB/H | N/A |
| OH-0255 | 3/29/2001 | AEP WATERFORD ENERGY LLC | AMERICAN ELECTRIC POWER | OH | 290 | KW | Carbon Monoxide | | 0.05 | T/YR | BACT-PSD |
| TX-0350 | 1/31/2002 | ENNIS TRACTEBEL POWER | ENNIS-TRACTEBEL II LP | TX | | | Carbon Monoxide | NONE INDICATED | 0.55 | LB/H | Other Case-by-Case |
| TX-0343 | 6/27/2001 | MONTGOMERY COUNTY POWER PROJECT | MC ENERGY PARTNERS LP | TX | | | Carbon Monoxide | NONE INDICATED | 1.01 | LB/H | Other Case-by-Case |
| FL-0318 | 12/10/2009 | HIGHLANDS ETHANOL FACILITY | VERENIUM | FL | 0 | | Carbon Monoxide | | 0 | | BACT-PSD |
| FL-0322 | 12/23/2010 | SWEET SORGHUM-TO-ETHANOL ADVANCED BIOREFINERY | SOUTHEAST RENEWABLE FUELS (SRF), LLC | FL | 0 | | Carbon Monoxide | | 2.6 | G/HP-H | BACT-PSD |
| GA-0140 | 12/3/2010 | MITCHELL STEAM-GENERATING PLANT (PLANT MITCHELL) | GEORGIA POWER CO. | GA | 1050 | bhp | Carbon Monoxide | Use of ultra-low sulfur diesel fuel only. | 3000 | H | BACT-PSD |
| ID-0018 | 6/25/2010 | LANGLEY GULCH POWER PLANT | IDAHO POWER COMPANY | ID | 235 | KW | Carbon Monoxide | TIER 3 ENGINE-BASED, GOOD COMBUSTION PRACTICES (GCP) | 0 | | BACT-PSD |
| *LA-0251 | 4/26/2011 | FLOPAM INC. FACILITY | FLOPAM INC. | LA | 444 | hp | Carbon Monoxide | good equipment design and proper combustion practices | 0.65 | LB/HR | BACT-PSD |
| *LA-0254 | 8/16/2011 | NINEMILE POINT ELECTRIC GENERATING PLANT | ENTERGY LOUISIANA LLC | LA | 350 | HP | Carbon Monoxide | ULTRA LOW SULFUR DIESEL AND GOOD COMBUSTION PRACTICES | 0 | | BACT-PSD |
| MI-0389 | 12/29/2009 | KARN WEADOCK GENERATING COMPLEX | CONSUMERS ENERGY | MI | 525 | HP | Carbon Monoxide | ENGINE DESIGN AND OPERATION. 15 PPM SULFUR FUEL | 2.6 | G/HP-H | BACT-PSD |
| MI-0389 | 12/29/2009 | KARN WEADOCK GENERATING COMPLEX | CONSUMERS ENERGY | MI | 40 | KW | Carbon Monoxide | ENGINE DESIGN AND OPERATION. 15 PPM SULFUR FUEL. | 5 | G/KW-H | BACT-PSD |

**Table D-6 - RBLC Results for Emissions for Emergency Fire Pump and Generator**

| RBLCID | Permit Date | Facility Name | Corporation | State | Throughput | Units | Pollutant | Control Device | Emission Limit 1 | Units | Type |
|---|---|---|---|---|---|---|---|---|---|---|---|
| LA-0224 | 3/20/2008 | ARSENAL HILL POWER PLANT | SOUTHWEST ELECTRIC POWER COMPANY (SWEPCO) | LA | 310 | HORSEPOWER | Volatile Organic Compounds (VOC) | OPERATING HOURS AND PROPER ENGINE MAINTENANCE | 0.77 | LB/H | BACT-PSD |
| NC-0101 | 9/29/2005 | FORSYTH ENERGY PLANT | FORSYTH ENERGY PROJECTS, LLC | NC | 11.4 | MMBTU/H | Volatile Organic Compounds (VOC) | | 1.04 | LB/H | BACT-PSD |
| LA-0192 | 6/6/2005 | CRESCENT CITY POWER | CRESENT CITY POWER, LLC | LA | | | Volatile Organic Compounds (VOC) | GOOD ENGINE DESIGN AND PROPER OPERATING PRACTICES | 0.05 | LB/H | BACT-PSD |
| OH-0252 | 12/28/2004 | DUKE ENERGY HANGING ROCK ENERGY FACILITY | DUKE ENERGY HANGING ROCK, LLC | OH | 265 | HP | Volatile Organic Compounds (VOC) | | 0.66 | LB/H | BACT-PSD |
| LA-0194 | 11/24/2004 | SABINE PASS LNG IMPORT TERMINAL | SABINE PASS LNG, LP | LA | 660 | HP EA. | Volatile Organic Compounds (VOC) | GOOD COMBUSTION PRACTICES | 0.07 | LB/H | BACT-PSD |
| LA-0194 | 11/24/2004 | SABINE PASS LNG IMPORT TERMINAL | SABINE PASS LNG, LP | LA | 300 | HP EA. | Volatile Organic Compounds (VOC) | GOOD ENGINE DESIGN & PROPER OPERATING PRACTICES | 0.1 | LB/H | BACT-PSD |
| MN-0053 | 7/15/2004 | FAIRBAULT ENERGY PARK | MN MUNICIPAL POWER AGENCY | MN | 250 | HP | Volatile Organic Compounds (VOC) | GOOD COMBUSTION. | 0.36 | LB/MMBTU | BACT-PSD |
| MN-0054 | 12/4/2003 | MANKATO ENERGY CENTER | | MN | 290 | HP | Volatile Organic Compounds (VOC) | GOOD COMBUSTION | 0.08 | G/B-HP-H | BACT-PSD |
| OK-0090 | 3/21/2003 | DUKE ENERGY STEPHENS, LLC STEPHENS ENERGY | DUKE ENERGY | OK | 265 | BHP | Volatile Organic Compounds (VOC) | ENGINE DESIGN | 0.7 | LB/H | BACT-PSD |
| MD-0040 | 11/12/2008 | CPV ST CHARLES | VENTURES, INC./CPV MARYLAND, LLC | MD | | | Volatile Organic Compounds (VOC) | | 4.8 | G/HP-H | BACT-PSD |
| LA-0224 | 3/20/2008 | ARSENAL HILL POWER PLANT | SOUTHWEST ELECTRIC POWER COMPANY (SWEPCO) | LA | 310 | HORSEPOWER | Volatile Organic Compounds (VOC) | OPERATING HOURS AND PROPER ENGINE MAINTENANCE | 0.77 | LB/H | BACT-PSD |
| TX-0352 | 12/31/2002 | BRAZOS VALLEY ELECTRIC GENERATING FACILITY | BRAZOS VALLEY ENERGY LP | TX | 300 | HP | Volatile Organic Compounds (VOC) | NONE INDICATED | 0.75 | LB/H | Other Case-by-Case |
| TX-0407 | 12/6/2002 | STERNE ELECTRIC GENERATING FACILITY | STEAG POWER LLC | TX | 300 | HP | Volatile Organic Compounds (VOC) | | 0.74 | LB/H | BACT-PSD |
| NJ-0043 | 3/28/2002 | LIBERTY GENERATING STATION | LIBERTY GENERATING STATION | NJ | 14.1 | MMBTU/H | Volatile Organic Compounds (VOC) | NONE | 1.4 | LB/H | Other Case-by-Case |
| NJ-0043 | 3/28/2002 | LIBERTY GENERATING STATION | LIBERTY GENERATING STATION | NJ | 3.5 | MMBTU/H | Volatile Organic Compounds (VOC) | NONE | 1.2 | LB/H | Other Case-by-Case |
| OK-0056 | 2/12/2002 | HORSESHOE ENERGY PROJECT | MUSTANG POWER LLC | OK | 250 | HP | Volatile Organic Compounds (VOC) | COMBUSTION PRACTICES AND DESIGN | 0.36 | LB/MMBTU | BACT-PSD |
| MD-0033 | 9/27/2001 | KELSON RIDGE | FREE STATE ELECTRIC, LLC | MD | 700 | KW | Volatile Organic Compounds (VOC) | GOOD COMBUSTION CONTROLS OPERATIONAL LIMITATION | | | LAER |
| MD-0033 | 9/27/2001 | KELSON RIDGE | FREE STATE ELECTRIC, LLC | MD | 200 | HP | Volatile Organic Compounds (VOC) | GOOD COMBUSTION CONTROLS | | | LAER |
| NJ-0044 | 6/26/2001 | MANTUA CREEK GENERATING FACILITY | MANTUA CREEK GENERATING FACILITY | NJ | 1.5 | MMBTU/H | Volatile Organic Compounds (VOC) | NONE | 0.1 | LB/H | N/A |
| OH-0255 | 3/29/2001 | AEP WATERFORD ENERGY LLC | AMERICAN ELECTRIC POWER | OH | 290 | KW | Volatile Organic Compounds (VOC) | | 0.02 | T/YR | BACT-PSD |
| TX-0350 | 1/31/2002 | ENNIS TRACTEBEL POWER | ENNIS-TRACTEBEL II LP | TX | | | Volatile Organic Compounds (VOC) | NONE INDICATED | 0.05 | LB/H | Other Case-by-Case |
| TX-0343 | 6/27/2001 | MONTGOMERY COUNTY POWER PROJECT | MC ENERGY PARTNERS LP | TX | | | Volatile Organic Compounds (VOC) | NONE INDICATED | 0.59 | LB/H | Other Case-by-Case |
| GA-0140 | 12/3/2010 | MITCHELL STEAM-GENERATING PLANT (PLANT MITCHELL) | GEORGIA POWER CO. | GA | 1050 | bhp | Volatile Organic Compounds (VOC) | Use of ultra-low sulfur diesel fuel only. | 3000 | H | BACT-PSD |
| ID-0018 | 6/25/2010 | LANGLEY GULCH POWER PLANT | IDAHO POWER COMPANY | ID | 235 | KW | Volatile Organic Compounds (VOC) | TIER 3 ENGINE-BASED, GOOD COMBUSTION PRACTICES (GCP) | 4 | G/KW-H | BACT-PSD |
| *LA-0254 | 8/16/2011 | NINEMILE POINT ELECTRIC GENERATING PLANT | ENTERGY LOUISIANA LLC | LA | 350 | HP | Volatile Organic Compounds (VOC) | ULTRA LOW SULFUR DIESEL AND GOOD COMBUSTION PRACTICES | 0 | | BACT-PSD |

**Table D-6 - RBLC Results for Emissions for Emergency Fire Pump and Generator**

| RBLCID | Permit Date | Facility Name | Corporation | State | Throughput | Units | Pollutant | Control Device | Emission Limit 1 | Units | Type |
|---|---|---|---|---|---|---|---|---|---|---|---|
| *LA-0254 | 8/16/2011 | NINEMILE POINT ELECTRIC GENERATING PLANT | ENTERGY LOUISIANA LLC | LA | 350 | HP | Particulate matter, total; 10 µ (TPM10) | ULTRA LOW SULFUR DIESEL AND GOOD COMBUSTION PRACTICES | 0 | | BACT-PSD |
| GA-0141 | 12/17/2010 | WARREN COUNTY BIOMASS ENERGY FACILITY | OGETHORPE POWER CORPERATION | GA | 595 | HP (combined, se | Particulate matter, total (TPM) | Compliance with 40 CFR 60, Subpart IIII. | 0 | | BACT-PSD |
| *LA-0251 | 4/26/2011 | FLOPAM INC. FACILITY | FLOPAM INC. | LA | 444 | hp | Particulate matter, filterable; 10 µ (FPM10) | no additional control | 0.01 | LB/HR | BACT-PSD |
| OH-0255 | 3/29/2001 | AEP WATERFORD ENERGY LLC | AMERICAN ELECTRIC POWER | OH | 290 | KW | Particulate matter, filterable < 10 µ (FPM10) | | 0.017 | T/YR | BACT-PSD |
| OK-0070 | 6/13/2002 | GENOVA OK I POWER PROJECT | GENOVA OKLAHOMA LLC | OK | 200 | BHP | Particulate matter, filterable < 10 µ (FPM10) | ENGINE DESIGN AND GOOD COMBUSTION | 0.031 | LB/MMBTU | BACT-PSD |
| LA-0194 | 11/24/2004 | SABINE PASS LNG IMPORT TERMINAL | SABINE PASS LNG, LP | LA | 300 | HP EA. | Particulate Matter < 10 µ (PM10) | OPERATING PRACTICES, AND USE OF LOW SULFUR DIESEL | 0.06 | LB/H | BACT-PSD |
| MN-0054 | 12/4/2003 | MANKATO ENERGY CENTER | | MN | 290 | HP | Particulate Matter (PM) | GOOD COMBUSTION | 0.07 | G/B-HP-H | BACT-PSD |
| MN-0054 | 12/4/2003 | MANKATO ENERGY CENTER | | MN | 290 | HP | Particulate Matter < 10 µ (PM10) | GOOD COMBUSTION | 0.07 | G/B-HP-H | BACT-PSD |
| *CA-1144 | 4/25/2007 | BLYTHE ENERGY PROJECT II | CAITHNESS BLYTHE II, LLC | CA | 303 | HP | Particulate Matter < 10 µ (PM10) | | 0.1 | LB/H | BACT-PSD |
| LA-0192 | 6/6/2005 | CRESCENT CITY POWER | CRESENT CITY POWER, LLC | LA | | | Particulate Matter < 10 µ (PM10) | GOOD ENGINE DESIGN AND PROPER OPERATING PRACTICES | 0.14 | LB/H | BACT-PSD |
| MD-0040 | 11/12/2008 | CPV ST CHARLES | VENTURES, INC./CPV MARYLAND, LLC | MD | 300 | HP | Particulate Matter (PM) | | 0.15 | G/HP-H | BACT-PSD |
| MD-0040 | 11/12/2008 | CPV ST CHARLES | VENTURES, INC./CPV MARYLAND, LLC | MD | | | Particulate Matter (PM) | | 0.15 | G/HP-H | BACT-PSD |
| MD-0040 | 11/12/2008 | CPV ST CHARLES | VENTURES, INC./CPV MARYLAND, LLC | MD | 300 | HP | Particulate matter, filterable < 10 µ (FPM10) | | 0.15 | GR-HP-H | BACT-PSD |
| MD-0040 | 11/12/2008 | CPV ST CHARLES | VENTURES, INC./CPV MARYLAND, LLC | MD | | | Particulate matter, filterable < 10 µ (FPM10) | | 0.15 | G/HP-H | BACT-PSD |
| TX-0350 | 1/31/2002 | ENNIS TRACTEBEL POWER | ENNIS-TRACTEBEL II LP | TX | | | Particulate matter, filterable < 10 µ (FPM10) | NONE INDICATED | 0.15 | LB/H | Other Case-by-Case |
| TX-0343 | 6/27/2001 | MONTGOMERY COUNTY POWER PROJECT | MC ENERGY PARTNERS LP | TX | | | Particulate matter, filterable < 10 µ (FPM10) | NONE INDICATED | 0.15 | LB/H | Other Case-by-Case |
| NJ-0044 | 6/26/2001 | MANTUA CREEK GENERATING FACILITY | MANTUA CREEK GENERATING FACILITY | NJ | 1.5 | MMBTU/H | Particulate matter, filterable < 10 µ (FPM10) | | 0.25 | LB/H | N/A |
| NH-0018 | 7/26/2010 | BERLIN BIOPOWER | LAIDLAW BERLIN BIOPOWER, LLC | NH | 2.27 | MMBTU/H | Particulate matter, filterable (FPM) | | 0.3 | E-5 LB/MMBTU | MACT |
| MN-0053 | 7/15/2004 | FAIRBAULT ENERGY PARK | MN MUNICIPAL POWER AGENCY | MN | 250 | HP | Particulate Matter (PM) | CLEAN FUEL AND GOOD COMBUSTION. | 0.31 | LB/MMBTU | BACT-PSD |
| OK-0090 | 3/21/2003 | DUKE ENERGY STEPHENS, LLC STEPHENS ENERGY | DUKE ENERGY | OK | 265 | BHP | Particulate Matter < 10 µ (PM10) | COMBUSTION CONTROL AND GOOD ENGINE DESIGN | 0.31 | LB/MMBTU | BACT-PSD |
| OK-0056 | 2/12/2002 | HORSESHOE ENERGY PROJECT | MUSTANG POWER LLC | OK | 250 | HP | Particulate matter, filterable < 10 µ (FPM10) | LOW ASH FUEL | 0.31 | LB/MMBTU | BACT-PSD |
| MI-0389 | 12/29/2009 | KARN WEADOCK GENERATING COMPLEX | CONSUMERS ENERGY | MI | 525 | HP | Particulate matter, total; 10 µ (TPM10) | ENGINE DESIGN AND OPERATION. 15 PPM SULFUR FUEL. | 0.31 | LB/MMBTU | BACT-PSD |
| MI-0389 | 12/29/2009 | KARN WEADOCK GENERATING COMPLEX | CONSUMERS ENERGY | MI | 40 | KW | Particulate matter, total; 10 µ (TPM10) | ENGINE DESIGN AND OPERATION. 15 PPM SULFUR FUEL. | 0.31 | LB/MMBTU | BACT-PSD |
| *FL-0286 | 1/10/2007 | FPL WEST COUNTY ENERGY CENTER | FLORIDA POWER AND LIGHT COMPANY | FL | | | Particulate Matter < 10 µ (PM10) | | 0.4 | GM/B-HP-H | BACT-PSD |
| MI-0389 | 12/29/2009 | KARN WEADOCK GENERATING COMPLEX | CONSUMERS ENERGY | MI | 40 | KW | Particulate matter, total (TPM) | ENGINE DESIGN AND OPERATION. 15 PPM SULFUR FUEL. | 0.4 | G/KW-H | BACT-PSD |
| IA-0058 | 4/10/2002 | GREATER DES MOINES ENERGY CENTER | MIDAMERICAN ENERGY | IA | 235 | BHP | Particulate matter, filterable < 10 µ (FPM10) | | 0.56 | LB/H | BACT-PSD |
| OH-0252 | 12/28/2004 | DUKE ENERGY HANGING ROCK ENERGY FACILITY | DUKE ENERGY HANGING ROCK, LLC | OH | 265 | HP | Particulate Matter (PM) | | 0.66 | LB/H | BACT-PSD |
| TX-0352 | 12/31/2002 | BRAZOS VALLEY ELECTRIC GENERATING FACILITY | BRAZOS VALLEY ENERGY LP | TX | 300 | HP | Particulate matter, filterable < 10 µ (FPM10) | NONE INDICATED | 0.66 | LB/H | Other Case-by-Case |
| TX-0407 | 12/6/2002 | STERNE ELECTRIC GENERATING FACILITY | STEAG POWER LLC | TX | 300 | HP | Particulate matter, filterable < 10 µ (FPM10) | | 0.66 | LB/H | BACT-PSD |
| LA-0224 | 3/20/2008 | ARSENAL HILL POWER PLANT | SOUTHWEST ELECTRIC POWER COMPANY (SWEPCO) | LA | 310 | HORSEPOWER | Particulate Matter < 10 µ (PM10) | OPERATING HOURS AND PROPER ENGINE MAINTENANCE | 0.68 | LB/H | BACT-PSD |
| LA-0224 | 3/20/2008 | ARSENAL HILL POWER PLANT | SOUTHWEST ELECTRIC POWER COMPANY (SWEPCO) | LA | 310 | HORSEPOWER | Particulate matter, filterable < 10 µ (FPM10) | OPERATING HOURS AND PROPER ENGINE MAINTENANCE | 0.68 | LB/H | BACT-PSD |
| OH-0254 | 8/14/2003 | DUKE ENERGY WASHINGTON COUNTY LLC | DUKE ENERGY NORTH AMERICA | OH | 400 | HP | Particulate Matter (PM) | LOW SULFUR FUEL, COMBUSTION CONTROL | 0.88 | LB/H | BACT-PSD |
| NJ-0043 | 3/28/2002 | LIBERTY GENERATING STATION | LIBERTY GENERATING STATION | NJ | 3.5 | MMBTU/H | Particulate matter, filterable < 10 µ (FPM10) | NONE | 1.1 | LB/H | Other Case-by-Case |
| NC-0101 | 9/29/2005 | FORSYTH ENERGY PLANT | FORSYTH ENERGY PROJECTS, LLC | NC | 11.4 | MMBTU/H | Particulate Matter < 10 µ (PM10) | | 1.14 | LB/H | BACT-PSD |
| LA-0194 | 11/24/2004 | SABINE PASS LNG IMPORT TERMINAL | SABINE PASS LNG, LP | LA | 660 | HP EA. | Particulate Matter < 10 µ (PM10) | GOOD COMBUSTION PRACTICES | 1.24 | LB/H | BACT-PSD |
| NJ-0043 | 3/28/2002 | LIBERTY GENERATING STATION | LIBERTY GENERATING STATION | NJ | 14.1 | MMBTU/H | Particulate matter, filterable < 10 µ (FPM10) | NONE | 1.4 | LB/H | Other Case-by-Case |
| CO-0052 | 8/11/2002 | ROCKY MOUNTAIN ENERGY CENTER, LLC. | ROCKY MOUNTAIN ENERGY CENTER, LLC. | CO | | | Particulate matter, filterable < 10 µ (FPM10) | | 2.4 | T/YR | Other Case-by-Case |
| GA-0140 | 12/3/2010 | MITCHELL STEAM-GENERATING PLANT (PLANT MITCHELL) | GEORGIA POWER CO. | GA | 1050 | bhp | Particulate matter, filterable; 10 µ (FPM10) | Use of ultra-low sulfur diesel fuel only. | 3000 | H | BACT-PSD |

# APPENDIX E - ECONOMIC TABLES

**Table E-1**
**SCR System Capital Cost Analysis - Fuel-Gas Heater**

| Item | Value | Basis |
|---|---|---|
| **Direct Costs** | | |
| **Purchased Equipment Cost** | | |
| Equipment cost + auxiliaries **[A]** | **$21,429** | A (SCR system cost) |
| Instrumentation | $2,143 | 0.10 x (A) |
| Sales taxes | $0 | Pollution Control Equipment Exempt |
| Freight | $1,071 | 0.05 x (A) |
| **Total Purchased Equipment Cost (PEC) [B]** | **$24,643** | B = 1.15 x (A) |
| **Direct Installation Costs** | | |
| Total Direct Installation Cost | $7,393 | 0.30 x B |
| Site Preparation (SP) | $0 | As required |
| Buildings (Bldg.) | $0 | As required |
| **Total Direct Cost (DC)** | **$32,036** | 1.30B + SP + Bldg. |
| **Indirect Costs (Installation)** | | |
| Engineering | $2,464 | 0.10 x B |
| Construction and field expenses | $1,232 | 0.05 x B |
| Contractor fees | $2,464 | 0.10 x B |
| Start-up | $493 | 0.02 x B |
| Performance test | $0 | Assume not required |
| Contingencies | $1,232 | 0.05 x B |
| Other | $0 | As required |
| **Total Indirect Cost (IC)** | **$7,886** | 0.32B + Other + Perf. Test |
| **Total Capital Investment (TCI) = DC + IC** | **$39,921** | 1.62B + Performance test + Other + SP + Bldg. |

**Table E-2**
**SCR System Annual Cost Analysis - Fuel-Gas Heater**

| Item | Value | Basis |
|---|---|---|
| **Direct Annual Costs (DC)** | | |
| **Electricity** | | |
| Press. Drop (in W.C.) | 3.0 | Pressure drop - catalyst bed |
| Power output of Gas Heater (kW) | 703 | ISO Rating |
| Power Loss Due to Pressure Drop (%) | 0.30% | 0.1% for every 1" pressure drop |
| Power Loss Due to Pressure Drop (kW) | 2.11 | |
| Unit cost ($/kWh) | $0.045 | Estimated market value |
| Cost of Power Loss ($/yr) | $831 | Based on operation 8,760 hours/yr |
| **Operating Labor** | | |
| Catalyst labor req. | $16,425 | 1/2 hr/shift @ $30/hr |
| Ammonia delivery requirement (SCR) | $720 | 24 hr/yr (3 deliveries per year) @ $30/hr |
| Ammonia recordkeeping and reporting (SCR) | $1,200 | 40 hours per year @ $30/hr |
| Catalyst cleaning | $1,200 | 40 hours per year @ $30/hr |
| Supervisor | $2,464 | 15% Operating labor |
| Total Cost ($/yr) | $22,009 | |
| **Maintenance** | | |
| Catalyst replacement labor | $3,200 | 107 hr/yr (8 workers, 40 hr, every 3 years) |
| Catalyst system maintenance labor req. | $16,425 | 1/2 hr/shift @ $30/hr |
| Ammonia system maintenance labor req. | $10,950 | 1 hr/day @ $30/hr |
| Material | $27,375 | 100% of maintenance labor |
| Total Cost ($/yr) | $57,950 | |
| **Ammonia** | | |
| Requirement (tons/yr) | 2.7 | 29% aqueous ammonia @ $375/ton |
| Unit Cost ($/ton) | $375 | Estimate |
| Total Cost ($/yr) | $1,019 | |
| **Process Air** | | |
| Requirement (scf/lb $NH_3$) | 350 | |
| Requirement (mscf/yr) | 8,334 | |
| Unit Cost ($/mscf) | $0.20 | $0.20 per 1000 scf |
| Total Cost ($/yr) | $1,667 | |
| **Catalyst** | | |
| Catalyst Cost ($) | $2,602 | Catalyst modules |
| Catalyst Disposal Cost ($) | $38 | Disposal of catalyst modules |
| Sales Tax ($) | $0 | Pollution Control Equipment Exempt |
| Catalyst Life (yrs) | 3 | n |
| Interest Rate (%) | 7.0% | i |
| CRF | 0.381 | Amortization of catalyst for 3 yrs |
| Total Cost ($/yr) | $1,006 | (Volume) * (Unit Cost) * (CRF) |
| **Indirect Annual Costs (IC)** | | |
| Overhead | $0 | OAQPS SCR Assumption |
| Administrative charges | $0 | OAQPS SCR Assumption |
| Annual Contingency | $0 | OAQPS SCR Assumption |
| Property taxes | $0 | OAQPS SCR Assumption |
| Insurance | $0 | OAQPS SCR Assumption |
| Capital Recovery | $3,768 | CRF x TCI (20 yr life, 7.0% interest) |
| Total Indirect Costs ($/yr) | $3,768 | |
| **Total Annualized Costs (TAC) ($)** | **$88,251** | |
| Total NOx Controlled (ton/yr) | 1.1 | 90% reduction |
| **COST EFFECTIVENESS ($/ton)** | **$77,197** | |

**Table E-3**
**CO Catalyst Capital Cost Analysis - Fuel-Gas Heater**

| Item | Value | Basis |
|---|---|---|
| **Direct Costs** | | |
| **Purchased Equipment Cost** | | |
| Equipment cost + auxiliaries **[A]** | **$4,286** | A |
| Instrumentation | $429 | 0.10 x (A) |
| Sales taxes | $0 | Pollution Control Equipment Exempt |
| Freight | $214 | 0.05 x (A) |
| **Total Purchased Equipment Cost (PEC) [B]** | **$4,929** | B = 1.15 x (A) |
| **Direct Installation Costs** | | |
| Foundations and supports | $394.29 | 0.08 x B |
| Handling and erection | $690 | 0.14 x B |
| Electrical | $197 | 0.04 x B |
| Piping | $99 | 0.02 x B |
| Insulation for ductwork | $49 | 0.01 x B |
| Painting | $49 | 0.01 x B |
| Total Direct Installation Cost | $1,479 | 0.30 x B |
| Site Preparation (SP) | $0 | As required |
| Buildings (Bldg.) | $0 | As required (5-18% PEC) |
| **Total Direct Cost (DC)** | **$6,407** | 1.3B + SP + Bldg. |
| **Indirect Costs (Installation)** | | |
| Engineering | $493 | 0.10 x B |
| Construction and field expenses | $246 | 0.05 x B |
| Contractor fees | $493 | 0.10 x B |
| Start-up | $99 | 0.02 x B |
| Performance test | $1,500 | Stack Test Vendor Quote |
| Contingencies | $246 | 0.05 x B |
| Other | $0 | As required |
| **Total Indirect Cost (IC)** | **$3,077** | 0.32B + Other + Perf. Test |
| **Total Capital Investment (TCI) = DC + IC** | **$9,484** | 1.62B + Performance test + Other + SP + Bldg. |

**Table E-4**
**CO Catalyst Annual Cost Analysis - Fuel-Gas Heater**

| Item | Value | Basis |
|---|---|---|
| **Direct Annual Costs (DC)** | | |
| **Steam** | | |
| Press. Drop (in W.C.) | 3.0 | Pressure drop - catalyst bed |
| Power output of Gas Heater (kW) | 703 | ISO Rating |
| Output Loss Due to Pressure Drop (%) | 0.30% | 0.1% for every 1" pressure drop |
| Output Loss Due to Pressure Drop (kW) | 2.11 | |
| Unit cost ($/kWh) | $0.059 | Current Purchase Price |
| Cost of Heat Rate Loss ($/yr) | $1,090 | Based on operation 8,760 hours/yr |
| **Operating Labor** | | Assumed $30/hr |
| Catalyst labor req. | $16,425 | 216 hr/yr (1/2 hr/shift. 431 shifts/yr) |
| Supervisor | $2,464 | 15% Operating labor |
| Total Cost ($/yr) | $18,889 | |
| **Maintenance** | | |
| Catalyst replacement labor | $3,200 | 107 hr/yr(8 worker, 40 hr, every 3 years) |
| Material | $3,200 | 100% of maintenance labor |
| Total Cost ($/yr) | $6,400 | |
| **Catalyst** | | |
| Catalyst Cost ($) | $4,286 | Catalyst modules |
| Catalyst Disposal Cost ($) | $1,500 | Disposal of catalyst modules |
| Sales Tax ($) | $0 | Assume exempt from taxes |
| Catalyst Life (yrs) | 3 | n |
| Interest Rate (%) | 7% | I |
| CRF | 0.381 | Amortization of catalyst over 3 yrs |
| Total Cost ($/yr) | $2,205 | (Volume)(Unit Cost)(CRF) |
| **Indirect Annual Costs (IC)** | | |
| Overhead | $0 | OAQPS SCR Assumption |
| Administrative charges | $0 | OAQPS SCR Assumption |
| Annual Contingency | $0 | OAQPS SCR Assumption |
| Property taxes | $0 | OAQPS SCR Assumption |
| Insurance | $0 | OAQPS SCR Assumption |
| Capital Recovery | $895 | CRF x TCI (20 yr life, 7.0% interest) |
| Total Indirect Costs ($/yr) | $895 | |
| Total Annualized Costs (TAC) ($) | $29,478 | |
| Total CO Controlled (ton/yr) | 0.99 | 90% removal |
| Total VOC Controlled (ton/yr) | 0.04 | 50% removal |
| **COST EFFECTIVENESS ($/ton)** | **$28,874** | |

**Table E-5**
**SCR System Capital Cost Analysis - Emergency Generator**

| Item | Value | Basis |
|---|---|---|
| **Direct Costs** | | |
| **Purchased Equipment Cost** | | |
| Equipment cost + auxiliaries **[A]** | **$9,256** | A |
| Instrumentation | $926 | 0.10 x (A) |
| Sales taxes | $0 | Pollution Control Equipment Exempt |
| Freight | $463 | 0.05 x (A) |
| **Total Purchased Equipment Cost (PEC) [B]** | **$10,644** | B = 1.15 x (A) |
| **Direct Installation Costs** | | |
| Total Direct Installation Cost | $3,193 | 0.30 x B |
| Site Preparation (SP) | $0 | As required |
| Buildings (Bldg.) | $0 | As required |
| **Total Direct Cost (DC)** | **$13,838** | B + SP + Bldg. + Total Direct Install. Cost |
| **Indirect Costs (Installation)** | | |
| Engineering | $1,064 | 0.10 x B |
| Construction and field expenses | $532 | 0.05 x B |
| Contractor fees | $1,064 | 0.10 x B |
| Start-up | $213 | 0.02 x B |
| Performance test | $1,500 | Stack Test Vendor Quote |
| Contingencies | $532 | 0.05 x B |
| Other | $0 | As required |
| **Total Indirect Cost (IC)** | **$4,906** | 0.32B + Other + Performance Test |
| **Total Capital Investment (TCI) = DC + IC** | **$18,744** | 1.32B + Perf. Test + SP + Bldg + DC |

**Table E-6**
**SCR System Annual Cost Analysis - Emergency Generator**

| Item | Value | Basis |
|---|---|---|
| **Direct Annual Costs (DC)** | | |
| **Electricity** | | |
| Press. Drop (in W.C.) | 3.0 | Pressure drop - catalyst bed |
| Power output of Black Start (kW) | 450 | ISO Rating |
| Power Loss Due to Pressure Drop (%) | 0.30% | 0.1% for every 1" pressure drop |
| Power Loss Due to Pressure Drop (kW) | 1.35 | |
| Unit cost ($/kWh) | $0.059 | Estimated market value |
| Cost of Power Loss ($/yr) | $8 | Based on operation of 100 hours/yr |
| **Operating Labor** | | |
| Catalyst labor req. | $188 | 1/2 hr/shift @ $30/hr |
| Ammonia delivery requirement (SCR) | $720 | 24 hr/yr (3 deliveries per year) @ $30/hr |
| Ammonia recordkeeping and reporting (SCR) | $1,200 | 10 hours per year @ $30/hr |
| Catalyst cleaning | $1,200 | 10 hours per year @ $30/hr |
| Supervisor | $28 | 15% Operating labor |
| Total Cost ($/yr) | $3,336 | |
| **Maintenance** | | |
| Catalyst replacement labor | $3,210 | 107 hr/yr (8 workers, 40 hr, every 3 years) |
| Catalyst system maintenance labor req. | $188 | 1/2 hr/shift @ $30/hr |
| Ammonia system maintenance labor req. | $10,950 | 1 hr/day @ $30/hr |
| Material | $11,138 | 100% of maintenance labor |
| Total Cost ($/yr) | $25,485 | |
| **Ammonia** | | |
| Requirement (tons/yr) | 0.2 | 29% aqueous ammonia @ $375/ton |
| Unit Cost ($/ton) | $375 | Estimate |
| Total Cost ($/yr) | $80 | |
| **Process Air** | | |
| Requirement (scf/lb $NH_3$) | 350 | |
| Requirement (mscf/yr) | 651 | |
| Unit Cost ($/mscf) | $0.20 | $0.20 per 1000 scf |
| Total Cost ($/yr) | $130 | |
| **Catalyst** | | |
| Catalyst Cost ($) | $1,124 | Catalyst modules |
| Catalyst Disposal Cost ($) | $38 | Disposal of catalyst modules |
| Sales Tax ($) | $0 | Pollution Control Equipment Exempt |
| Catalyst Life (yrs) | 3 | n |
| Interest Rate (%) | 7.0% | i |
| CRF | 0.381 | Amortization of catalyst for 3 yrs |
| Total Cost ($/yr) | $443 | (Volume) * (Unit Cost) * (CRF) |
| **Indirect Annual Costs (IC)** | | |
| Overhead | $0 | OAQPS SCR Assumption |
| Administrative charges | $0 | OAQPS SCR Assumption |
| Annual Contingency | $0 | OAQPS SCR Assumption |
| Property taxes | $0 | OAQPS SCR Assumption |
| Insurance | $0 | OAQPS SCR Assumption |
| Capital Recovery | $1,769 | CRF x TCI (20 yr life, 7.0% interest) |
| Total Indirect Costs ($/yr) | $1,769 | |
| **Total Annualized Costs (TAC) ($)** | **$31,250** | |
| Total Pollutant Controlled (ton/yr) | 0.1 | 85% reduction (Based on 100 hrs/yr) |
| **COST EFFECTIVENESS ($/ton)** | **$350,144** | |

## Emergency Generator Data

| | | |
|---|---|---|
| Operating Temperature | 59 | F |
| Load | 100% | |
| | | |
| Fuel Type | **Diesel** | |
| Hours of Operation | **100** | |
| | | |
| Emission Characteristics | | |
| NOx | | ppmvd @ 15% O2 |
| | 2.1 | lb/hr |

| | | | | |
|---|---|---|---|---|
| **For NOx:** | A reduction to | | ppmvd is a | 85.0% reduction over uncontrolled levels |
| This is equivalent to an hourly emission rate of | | 0.315 | lb/hr | |
| which equates to | | 0.1 | tons per year reduction | |
| | | | | |
| Which equals: | | 0.2 | tons of 29% aqueous ammonia solution required | |

**Table E-7**
**CO Catalyst Capital Cost Analysis - Emergency Generator**

| Item | Value | Basis |
|---|---|---|
| **Direct Costs** | | |
| **Purchased Equipment Cost** | | |
| Equipment cost + auxiliaries **[A]** | **$1,663** | A |
| Instrumentation | $166 | 0.10 x A |
| Sales taxes | $0 | Pollution Control Equipment Exempt |
| Freight | $83 | 0.05 x A |
| **Total Purchased Equipment Cost (PEC) [B]** | **$1,913** | B = 1.15 x A |
| **Direct Installation Costs** | | |
| Foundations and supports | $153 | 0.08 x B |
| Handling and erection | $268 | 0.14 x B |
| Electrical | $77 | 0.04 x B |
| Piping | $38 | 0.02 x B |
| Insulation for ductwork | $19 | 0.01 x B |
| Painting | $19 | 0.01 x B |
| Total Direct Installation Cost | $574 | 0.30 x B |
| Site Preparation (SP) | $0 | As required |
| Buildings (Bldg.) | $0 | As required (5-18% PEC) |
| **Total Direct Cost (DC)** | **$2,486** | 1.3B + SP + Bldg. |
| **Indirect Costs (Installation)** | | |
| Engineering | $191 | 0.10 x B |
| Construction and field expenses | $96 | 0.05 x B |
| Contractor fees | $191 | 0.10 x B |
| Start-up | $38 | 0.02 x B |
| Performance test | $1,500 | Stack Test Vendor Quote |
| Contingencies | $96 | 0.05 x B |
| Other | $0 | As required |
| **Total Indirect Cost (IC)** | **$2,112** | 0.32B + Other + Performance Test |
| **Total Capital Investment (TCI) = DC + IC** | **$4,598** | 1.62B + Performance Test + SP + Bldg |

**Table E-8**
**CO Catalyst Annual Cost Analysis - Emergency Generator**

| Item | Value | Basis |
|---|---|---|
| **Direct Annual Costs (DC)** | | |
| **Electricity** | | |
| Press. Drop (in W.C.) | 3.0 | Pressure drop - catalyst bed |
| Power output of Black Start Engine (kW) | 450 | ISO Rating |
| Output Loss Due to Pressure Drop (%) | 0.30% | 0.1% for every 1" pressure drop |
| Output Loss Due to Pressure Drop (kW) | 1.35 | |
| Unit cost ($/kWh) | $0.059 | Current Purchase Price |
| Cost of Heat Rate Loss ($/yr) | $8 | Based on operation of 100 hours/yr |
| **Operating Labor** | | Assumed $30/hr |
| Catalyst labor | $188 | 1/2 hr per shift |
| Material | $188 | 100% of maintenance labor |
| Supervisor | $28 | 15% Operating labor |
| Total Cost ($/yr) | $403 | |
| **Catalyst** | | |
| Catalyst Cost ($) | $950 | Catalyst modules |
| Catalyst Disposal Cost ($) | $38 | Disposal of catalyst modules |
| Catalyst replacement labor | $3,200 | 107 hr/yr (8 worker, 40 hr, every 3 years) |
| Sales Tax ($) | $0 | Assume exempt from taxes |
| Catalyst Life (yrs) | 3 | n |
| Interest Rate (%) | 7% | I |
| CRF | 0.381 | Amortization of catalyst over 3 yrs |
| Total Cost ($/yr) | $1,596 | (Material + Labor Costs) * CRF |
| **Indirect Annual Costs (IC)** | | |
| Overhead | $0 | OAQPS SCR Assumption |
| Administrative charges | $0 | OAQPS SCR Assumption |
| Annual Contingency | $0 | OAQPS SCR Assumption |
| Property taxes | $0 | OAQPS SCR Assumption |
| Insurance | $0 | OAQPS SCR Assumption |
| Capital Recovery | $434 | CRF x TCI (20 yr life, 7.0% interest) |
| Total Indirect Costs ($/yr) | $434 | |
| Total Annualized Costs (TAC) ($) | $2,441 | |
| Total CO Controlled (ton/yr) | 0.07 | 80% reduction |
| Total VOC Controlled (ton/yr) | 0.05 | 50% reduction |
| **COST EFFECTIVENESS ($/ton)** | **$19,237** | |

Emergency Generator Data

| | | |
|---|---|---|
| Fuel Type | **Gas** | |
| Hours of Operation | **100** | |

Emission Characteristics

| | | |
|---|---|---|
| CO | 1.86 | lb/hr |
| VOC | 2.1 | lb/hr |

| | | | | |
|---|---|---|---|---|
| **For CO:** | A reduction to | 80.0% | reduction over uncontrolled levels | 80 |
| This is equivalent to an hourly emission rate of | | 0.372 | lb/hr | |
| | which equates to | 0.074 | tons per year reduction | |
| **For VOC:** | A reduction to | 50.0% | reduction over uncontrolled levels | 50 |
| This is equivalent to an hourly emission rate of | | 1.05 | lb/hr | |
| | which equates to | 0.053 | tons per year reduction | |

# APPENDIX F - MODELING PROTOCOL

# Prevention of Significant Deterioration Class II Air Dispersion Modeling Protocol

**TRADEWIND ENERGY, INC.**

**Lacey Randall Station Project**

**Project No. 72125**

**April 2013**

# Prevention of Significant Deterioration Class II Air Dispersion Modeling Protocol

**prepared for**

**TradeWind Energy, Inc.**

**April 2013**

**Project No. 72125**

**prepared by**

**Burns & McDonnell Engineering Company, Inc.**
**Kansas City, Missouri**

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# 1.0 INTRODUCTION

TradeWind Energy, Inc. (TradeWind), is proposing to construct a nominal 93.4-megawatt (MW) power facility in Thomas County, Kansas. The proposed facility will consist of ten nominal 9.34-MW internal combustion engines and associated equipment and will be operated by TradeWind. The Lacey Randall Station Project (hereinafter referred to as Project) will be located on a greenfield site approximately five miles north of Colby, Kansas. Preliminary estimated potential emissions indicate that the proposed Project will be considered a major source under Prevention of Significant Deterioration (PSD) rules; as a result, the project will be subject to PSD construction permit review. Since a PSD permit requires an assessment of ambient impacts for those pollutants subject to PSD review, this document presents a Class II air dispersion modeling protocol to be used in developing the PSD application. Submittal of this protocol will allow the Kansas Department of Health and Environment (KDHE) to review and comment upon the methodology to be employed in the modeling analysis.

Included in this document is a brief description of the project, proposed model to be used, and input parameters for the proposed model. This modeling protocol has been drafted in accordance with the U.S. Environmental Protection Agency (EPA) and KDHE modeling guidelines.

# 2.0 PROJECT DESCRIPTION

TradeWind is proposing to build ten nominal 9.34-MW internal combustion engines and associated equipment on a greenfield site approximately five miles north of Colby in Thomas County, Kansas. The proposed site will be located within the area shown on Figure 1, Appendix A.

Thomas County is currently designated as an attainment/unclassified area for all criteria pollutants; therefore, the Project is not subject to non-attainment new source review.

The preliminary estimated air emissions for the proposed Project are presented in Table 1. The estimated potential air emissions are based on all engines operating year-round (8,760 hours per year, per engine). The project preliminary estimated potential emissions shown in Table 1 also include the emissions from four startup events per day for each engine and emissions from a natural gas heater, emergency diesel generator, and emergency diesel fire pump. The maximum emissions from each operating load for the combustion engines were used to demonstrate the maximum preliminary estimated potential emissions for each pollutant. The proposed combustion engine operating loads for the permit conditions will be 50 percent, 75 percent, 90 percent, and 100 percent load.

**Table 1: Preliminary Estimated Potential Emissions and PSD Significance Levels for the Project**

| Pollutant[A] | Preliminary Estimated Potential Emissions (Tons per Year)[B,D] | PSD Significance Levels (Tons per Year) |
|---|---|---|
| $NO_x$ | **136.19** | 40 |
| $SO_2$ | 2.26 | 40 |
| CO | **225.19** | 100 |
| PM | **91.09** | 25 |
| $PM_{10}$[C] | **91.09** | 15 |
| $PM_{2.5}$[C] | **91.09** | 10 |
| VOC | **170.79** | 40 |
| Lead | $6.44 \times 10^{-6}$ | 10 |
| $H_2SO_4$ Mist | 0.35 | 7 |
| $CO_2e$ | **445,159** | 100,000 |

[A] $NO_x$ = nitrogen oxides; CO = carbon monoxide; $SO_2$ = sulfur dioxide; VOC = volatile organic carbons; PM= total particulate matter; $PM_{10}$ = particulate matter less than 10 microns in diameter; $PM_{2.5}$ = particulate matter less than 2.5 microns in diameter; $CO_2e$ = carbon dioxide equivalent (greenhouse gases); $H_2SO_4$ Mist = sulfuric acid mist
[B] Numbers in **bold** indicate the PSD significance level is exceeded
[C] Filterable plus condensable
[D] Based on 4 startups per day at 30 minutes each plus full load operation for the rest of the year (8,030 hours per engine) for each engine (worst-case emissions scenario).

Based on the preliminary estimated potential emissions shown in Table 1, it is expected that $NO_x$, CO, PM, $PM_{10}$, $PM_{2.5}$, VOC, and $CO_2e$ will be subject to PSD review. Accordingly, an air quality analysis will be performed for $NO_x$, CO and $PM_{10}/PM_{2.5}$ using the EPA-approved AMS/EPA Regulatory Model (AERMOD). However, in accordance with guidance, modeling of PM, VOCs, and $CO_2e$ has not been carried out, because there are no modeling thresholds for these pollutants.

Auxiliary equipment will consist of a natural gas heater, emergency diesel fire pump, and emergency diesel generator. Annual emissions for the natural gas heater will be based on 8,760 hours per year, while the annual emissions for the emergency generator and emergency fire pump will be based on 100 hours per year each. TradeWind understands that a limit of 100 hours per year in the modeling will result in a similar permit limit.

## 3.0 PROPOSED MODEL

TradeWind is proposing to use the most current version of the AMS/EPA Regulatory Model (AERMOD) for the air quality analysis (Version 12345). The AERMOD model is an EPA-approved, steady-state Gaussian plume model capable of modeling multiple sources in simple and complex terrain using detailed meteorological data.

The following default model options will be used:

- Gradual Plume Rise
- Stack-tip Downwash
- Buoyancy-induced Dispersion
- Calms and Missing Data Processing Routine
- Calculate Wind Profiles
- Calculate Vertical Potential Temperature Gradient
- Rural Dispersion

Details of the modeling algorithms contained in the AERMOD may be found in the User's Guide for AERMOD. The regulatory default option will be selected for this analysis.

## 4.0 MODELING PARAMETERS

It is expected that $NO_x$, CO, PM, $PM_{10}$, $PM_{2.5}$, VOC, and $CO_2e$ will be subject to PSD review, and an air quality analysis will be performed for each of them. Since VOCs are photoreactive pollutants and are generally regional in nature in terms of their contribution to ozone formation, no reactive-pollutant modeling of VOCs from the Project is proposed at this point. Additionally, and in accordance with guidance, modeling of PM, VOCs, and $CO_2e$ has not been carried out, because there are no modeling thresholds for these pollutants.

### 4.1 $NO_2$ MODELING – MULTI-TIERED SCREENING APPROACH

The annual emissions presented above represent operations at worst-case ambient conditions under various operating capacities. The AERMOD model gives the emission results for all pollutants, including $NO_x$ without chemical transformations. However, impacts of nitrogen dioxide ($NO_2$) must be examined for comparison to NAAQS, PSD increments and significance values. Therefore, TradeWind proposes a three step process to analyze the 1-hour and annual $NO_x$ modeled impacts.

EPA has a three-tier approach to modeling $NO_2$ concentrations.

- Tier I – total conversion, or all $NO_x = NO_2$
- Tier II – use a default $NO_2/NO_x$ ratio
- Tier III – case-by-case detailed screening methods, such as OLM and Plume Volume Molar Ratio Method (PVMRM)

Step 1 uses the AERMOD regulatory default options and assumes all $NO_x$ emissions are $NO_2$ (Tier 1 methodology). If Step 1 produces unacceptable results then Step 2 will be used. Step 2 uses the AERMOD regulatory default options and assumes 75 percent of the $NO_x$ emissions are in the form of $NO_2$ for the annual average and 80 percent of the $NO_x$ emissions are in the form of $NO_2$ for the 1-hour standard (Tier 2 methodology). If Step 2 produces unacceptable results then Step 3 will be used. Step 3 proposes to use Tier 3 methodology as presented in EPA's March 2011 memo[1], the Ozone Limiting Method (OLM) or the Plume Volume Molar Ratio Method PVMRM. If Tier 3 is used, a separate modeling protocol specific to the Tier 3 methodology will be submitted to the KDHE.

Based on preliminary modeling, it has been determined that the Tier 3 methodology (OLM) will be used for the $NO_2$ 1-hour air dispersion modeling. The OLM modeling protocol that proposes the modeling methodology that will be used for the $NO_2$ 1-hour air dispersion modeling for the Project is shown in Appendix B. The OLM modeling protocol will be submitted to EPA for review and comment.

The OLM methodology will not be applied to the $NO_2$ annual averaging period. The modeled concentrations of annual $NO_x$ will be adjusted using the EPA-approved Ambient Ratio Method (ARM) (Tier 2 methodology). Tier 2 of the ARM allows the use of an empirically derived $NO_2/NO_x$ ratio of 0.75, which means that approximately 75 percent of the $NO_x$ emissions will be converted to $NO_2$, the regulated pollutant. This factor will be applied to the annual modeled results for $NO_x$ to determine the predicted ground-level concentration of $NO_2$.

## 4.2 GOOD ENGINEERING PRACTICE STACK HEIGHT

Sources included in a PSD permit application are subject to Good Engineering Practice (GEP) stack height requirements outlined in 40 CFR Part 51, Sections 51.100 and 51.118. As defined by the regulations, GEP height is calculated as the greater of 65 meters (measured from the ground level elevation at the base of the stack) or the height resulting from the following formula:

[1] March 01, 2011 EPA Memo from Tyler Fox. Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour $NO_2$ National Ambient Air Quality Standard

$$GEP = H + 1.5L$$

Where,

H = the building height; and

L = the lesser of the building height or the greatest crosswind distance of the building - also known as maximum projected width.

To meet stack height requirements, the proposed point sources will be evaluated in terms of their proximity to nearby structures. The purpose of this evaluation is to determine if the discharge from each stack will become caught in the turbulent wake of a building or other structure, resulting in downwash of the plume. Downwash of the plume can result in elevated ground-level concentrations. EPA provides guidance for determining whether building downwash will occur in *Guideline for Determination of Good Engineering Practice Stack Height* (EPA 1985). The KDHE provides guidance for determining whether building downwash will occur in K.A.R 28-19-18. The downwash analysis will be performed consistent with the methods prescribed in the EPA guidance document and the KDHE regulation. The point sources will be evaluated in terms of their proximity to nearby structures.

Calculations for determining the direction-specific downwash parameters will be performed using the most current version of the EPA's Building Profile Input Program – Plume Rise Model Enhancements, otherwise referred to as the BPIP-PRIME downwash algorithm (Version 04274). The BPIP-PRIME algorithm provides direction-specific building dimensions to evaluate downwash conditions. Lacey Randall Station is located in a rural area, and the only buildings that could potentially affect emissions from the Project are the on-site structures.

## 4.3 EMISSION SOURCE PARAMETERS

Modeling runs will be conducted at full load and partial loads to confirm that operation of the Project will not exceed the required air dispersion modeling thresholds. In addition to modeling steady state operation of the proposed engines, startup operation will be modeled. The emission rates modeled will represent the projected worst-case ambient conditions under various operating loads. Annual emissions will be based on 4 startups per day at 30 minutes each plus full load operation for the rest of the year (8,030 hours per engine). No fugitive emission sources are proposed for this project.

# 5.0 MODELING METHODOLOGY

## 5.1 RECEPTOR GRID

The overall purpose of the modeling analysis is to ensure that operation of the proposed facility will not result in, or contribute to, concentrations above the NAAQS or PSD Class II Increments. The modeling

runs will be conducted using the AERMOD model in simple and complex terrain mode within a 10- by 10-kilometer Cartesian grid to determine the significant impact area (SIA) for each pollutant. The grid will incorporate the following spacing between receptors: 50 meters out to 0.1 kilometers, 100 meters out to two kilometers, and 250 meters out to ten kilometers. Receptors also were placed along the fence line boundary at a spacing of 50 meters. If the SIA exceeds 10 kilometers, the grid will be extended to encompass the entire SIA. If the modeling impacts show "hot spots" outside 1,000 meters, 100-meter grid spacing will be used to encompass the maximum concentrations to ensure that the maximum impact has been identified.

After reviewing the topography of the project area, it was determined that terrain elevations should be incorporated into the model. Therefore, the appropriate U.S. Geological Survey (USGS) National Elevation Dataset (NED) will be used to obtain the necessary receptor elevations. North American Datum of 1983 (NAD 83) will be used to develop the Universal Transverse Mercator (UTM) coordinates for this project.

AERMOD has a terrain preprocessor (AERMAP) which uses gridded terrain data for the modeling domain to calculate not only a XYZ coordinate, but a representative terrain-influence height associated with each receptor location selected. This terrain-influenced height is called the height scale and is separate for each individual receptor. AERMAP (Version 11103) will utilize the electronic NED data to populate the model with receptor elevations.

## 5.2 METEOROLOGICAL DATA

AERMOD requires a preprocessor called AERMET to process meteorological data for five years from off-site locations to estimate the boundary layer parameters for the dispersion calculations. Meteorological inputs from AERSURFACE obtained from the KDHE will be used. Surface air meteorological data from the Goodland Municipal Airport (station # 23065) and upper air data from the Dodge City Regional Airport (station #13985) will be used in the analysis. A profile base elevation value of ~~3,687~~ 3655.9 ft feet will be used. The most recent five-year data set available covers the period of 2007 to 2011. One-minute meteorological data is included in the meteorological files.

## 5.3 LAND MODELING PARAMETERS

Based on the Auer scheme, the existing land use for a three-kilometer area surrounding the proposed project site is more than 50 percent rural. Also, the population density is less than 750 people per square kilometer for the same area. Because this area is considered rural, the rural dispersion coefficients option in the AERMOD model will be selected.

## 5.4 EMISSION FACTORS

Emissions factor (EMISFACT) modeling options in AERMOD allow a user to model emissions only when certain criteria are met. EMISFACT will be used to model the appropriate hourly restrictions on any equipment activities that only occur over a certain number of hours per day or seasons per year. A more detailed breakdown of operation times will be presented with the final modeling analysis if this option is utilized. TradeWind understands that hourly restrictions in the modeling will likely result in corresponding permit limitations.

## 5.5 SIGNIFICANT IMPACT AREA DETERMINATION

To determine the facility's SIA, all emission sources from the proposed Project will be modeled alone; that is, modeled without existing sources in the area. The initial step in defining the SIA will be to model the engine at 50, 75, 90, and 100 percent capacity for each pollutant and at startup/shutdown conditions along with all other emission sources from the proposed facility. The initial modeling analysis will be performed using the KDHE approved five-year meteorological data set. The SIA is determined to be the distance from the proposed fence line where any pollutant concentration exceeds its PSD modeling significance threshold. Each load case will be analyzed using the five years of meteorological data. If the modeling results indicate that a pollutant exceeds the PSD modeling significance threshold for any averaging period, the maximum distance from the property line that the pollutant concentration exceeds the threshold level will be determined. This distance is then considered as a radius from the source, creating a circular SIA around the proposed source. The radius of impact (ROI) will then be identified and submitted to the KDHE for refined modeling purposes.

Depending on the initial modeling results, TradeWind will request from KDHE an emission inventory of PSD Class II Increment-consuming sources and NAAQS sources that are located within the ROI that should be included in the modeling analyses.

## 5.6 BACKGROUND AIR QUALITY

As stated previously, if any pollutant exceeds its respective PSD significance level, a refined analysis (cumulative analysis) will be performed for that pollutant and averaging period. This analysis will be used to determine compliance with the PSD Class II Increments and the NAAQS. The NAAQS are set up to protect the air quality for all sensitive populations and attainment is determined by the comparison to the NAAQS thresholds. As such, there are existing concentrations of each criteria pollutant that is present in ambient air that must be included in an analysis to account for items such as mobile source emissions that are not accounted for in the model. Monitored ambient emission levels will be added to the modeled ground level impacts to account for these sources.

KDHE provided background values for each pollutant which will require a refined analysis. These values are based available monitors in the area. The monitored background levels will be added to the modeled impacts and are shown in Table 2.

**Table 2: Background Levels**

| Pollutant | Averaging Period | Background Concentration ($\mu g/m^3$) | Air Quality System Monitor ID |
|---|---|---|---|
| $NO_2$ | Annual | 7.5 | 20-191-0002 (Peck) |
| | 1-hour | 49.0 | |
| $PM_{10}$ | 24-hour | To Be Provided by KDHE | 20-181-0001 (Goodland) |
| $PM_{2.5}$ | Annual | 7 | 20-195-0001 (Cedar Bluff) |
| | 24-hour | 17 | |

## 5.7 NAAQS AND CLASS II INCREMENT ANALYSIS

If refined modeling is required, the inventories of sources within the ROI will be developed in accordance with applicable EPA guidance, input from the KDHE, and neighboring state agencies. For the NAAQS and PSD Class II Increment analysis, all stationary sources identified by KDHE that emit pollutants subject to this analysis and are located within the ROI will be addressed. Some sources within the ROI may be eliminated from the analysis if it is determined to have a negligible contribution to impacts when combined with the Project impacts. TradeWind will consult with KHDE to determine acceptable methods of eliminating sources from the analysis.

Background air quality values were selected (as described in the previous section) to add to model-predicted concentrations for comparison to the NAAQS and are shown in Table 2. If the refined analysis does not result in any concentrations above the NAAQS or PSD Class II Increments, no further modeling will be conducted.

## 5.8 AMBIENT MONITORING

The modeling analysis for emissions sources for the proposed Project will also address the pre-construction monitoring provision of the PSD regulations. The regulations specify monitoring *de minimis* levels for each PSD pollutant that, if exceeded, trigger the requirement to perform one year of pre-construction ambient air monitoring. If any predicted concentrations reach or exceed the monitoring *de minimis* levels, TradeWind will consult with the KDHE to determine if pre-construction ambient air

monitoring will be required. If modeled values exceed their respective monitoring *de minimus* values, TradeWind will request a waiver to use local ambient monitoring data to fulfill the pre-construction monitoring provisions of the PSD regulations or develop an acceptable monitoring plan at that time. For any impacts predicted to be below the monitoring *de minimis* levels, TradeWind will request an exemption from pre-construction ambient air monitoring, given that representative monitors in the area may be used for appropriate background concentrations.

Potential VOC emissions from the Project are estimated to be more than 100 tons per year. TradeWind requests that local ambient monitoring data for ozone that is available be used to fulfill the pre-construction monitoring provisions of the PSD regulations.

The NAAQS, modeling/monitoring significance levels, and PSD Class II Increments are presented in Table 3.[2]

**Table 3: NAAQS, Significance/Monitoring, and PSD Class II Increments (µg/m$^3$)**

| Pollutant | Averaging Period | NAAQS | Modeling Significance Level | Monitoring Significance Level | PSD Class II Increment |
|---|---|---|---|---|---|
| $NO_2$ | annual | 100 | 1 | 14 | 25 |
| | 1-hour | 188.7 | 7.5 | NA | NA |
| CO | 8-hour | 10,000 | 500 | 575 | NA |
| | 1-hour | 40,000 | 2,000 | NA | NA |
| $PM_{10}$ | annual | NA | 1 | NA | 17 |
| | 24-hour | 150 | 5 | 10 | 30 |
| $PM_{2.5}$ | annual | 12 | 0.3[A] | NA | 4 |
| | 24-hour | 35 | 1.2[A] | 4[A] | 9 |

[A]United States Court of Appeals for the District of Columbia Circuit on January 22, 2013 vacated and remanded portions of the U.S. EPA rule establishing significant impact levels (SILs) and vacated the rule establishing the significant monitoring concentration (SMC) for particulate matter less than 2.5 micrometers ($PM_{2.5}$), however the $PM_{2.}5$ SILs and SMCs are still valid in Kansas per guidance from KDHE.

For PSD Class II increment, the 24-hour $PM_{10}$ and 24-hour $PM_{2.5}$ will all be compared to the second highest high. Annual standards will be compared to the first highest high. The NAAQS thresholds will be compared to the following highs shown in Table 4 for each averaging period.

[2]The pollutants that are allowed one NAAQS exceedance per year and one PSD Increment exceedance per year are: 1-hour and 8-hour CO; 3-hour $SO_2$; and 24-hour $PM_{10.}$

**Table 4: Modeled Highs**

| Pollutant | Averaging Period | Modeled High |
|---|---|---|
| $NO_2$ | Annual | Annual Mean |
| | 1-hour | 98th Percentile |
| CO | 1-hour | Second High |
| | 8-hour | Second High |
| $PM_{10}$ | 24-hour | Sixth High |
| $PM_{2.5}$ | Annual | Annual Mean |
| | 24-hour | 98th Percentile |

In addition, in accordance with EPA's March 2011 memo, TradeWind proposes to only model continuous operation for the 1-hour standard. The emergency diesel generator and emergency diesel fire pump will be limited to 100 hours per year (for testing and maintenance) and hence will not be included in the 1-hour modeling analysis, as they will be intermittent sources. These operations will not contribute significantly to the annual distribution of the daily maximum 1-hour concentrations.

## 6.0 CLASS I AREA IMPACTS

Recent Federal Land Manager (FLM) guidance requires that a proposed major source, in the course of a PSD application, perform an assessment of air quality impacts at Class I areas if these areas are located within approximately 300 kilometers of the proposed facility. There are no Class I areas that are within 300 kilometers of the proposed Project; therefore, no assessment of air quality impacts at Class I areas will be performed for this Project.

## 7.0 ADDITIONAL IMPACT ANALYSIS

The additional impacts analysis requirement under PSD will include the ambient air quality impact analysis, soils and vegetation impacts, visibility impairment, and growth analysis on Class II areas. This analysis will follow EPA's guidance provided in the New Source Review Workshop Manual (October 1990 draft).

The growth analysis will quantify the number of employees, the availability of housing in the area, and associated commercial and industrial growth, and construction related activities and mobile sources. The number of employees is not envisioned to be large enough to result in a quantifiable increase in emissions from residential, commercial, or industrial growth.

While there are no Class II visibility standards, a visual plume blight analysis will be performed in accordance with the guidelines set forth in EPA-450/4-88-015, Workbook for Plume Visual Impact Screening and Analysis (Revised). A visual plume blight analysis will be conducted for surrounding Class II areas for emissions from the project.

## 8.0 SUMMARY

Modeling methodology has been presented for the construction of ten nominal 9.34-MW, natural gas-fired, internal combustion engines and associated equipment for the proposed Project. TradeWind would like to proceed with the initial modeling analysis as soon as possible in order to ensure that a pre-construction ambient air monitoring study will not be required. Also, if emission inventories and background air quality data are needed from KDHE and other agencies to complete refined modeling analyses, initial modeling to determine the ROI for each pollutant will be expedited to give KDHE enough time to process these requests.

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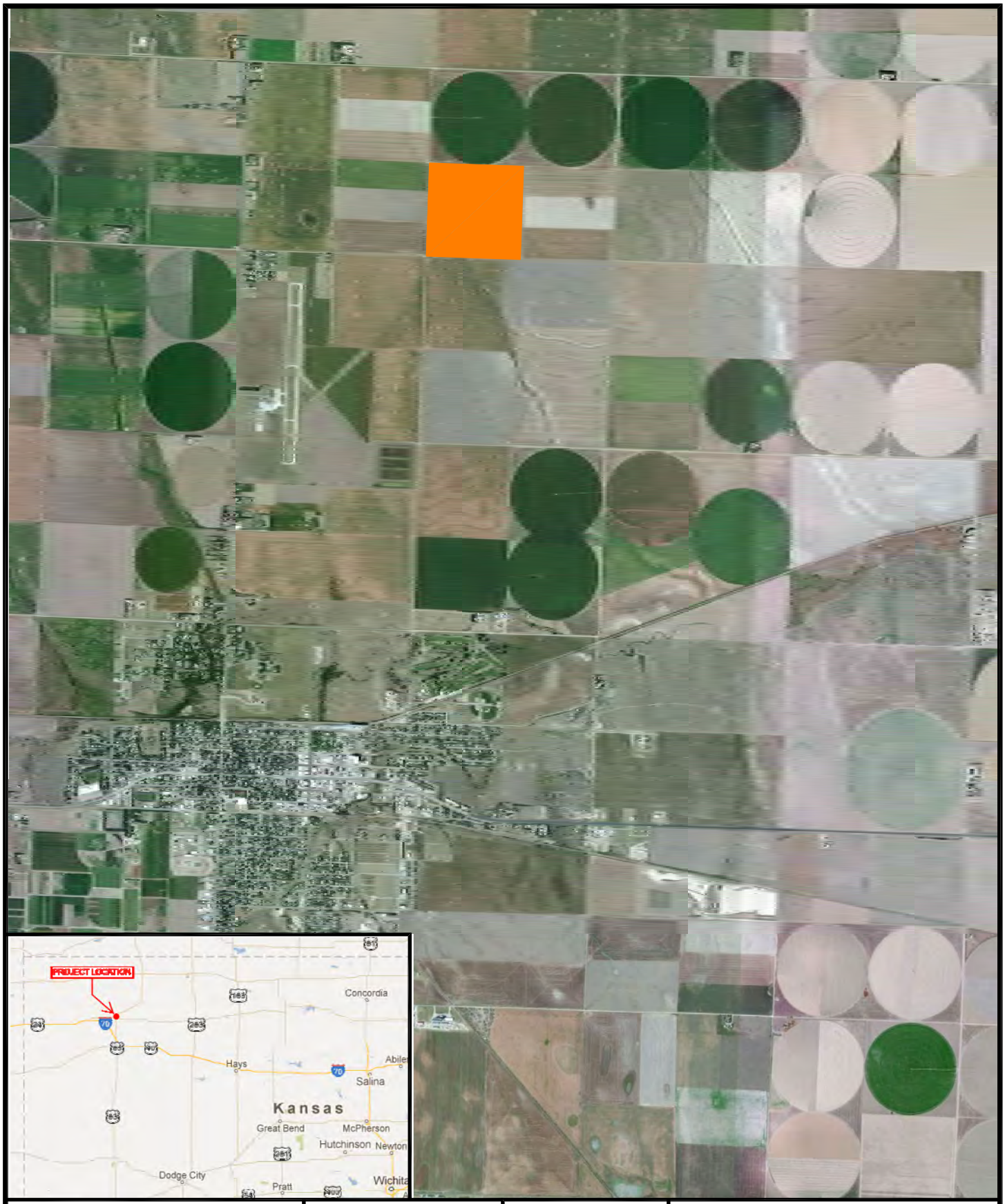
# APPENDIX A




Legend

Cities

Proposed Site Location

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Burns & McDonnell
SINCE 1898

Figure 1: Proposed Site Location

# APPENDIX B

**APPENDIX B**

# Ozone Limiting Method Modeling Protocol for AERMOD

**TRADEWIND ENERGY, INC.**

**Lacey Randall Station Project**

**Project No. 72125**

**April 2013**

# Ozone Limiting Method Modeling Protocol for AERMOD

**prepared for**

**TradeWind Energy, Inc.**

**April 2013**

**Project No. 72125**

**prepared by**

**Burns & McDonnell Engineering Company, Inc.**
**Kansas City, Missouri**

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## 1.0 INTRODUCTION

TradeWind Energy, Inc. (TradeWind) is proposing to construct a nominal 93.4-megawatt (MW) power facility in Thomas County, Kansas. The proposed facility will consist of ten nominal 9.34-MW internal combustion engines and associated equipment (gas heater, emergency fire pump, and emergency generator) and will be operated by TradeWind Energy, Inc. The Lacey Randall Station Project (hereinafter referred to as Project) will be located on a greenfield site approximately five miles north of Colby, Kansas. Preliminary estimated potential emissions indicate that the proposed facility will be a major source under Prevention of Significant Deterioration (PSD) rules; as a result, the project will be subject to PSD construction permit review. A PSD permit requires an assessment of ambient impacts for those pollutants subject to PSD review.

This modeling protocol addresses the ozone limiting method (OLM) methodology that will be used for the nitrogen dioxide ($NO_2$) 1-hour air dispersion modeling for the Project. This modeling protocol has been drafted in accordance with the U.S. Environmental Protection Agency (EPA) and the Kansas Department of Health and Environment (KDHE) modeling guidelines.

## 2.0 PROPOSED MODEL

TradeWind is proposing to use the most current version of the AMS/EPA Regulatory Model (AERMOD) for the air quality analysis (version 12345). AERMOD is an EPA-approved, steady-state Gaussian plume model capable of modeling multiple sources in simple and complex terrain. AERMOD is currently approved for industrial sources and PSD permits, and has been approved by the EPA as an appropriate model to demonstrate regulatory compliance.

The following default model options will be used:

- Gradual Plume Rise
- Stack-tip Downwash
- Buoyancy-induced Dispersion
- Calms and Missing Data Processing Routine
- Calculate Wind Profiles
- Calculate Vertical Potential Temperature Gradient
- Rural Dispersion

Additionally the following non-default model option will be used:

- $NO_2$ Modeling

Details of the modeling algorithms contained in AERMOD may be found in the User's Guide for AERMOD. The regulatory non-default option will be selected for this analysis to perform the OLM $NO_2$ modeling. The OLM modeling parameters that will be used in the model are discussed in Section 3.0.

Per KDHE guidance and EPA's March 2011 memo[1] the emergency generator and emergency fire pump will operate less than 100 hours annually and are considered intermittent sources; therefore, these sources will not be included in the 1-hour modeling analysis.

# 3.0 MODELING METHODOLOGY

## 3.1 1-HOUR $NO_2$ AVERAGING PERIOD - OZONE LIMITING METHOD

The emission rates to be modeled will represent operations at worst-case ambient conditions under various operating capacities. The AERMOD model predicts ground-level concentrations of any generic pollutant without chemical transformations. Thus, the modeled nitrogen oxides ($NO_x$) emission rate will give ground-level modeled concentrations of $NO_x$. NAAQS values are presented as $NO_2$.

The (EPA) has a three tier approach to modeling $NO_2$ concentrations.

- Tier I – total conversion, or all $NO_x = NO_2$
- Tier II – use a default $NO_2/NO_x$ ratio
- Tier III – case-by-case detailed screening methods, such as OLM and Plume Volume Molar Ratio Method (PVMRM)

Initial modeling was performed using both Tier I and Tier II methodologies. It was determined from these modeling iterations that less conservative methods for determining 1-hour $NO_2$ compliance would be needed for this project. To account for the conversion of $NO_x$ to $NO_2$ in the modeling, the Tier III approach using the OLM method will be used for the 1-hour $NO_2$ PSD significance and refined (cumulative) air dispersion modeling. The PSD significance threshold will be compared to the modeled first high, while the NAAQS threshold will be compared to the five-year average modeled 98$^{th}$ percentile of the annual distribution of maximum daily 1-hour values.

The amount of $NO_2$ present in the stack gases was determined for each piece of equipment being modeled and was determined from published data. Based on available information provided by the San Joaquin Valley Air Pollution Control District (APCD)[2], the following in-stack $NO_2/NO_x$ ratios will be used:

- Natural gas-fired reciprocating engine with post combustion controls: 0.0115
- Natural gas-fired fuel heater: 0.10

Documentation of the in-stack $NO_2/NO_x$ ratios is shown in Attachment A.

The selection of source-specific in-stack ratios instead of using a default in-stack ratio is in accordance with methodology presented in EPA's March 2011 memo.

For inventory sources included in the cumulative modeling, an in-stack $NO_2/NO_x$ ratio of 0.2 will be used for sources, unless source-specific data is available.

Additionally, an equilibrium $NO_2/NO_x$ ratio of 0.90 will be used per EPA's March 2011 memo.

## 3.2 ANNUAL $NO_2$ AVERAGING PERIOD

The OLM methodology will not be applied to the $NO_2$ annual averaging period. The modeled concentrations of annual $NO_x$ will be adjusted using the EPA-approved Ambient Ratio Method (ARM) (Tier 2 methodology). Tier 2 of the ARM allows the use of an empirically derived $NO_2/NO_x$ ratio of 0.75, which means that approximately 75 percent of the $NO_x$ emissions will be converted to $NO_2$, the regulated pollutant. This factor will be applied to the annual modeled results for $NO_x$ to determine the predicted ground-level concentration of $NO_2$.

## 3.3 SPECIFYING COMBINED PLUMES

When using the OLM option, the model includes an option for specifying which sources are to be modeled as combined plumes ($NO_x$ within the plumes competes for the available ambient ozone). A group ID of ALL will be selected for this modeling analysis, which means that the OLM will be applied on a combined plume basis to all sources within a specified source group. The use of this option is in accordance with the methodology presented in EPA's June 2010 memo which states, "Applications of the

[1] March 1, 2011 EPA Memo from Tyler Fox. Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour $NO_2$ National Ambient Air Quality Standard
[2] http://www.valleyair.org/busind/pto/Tox_Resources/AirQualityMonitoring.htm#no2_data (Found under "Modeling Guidance", titled "$NO_2/NO_x$ In-Stack Ratios").

OLM option in AERMOD, subject to approval under Section 3.2.2e of Appendix W, should routinely utilize the "OLMGROUP ALL" option for combining plumes."[3]

## 3.4 BACKGROUND OZONE

Hourly background ozone concentrations will be obtained from the KDHE for years 2006 to 2010 for the Cedar Bluff monitoring station located in Trego County, Kansas (AQS ID: 20-195-0001). A default value of 34 parts per billion (ppb) will be used as a substitute for missing ozone data from the ozone file.

The background ozone data was formatted to be used in the AERMOD model and matches the meteorological data years that are currently being used in the modeling.

## 3.5 NAAQS AND $NO_2$ BACKGROUND VALUE

The $NO_2$ 1-hour background air quality value will be obtained from the KDHE for years 2006 to 2010 for the Peck monitoring station located in Sumner County, Kansas (AQS ID: 20-191-0002). The five year average monitored 98$^{th}$ percentile of the annual distribution of maximum daily 1-hour concentration for $NO_2$ is 49.0 micrograms per cubic meter ($\mu g/m^3$).

This background value will be added to the model-predicted concentration (98$^{th}$ percentile) for comparison to the 1-hour $NO_2$ NAAQS value of 188.0 $\mu g/m^3$.

## 4.0 SUMMARY

This modeling protocol has been presented for an OLM modeling method for $NO_2$ 1-hour modeling using AERMOD for the construction of ten new 9.34-MW, natural gas-fired, internal combustion engines and associated equipment for the proposed Project. The modeling protocol has been submitted for KDHE and EPA concurrence with the modeling methods.

[3] June 28, 2010 EPA Memo from Tyler Fox. Applicability of Appendix W Modeling Guidance for the 1-hour NO2 National Ambient Air Quality Standard.

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# ATTACHMENT A

# San Joaquin Valley Air Pollution Control District
# Background Information
# and
# In-stack Ratios

http://www.valleyair.org/busind/pto/Tox_Resources/AirQualityMonitoring.htm#no2_data

(Found under “Modeling Guidance”, titled “NO2/NOx In-Stack Ratios”).

| Recommend In-stack NO2/NOx Ratios | | | | |
|---|---|---|---|---|
| **Refer #** | **Fuel** | **Equipment Category (Controls)** | **Range of Ratios (%)** | **Recommended Ratio (%)** |
| | | **Boilers** | | |
| 1 | **NG** | Default | 10 | 10 |
| 2 | | 6.6 MMBtu/Hr (Force Draft)*[L] | 0.0 – 2.90 | 1.58** |
| 2 | | 7.6 MMBtu/Hr (SCR / FGR)* | 3.45 – 15.79 | 9.65** |
| 2 | | 11.4 MMBtu/Hr (Force Draft)*[L] | 1.81 – 3.51 | 2.68** |
| | | **Compressor IC Engines** | | |
| 1 | **NG** | Default | 60 | 60 |
| 2a | | 225 BHP IGN Timing BTC 17*** | 11.61 – 11.86 | 11.76** |
| 2a | | 350 BHP IGN Timing BTC 18*** | 4.37 – 4.83 | 4.66** |
| 2a | | 550 BHP IGN Timing BTC 20*** | 0.93 – 2.98 | 1.96** |
| 2a | | 625 BHP IGN Timing BTC 10*** | 10.97 – 11.96 | 11.6** |
| 2a | | 773 BHP IGN Timing BTC 9*** | 58.04 – 58.54 | 58.3** |
| 2a | | 773 BHP IGN Timing BTC 20*** | 72.65 – 73.42 | 73.12** |
| 2a | | 880 BHP IGN Timing BTC 8*** | 9.79 – 14.14 | 11.93** |
| 2a | | 880 BHP IGN Timing BTC 15*** | 0.7 – 8.28 | 2.52** |
| 2a | | 1500 BHP IGN Timing BTC 12*** | 10.32 – 12.03 | 11.47** |
| 2a | | 1500 BHP IGN Timing BTC 6.5*** | 18.42 – 21.33 | 19.97** |
| 2a | | 4000 BHP IGN Timing BTC 5*** | 22.36 – 25.69 | 23.82** |
| 2a | **Waste Gas** | 880 BHP IGN Timing BTC 20*** | 1.77 – 6.10 | 3.86** |
| 2a | **(Field Gas)** | 1000 BHP*** | 0.40 – 0.81 | 0.64** |
| | | **Dryer** | | |
| | **NG** | 20 MMBTU/Hr (Milk -Tower Dryer)* | 3.85 – 11.11 | 6.88** |
| | | **Glass Furnace** | | |
| 2 | **NG** | **Glass Furnace** | 2.45 – 11.59 | 4.32** |
| | | **Heaters** | | |
| 2 | **NG / Refinery Gas** | 14.1 MMBTU/Hr (John Zink PSMR)* | 11.54 – 52.63 | 32.0** |
| | | **IC Engines** | | |
| 2 | **Biogas** | 200 BHP* | 0.0 – 1.90 | 0.37** |
| 1 | **Diesel** | Default | 20 | 20 |
| | | 322 BHP (WP)* | 0.0 – 50.0 | 15.64** |
| 4 | **NG** | Default – Lean Burn | 5-10 | 10 |
| 2 | | 120 BHP (3-Way Catalyst)* | 0.1 – 2.83 | 0.9** |
| 2 | | 162 BHP (Catalytic converter, air/fuel ratio)* | 0.0 – 12.5 | 1.81** |
| 2 | | 165 BHP (3-Way Catalyst)* | 0.0 – 17.58 | 3.16** |
| 2 | | 180 BHP (NSCR)* | 1.02 – 3.41 | 1.82** |
| 2 | | 208 BHP (Catalytic converter, air/fuel ratio)* | 0.0 – 1.44 | 0.48** |
| 2 | | 1,070 BHP (LB/WP–Turbocharger/Intercooler)* | 20.91 – 39.62 | 34.41** |
| 2 | | 1,529 BHP (LB - CO Catalyst, SCR)* | 2.70 – 4.58 | 3.59** |
| 2 | | 2,775 BHP (SCR)* | 14.53 – 26.33 | 19.46** |
| 2 | | 4,175 BHP (SCR,CO & VOC Catalysts)* | 0.0 – 21.28 | 1.15** |
| | | **Transportation Refrigeration Units (TRUs)** | | |
| 5 | | CARB= CARB Diesel<br>GTL = Gas To Liquid | | |

| Fuel | Eng Speed | Exhaust | $NO_2$/ $NO_x$ Ratio |
|---|---|---|---|
| CARB | High | Muffler | 15.37 |
| GTL | High | Muffler | 16.17 |
| CARB | High | pDPF | 25.71 |
| CARB | Low | Muffler | 22.66 |
| GTL | Low | Muffler | 25.12 |
| CARB | Low | pDPF | 12.98 |

| | | | | |
|---|---|---|---|---|
| | | **Truck / Cars** | | |
| 6 | **Gas/Diesel** | Light / Medium Duty | 16-25 | 25 |
| | **Diesel** | Heavy Duty | 6-11 | 11 |
| | | **Turbines** | | |
| 3 | **NG** | GE Turbines | 8.33 – 9.1 | 9.1 |
| 2a | | Solar Centaur T-4702 (3.4 MW)*** | 8.43 – 12.42 | 10.32** |

* Samples taken each minute or several minutes

**Value represents the statistical average of all data points

*** 30 min / 1 hour Source Test

L = Load ratings have been included in average

LB = Lean Burn

WP = Water Pump

## References


1. Barrie Lawrence, Environmental Scientist, Government of Newfoundland and Labrador, "Guideline for Plume Dispersion Modeling" 1st Revision: November 20, 2006, Page 14
2. District Database "NO2 -NOx Ratio.mdb" - Data is based on CEMs, source test, and portable analyzer data collected in the San Joaquin Valley
   a. District Database "NO2 -NOx Ratio.mdb" - Data is based on source test data collected from out of state (Arkansas Department of Environmental Quality Office of Air Quality)
3. Roointon Pavri and Gerald D. Moore, GE Energy Services Atlanta, GA, "Gas Turbine Emissions and Control" March 2001 Page 6
4. Nigel N. Clark, Center for Alternative Fuels, Engines and Emissions Department of Mechanical and Aerospace Engineering West Virginia University Morgantown, WV 26506, "Selective NOx Recirculation for Stationary Lean-Burn Natural Gas Engines" April 30, 2007 Page 64
5. Robb A. Barnitt, National Renewable Energy Laboratory, "Emissions of Transport Refrigeration Units with CARB Diesel, Gas-to-Liquid Diesel, and Emissions Control Devices", May 1, 2010
6. P G Boulter, I S McCrae, and J Green, Transportation research Laboratory, "Primary NIO2 Emissions From Road Vehicles in the Hatfield and Bell Commons Tunnels", July 2007

## Nelson, Minda

**From:** Hauner-Davis, Mary
**Sent:** Thursday, March 29, 2012 3:50 PM
**To:** Nelson, Minda
**Subject:** FW: NO2-NOx Ratio Citations
**Attachments:** c3775 1926693 .pdf

Background information on the NOx ratios.

**Mary Hauner-Davis**
Burns & McDonnell
Phone: 816-822-4252
Mobile: 402-730-9631
Fax: 816-822-4299

---

**From:** Leland Villalvazo [mailto:leland.villalvazo@valleyair.org]
**Sent:** Thursday, March 29, 2012 3:49 PM
**To:** Hauner-Davis, Mary
**Subject:** RE: NO2-NOx Ratio Citations

Here's the data you requested.

Leland Villalvazo
Supervising Air Quality Specialist
San Joaquin Valley APCD
1990 E Gettysburg Ave
Fresno, CA 93726
Ph:(559) 230-5881
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HRAModeler@valleyair.org
inventory@valleyair.org

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---

**From:** Hauner-Davis, Mary [mailto:mhauner@burnsmcd.com]
**Sent:** Thursday, March 29, 2012 11:47 AM
**To:** Leland Villalvazo
**Cc:** Nelson, Minda
**Subject:** NO2-NOx Ratio Citations

Please send me the data for 4175 BHP IC Engines from your posted NO2-NOx ration database. Thank you very much!!

### Citation:

**2.** District Database “NO2 -NOx Ratio.mdb” - Data is based on CEMs, source test, and portable analyzer data collected in the San Joaquin
Valley

**Mary Hauner-Davis**
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SJVAPCD
Variance

# Compliance Verification Report

03/17/2010
11:41 am

**Variance:** C-10-05E **Type:** Emergency **Hearing Date:** 02/16/2010

**Source:** CALIFORNIA POWER HOLDINGS LLC

**Location:** 16457 AVENUE 24 1/2 **City:** Chowchilla

**Rule(s):** 1081,2070,2201,4702

**Equipment:** The subject equipment consists of a 4,157 HP Deutz natural gas fired engine used to generate electricity. The emissions are controlled by a selective catalytic reduction (SCR) system

**Scope Of Variance:** The variance shall allow for the operation of the subject engine with excess NOX while CPH operates the engine to diagnose the reason behind the high NOX measurements. In addition, the variance will allow for the postponement of the annual source test.

**Please verify that the following increments of progress have been met. After verifying that final compliance has been achieved, send the report with any supporting documentation to the Central Region Office.**

| DATE | INCREMENTS OF PROGRESS | COMPLETED |
|---|---|---|
| 02/16/2010 | Variance Begins | 2/16/2010 |
| 03/17/2010 | Variance Ends/Compliance Required | 3/01/2010 |
| 04/01/2010 | Summary Report Due | 3/15/2010 |

Compliance with all applicable District rules was achieved on 3 / 01 / 2010

Compliance with all of the above increments was achieved on 3 / 01 / 2010

Final compliance with this variance was verified on 3 / 17 / 2010

Method of verification: Summary Report
(CEM Data, Correspondence, District Action, Email, Hearing Board Action, Inspection, Production Data, Report, Source Test, Notice, or VEE)

Excess emissions associated with variance: Ø

| Pollutant | Quantity | Units | Pollutant | Quantity | Units | Pollutant | Quantity | Units |
|---|---|---|---|---|---|---|---|---|
| | | | | | | | | |

| Pollutant | Quantity | Units | Pollutant | Quantity | Units | Pollutant | Quantity | Units |
|---|---|---|---|---|---|---|---|---|
| | | | | | | | | |

Inspector

Supervisor

**BEFORE THE HEARING BOARD**
**OF THE**
**SAN JOAQUIN VALLEY UNIFIED AIR POLLUTION CONTROL DISTRICT**
**CENTRAL REGION**
**STATE OF CALIFORNIA**

| | |
|---|---|
| **In the matter of:**<br>California Power Holdings, LLC<br>16457 Avenue 24 ½<br>Chowchilla, CA 93610 | **DOCKET NO. C-10-05E** |
| **For a variance from:**<br>1081 – *Source Sampling*<br>2070.7.0 – *Operation According to the Permit to Operate Conditions*<br>2201 – *New and Modified Stationary Source Review Rule*<br>4702 – *Internal Combustion Engines* | **ORDER GRANTING AN EMERGENCY VARIANCE** |
| **District Permit Number:**<br>C-3775-12-5 | **Granted on:** February 16, 2010 |
| **EPA Airs Number:**<br>N/A | **Effective from:** February 16, 2010<br>**Effective to:** March 17, 2010 |

On February 11, 2010, California Power Holdings, LLC, (CPH) filed with the Central Region Hearing Board a petition for an emergency variance. CPH requested that the Hearing Board grant an emergency variance from San Joaquin Valley Unified Air Pollution Control District (District) Rules 1081, 2070.7.0, 2201, and 4702.

On February 16, 2010, CPH came before Mr. Robert Schumacher, Vice Chair of the Central Region Hearing Board, to obtain an emergency variance. The hearing was held pursuant to California Health and Safety Code (CH&SC) Section 42359.5 and District Rule 5200 – *Emergency Variance*. Mr. Ron Dahlin represented CPH, while Mr. Patrick Houlihan, Senior Air Quality Specialist, represented the District.

## LOCATION AND EQUIPMENT

1. CPH operates a "peaker plant" electrical power generating facility located at 16457 Avenue 24 ½ in Chowchilla, CA.

2. The subject equipment consists of a 4,157 HP Deutz natural gas fired engine used to generate electricity. The emissions are controlled by a selective catalytic reduction (SCR) system.

3. The operation of the subject equipment is authorized by duly issued District Permit to Operate (PTO) #C-3775-12-5.

## BACKGROUND

CPH operates 16 natural gas fired engines that are used to generate electricity. Each engine is connected to a 3.1 mega-watt generator. CPH is a "peaker plant" and only operates their engines when called upon to provide electricity to the grid. These engines were due for their annual source test by February 26, 2010. In anticipation of the source test, CPH started the engines to pre-test the exhaust emissions and perform any maintenance if deemed necessary. CPH pre-tested the emissions with a portable exhaust analyzer. Engine #12 tested with high $NO_X$ emissions of 9.5 ppm. The PTO requires that $NO_X$ emissions stay below a concentration of 9 ppm. CPH shut the engine down and replaced the catalyst, adjusted the engine valves, and replaced the spark plugs. Unfortunately, this still did not reduce emissions down below the PTO limit. CPH preceded with the source tests on the other 15 engines, but had to postpone engine #12's source test. Since CPH still hadn't brought the engine into compliance, they had to request a variance to allow for excess emissions and to postpone the source test. CPH needs to evaluate the engine and control technology to bring the engine into compliance quickly because they stand the chance of losing revenue if called upon to provide electricity and can't do so.

## RULE REQUIREMENTS AND VIOLATIONS

1. The equipment subject to this variance is regulated by the following District Rules:

   A. 1081 – *Source Sampling*
   B. 2070.7.0 – *Operation According to the Permit to Operate Conditions*
   C. 2201 – *New and Modified Stationary Source Review Rule*
   D. 4702 – *Internal Combustion Engines*

2. District Rule 2070.7.0 requires that the subject equipment be operated in accordance with the conditions of the applicable PTO. District Rules 2201 and 4702 limits $NO_X$ emissions. District Rules 1081 and 4702 require a source test every 12 months for this engine.

3. The subject equipment will be in violation of the applicable District Rules and PTO conditions if the subject engine operates during the variance period with excess $NO_X$ emissions.

## FINDING OF FACT

Pursuant to CH&SC Sections 42352 - 53 and District Rule 5200 – *Emergency Variance*, the following findings have been made:

1. ***That the petitioner for a variance is, or will be, in violation of Section 41701 or of any rule, regulation, or order of the District.***

   The Hearing Board finds that the operation of the engine with excess $NO_X$ emissions is a violation of District Rules 2070.7.0, 2201, and 4702, in addition to the applicable PTO conditions. Not source testing every 12 months is a violation of District Rules 1081 and 4702 in addition to the applicable PTO conditions.

2. ***That, due to conditions beyond the reasonable control of the petitioner requiring compliance would result in either (1) an arbitrary or unreasonable taking of property, or (2) the practical closing and elimination of a lawful business.***

The Hearing Board finds that CPH attempted to correct the emissions violation within the timeframe allotted by the conditions of the PTO. The attempts were unsuccessful and a proper cause of the excess emissions was not diagnosed. Because the PTO does not allow for anymore operation with excess emissions, CPH would not be allowed to operate this engine without receiving a Notice of Violation. CPH did shut down the engine after measuring the excess emissions and have not operated it since. Not allowing future operation of this engine would result in an arbitrary or unreasonable taking of property.

3. ***That the closing or taking would be without a corresponding benefit in reducing air contaminants.***

The Hearing Board finds that given the minimal excess emissions, the closing or taking would be without a corresponding benefit in reducing air contaminants. In addition, if the variance is not granted to allow CPH to fix the engine, CPH could lose approximately $1000 a day each time the subject engine is called upon by the California Independent System Operator (Cal ISO) to provide electricity to the grid.

4. ***That the applicant for the variance has given consideration to curtailing operations of the source in lieu of obtaining a variance.***

The Hearing Board finds that CPH shut down the engine upon discovering the excess emissions. However, a long term operational curtailment is not feasible due to the contractual requirements to provide power when called into service by the Cal ISO. Also, a curtailment will not allow CPH to diagnose the problem. The engine needs to be in operation for diagnosis.

5. ***During the period the variance is in effect, that the applicant will reduce excess emissions to the maximum extent feasible.***

The Hearing Board finds that excess emissions will be reduced to the maximum extent feasible by only operating the engine as necessary to diagnose and fix the cause of the excess $NO_X$.

6. ***During the period the variance is in effect, that the applicant will monitor or otherwise quantify emission levels from the source, if requested to do so by the District, and report these emissions levels to the District pursuant to a schedule established by the District.***

The Hearing Board finds that during the variance period, CPH will continue to monitor emissions from the subject engine with a portable exhaust emissions analyzer. This information will be provided to the District upon request.

## CONCLUSIONS AND ORDER

NOW, THEREFORE, the CENTRAL REGION HEARING BOARD ORDERS that an emergency variance be granted to California Power Holdings, LLC, subject to the following conditions:

1. The variance shall be effective from February 16, 2010 to March 17, 2010, or until such time the engine achieves compliance with the permitted emissions limit, whichever occurs first.

2. Variance relief shall only be granted from the applicable sections of District Rules 1081, 2070.7.0, 2201, and 4702, in addition to conditions 9 and 18 of PTO #C-3775-12-5, but only as they pertain to the operation of the subject engine with excess $NO_X$ emissions and source testing every 12 months.

3. The variance shall allow for the operation of the subject engine with excess $NO_X$ while CPH operates the engine to diagnose the reason behind the high $NO_X$ measurements. In addition, the variance will allow for the postponement of the annual source test.

4. Excess $NO_X$ emissions shall not exceed 0.5 pounds per hour during operation of the subject engine during the variance period.

5. No relief from other excess emissions shall be provided.

6. No relief shall be provided from the results of the source test.

7. No exceedences of the Daily Emission Limit shall be allowed.

8. CPH shall maintain records in accordance with condition #31 of PTO C-3775-12-5 and shall report those on the summary report as required below.

9. CPH shall utilize a portable exhaust analyzer to measure the emissions every time the subject engine operates. The results reported to the District shall be the average of a consecutive 15 minute run corrected to 15% oxygen.

10. Should the District receive complaints or if the facility experiences operation conditions likely to cause a public nuisance, CPH shall cease the operations causing the complaints or problems and take all necessary actions to abate the problem immediately.

11. By April 1, 2010, or 15 days after the emergency variance is completed, whichever occurs first, CPH shall submit to the District a summary report. However, if another variance or series of variances regarding this same matter should be granted by the Central Region Hearing Board, submittal of said summary report should occur in accordance with the time frames established within said variances. The report shall include:

    A. A summary of all corrective actions taken to bring the engine's emissions into compliance;
    B. Date, time, and duration of operation of the engine;
    C. Date of source test;

D. Copies of all emissions sampling and calibration data from the portable exhaust analyzer; and

E. Calculation of the actual excess $NO_X$ emissions released during the variance period.

12. All notifications and submittals to the District pursuant to this variance shall be submitted to the attention of:

Mr. Ryan Hayashi, Supervising AQS
SJVUAPCD – Compliance Department
1990 E. Gettysburg Avenue
Fresno, CA 93726
Telephone: (559) 230-6000
E-mail: ryan.hayashi@valleyair.org

13. Failure to comply with any condition of this variance may render the variance null and void.

**THE FORGOING DECISION IS APPROVED:**

Mr. Robert Schumacher, Vice Chair
Hearing Board – Central Region
San Joaquin Valley Unified APCD

2-28-10
Date

**ATTEST:**

Angie DeSantiago, Clerk to the Boards

3/2/10
Date

# Corrective Actions Summary

PTO Emissions Variance

California Power Holdings, Chow II Facility
Date: March 5, 2010
Asset Manager: John Walsh
Facility Manager: Ron Dahlin
Operator: Gary Dean

RE: Statement of corrective actions taken to correct Engine 12 emissions problem including sampling & calibration data.

February 24, 2010

- Replaced worn ball joints for both A & B side speed governor throttle linkages after they were found to be sticky.
- Re-checked all valve clearances to confirm proper adjustment.
- The engine was not operated.

February 25, 2010

- During calibration of the two fuel stepper motors, a strange sound was noticed from the B-side unit. The motor was tested off the engine and found to be intermittently faulty. It failed to move properly in both directions.
- Replaced the faulting stepper motor with spare.
- At 10:28 engine 12 was started and brought to proper operating temperature then operated until 14:53. While monitoring with the portable analyzer the engine emission levels were below permit limits.
- Measured 15-min average NOx @ 15% O2 – 4.6ppm

February 26, 2010

- At 08:59 engine 12 was started and brought to normal operating temperature then operated until 13:48.
- Adjustments were made to the jacket water control valve to improve engine load fluctuations.
- Adjusted SCR dosing system back to standard operating levels.
- While monitoring with the portable analyzer emission levels were below permit limits.
- Measured 15-min average NOx @ 15% O2 – 4.5ppm

March 1, 2010

- At 08:34 engine 12 was started and brought to normal operating temperature then operated until 12:26.
- Made additional adjustments to jacket water control system to further improve engine load fluctuations. Engine load now running with very little fluctuation, improving overall engine performance.
- While monitoring with the portable analyzer emission levels were below permit limits.
- Measured 15-min average NOx @ 15% O2 – 5.8ppm

Conclusion

- Corrections for engine 12 are complete and the unit is available to operate normally with all emissions within compliance of the PTO.
- The follow-up source test for Engine 12 is scheduled for March 12, 2010.
- Copies of all emissions sampling and calibration data are attached.
- There were no excess NOx emissions during the period of time that the unit operated.

In accordance with Condition 1 of the Emergency Variance, Engine 12 achieved compliance with the permitted emission limits and was returned to normal operation on March 1, 2010. Therefore, the Emergency Variance is no longer in effect.

Asset Manager_____ Date _____

# Corrective Actions Summary

PTO Emissions Variance

California Power Holdings, Chow II Facility
Date: March 8, 2010
Asset Manager: John Walsh
Facility Manager: Ron Dahlin
Operator: Gary Dean

RE: Statement of corrective actions taken to correct Engine 12 emissions problem including sampling & calibration data.

February 24, 2010

- Replaced worn ball joints for both A & B side speed governor throttle linkages after they were found to be sticky.
- Re-checked all valve clearances to confirm proper adjustment.
- The engine was not operated.

February 25, 2010

- During calibration of the two fuel stepper motors, a strange sound was noticed from the B-side unit. The motor was tested off the engine and found to be intermittently faulty. I failed to move properly in both directions.
- Replaced the faulting stepper motor with spare.
- At 10:28 engine 12 was started and brought to proper operating temperature then operated until 14:53. While monitoring with the portable analyzer the engine emission levels were below permit limits.
- Measured 15-min average NOx @ 15% O2 – 4.6ppm

February 26, 2010

- At 08:59 engine 12 was started and brought to normal operating temperature then operated until 13:48.
- Adjustments were made to the jacket water control valve to improve engine load fluctuations.
- Adjusted SCR dosing system back to standard operating levels.
- While monitoring with the portable analyzer emission levels were below permit limits.
- Measured 15-min average NOx @ 15% O2 – 4.5ppm

March 1, 2010

- At 08:34 engine 12 was started and brought to normal operating temperature then operated until 12:26.
- Made additional adjustments to jacket water control system to further improve engine load fluctuations. Engine load now running with very little fluctuation, improving overall engine performance.
- While monitoring with the portable analyzer emission levels were below permit limits.
- Measured 15-min average NOx @ 15% O2 – 5.8ppm

Conclusion

- Corrections for engine 12 are complete and the unit is available to operate normally with all emissions within compliance of the PTO.
- The follow-up source test for Engine 12 is scheduled for March 12, 2010.
- Copies of all emissions sampling and calibration data are attached.
- There were no excess NOx emissions during the period of time that the unit operated.

In accordance with Condition 1 of the Emergency Variance, Engine 12 achieved compliance with the permitted emission limits and was returned to normal operation on March 1, 2010. Therefore the Emergency Variance is no longer in effect.

Asset Manager _____ Date 3/12/10

2-25-10

Engine #12
During Variance

ECOM-A Plus

| Date | Time |
|---|---|
| 02.25.10 | 12:22:12 PM |

Gas analysis

Fuel type
Natural gas

| | | | |
|---|---|---|---|
| T.Air | | 68 | °F |
| T.Gas | | 65 | °F |
| O2 | | 9.1 | % |
| CO | 15.0% | 12 | ppm |
| NO | 15.0% | 3.4 | ppm |
| NO2 | 15.0% | 0.0 | ppm |
| NOx | 15.0% | 3.5 | ppm |
| CO2 | | 6.6 | % |
| Exc.air | | 1.76 | |
| Sen.temp. | | 71 | °F |

California Power
Holdings, LLC.
16457 Avenue 24 1/2
Bldg. 6
Chowchilla, CA 93610
Phone: 559-665-4577
Fax: 559-665-4866

ECOM-A Plus

| Date | Time |
|---|---|
| 02.25.10 | 02:24:10 PM |

Gas analysis 12

Fuel type
Natural gas

| | | | |
|---|---|---|---|
| T.Air | | 76 | °F |
| T.Gas | | 68 | °F |
| O2 | | 9.3 | % |
| CO | 15.0% | 10 | ppm |
| NO | 15.0% | 4.7 | ppm |
| NO2 | 15.0% | 0.0 | ppm |
| NOx | 15.0% | 4.7 | ppm |
| CO2 | | 6.5 | % |
| Exc.air | | 1.79 | |
| Sen.temp. | | 79 | °F |

California Power
Holdings, LLC.
16457 Avenue 24 1/2
Bldg. 6
Chowchilla, CA 93610
Phone: 559-665-4577
Fax: 559-665-4866

ECOM-A Plus

| Date | Time |
|---|---|
| 02.25.10 | 12:22:44 PM |

Gas analysis

Fuel type
Natural gas

| | | |
|---|---|---|
| T.Air | 68 | °F |
| T.Gas | 65 | °F |
| O2 | 9.1 | % |
| CO | 25 | ppm |
| NO | 10.3 | ppm |
| NO2 | 0.1 | ppm |
| NOx | 10.4 | ppm |
| CO2 | 6.6 | % |
| Exc.air | 1.76 | |
| Sen.temp. | 71 | °F |

California Power
Holdings, LLC.
16457 Avenue 24 1/2

ECOM-A Plus

| Date | Time |
|---|---|
| 02.25.10 | 02:24:31 PM |

Gas analysis

Fuel type
Natural gas

| | | |
|---|---|---|
| T.Air | 76 | °F |
| T.Gas | 68 | °F |
| O2 | 9.3 | % |
| CO | 21 | ppm |
| NO | 9.1 | ppm |
| NO2 | 0.0 | ppm |
| NOx | 9.1 | ppm |
| CO2 | 6.5 | % |
| Exc.air | 1.79 | |
| Sen.temp. | 79 | °F |

California Power
Holdings, LLC.
16457 Avenue 24 1/2
Bldg. 6

2-25-10

ECOM-A Plus

Date 02.25.10 Time 01:58:35 PM

Gas analysis

Fuel type
Natural gas

| | | | |
|---|---|---|---|
| T.Air | | 73 | °F |
| T.Gas | | 68 | °F |
| O2 | | 9.3 | % |
| CO | 15.0% | 9 | ppm |
| NO | 15.0% | 6.1 | ppm |
| NO2 | 15.0% | 0.0 | ppm |
| NOx | 15.0% | 6.1 | ppm |
| CO2 | | 6.5 | % |
| Exc.air | | 1.79 | |
| Sen.temp. | | 76 | °F |

California Power
Holdings, LLC.
16457 Avenue 24 1/2
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Chowchilla, CA 93610
Phone: 559-665-4577
Fax: 559-665-4866

ECOM-A Plus

Date 02.25.10 Time 02:01:17 PM

Gas analysis

Fuel type
Natural gas

| | | | |
|---|---|---|---|
| T.Air | | 74 | °F |
| T.Gas | | 68 | °F |
| O2 | | 9.2 | % |
| CO | 15.0% | 10 | ppm |
| NO | 15.0% | 5.1 | ppm |
| NO2 | 15.0% | 0.0 | ppm |
| NOx | 15.0% | 5.1 | ppm |
| CO2 | | 6.6 | % |
| Exc.air | | 1.78 | |
| Sen.temp. | | 76 | °F |

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Fax: 559-665-4866

ECOM-A Plus

Date 02.25.10 Time 02:05:08 PM

Gas analysis

Fuel type
Natural gas

| | | | |
|---|---|---|---|
| T.Air | | 74 | °F |
| T.Gas | | 68 | °F |
| O2 | | 9.2 | % |
| CO | 15.0% | 10 | ppm |
| NO | 15.0% | 4.4 | ppm |
| NO2 | 15.0% | 0.0 | ppm |
| NOx | 15.0% | 4.4 | ppm |
| CO2 | | 6.6 | % |
| Exc.air | | 1.78 | |
| Sen.temp. | | 77 | °F |

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Chowchilla, CA 93610
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ECOM-A Plus

Date 02.25.10 Time 02:09:30

Gas analysis

Fuel type
Natural gas

| | | | |
|---|---|---|---|
| T.Air | | 75 | °F |
| T.Gas | | 69 | °F |
| O2 | | 9.3 | % |
| CO | 15.0% | 10 | ppm |
| NO | 15.0% | 4.2 | ppm |
| NO2 | 15.0% | 0.0 | ppm |
| NOx | 15.0% | 4.2 | ppm |
| CO2 | | 6.5 | % |
| Exc.air | | 1.79 | |
| Sen.temp. | | 78 | °F |

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ECOM-A Plus

Date 02.25.10 Time 01:59:02 PM

Gas analysis

Fuel type
Natural gas

| | | |
|---|---|---|
| T.Air | 73 | °F |
| T.Gas | 68 | °F |
| O2 | 9.3 | % |
| CO | 19 | ppm |
| NO | 11.4 | ppm |
| NO2 | 0.0 | ppm |
| NOx | 11.4 | ppm |
| CO2 | 6.5 | % |
| Exc.air | 1.79 | |
| Sen.temp. | 76 | °F |

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Fax: 559-665-4866

ECOM-A Plus

Date 02.25.10 Time 02:01:17 PM

Gas analysis

Fuel type
Natural gas

| | | |
|---|---|---|
| T.Air | 74 | °F |
| T.Gas | 68 | °F |
| O2 | 9.2 | % |
| CO | 20 | ppm |
| NO | 10.1 | ppm |
| NO2 | 0.0 | ppm |
| NOx | 10.1 | ppm |
| CO2 | 6.6 | % |
| Exc.air | 1.78 | |
| Sen.temp. | 76 | °F |

California Power
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ECOM-A Plus

Date 02.25.10 Time 02:05:32 PM

Gas analysis

Fuel type
Natural gas

| | | |
|---|---|---|
| T.Air | 74 | °F |
| T.Gas | 68 | °F |
| O2 | 9.3 | % |
| CO | 20 | ppm |
| NO | 8.7 | ppm |
| NO2 | 0.0 | ppm |
| NOx | 8.7 | ppm |
| CO2 | 6.5 | % |
| Exc.air | 1.79 | |
| Sen.temp. | 77 | °F |

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Fax: 559-665-4866

ECOM-A Plus

Date 02.25.10 Time 02:09:30 PM

Gas analysis

Fuel type
Natural gas

| | | |
|---|---|---|
| T.Air | 75 | °F |
| T.Gas | 69 | °F |
| O2 | 9.3 | % |
| CO | 21 | ppm |
| NO | 8.2 | ppm |
| NO2 | 0.0 | ppm |
| NOx | 8.2 | ppm |
| CO2 | 6.5 | % |
| Exc.air | 1.79 | |
| Sen.temp. | 78 | °F |

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Chowchilla, CA 93610
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Fax: 559-665-4866

2-25-10

Engine #12
During Variance.

ECOM-A Plus

Date Time
02.25.10 02:12:42 PM

Gas analysis

Fuel type
Natural gas

| | | | |
|---|---|---|---|
| T.Air | | 75 | °F |
| T.Gas | | 69 | °F |
| O2 | | 9.2 | % |
| CO | 15.0% | 10 | PPM |
| NO | 15.0% | 4.7 | PPM |
| NO2 | 15.0% | 0.0 | PPM |
| NOx | 15.0% | 4.7 | PPM |
| CO2 | | 6.6 | % |
| Exc.air | | 1.78 | |
| Sen.temp. | | 78 | °F |

California Power
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Fax: 559-665-4866

ECOM-A Plus

Date Time
02.25.10 02:16:08 PM

Gas analysis

Fuel type
Natural gas

| | | | |
|---|---|---|---|
| T.Air | | 76 | °F |
| T.Gas | | 69 | °F |
| O2 | | 9.3 | % |
| CO | 15.0% | 10 | PPM |
| NO | 15.0% | 5.0 | PPM |
| NO2 | 15.0% | 0.0 | PPM |
| NOx | 15.0% | 5.0 | PPM |
| CO2 | | 6.5 | % |
| Exc.air | | 1.79 | |
| Sen.temp. | | 79 | °F |

California Power
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Fax: 559-665-4866

ECOM-A Plus

Date Time
02.25.10 02:18:50 PM

Gas analysis

Fuel type
Natural gas

| | | | |
|---|---|---|---|
| T.Air | | 76 | °F |
| T.Gas | | 69 | °F |
| O2 | | 9.2 | % |
| CO | 15.0% | 10 | PPM |
| NO | 15.0% | 4.7 | PPM |
| NO2 | 15.0% | 0.0 | PPM |
| NOx | 15.0% | 4.7 | PPM |
| CO2 | | 6.6 | % |
| Exc.air | | 1.78 | |
| Sen.temp. | | 79 | °F |

California Power
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Chowchilla, CA 93610
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Fax: 559-665-4866

ECOM-A Plus

Date Time
02.25.10 02:13:06 PM

Gas analysis

Fuel type
Natural gas

| | | | |
|---|---|---|---|
| T.Air | | 75 | °F |
| T.Gas | | 69 | °F |
| O2 | | 9.3 | % |
| CO | | 20 | PPM |
| NO | | 9.0 | PPM |
| NO2 | | 0.0 | PPM |
| NOx | | 9.0 | PPM |
| CO2 | | 6.5 | % |
| Exc.air | | 1.79 | |
| Sen.temp. | | 78 | °F |

California Power
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Phone: 559-665-4577
Fax: 559-665-4866

ECOM-A Plus

Date Time
02.25.10 02:16:33 PM

Gas analysis 12

Fuel type
Natural gas

| | | | |
|---|---|---|---|
| T.Air | | 76 | °F |
| T.Gas | | 69 | °F |
| O2 | | 9.3 | % |
| CO | | 21 | PPM |
| NO | | 9.5 | PPM |
| NO2 | | 0.0 | PPM |
| NOx | | 9.5 | PPM |
| CO2 | | 6.5 | % |
| Exc.air | | 1.79 | |
| Sen.temp. | | 79 | °F |

California Power
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Chowchilla, CA 93610
Phone: 559-665-4577
Fax: 559-665-4866

ECOM-A Plus

Date Time
02.25.10 02:22:29 PM

Gas analysis

Fuel type
Natural gas

| | | | |
|---|---|---|---|
| T.Air | | 76 | °F |
| T.Gas | | 69 | °F |
| O2 | | 9.2 | % |
| CO | | 21 | PPM |
| NO | | 8.7 | PPM |
| NO2 | | 0.0 | PPM |
| NOx | | 8.7 | PPM |
| CO2 | | 6.6 | % |
| Exc.air | | 1.78 | |
| Sen.temp. | | 79 | °F |

California Power
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Phone: 559-665-4577

2-26-10

ECOM-A Plus

Date 02.26.10 Time 10:17:11 AM

Gas analysis

Fuel type
Natural gas

| | | |
|---|---|---|
| T.Air | 71 | °F |
| T.Gas | 67 | °F |
| O2 | 9.2 | % |
| CO 15.0% | 11 | PPM |
| NO 15.0% | 6.3 | PPM |
| NO2 15.0% | 0.1 | PPM |
| NOx 15.0% | 6.4 | PPM |
| CO2 | 6.6 | % |
| Exc.air | 1.78 | |
| Sen.temp. | 75 | °F |

California Power
Holdings, LLC.
16457 Avenue 24 1/2
Bldg. 6
Chowchilla, CA 93610
Phone: 559-665-4577
Fax: 559-665-4866

ECOM-A Plus

Date 02.26.10 Time 10:18:05 AM

Gas analysis

Fuel type
Natural gas

| | | |
|---|---|---|
| T.Air | 72 | °F |
| T.Gas | 67 | °F |
| O2 | 9.2 | % |
| CO | 24 | PPM |
| NO | 11.9 | PPM |
| NO2 | 0.3 | PPM |
| NOx | 12.2 | PPM |
| CO2 | 6.6 | % |
| Exc.air | 1.78 | |
| Sen.temp. | 75 | °F |

California Power
Holdings, LLC.
16457 Avenue 24 1/2
Bldg. 6
Chowchilla, CA 93610
Phone: 559-665-4577
Fax: 559-665-4866

ECOM-A Plus

Date 02.26.10 Time 10:52:04 AM

Gas analysis

Fuel type
Natural gas

| | | |
|---|---|---|
| T.Air | 73 | °F |
| T.Gas | 68 | °F |
| O2 | 9.2 | % |
| CO 15.0% | 11 | PPM |
| NO 15.0% | 6.7 | PPM |
| NO2 15.0% | 0.1 | PPM |
| NOx 15.0% | 6.8 | PPM |
| CO2 | 6.6 | % |
| Exc.air | 1.78 | |
| Sen.temp. | 76 | °F |

California Power
Holdings, LLC.
16457 Avenue 24 1/2
Bldg. 6
Chowchilla, CA 93610
Phone: 559-665-4577
Fax: 559-665-4866

ECOM-A Plus

Date 02.26.10 Time 10:52:27 AM

Gas analysis

Fuel type
Natural gas

| | | |
|---|---|---|
| T.Air | 73 | °F |
| T.Gas | 68 | °F |
| O2 | 9.2 | % |
| CO | 23 | PPM |
| NO | 13.4 | PPM |
| NO2 | 0.2 | PPM |
| NOx | 13.6 | PPM |
| CO2 | 6.6 | % |
| Exc.air | 1.78 | |
| Sen.temp. | 76 | °F |

California Power
Holdings, LLC.
16457 Avenue 24 1/2
Bldg. 6
Chowchilla, CA 93610
Phone: 559-665-4577
Fax: 559-665-4866

ECOM-A Plus

Date 02.26.10 Time 11:10:53 AM

Gas analysis

Fuel type
Natural gas

| | | |
|---|---|---|
| T.Air | 73 | °F |
| T.Gas | 67 | °F |
| O2 | 9.2 | % |
| CO 15.0% | 12 | PPM |
| NO 15.0% | 6.2 | PPM |
| NO2 15.0% | 0.2 | PPM |
| NOx 15.0% | 6.4 | PPM |
| CO2 | 6.6 | % |
| Exc.air | 1.78 | |
| Sen.temp. | 77 | °F |

California Power
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Bldg. 6
Chowchilla, CA 93610
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Fax: 559-665-4866

ECOM-A Plus

Date 02.26.10 Time 11:11:15 AM

Gas analysis

Fuel type
Natural gas

| | | |
|---|---|---|
| T.Air | 73 | °F |
| T.Gas | 67 | °F |
| O2 | 9.2 | % |
| CO | 24 | PPM |
| NO | 10.9 | PPM |
| NO2 | 0.3 | PPM |
| NOx | 11.2 | PPM |
| CO2 | 6.6 | % |
| Exc.air | 1.78 | |
| Sen.temp. | 77 | °F |

California Power
Holdings, LLC.
16457 Avenue 24 1/2
Bldg. 6
Chowchilla, CA 93610
Phone: 559-665-4577
Fax: 559-665-4866

2-26-10

ECOM-A Plus

Date 02.26.10 Time 11:42:17 AM

Gas analysis

Fuel type
Natural gas

| | | | |
|---|---|---|---|
| T.Air | | 74 | °F |
| T.Gas | | 68 | °F |
| O2 | | 9.3 | % |
| CO | 15.0% | 11 | ppm |
| NO | 15.0% | 5.0 | ppm |
| NO2 | 15.0% | 0.1 | ppm |
| NOx | 15.0% | 5.1 | ppm |
| CO2 | | 6.5 | % |
| Exc.air | | 1.79 | |
| Sen.temp. | | 78 | °F |

California Power
Holdings, LLC.
16457 Avenue 24 1/2
Bldg. 6
Chowchilla, CA 93610
Phone: 559-665-4577
Fax: 559-665-4866

ECOM-A Plus

Date 02.26.10 Time 11:47:17 AM

Gas analysis

Fuel type
Natural gas

| | | | |
|---|---|---|---|
| T.Air | | 74 | °F |
| T.Gas | | 68 | °F |
| O2 | | 9.2 | % |
| CO | 15.0% | 11 | ppm |
| NO | 15.0% | 3.9 | ppm |
| NO2 | 15.0% | 0.0 | ppm |
| NOx | 15.0% | 3.9 | ppm |
| CO2 | | 6.6 | % |
| Exc.air | | 1.78 | |
| Sen.temp. | | 78 | °F |

California Power
Holdings, LLC.
16457 Avenue 24 1/2
Bldg. 6
Chowchilla, CA 93610
Phone: 559-665-4577
Fax: 559-665-4866

ECOM-A Plus

Date 02.26.10 Time 11:51:52 AM

Gas analysis

Fuel type
Natural gas

| | | | |
|---|---|---|---|
| T.Air | | 74 | °F |
| T.Gas | | 68 | °F |
| O2 | | 9.3 | % |
| CO | 15.0% | 10 | ppm |
| NO | 15.0% | 4.3 | ppm |
| NO2 | 15.0% | 0.0 | ppm |
| NOx | 15.0% | 4.3 | ppm |
| CO2 | | 6.5 | % |
| Exc.air | | 1.79 | |
| Sen.temp. | | 78 | °F |

California Power
Holdings, LLC.
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ECOM-A Plus

Date 02.26.10 Time 12:05:55 PM

Gas analysis

Fuel type
Natural gas

| | | | |
|---|---|---|---|
| T.Air | | 75 | °F |
| T.Gas | | 68 | °F |
| O2 | | 9.2 | % |
| CO | 15.0% | 11 | ppm |
| NO | 15.0% | 4.5 | ppm |
| NO2 | 15.0% | 0.0 | ppm |
| NOx | 15.0% | 4.6 | ppm |
| CO2 | | 6.6 | % |
| Exc.air | | 1.78 | |
| Sen.temp. | | 79 | °F |

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ECOM-A Plus

Date 02.26.10 Time 11:42:40 AM

Gas analysis

Fuel type
Natural gas

| | | | |
|---|---|---|---|
| T.Air | | 74 | °F |
| T.Gas | | 68 | °F |
| O2 | | 9.3 | % |
| CO | | 22 | ppm |
| NO | | 9.0 | ppm |
| NO2 | | 0.2 | ppm |
| NOx | | 9.2 | ppm |
| CO2 | | 6.5 | % |
| Exc.air | | 1.79 | |
| Sen.temp. | | 78 | °F |

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ECOM-A Plus

Date 02.26.10 Time 11:47:38 AM

Gas analysis

Fuel type
Natural gas

| | | | |
|---|---|---|---|
| T.Air | | 74 | °F |
| T.Gas | | 68 | °F |
| O2 | | 9.2 | % |
| CO | | 23 | ppm |
| NO | | 8.1 | ppm |
| NO2 | | 0.1 | ppm |
| NOx | | 8.2 | ppm |
| CO2 | | 6.6 | % |
| Exc.air | | 1.78 | |
| Sen.temp. | | 78 | °F |

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ECOM-A Plus

Date 02.26.10 Time 11:52:13 AM

Gas analysis

Fuel type
Natural gas

| | | | |
|---|---|---|---|
| T.Air | | 74 | °F |
| T.Gas | | 68 | °F |
| O2 | | 9.3 | % |
| CO | | 22 | ppm |
| NO | | 8.3 | ppm |
| NO2 | | 0.1 | ppm |
| NOx | | 8.4 | ppm |
| CO2 | | 6.5 | % |
| Exc.air | | 1.79 | |
| Sen.temp. | | 78 | °F |

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ECOM-A Plus

Date 02.26.10 Time 12:06:19 PM

Gas analysis

Fuel type
Natural gas

| | | | |
|---|---|---|---|
| T.Air | | 75 | °F |
| T.Gas | | 68 | °F |
| O2 | | 9.2 | % |
| CO | | 22 | ppm |
| NO | | 10.0 | ppm |
| NO2 | | 0.1 | ppm |
| NOx | | 10.1 | ppm |
| CO2 | | 6.6 | % |
| Exc.air | | 1.78 | |
| Sen.temp. | | 79 | °F |

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2-26-10

ECOM-A Plus

Date 02.26.10 Time 12:21:22 PM

Gas analysis

Fuel type
Natural gas

| | | | |
|---|---|---|---|
| T.Air | | 75 | °F |
| T.Gas | | 68 | °F |
| O2 | | 9.3 | % |
| CO | 15.0% | 10 | ppm |
| NO | 15.0% | 4.1 | ppm |
| NO2 | 15.0% | 0.1 | ppm |
| NOx | 15.0% | 4.2 | ppm |
| CO2 | | 6.5 | % |
| Exc.air | | 1.79 | |
| Sen.temp. | | 79 | °F |

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ECOM-A Plus

Date 02.26.10 Time 12:27:20 PM

Gas analysis

Fuel type
Natural gas

| | | | |
|---|---|---|---|
| T.Air | | 75 | °F |
| T.Gas | | 68 | °F |
| O2 | | 9.3 | % |
| CO | 15.0% | 11 | ppm |
| NO | 15.0% | 4.3 | ppm |
| NO2 | 15.0% | 0.1 | ppm |
| NOx | 15.0% | 4.4 | ppm |
| CO2 | | 6.5 | % |
| Exc.air | | 1.79 | |
| Sen.temp. | | 79 | °F |

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ECOM-A Plus

Date 02.26.10 Time 12:33:47 PM

Gas analysis

Fuel type
Natural gas

| | | | |
|---|---|---|---|
| T.Air | | 75 | °F |
| T.Gas | | 68 | °F |
| O2 | | 9.3 | % |
| CO | 15.0% | 11 | ppm |
| NO | 15.0% | 4.8 | ppm |
| NO2 | 15.0% | 0.1 | ppm |
| NOx | 15.0% | 4.9 | ppm |
| CO2 | | 6.5 | % |
| Exc.air | | 1.79 | |
| Sen.temp. | | 79 | °F |

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ECOM-A Plus

Date 02.26.10 Time 12:40:43 PM

Gas analysis

Fuel type
Natural gas

| | | | |
|---|---|---|---|
| T.Air | | 75 | °F |
| T.Gas | | 68 | °F |
| O2 | | 9.3 | % |
| CO | 15.0% | 11 | ppm |
| NO | 15.0% | 4.6 | ppm |
| NO2 | 15.0% | 0.1 | ppm |
| NOx | 15.0% | 4.7 | ppm |
| CO2 | | 6.5 | % |
| Exc.air | | 1.79 | |
| Sen.temp. | | 79 | °F |

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ECOM-A Plus

Date 02.26.10 Time 12:21:45 PM

Gas analysis

Fuel type
Natural gas

| | | | |
|---|---|---|---|
| T.Air | | 75 | °F |
| T.Gas | | 68 | °F |
| O2 | | 9.3 | % |
| CO | | 21 | ppm |
| NO | | 7.7 | ppm |
| NO2 | | 0.1 | ppm |
| NOx | | 7.8 | ppm |
| CO2 | | 6.5 | % |
| Exc.air | | 1.79 | |
| Sen.temp. | | 79 | °F |

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ECOM-A Plus

Date 02.26.10 Time 12:27:44 PM

Gas analysis

Fuel type
Natural gas

| | | | |
|---|---|---|---|
| T.Air | | 75 | °F |
| T.Gas | | 68 | °F |
| O2 | | 9.3 | % |
| CO | | 22 | ppm |
| NO | | 8.2 | ppm |
| NO2 | | 0.2 | ppm |
| NOx | | 8.4 | ppm |
| CO2 | | 6.5 | % |
| Exc.air | | 1.79 | |
| Sen.temp. | | 79 | °F |

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ECOM-A Plus

Date 02.26.10 Time 12:34:08 PM

Gas analysis

Fuel type
Natural gas

| | | | |
|---|---|---|---|
| T.Air | | 75 | °F |
| T.Gas | | 68 | °F |
| O2 | | 9.3 | % |
| CO | | 22 | ppm |
| NO | | 8.9 | ppm |
| NO2 | | 0.1 | ppm |
| NOx | | 9.0 | ppm |
| CO2 | | 5.5 | % |
| Exc.air | | 1.79 | |
| Sen.temp. | | 79 | °F |

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ECOM-A Plus

Date 02.26.10 Time 12:41:05 PM

Gas analysis

Fuel type
Natural gas

| | | | |
|---|---|---|---|
| T.Air | | 75 | °F |
| T.Gas | | 68 | °F |
| O2 | | 9.2 | % |
| CO | | 22 | ppm |
| NO | | 9.0 | ppm |
| NO2 | | 0.2 | ppm |
| NOx | | 9.2 | ppm |
| CO2 | | 5.6 | % |
| Exc.air | | 1.78 | |
| Sen.temp. | | 79 | °F |

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2-26-10

ECOM-A Plus

Date Time
02.26.10 12:47:22 PM

Gas analysis

Fuel type
Natural gas

| | | | |
|---|---|---|---|
| T.Air | | 75 | °F |
| T.Gas | | 68 | °F |
| O2 | | 9.3 | % |
| CO | 15.0% | 11 | ppm |
| NO | 15.0% | 4.3 | ppm |
| NO2 | 15.0% | 0.1 | ppm |
| NOx | 15.0% | 4.4 | ppm |
| CO2 | | 6.5 | % |
| Exc.air | | 1.79 | |
| Sen.temp. | | 79 | °F |

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ECOM-A Plus

Date Time
02.26.10 01:01:34 PM

Gas analysis

Fuel type
Natural gas

| | | | |
|---|---|---|---|
| T.Air | | 75 | °F |
| T.Gas | | 69 | °F |
| O2 | | 9.3 | % |
| CO | 15.0% | 11 | ppm |
| NO | 15.0% | 4.4 | ppm |
| NO2 | 15.0% | 0.0 | ppm |
| NOx | 15.0% | 4.4 | ppm |
| CO2 | | 6.5 | % |
| Exc.air | | 1.79 | |
| Sen.temp. | | 79 | °F |

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*ECOM-A Plus

Date Time
02.26.10 01:30:17 PM

Gas analysis

Fuel type
Natural gas

| | | | |
|---|---|---|---|
| T.Air | | 75 | °F |
| T.Gas | | 69 | °F |
| O2 | | 9.3 | % |
| CO | 15.0% | 11 | ppm |
| NO | 15.0% | 4.6 | ppm |
| NO2 | 15.0% | 0.1 | ppm |
| NOx | 15.0% | 4.7 | ppm |
| CO2 | | 6.5 | % |
| Exc.air | | 1.79 | |
| Sen.temp. | | 79 | °F |

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ECOM-A Plus

Date Time
02.26.10 12:47:48 PM

Gas analysis

Fuel type
Natural gas

| | | | |
|---|---|---|---|
| T.Air | | 75 | °F |
| T.Gas | | 68 | °F |
| O2 | | 9.2 | % |
| CO | | 22 | ppm |
| NO | | 8.6 | ppm |
| NO2 | | 0.2 | ppm |
| NOx | | 8.3 | ppm |
| CO2 | | 6.6 | % |
| Exc.air | | 1.78 | |
| Sen.temp. | | 79 | °F |

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ECOM-A Plus

Date Time
02.26.10 01:01:34 PM

Gas analysis

Fuel type
Natural gas

| | | | |
|---|---|---|---|
| T.Air | | 75 | °F |
| T.Gas | | 69 | °F |
| O2 | | 9.3 | % |
| CO | 15.0% | 11 | ppm |
| NO | 15.0% | 4.4 | ppm |
| NO2 | 15.0% | 0.0 | ppm |
| NOx | 15.0% | 4.4 | ppm |
| CO2 | | 6.5 | % |
| Exc.air | | 1.79 | |
| Sen.temp. | | 79 | °F |

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ECOM-A Plus

Date Time
02.26.10 01:30:41 PM

Gas analysis

Fuel type
Natural gas

| | | | |
|---|---|---|---|
| T.Air | | 75 | °F |
| T.Gas | | 69 | °F |
| O2 | | 9.3 | % |
| CO | | 22 | ppm |
| NO | | 9.0 | ppm |
| NO2 | | 0.2 | ppm |
| NOx | | 9.2 | ppm |
| CO2 | | 6.5 | % |
| Exc.air | | 1.79 | |
| Sen.temp. | | 79 | °F |

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3-1-10

ECOM-A Plus

Date 03.01.10 Time 09:29:15

Gas analysis

Fuel type
Natural gas

| | | | |
|---|---|---|---|
| T.Air | | 71 | °F |
| T.Gas | | 66 | °F |
| O2 | | 9.2 | % |
| CO | 15.0% | 10 | ppm |
| NO | 15.0% | 4.8 | ppm |
| NO2 | 15.0% | 0.0 | ppm |
| NOx | 15.0% | 4.8 | ppm |
| CO2 | | 6.6 | % |
| Exc.air | | 1.78 | |
| Sen.temp. | | 75 | °F |

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ECOM-A Plus

Date 03.01.10 Time 09:41:47 AM

Gas analysis

Fuel type
Natural gas

| | | | |
|---|---|---|---|
| T.Air | | 72 | °F |
| T.Gas | | 67 | °F |
| O2 | | 9.2 | % |
| CO | 15.0% | 10 | ppm |
| NO | 15.0% | 5.4 | ppm |
| NO2 | 15.0% | 0.0 | ppm |
| NOx | 15.0% | 5.4 | ppm |
| CO2 | | 6.6 | % |
| Exc.air | | 1.78 | |
| Sen.temp. | | 76 | °F |

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ECOM-A Plus

Date 03.01.10 Time 09:49:59 AM

Gas analysis

Fuel type
Natural gas

| | | | |
|---|---|---|---|
| T.Air | | 73 | °F |
| T.Gas | | 67 | °F |
| O2 | | 9.2 | % |
| CO | 15.0% | 11 | ppm |
| NO | 15.0% | 5.3 | ppm |
| NO2 | 15.0% | 0.0 | ppm |
| NOx | 15.0% | 5.3 | ppm |
| CO2 | | 6.6 | % |
| Exc.air | | 1.78 | |
| Sen.temp. | | 76 | °F |

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ECOM-A Plus

Date 03.01.10 Time 11:03:53 AM

Gas analysis

Fuel type
Natural gas

| | | | |
|---|---|---|---|
| T.Air | | 75 | °F |
| T.Gas | | 69 | °F |
| O2 | | 9.2 | % |
| CO | 15.0% | 12 | ppm |
| NO | 15.0% | 5.9 | ppm |
| NO2 | 15.0% | 0.0 | ppm |
| NOx | 15.0% | 5.9 | ppm |
| CO2 | | 6.6 | % |
| Exc.air | | 1.78 | |
| Sen.temp. | | 79 | °F |

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ECOM-A Plus

Date 03.01.10 Time 09:29:43 A

Gas analysis

Fuel type
Natural gas

| | | | |
|---|---|---|---|
| T.Air | | 71 | °F |
| T.Gas | | 66 | °F |
| O2 | | 9.2 | % |
| CO | | 21 | ppm |
| NO | | 8.6 | ppm |
| NO2 | | 0.0 | ppm |
| NOx | | 8.6 | ppm |
| CO2 | | 6.6 | % |
| Exc.air | | 1.78 | |
| Sen.temp. | | 75 | °F |

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ECOM-A Plus

Date 03.01.10 Time 09:42:16 AM

Gas analysis

Fuel type
Natural gas

| | | | |
|---|---|---|---|
| T.Air | | 72 | °F |
| T.Gas | | 67 | °F |
| O2 | | 9.2 | % |
| CO | | 21 | ppm |
| NO | | 10.4 | ppm |
| NO2 | | 0.0 | ppm |
| NOx | | 10.4 | ppm |
| CO2 | | 6.6 | % |
| Exc.air | | 1.78 | |
| Sen.temp. | | 76 | °F |

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ECOM-A Plus

Date 03.01.10 Time 09:50:41 AM

Gas analysis

Fuel type
Natural gas

| | | | |
|---|---|---|---|
| T.Air | | 73 | °F |
| T.Gas | | 67 | °F |
| O2 | | 9.2 | % |
| CO | | 22 | ppm |
| NO | | 9.3 | ppm |
| NO2 | | 0.0 | ppm |
| NOx | | 9.3 | ppm |
| CO2 | | 6.6 | % |
| Exc.air | | 1.78 | |
| Sen.temp. | | 76 | °F |

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ECOM-A Plus

Date 03.01.10 Time 11:04:29

Gas analysis

Fuel type
Natural gas

| | | | |
|---|---|---|---|
| T.Air | | 75 | °F |
| T.Gas | | 69 | °F |
| O2 | | 9.2 | % |
| CO | | 23 | ppm |
| NO | | 11.6 | ppm |
| NO2 | | 0.1 | ppm |
| NOx | | 11.7 | ppm |
| CO2 | | 6.6 | % |
| Exc.air | | 1.78 | |
| Sen.temp. | | 79 | °F |

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3-1-10

ECOM-A Plus

Date Time
03.01.10 11:33:59 AM

Gas analysis

Fuel type
Natural gas

| | | |
|---|---|---|
| T.Air | 77 | °F |
| T.Gas | 71 | °F |
| O2 | 9.2 | % |
| CO 15.0% | 12 | ppm |
| NO 15.0% | 6.9 | ppm |
| NO2 15.0% | 0.0 | ppm |
| NOx 15.0% | 6.9 | ppm |
| CO2 | 6.6 | % |
| Exc.air | 1.78 | |
| Sen.temp. | 80 | °F |

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ECOM-A Plus

Date Time
03.01.10 11:38:54 AM

Gas analysis

Fuel type
Natural gas

| | | |
|---|---|---|
| T.Air | 77 | °F |
| T.Gas | 71 | °F |
| O2 | 9.2 | % |
| CO 15.0% | 11 | ppm |
| NO 15.0% | 5.5 | ppm |
| NO2 15.0% | 0.0 | ppm |
| NOx 15.0% | 5.5 | ppm |
| CO2 | 6.6 | % |
| Exc.air | 1.78 | |
| Sen.temp. | 81 | °F |

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ECOM-A Plus

Date Time
03.01.10 11:45:45 AM

Gas analysis

Fuel type
Natural gas

| | | |
|---|---|---|
| T.Air | 77 | °F |
| T.Gas | 71 | °F |
| O2 | 9.2 | % |
| CO 15.0% | 11 | ppm |
| NO 15.0% | 5.3 | ppm |
| NO2 15.0% | 0.0 | ppm |
| NOx 15.0% | 5.3 | ppm |
| CO2 | 6.6 | % |
| Exc.air | 1.78 | |
| Sen.temp. | 81 | °F |

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ECOM-A Plus

Date Time
03.01.10 12:11:22 PM

Gas analysis

Fuel type
Natural gas

| | | |
|---|---|---|
| T.Air | 78 | °F |
| T.Gas | 72 | °F |
| O2 | 9.2 | % |
| CO 15.0% | 11 | ppm |
| NO 15.0% | 5.8 | ppm |
| NO2 15.0% | 0.0 | ppm |
| NOx 15.0% | 5.8 | ppm |
| CO2 | 6.6 | % |
| Exc.air | 1.78 | |
| Sen.temp. | 82 | °F |

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ECOM-A Plus

Date Time
03.01.10 11:34:20 AM

Gas analysis

Fuel type
Natural gas

| | | |
|---|---|---|
| T.Air | 77 | °F |
| T.Gas | 71 | °F |
| O2 | 9.2 | % |
| CO | 24 | ppm |
| NO | 13.5 | ppm |
| NO2 | 0.0 | ppm |
| NOx | 13.5 | ppm |
| CO2 | 6.6 | % |
| Exc.air | 1.78 | |
| Sen.temp. | 80 | °F |

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ECOM-A Plus

Date Time
03.01.10 11:39:44 AM

Gas analysis

Fuel type
Natural gas

| | | |
|---|---|---|
| T.Air | 77 | °F |
| T.Gas | 71 | °F |
| O2 | 9.2 | % |
| CO | 23 | ppm |
| NO | 14.1 | ppm |
| NO2 | 0.0 | ppm |
| NOx | 14.1 | ppm |
| CO2 | 6.6 | % |
| Exc.air | 1.78 | |
| Sen.temp. | 81 | °F |

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Blds. 6
Chowchilla, CA 93610
Phone: 559-665-4577
Fax: 559-665-4866

ECOM-A Plus

Date Time
03.01.10 11:46:07 AM

Gas analysis

Fuel type
Natural gas

| | | |
|---|---|---|
| T.Air | 77 | °F |
| T.Gas | 71 | °F |
| O2 | 9.2 | % |
| CO | 23 | ppm |
| NO | 10.3 | ppm |
| NO2 | 0.0 | ppm |
| NOx | 10.3 | ppm |
| CO2 | 6.6 | % |
| Exc.air | 1.78 | |
| Sen.temp. | 81 | °F |

California Power
Holdings, LLC.
16457 Avenue 24 1/2
Blds. 6
Chowchilla, CA 93610
Phone: 559-665-4577
Fax: 559-665-4866

ECOM-A Plus

Date Time
03.01.10 12:11:44 PM

Gas analysis

Fuel type
Natural gas

| | | |
|---|---|---|
| T.Air | 78 | °F |
| T.Gas | 72 | °F |
| O2 | 9.2 | % |
| CO | 23 | ppm |
| NO | 11.7 | ppm |
| NO2 | 0.0 | ppm |
| NOx | 11.7 | ppm |
| CO2 | 6.6 | % |
| Exc.air | 1.78 | |
| Sen.temp. | 82 | °F |

California Power
Holdings, LLC.
16457 Avenue 24 1/2
Blds. 6
Chowchilla, CA 93610
Phone: 559-665-4577
Fax: 559-665-4866

3-1-10

ECOM-A Plus

Date 03.01.10 Time 11:54:16 AM

Gas analysis

Fuel type
Natural gas

| | | | |
|---|---|---|---|
| T.Air | | 77 | °F |
| T.Gas | | 71 | °F |
| O2 | | 9.2 | % |
| CO | 15.0% | 11 | PPM |
| NO | 15.0% | 6.9 | PPM |
| NO2 | 15.0% | 0.0 | PPM |
| NOx | 15.0% | 6.9 | PPM |
| CO2 | | 6.5 | % |
| Exc.air | | 1.78 | |
| Sen.temp. | | 81 | °F |

California Power
Holdings, LLC.
16457 Avenue 24 1/2
Bldg. 6
Chowchilla, CA 93610
Phone: 559-665-4577
Fax: 559-665-4866

ECOM-A Plus

Date 03.01.10 Time 11:59:42 AM

Gas analysis

Fuel type
Natural gas

| | | | |
|---|---|---|---|
| T.Air | | 78 | °F |
| T.Gas | | 71 | °F |
| O2 | | 9.2 | % |
| CO | 15.0% | 11 | PPM |
| NO | 15.0% | 7.5 | PPM |
| NO2 | 15.0% | 0.0 | PPM |
| NOx | 15.0% | 7.5 | PPM |
| CO2 | | 6.6 | % |
| Exc.air | | 1.78 | |
| Sen.temp. | | 81 | °F |

California Power
Holdings, LLC.
16457 Avenue 24 1/2
Bldg. 6
Chowchilla, CA 93610
Phone: 559-665-4577
Fax: 559-665-4866

ECOM-A Plus

Date 03.01.10 Time 12:04:29 PM

Gas analysis

Fuel type
Natural gas

| | | | |
|---|---|---|---|
| T.Air | | 78 | °F |
| T.Gas | | 71 | °F |
| O2 | | 9.2 | % |
| CO | 15.0% | 11 | PPM |
| NO | 15.0% | 6.9 | PPM |
| NO2 | 15.0% | 0.0 | PPM |
| NOx | 15.0% | 6.9 | PPM |
| CO2 | | 6.6 | % |
| Exc.air | | 1.78 | |
| Sen.temp. | | 82 | °F |

California Power
Holdings, LLC.
16457 Avenue 24 1/2
Bldg. 6
Chowchilla, CA 93610
Phone: 559-665-4577
Fax: 559-665-4866

ECOM-A Plus

Date 03.01.10 Time 12:08:10 PM

Gas analysis

Fuel type
Natural gas

| | | | |
|---|---|---|---|
| T.Air | | 78 | °F |
| T.Gas | | 72 | °F |
| O2 | | 9.3 | % |
| CO | 15.0% | 11 | PPM |
| NO | 15.0% | 4.9 | PPM |
| NO2 | 15.0% | 0.0 | PPM |
| NOx | 15.0% | 4.9 | PPM |
| CO2 | | 6.5 | % |
| Exc.air | | 1.79 | |
| Sen.temp. | | 82 | °F |

California Power
Holdings, LLC.
16457 Avenue 24 1/2
Bldg. 6
Chowchilla, CA 93610
Phone: 559-665-4577
Fax: 559-665-4866

ECOM-A Plus

Date 03.01.10 Time 11:54:39 AM

Gas analysis

Fuel type
Natural gas

| | | |
|---|---|---|
| T.Air | 77 | °F |
| T.Gas | 71 | °F |
| O2 | 9.2 | % |
| CO | 23 | PPM |
| NO | 12.0 | PPM |
| NO2 | 9.0 | PPM |
| NOx | 12.9 | PPM |
| CO2 | 6.6 | % |
| Exc.air | 1.78 | |
| Sen.temp. | 81 | °F |

California Power
Holdings, LLC.
16457 Avenue 24 1/2
Bldg. 6
Chowchilla, CA 93610
Phone: 559-665-4577
Fax: 559-665-4866

ECOM-A Plus

Date 03.01.10 Time 11:59:26 AM

Gas analysis

Fuel type
Natural gas

| | | |
|---|---|---|
| T.Air | 78 | °F |
| T.Gas | 71 | °F |
| O2 | 9.2 | % |
| CO | 23 | PPM |
| NO | 12.8 | PPM |
| NO2 | 0.0 | PPM |
| NOx | 12.8 | PPM |
| CO2 | 6.6 | % |
| Exc.air | 1.78 | |
| Sen.temp. | 81 | °F |

California Power
Holdings, LLC.
16457 Avenue 24 1/2
Bldg. 6
Chowchilla, CA 93610
Phone: 559-665-4577
Fax: 559-665-4866

ECOM-A Plus

Date 03.01.10 Time 12:04:52 PM

Gas analysis

Fuel type
Natural gas

| | | |
|---|---|---|
| T.Air | 79 | °F |
| T.Gas | 71 | °F |
| O2 | 9.3 | % |
| CO | 23 | PPM |
| NO | 12.8 | PPM |
| NO2 | 0.0 | PPM |
| NOx | 12.8 | PPM |
| CO2 | 6.5 | % |
| Exc.air | 1.79 | |
| Sen.temp. | 82 | °F |

lifornia Power
ldings, LLC.
457 Avenue 24 1/2
lg. 6
owchilla, CA 93610
one: 559-665-4577
: 559-665-4866

ECOM-A Plus

Date 03.01.10 Time 12:09:11 PM

Gas analysis

Fuel type
Natural gas

| | | |
|---|---|---|
| T.Air | 79 | °F |
| T.Gas | 72 | °F |
| O2 | 9.2 | % |
| CO | 23 | PPM |
| NO | 9.5 | PPM |
| NO2 | 0.0 | PPM |
| NOx | 9.5 | PPM |
| CO2 | 6.6 | % |
| Exc.air | 1.78 | |
| Sen.temp. | 82 | °F |

California Power
Holdings, LLC.
16457 Avenue 24 1/2
Bldg. 6
Chowchilla, CA 93610
Phone: 559-665-4577
Fax: 559-665-4866

# Permit Required Emission Monitoring Data Sheet - Calendar Year 2010

| Engine No. | Required Data | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | | | | | April | | | | |
| 10 | Reading No. | 1 | 2 | 3 | 4 | 5 | Avg. | 1 | 2 | 3 | 4 | 5 | Avg. | 1 | 2 | 3 | 4 | 5 | Avg. | 1 | 2 | 3 | 4 | 5 |
| | Date | | | | | | | | | | | | | | | | | | | | | | | |
| | Time | | | | | | | | | | | | | | | | | | | | | | | |
| | NOx PPM @ 15% O2 | | | | | | 0.0 | | | | | | 0.0 | | | | | | 0.0 | | | | | |
| | CO PPM @ 15% O2 | | | | | | 0.0 | | | | | | 0.0 | | | | | | 0.0 | | | | | |
| | O2 % | | | | | | 0.0 | | | | | | 0.0 | | | | | | 0.0 | | | | | |
| 11 | Reading No. | 1 | 2 | 3 | 4 | 5 | Avg. | 1 | 2 | 3 | 4 | 5 | Avg. | 1 | 2 | 3 | 4 | 5 | Avg. | 1 | 2 | 3 | 4 | 5 |
| | Date | | | | | | | | | | | | | | | | | | | | | | | |
| | Time | | | | | | | | | | | | | | | | | | | | | | | |
| | NOx PPM @ 15% O2 | | | | | | 0.0 | | | | | | 0.0 | | | | | | 0.0 | | | | | |
| | CO PPM @ 15% O2 | | | | | | 0.0 | | | | | | 0.0 | | | | | | 0.0 | | | | | |
| | O2 % | | | | | | 0.0 | | | | | | 0.0 | | | | | | 0.0 | | | | | |
| 12 | Reading No. | 1 | 2 | 3 | 4 | 5 | Avg. | 1 | 2 | 3 | 4 | 5 | Avg. | 1 | 2 | 3 | 4 | 5 | Avg. | 1 | 2 | 3 | 4 | 5 |
| | Date | 25-Feb-10 | | | | | | 26-Feb-10 | | | | | | 1-Mar-10 | | | | | | | | | | |
| | Time | 14:03 | 14:06 | 14:09 | 14:12 | 14:15 | | 12:21 | 12:24 | 12:27 | 12:30 | 12:33 | | 11:32 | 11:35 | 11:38 | 11:41 | 11:44 | | | | | | |
| | NOx PPM @ 15% O2 | 4.7 | 4.4 | 4.2 | 4.7 | 5.0 | 4.6 | 4.2 | 4.4 | 4.4 | 4.6 | 4.9 | 4.5 | 6.8 | 6.0 | 5.5 | 5.5 | 5.3 | 5.8 | | | | | |
| | CO PPM @ 15% O2 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 11.0 | 11.0 | 11.0 | 11.0 | 10.8 | 12.0 | 11.0 | 11.0 | 11.0 | 11.0 | 11.2 | | | | | |
| | O2 % | 9.3 | 9.3 | 9.3 | 9.3 | 9.3 | 9.3 | 9.3 | 9.3 | 9.3 | 9.3 | 9.3 | 9.3 | 9.2 | 9.2 | 9.2 | 9.2 | 9.2 | 9.2 | | | | | |
| 13 | Reading No. | 1 | 2 | 3 | 4 | 5 | Avg. | 1 | 2 | 3 | 4 | 5 | Avg. | 1 | 2 | 3 | 4 | 5 | 3.0 | 1 | 2 | 3 | 4 | 5 |
| | Date | | | | | | | | | | | | | | | | | | | | | | | |
| | Time | | | | | | | | | | | | | | | | | | | | | | | |
| | NOx PPM @ 15% O2 | | | | | | 0.0 | | | | | | 0.0 | | | | | | 0.0 | | | | | |
| | CO PPM @ 15% O2 | | | | | | 0.0 | | | | | | 0.0 | | | | | | 0.0 | | | | | |
| | O2 % | | | | | | 0.0 | | | | | | 0.0 | | | | | | 0.0 | | | | | |
| 14 | Reading No. | 1 | 2 | 3 | 4 | 5 | Avg. | 1 | 2 | 3 | 4 | 5 | Avg. | 1 | 2 | 3 | 4 | 5 | Avg. | 1 | 2 | 3 | 4 | 5 |
| | Date | | | | | | | | | | | | | | | | | | | | | | | |
| | Time | | | | | | | | | | | | | | | | | | | | | | | |
| | NOx PPM @ 15% O2 | | | | | | 0.0 | | | | | | 0.0 | | | | | | 0.0 | | | | | |
| | CO PPM @ 15% O2 | | | | | | 0.0 | | | | | | 0.0 | | | | | | 0.0 | | | | | |
| | O2 % | | | | | | 0.0 | | | | | | 0.0 | | | | | | 0.0 | | | | | |
| 15 | Reading No. | 1 | 2 | 3 | 4 | 5 | Avg. | 1 | 2 | 3 | 4 | 5 | Avg. | 1 | 2 | 3 | 4 | 5 | Avg. | 1 | 2 | 3 | 4 | 5 |
| | Date | | | | | | | | | | | | | | | | | | | | | | | |
| | Time | | | | | | | | | | | | | | | | | | | | | | | |
| | NOx PPM @ 15% O2 | | | | | | 0.0 | | | | | | 0.0 | | | | | | 0.0 | | | | | |
| | CO PPM @ 15% O2 | | | | | | 0.0 | | | | | | 0.0 | | | | | | 0.0 | | | | | |
| | O2 % | | | | | | 0.0 | | | | | | 0.0 | | | | | | 0.0 | | | | | |

# ECOM AMERICA, LTD.

1628 Oakbrook Drive
Gainesville, GA 30507

## *Certificate of Calibration

This ECOM Model A Plus, Serial Number **9066,** has been Calibrated and found to be within manufacturer specifications.
Technician- *James Smith*
Factory service performed **February 2010.**
Next factory service recommended **August 2010.**

## Certified Calibration Gases Used By ECOM

These gases are traceable to the National Institute of Standards and Technology.

| | |
|---|---|
| CO Low 1000 PPM 2.00% Oxygen | Lot # CC121897 |
| NO 30.0 PPM 0.00% Oxygen | Lot # SG9138680BAL |
| NO2 10.0 PPM Balanced In Air | Lot # XC002496B |

## Calibration Data

| Type Gas | Actual Gas Value | As Found Data | Calibrated To Data |
|---|---|---|---|
| CO Low | 1000 PPM | 1359 PPM | 1000 PPM |
| NO | 30.0 PPM | 37.9 PPM | 30.0 PPM |
| NO2 | 10.0 PPM | 10.1 PPM | 10.0 PPM |

***Suitability for use is the sole responsibility of the user. Factors affecting the calibration and response of gas sensors include, but are not limited to Frequency & Duration of use, Concentration of gases measured, Shifts in ambient temperature (> 20 deg. F), & age of sensors.**
**This Certificate of Calibration verifies that the analyzer responded accurately, and within specification to the calibration gas concentrations listed above.**

**From:** Susana Pjesky
**To:** Andracsek, Robynn
**Cc:** Mindy Bowman; Marian Massoth; Daye, Richard; Burns, Ward; BAR ImageNow
**Subject:** FW: TradeWind: Lacey Randall- Modeling Protocol
**Date:** Thursday, April 25, 2013 12:52:39 PM

---

Source ID No. 1930036
C-10593

Hello Robynn,

KDHE has reviewed the modeling protocol you submitted for the TradeWind Energy, Inc. Lacey Randall Generation Facility on April 11, 2012. TradeWind Energy plans to submit a Prevention of Significant Deterioration construction permit application for a 93.4 MW power generation facility to be located approximately 5 miles north of Colby, Kansas. Comments from Richard Daye of EPA Region 7 are listed in his email below. KDHE comments are as follows:

- ***Section 4.2, Good Engineering Stack Height*** *and building downwash discussion.*

  KDHE comment:

  KDHE requests that BPIP-PRIME output be submitted with modeling files.

- ***Section 5.1, Receptor Grid***

  KDHE comment:

  KDHE requests that the following receptor grid be used:

| Distance from fenceline (km) | Receptor spacing (m) |
|---|---|
| 0-1 | 50 |
| 1-2 | 100 |
| 2-10 | 250 |
| 10-50 | 1000 |

  KDHE requests that modeling parameters such as stack parameters, the coordinates of the center of the facility, and coordinates of the fenceline of the facility be included in the modeling report.

- ***Section 5.8, Ambient Monitoring,*** *Table 3: NAAQS, Significance/Monitoring, and PSD Class II Increments*

  KDHE comments:

  The $PM_{2.5}$ 24-hour Significant Monitoring Concentration vacated by the United States Court of Appeals for the District of Columbia on January 22, 2013 is not considered valid in Kansas. However, representative local monitoring data is available for use.

- ***Section 5.8, Ambient Monitoring,*** *Table 4: Modeled highs*

  For $PM_{2.5}$, KDHE requests that the H1H be used for both the annual and 24-hour averaging periods, as recommended in the March 23, 2010 Memo from Stephen Page (available on EPA and KDHE web sites).

- ***Appendix B, Ozone Limiting Method Modeling Protocol for AERMOD***

  KDHE comment:

  KDHE requests that a formal submittal to EPA Region 7 be sent under separate cover, requesting approval for the OLM Protocol.

  When using OLM method, it recommended not to model "in groups" using different scenarios (or model different scenarios in one run).

If you have any questions or would like to discuss, please contact me at (785) 296-1691 or Mindy Bowman at (785) 296-6421.

Sincerely,

Susana Pjesky

C: File
Modeling

Susana C. Pjesky, Ph.D.
KDHE - Bureau of Air
1000 SW Jackson, Suite 310
Topeka, KS 66612-1366

spjesky@kdheks.gov

785.296.1691 (phone)
785.291.3953 (fax)
……..
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……. ……..

---

**From:** Daye, Richard [mailto:Daye.Richard@epa.gov]
**Sent:** Thursday, April 25, 2013 11:13 AM

**To:** Mindy Bowman
**Cc:** BAR ImageNow; Burns, Ward; Marian Massoth; Susana Pjesky
**Subject:** RE: TradeWind: Lacey Randall- Modeling Protocol

Hi Mindy,

Sorry for the delay in responding. I have a few comments.

Sec 4: The company should submit a formal request to Region 7 to use a Tier 3 analysis for NO2.

Sec 4.2: A plot plan with sufficient detail should be submitted with the final modeling in order to verify source locations and structures.

Sec 5.2: The meteorological data and the hourly background values should be for the same period.

Sec 5.5: It is not clear if the SIA will be measured from the fenced property line or from a source/location in its facility. Please clarify.

Sec 5.6: Justify that the proposed background values are representative of the Trade Wind area.

APPENDIX B:

Sec 3.4: The proposed background values are for a period different from the meteorological data (2006-2010 vs. 2007-2011).

Thanks again for letting us review the modeling protocol and pleasase call me it you have questions.

Mick

Richard L Daye
Regional Meteorologist
Environmental Protection Agency, Region 7
AWMD/APDB
11201 Renner Blvd
Lenxa, KS 66219

Tel: 913 551-7619

---

**From:** Mindy Bowman [mbowman@kdheks.gov]
**Sent:** Thursday, April 11, 2013 1:23 PM
**To:** Daye, Richard
**Cc:** BAR ImageNow; Burns, Ward; Marian Massoth; Susana Pjesky
**Subject:** FW: TradeWind: Lacey Randall- Modeling Protocol

Source ID No. 1930036

C-10593

Trade Wind Energy Lacey Randall Generation Facility

Copy to Modeling File with Attachments

Hello Mick,

We received a modeling protocol from Trade Wind Energy today for Lacey Randall Generation Facility, a proposed RICE engine facility to be located in Thomas County, near Colby, Kansas. This project will be subject to a Prevention of Significant Deterioration (PSD) review. I am forwarding the protocol for your review. KDHE respectfully requests your comments be submitted prior to April 25, to be included with the KDHE response.

If you have any questions or would like to discuss, please contact me at (785) 296-6421 or

Susana Pjesky at (785) 296-1691.

Thank you,

Mindy Bowman

---

Mindy Bowman, P.E.
Environmental Engineer
Bureau of Air
1000 SW Jackson, Suite 310
Topeka, KS 66612
Phone: (785) 296-6421
Fax: (785) 291-3953

Please note new e-mail address: MBowman@kdheks.gov

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May 30, 2013

Ms. Marion Massoth
Section Chief
Kansas Department of Health and Environment
Bureau of Air and Radiation
1000 SW Jackson, Suite 310
Topeka, KS 66612-1366

Re: Intermittent Source Status for Colby Municipal Power Plant

Dear Ms. Massoth:

Lacey Randall Generation Facility, LLC (Lacey Randall) is in the process of preparing a Prevention of Significant Deterioration (PSD) construction permit application for the installation of up to ten reciprocating internal combustion engines (RICE) plus auxiliary equipment at the Lacey Randall Station to be located in Thomas County, Kansas approximately 3 miles northeast of Colby, Kansas. The Project will have a total nominal power output of approximately 93.41 megawatts (MW) and the RICE electric generating units (EGUs) will be fired solely by natural gas. As part of this application, a dispersion modeling exercise is required to determine compliance with the 1-hour $NO_2$ National Ambient Air Quality Standard (NAAQS).

Several weeks ago, I initiated a discussion with Mindy Bowman to determine if the Colby Municipal Power Plant could be classified as an intermittent source and therefore excluded from the source inventory for the 1-hour $NO_2$ modeling exercise per EPA policy.[1] After consultation with you, Ms. Bowman informed me that the initial determination was that Colby operates as a peak shaving plant and therefore cannot be excluded.

In the intervening weeks, Lacey Randall and Burns & McDonnell have been in discussions with the City of Colby to gather additional information to support an "intermittent" classification and would like to present the following information for you in reconsideration of Colby's classification.

1. Outside legal counsel has reviewed Colby's contract with Midwest Energy and confirmed that Colby has no contractual obligation to provide power to Midwest or any other third party.
2. Historical operating hours for the six engines are shown below in Table 1 and illustrate that the facility operates much less than 100 hours per year per engine and on a random schedule that cannot be controlled.

[1] http://www.epa.gov/ttnnaaqs/aqmguide/collection/nsr/appwno2_2.pdf

**Table 1. Historical Operating Hours for the Colby Municipal Power Plant Engines.**

| Engine # | Year | | | | |
|---|---|---|---|---|---|
| | 2008 | 2009 | 2010 | 2011 | 2012 |
| 3 | 28 | 0 | 8 | 0 | 0 |
| 4 | 0 | 1 | 9 | 0 | 0 |
| 5 | 0 | 4 | 9 | 0 | 0 |
| 6 | 2 | 2 | 22 | 32 | 13 |
| 7 | 26 | 6 | 27 | 34 | 47 |
| 8 | 27 | 15 | 13 | 12 | 16 |
| **Annual Plant-wide Total** | **83** | **28** | **88** | **78** | **76** |

3. When Ms. Bowman called the power plant to discuss operating, it appears that she spoke with a person who did not understand that "peaking" has a regulatory definition that does not accurately describe the plant's operation. The plant does not operate as a peaking plant.

4. The state of Iowa (also in EPA Region VII) has recently issued revised draft modeling guidance, under which Colby would be excluded from the 1-hour $NO_2$ modeling. See http://www.iowadnr.gov/Portals/idnr/uploads/air/insidednr/stakeholder/draft_psd_modeling_guideline.pdf

   *Based on EPA guidance, the DNR has concluded that any source that operates on a purely random schedule (including testing and maintenance) and is limited to operating for no more than 500 hours/yr can be considered an intermittent source. In addition, any source that meets the 500 hour/yr criterion, but operates on a scheduled basis for testing and maintenance purposes, can be considered an intermittent source if the scheduled testing and maintenance is limited to the time of the day with the most favorable dispersion conditions (between 9 AM and 4 PM). Intermittent sources may be excluded from the 1-hour $NO_2$ and $SO_2$ NAAQS analyses. The protocol should include a discussion of how intermittent sources will be addressed. (page 6)*

5. The state of Wisconsin has also issued modeling guidance, under which Colby would be excluded from the 1-hour $NO_2$ modeling. See http://dnr.wi.gov/topic/AirPermits/documents/IntermittentSources2012.pdf

   *The 1 hour $SO_2$ and $NO_2$ standards, while being more conservative than existing SO2 or NO2 standards, are statistically derived rather than deterministic. It is unlikely that a unit would operate precisely during the hours of maximum*

> *modeled concentration, and do so often enough over the five modeled years to contribute to the deterioration of ambient air quality. Considering 50 hours to 200 hours of operation in one year (8760 hours) results in no more than a 0.6% to 2.3% chance the maximum impacts would overlap; it is 98% to 99% likely the maximum modeled concentrations will be the same whether or not the intermittent unit is included in dispersion modeling.*
>
> *In conjunction with the USEPA document cited previously, dispersion modeling for intermittent units WILL NOT BE performed for any of the State or Federal ambient air quality standards or increments.*

On behalf of Lacey Randall, I ask that you reconsider and classify the Colby Municipal Power Plant as an intermittent source exempt from inclusion in the 1-hour $NO_2$ NAAQS modeling exercise.

Please contact me at randracsek@burnsmcd.com or 816-822-3596 if you have any question or if you would like to discuss this issue further.

Sincerely,

Robynn Andracsek

Robynn Andracsek, P.E.
Associate Environmental Engineer

cc: Mindy Bowman, KDHE
Brice Barton, Jenni Dean- TradeWind Energy, Inc.

| | |
|---|---|
| **From:** | Mindy Bowman |
| **To:** | Andracsek, Robynn |
| **Cc:** | Marian Massoth; Susana Pjesky; Daye.Richard@epamail.epa.gov; Ward Burns (burns.ward@epa.gov); BAR ImageNow |
| **Subject:** | FW: Colby Municipal Power Plant |
| **Date:** | Tuesday, June 25, 2013 10:58:36 AM |
| **Attachments:** | kdhe letter re colby power plant.pdf |

---

TradeWind Lacey Randall Generating Station
Source ID No. 1930036
C-10593
Modeling File with attachment

Dear Ms. Andracsek,

Per you letter dated May 30, KDHE has reviewed your request to exclude Colby Municipal Power Plant, Source ID No. 1930007, from nearby source modeling for the proposed TradeWind Lacey Randall Generation Facility, LLC.

After working with the facility, we have learned that three of the engines (Units 3, 4, and 5) will be operated for emergency use only. These engines may be excluded from modeling short term standards, including 1-hour NO2. Units 6, 7, and 8 will continue to operate to provide power as needed under a contract with Midwest Energy in Hays (with very limited hours of operation), and should be included when modeling short term standards, including 1-hour NO2.

If you have questions, feel free to call or email.

Sincerely,

Mindy Bowman

---

Mindy Bowman, P.E.
Environmental Engineer
Bureau of Air
1000 SW Jackson, Suite 310
Topeka, KS 66612
Phone: (785) 296-6421
Fax: (785) 291-3953

Please note new e-mail address: MBowman@kdheks.gov

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**From:** Power Plant [mailto:pwrplant@cityofcolby.com]
**Sent:** Tuesday, June 25, 2013 10:09 AM
**To:** Mindy Bowman
**Subject:** RE: Colby Municipal Power Plant

Looks good!
Greg

---

**From:** Mindy Bowman [mailto:mbowman@kdheks.gov]
**Sent:** Tuesday, June 25, 2013 9:59 AM
**To:** 'pwrplant@cityofcolby.com'
**Cc:** Marian Massoth; Susana Pjesky; Jessica Webb
**Subject:** RE: Colby Municipal Power Plant

Greg Ellis
Plant Superintendant
Colby Municipal Power Plant
Source ID No. 1930007

Hi Greg,

Thanks for answering my follow up questions this morning. My understanding of our conversation is as follows, concerning operation of Colby Municipal Power Plant:

Units 4 and 5 are operated as black start engines.
Unit 3 is operated as a "makeup engine", meaning it is only operated if Units 6, 7, and 8 are unable to generate enough power. It has operated 54 hours total in the last 10 years.

For future compliance with 40 CFR Part 63, Subpart ZZZZ, Colby Municipal Power Plant currently plans to list engines 3, 4, and 5 as emergency use engines, although a formal commitment has not been made.

Could you send a response and let me know if this is correct? Thanks so much for all your help.

Sincerely,

Mindy Bowman

_____

Mindy Bowman, P.E.
Environmental Engineer
Bureau of Air
1000 SW Jackson, Suite 310
Topeka, KS 66612
Phone: (785) 296-6421
Fax: (785) 291-3953

Please note new e-mail address: MBowman@kdheks.gov

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**From:** Power Plant [mailto:pwrplant@cityofcolby.com]
**Sent:** Tuesday, June 18, 2013 11:50 AM
**To:** Mindy Bowman
**Subject:** RE: Colby Municipal Power Plant

Mindy,

The engine hours are correct.
We also run for our or Midwest Energy none peak maintenance issues.
When we do run peak they can call us to be on by 11:00 AM to when the load drops enough to shut down. Sometimes it can be as late as Midnight.
I see no changes in the way we do things for the future.
Basically Midwest Energy counts on our capacity to run so we can have a cheaper energy rate.
I hope this is helpful.
Greg

---

**From:** Mindy Bowman [mailto:mbowman@kdheks.gov]
**Sent:** Tuesday, June 18, 2013 10:30 AM
**To:** 'PWRplant@cityofcolby.com'
**Cc:** Susana Pjesky; Marian Massoth
**Subject:** Colby Municipal Power Plant

Greg Ellis
Plant Superintendant
Colby Municipal Power Plant
Source ID No. 1930007

Hi Greg,

Thanks for talking with me this morning about how your plant operates. I am writing this email to summarize our discussion, and I am hoping you can confirm that I summarized correctly, or make some corrections if needed.

A consultant for Tradewind Energy, Lacey Randall Generation Facility, which is a 100 MW power plant proposed to be in Thomas County, provided the following data concerning hours of operation at Colby Municipal Power Plant (Colby MPP). Could you confirm that these hours are representative of plant operations for the past 5 years?

Table 1. Historical Operating Hours for the Colby Municipal Power Plant Engines

| | Year | | | | |
|---|---|---|---|---|---|
| Engine # | 2008 | 2009 | 2010 | 2011 | 2012 |
| 3 | 28 | 0 | 8 | 0 | 0 |
| 4 | 0 | 1 | 9 | 0 | 0 |
| 5 | 0 | 4 | 9 | 0 | 0 |
| 6 | 2 | 2 | 22 | 32 | 13 |
| 7 | 26 | 6 | 27 | 34 | 47 |
| 8 | 27 | 15 | 13 | 12 | 16 |
| Annual Plant-wide Total | 83 | 28 | 88 | 78 | 76 |

The following is a summary of my understanding of how you operate your plant:

- Colby MPP has a contract with Midwest Energy in Hays.
- If Midwest Energy needs power, they contact Colby MPP, and Colby MPP starts up and provides power as needed. There are no set hours, Colby runs only on an as needed basis.
- An example of when Colby MPP might run is as follows. On a hot day, Midwest Energy in Hays needs power, and calls and Colby MPP starts up. Colby MPP might run from 11 am – 7 pm.
- Midwest Energy typical asks Colby MPP to run about twice a year (2 days). Colby MPP might be put "on alert", which means be ready to run, more frequently.
- If Midwest Energy asks Colby MPP to run, Colby MPP could not say no, unless a catastrophic equipment failure occurred.
- Colby MPP normally only runs Engines 6, 7, and 8, although the other engines could run.

Is this correct?

One more thing, does Colby plan to continue to operate the MPP pretty much the same in the future?

I really appreciate all your help, thank you.

Sincerely,

Mindy Bowman

_____

Mindy Bowman, P.E.
Environmental Engineer
Bureau of Air
1000 SW Jackson, Suite 310
Topeka, KS 66612
Phone: (785) 296-6421
Fax: (785) 291-3953

Please note new e-mail address: MBowman@kdheks.gov

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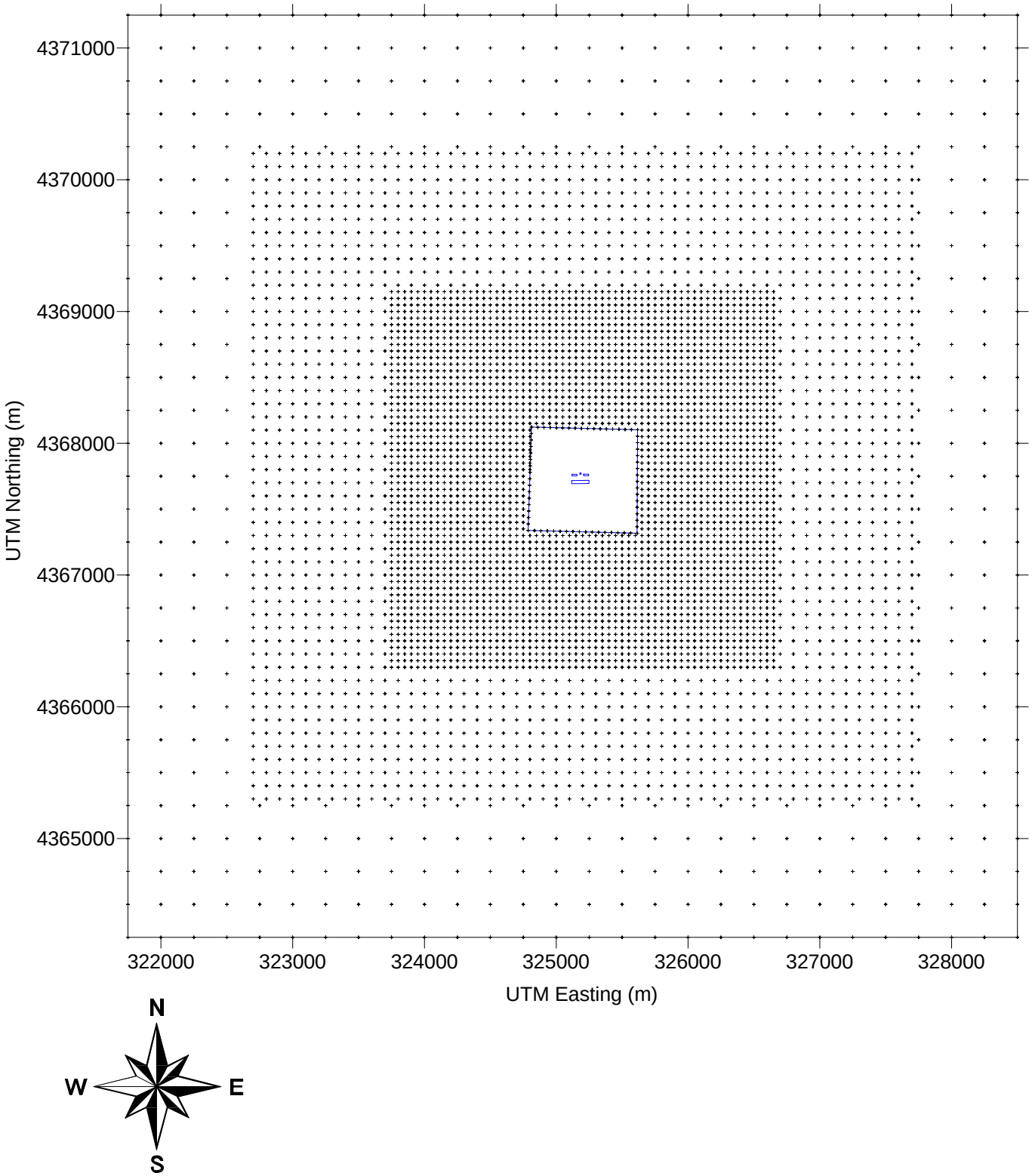
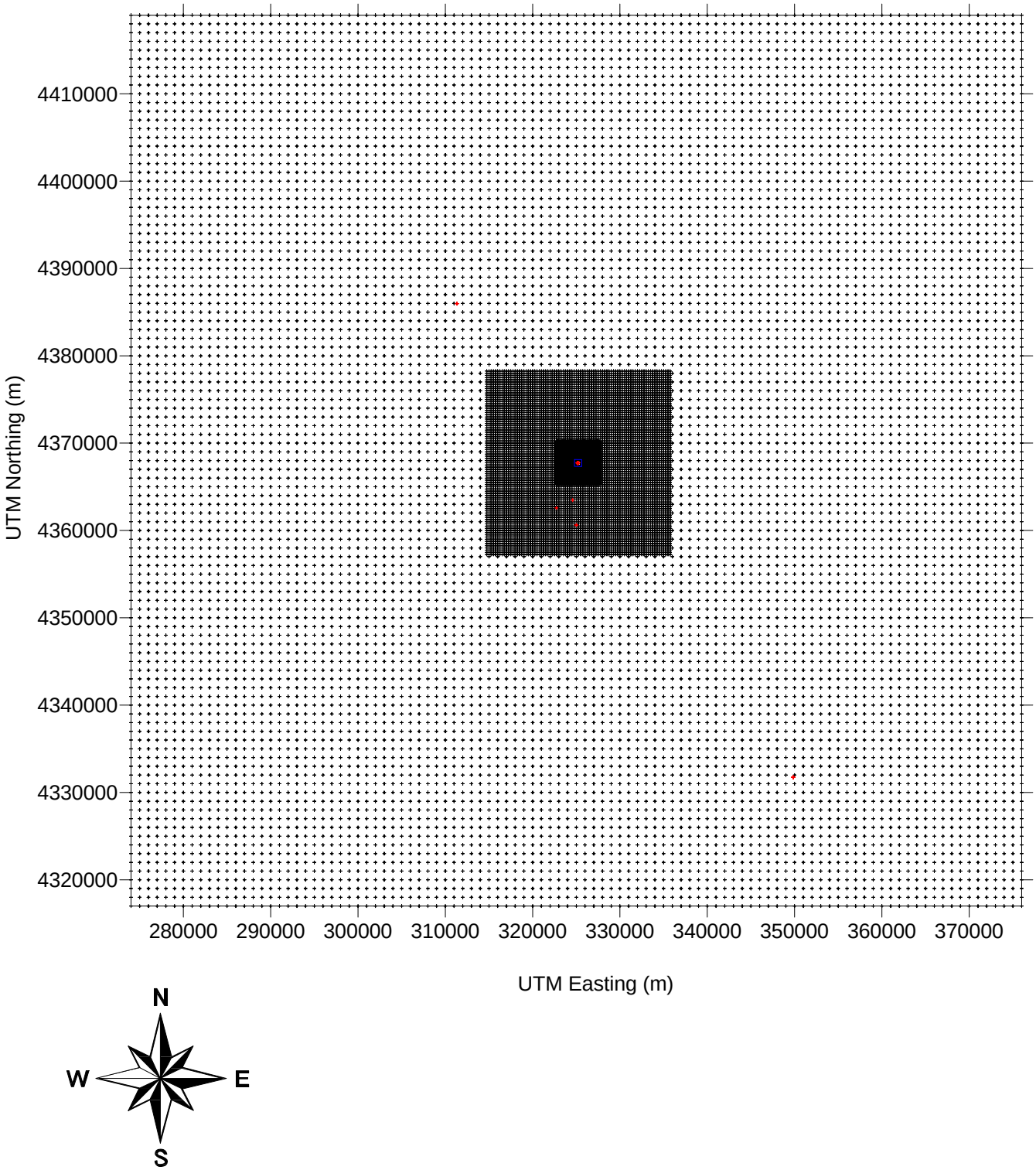
# APPENDIX G - FIGURES

# Figure 7-1: 7 km by 7 km Cartesian Grid



# Figure 7-2: 50 km by 50 km Cartesian Grid

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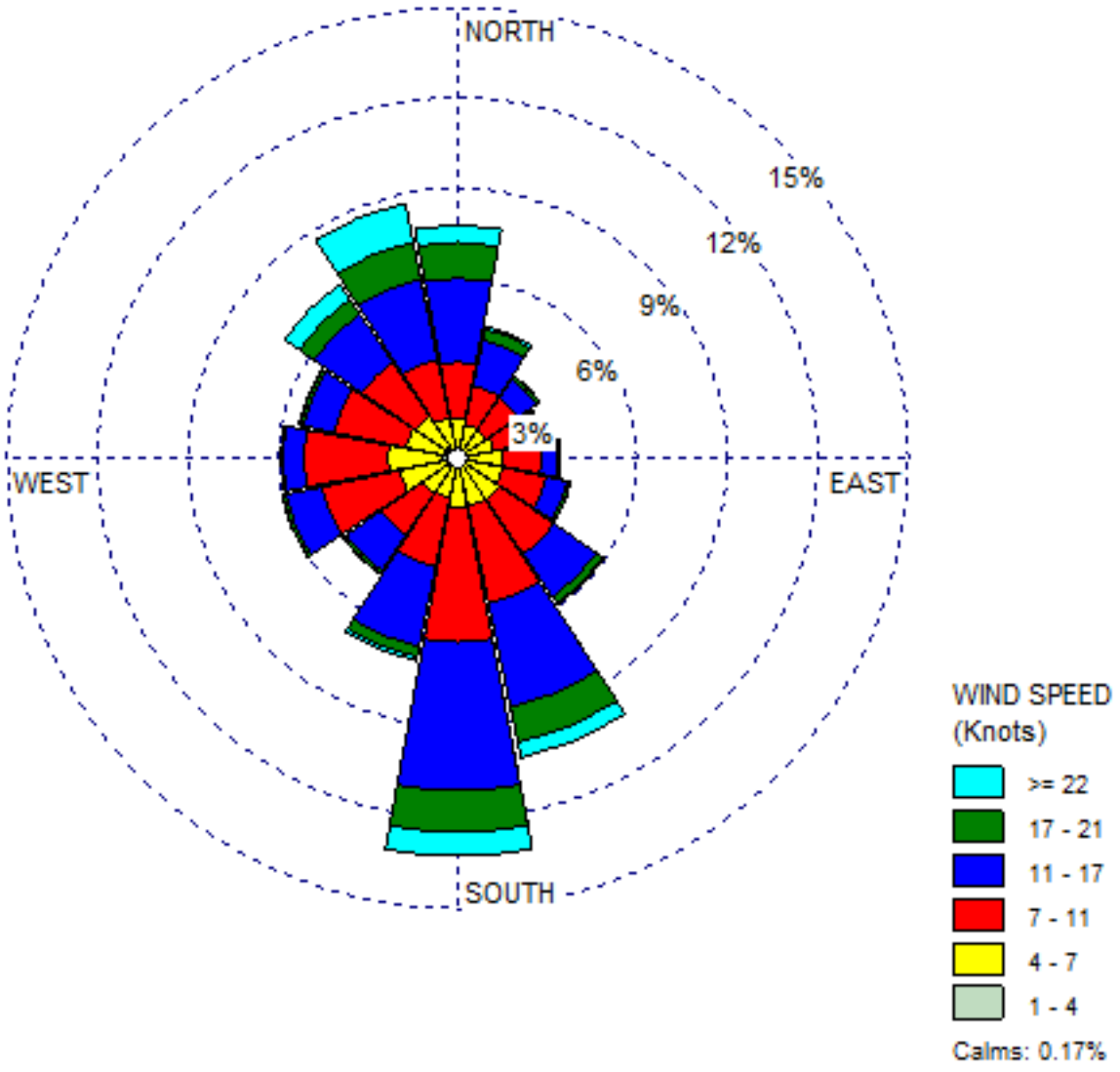
## Figure 7-3: Wind Speed and Wind Direction for Years 2007 to 2011

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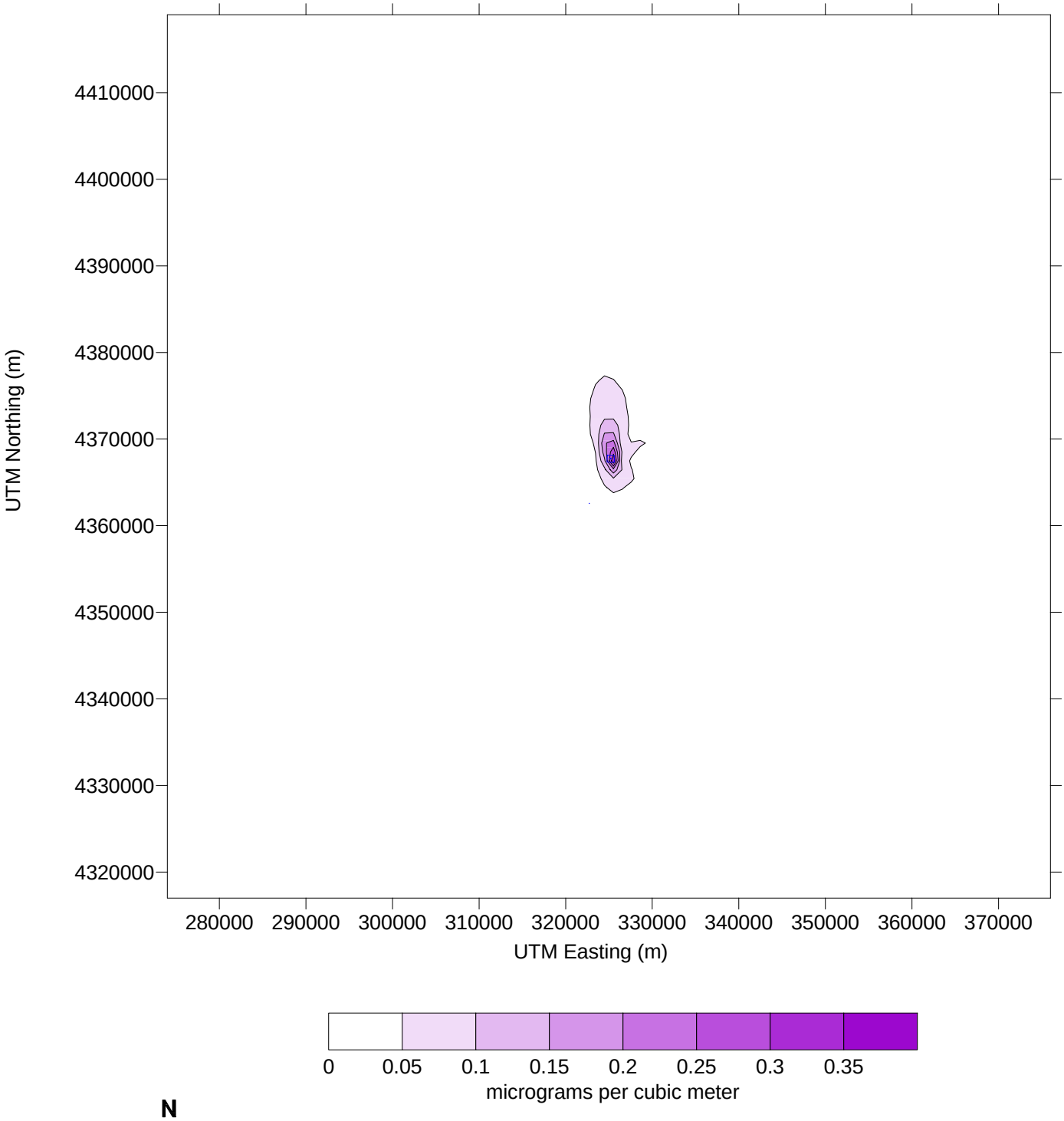
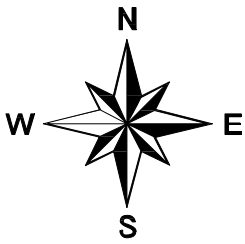
# Figure 7-4: NO2 Annual Significance

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# Figure 7-5: NO2 1-hour Significance

UTM Northing (m)

UTM Easting (m)

micrograms per cubic meter

N

W

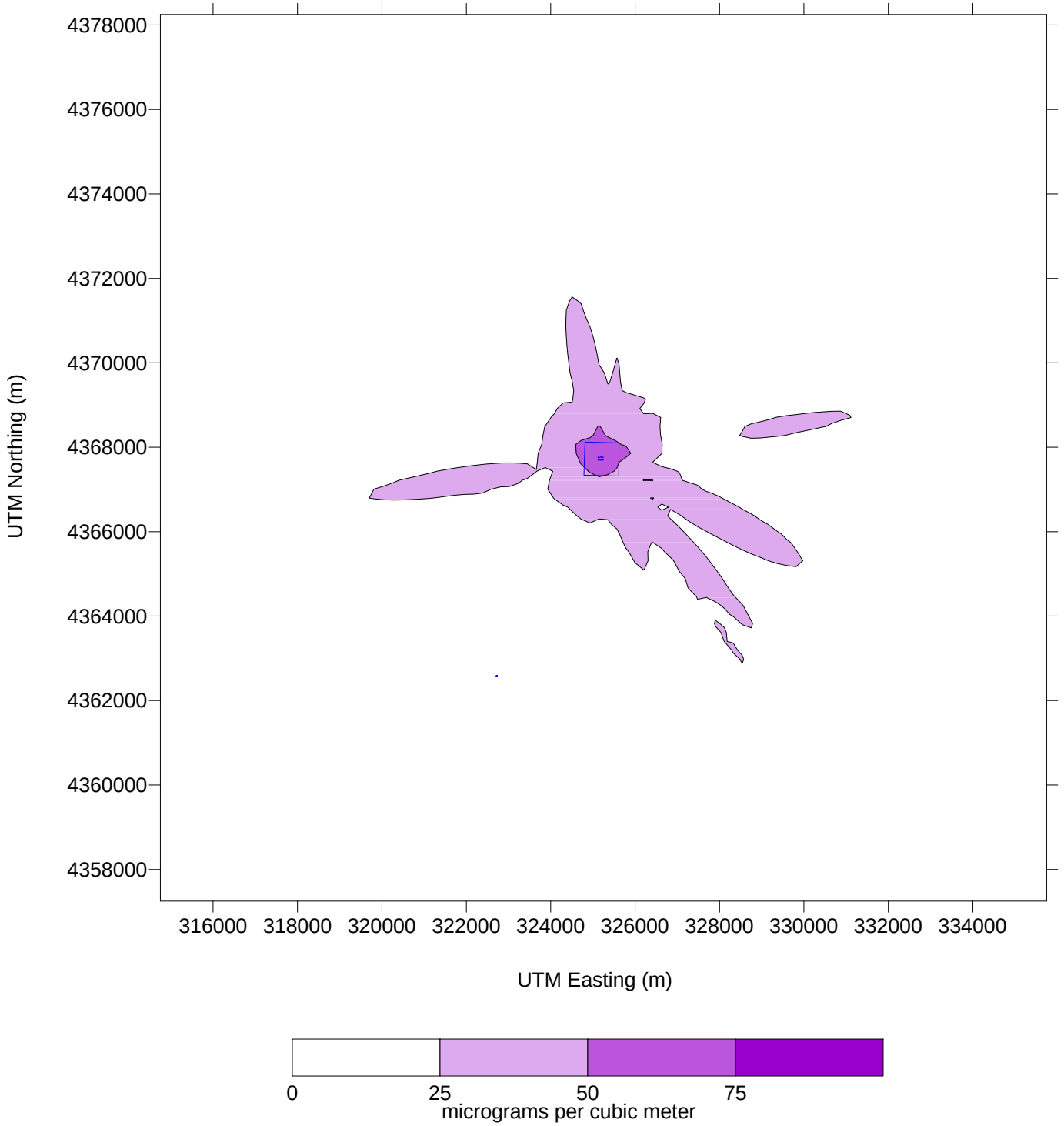
E

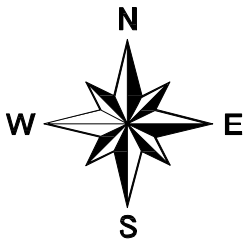
S

Burns & McDonnell

SINCE 1898

# Figure 7-6: CO 1-hr Significance

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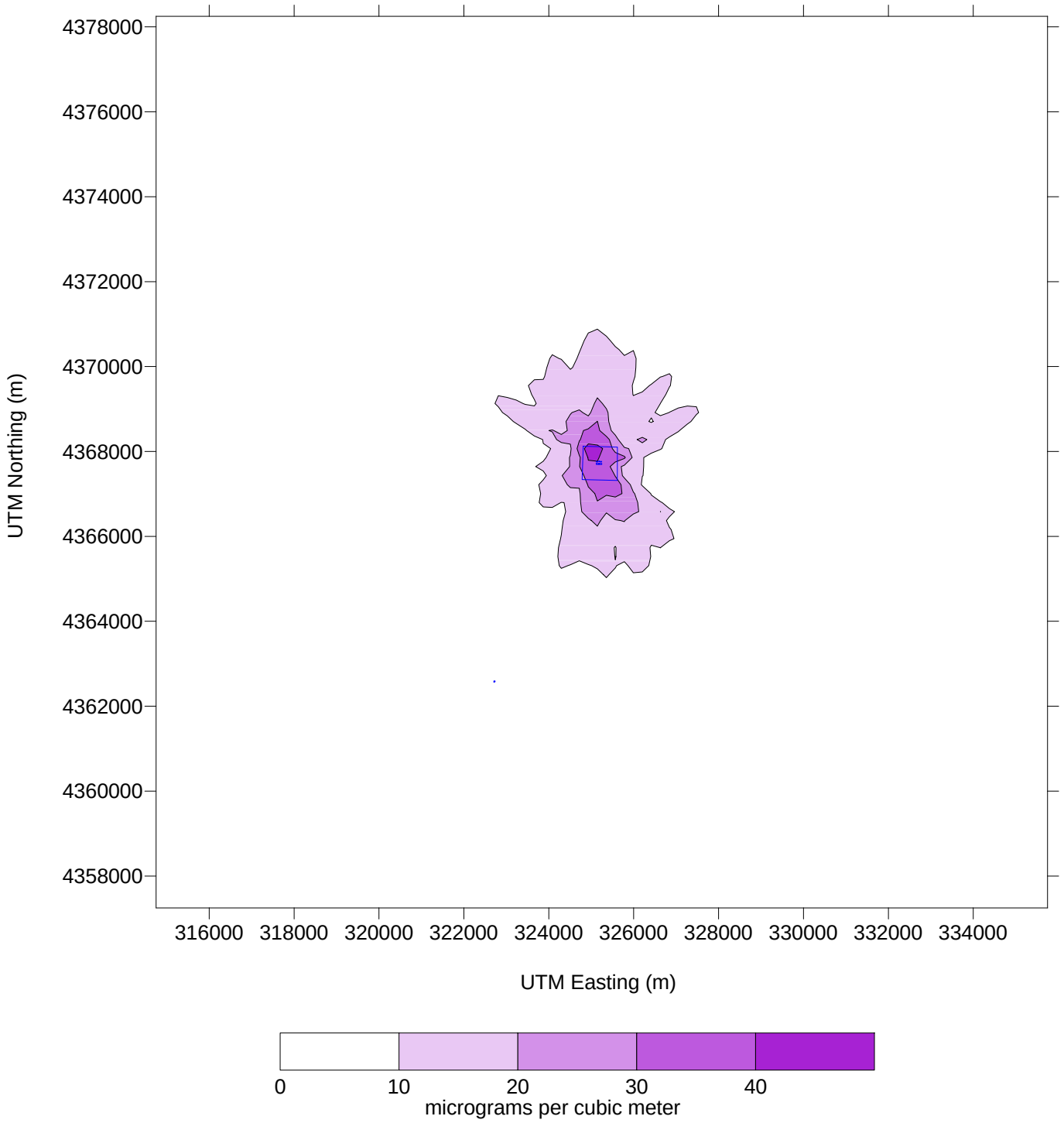
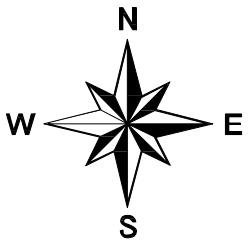
# Figure 7-7: CO 8-hr Significance

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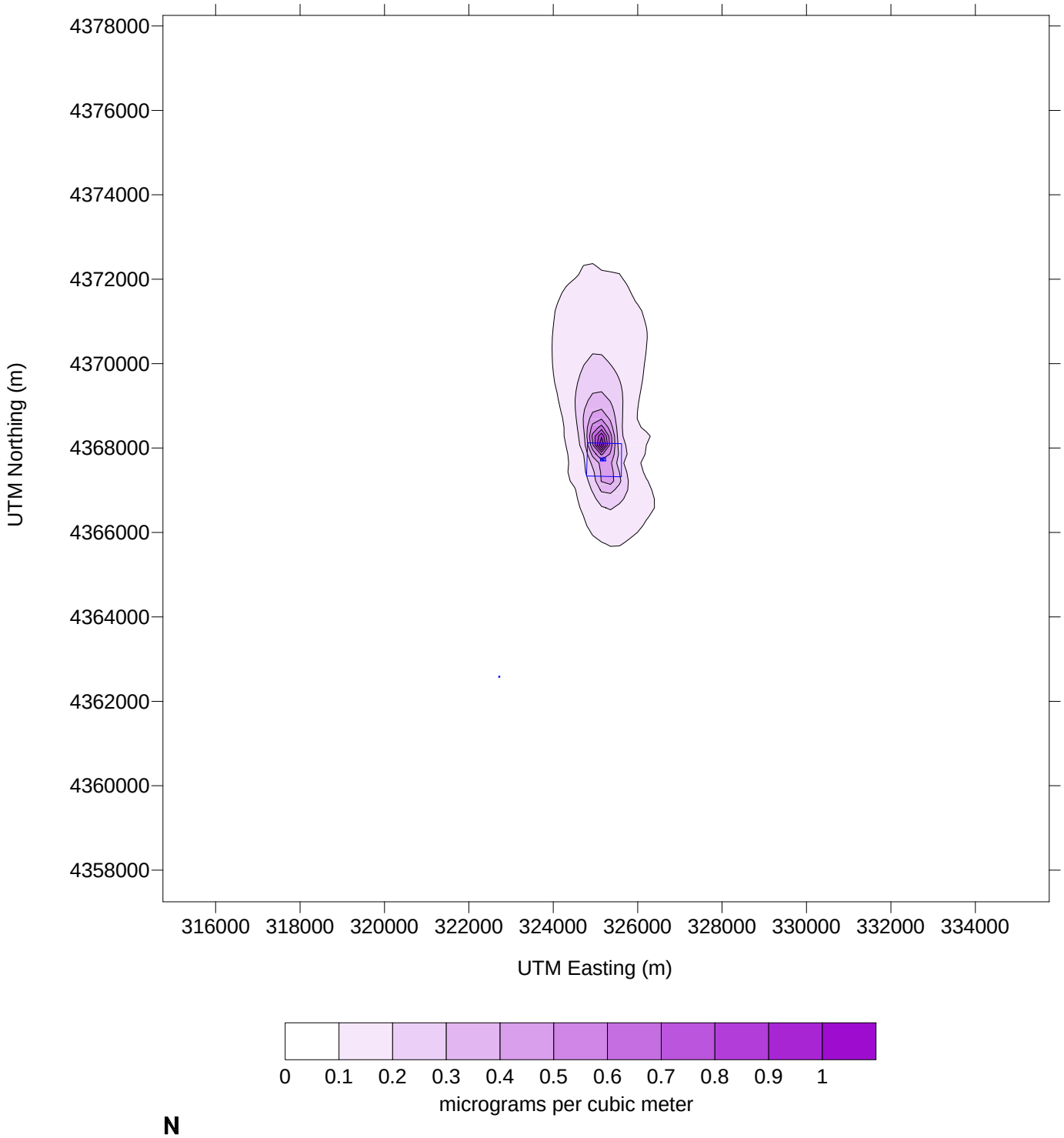
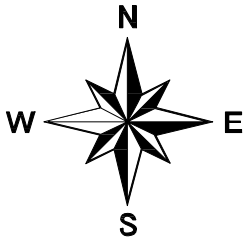
# Figure 7-8: PM10 Annual Significance

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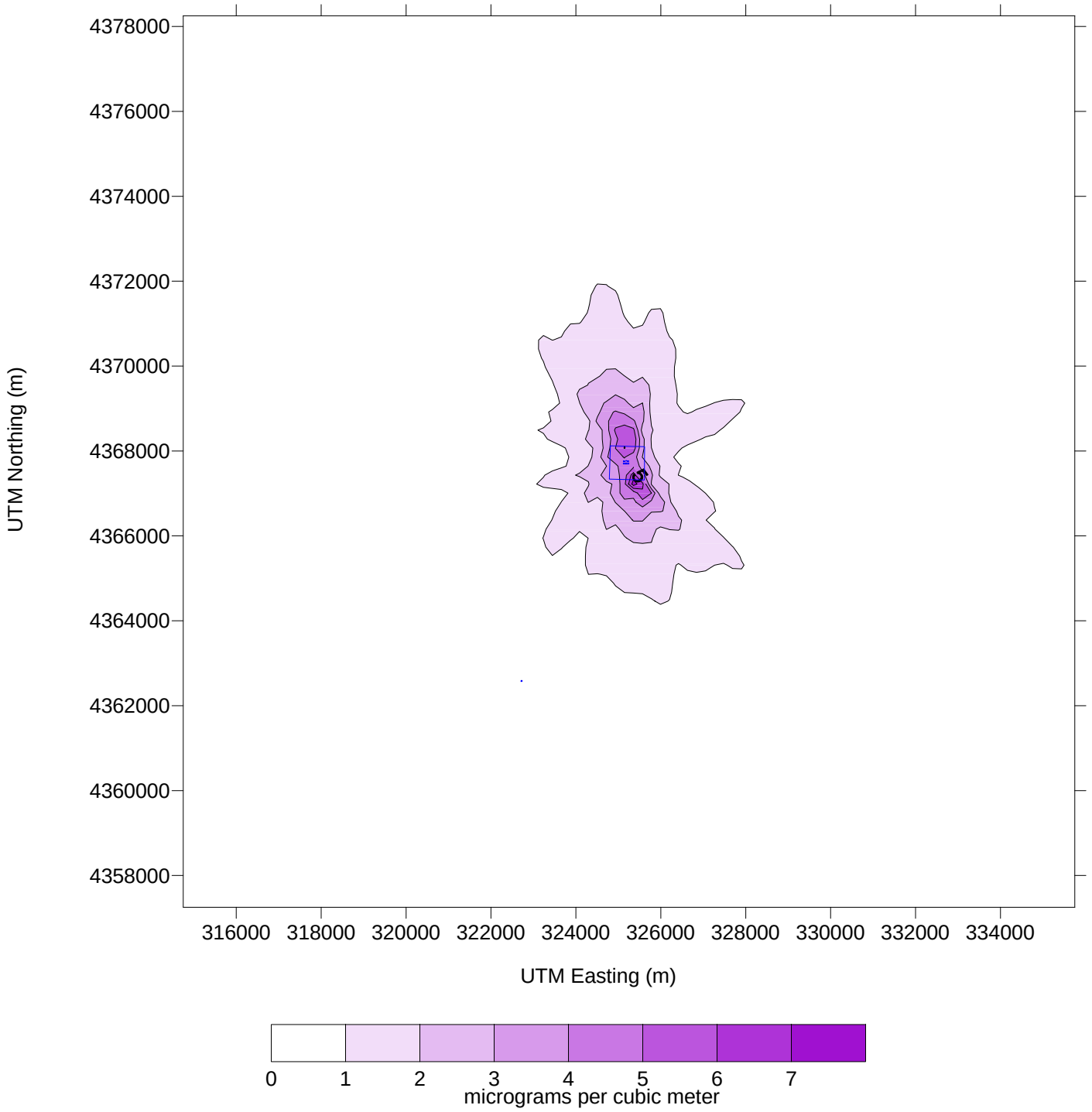
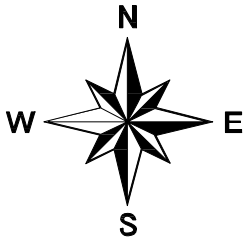
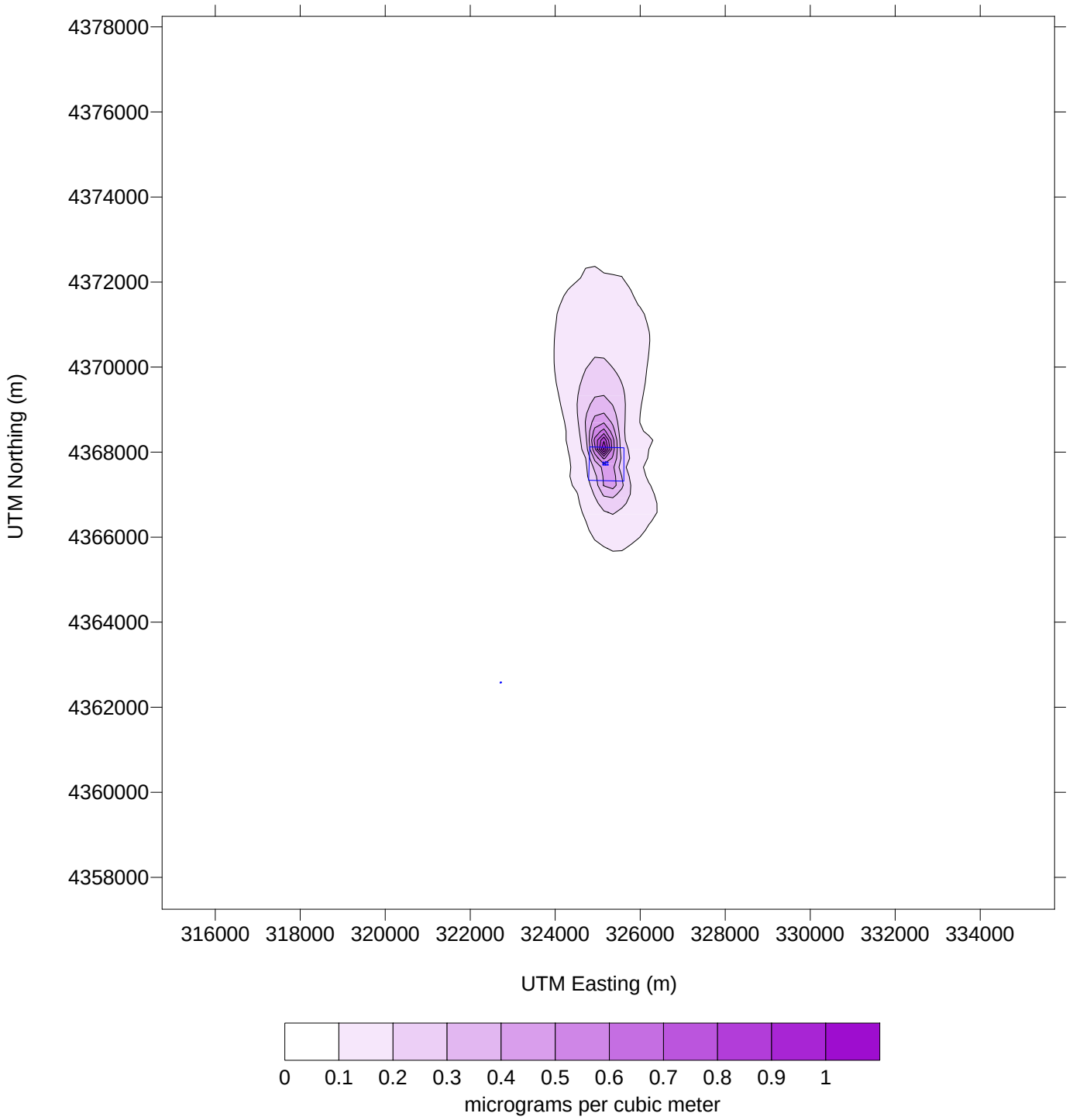
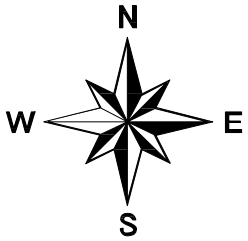
# Figure 7-9: PM10 24-hour Significance



# Figure 7-10: PM2.5 Annual Significance

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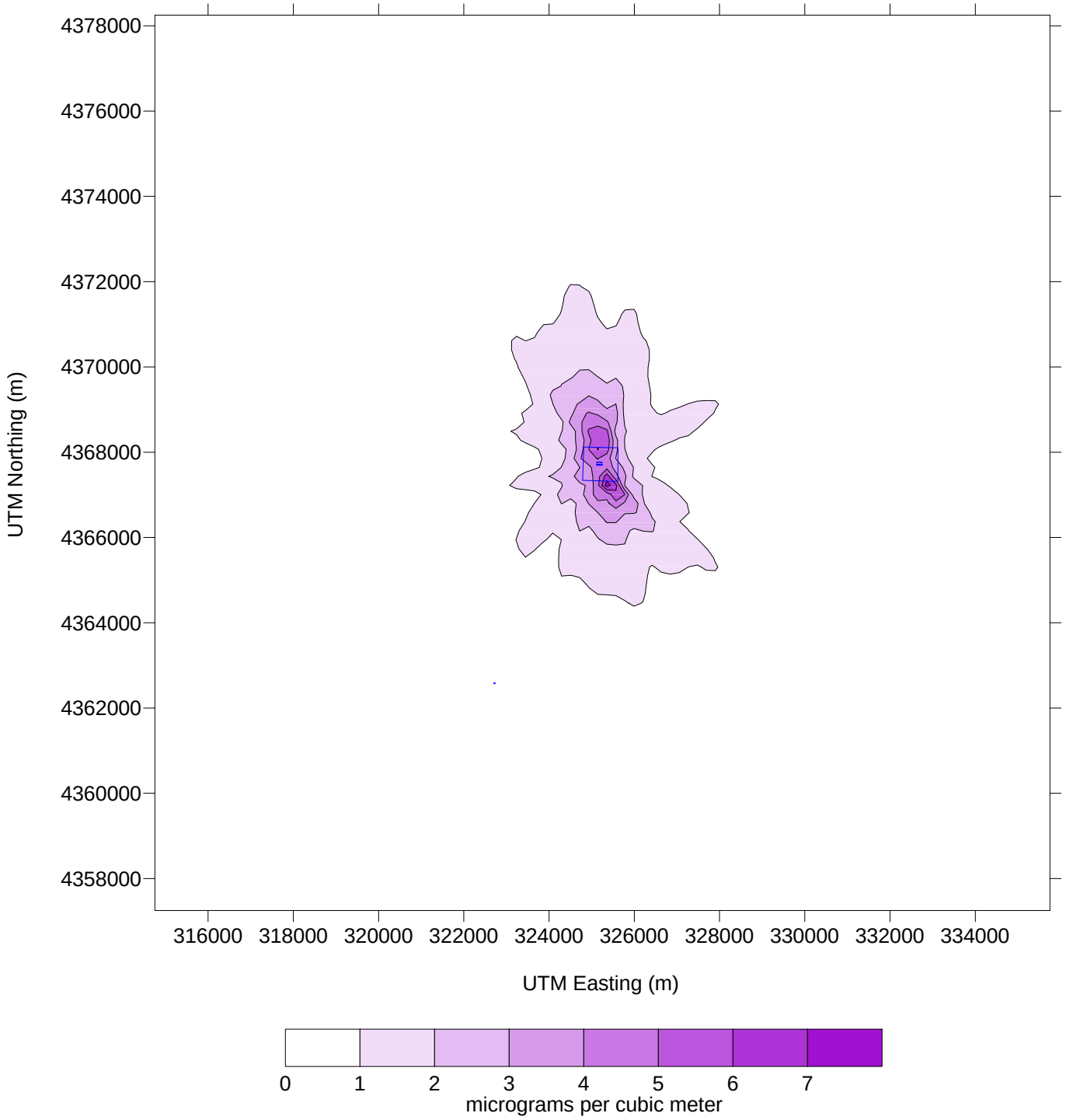
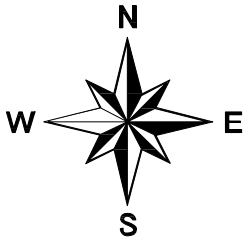
# Figure 7-11: PM2.5 24-hour Significance

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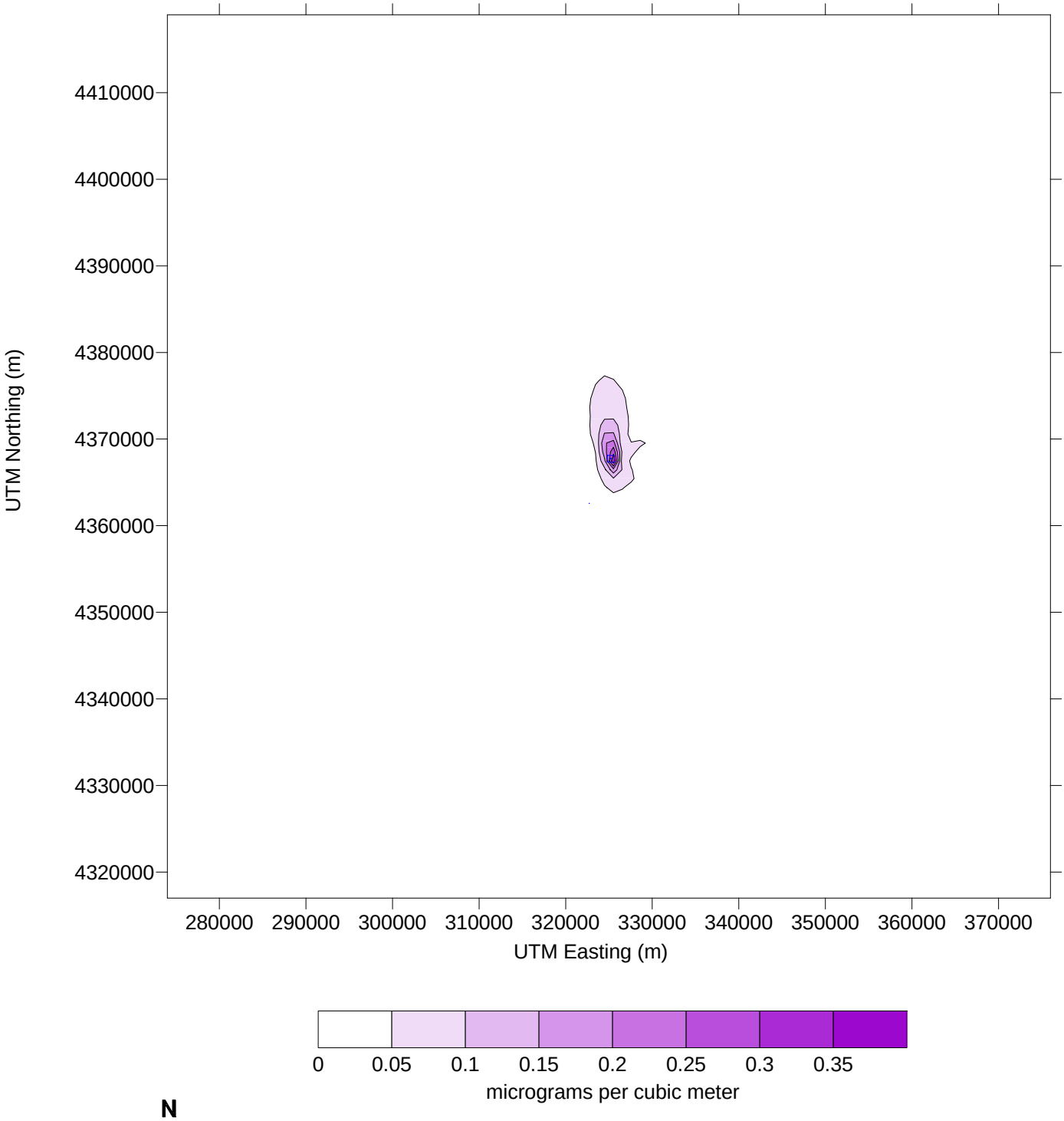
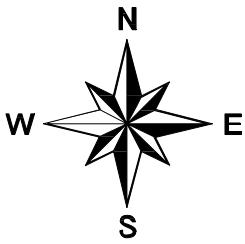
# Figure 7-12: NO2 Annual Increment

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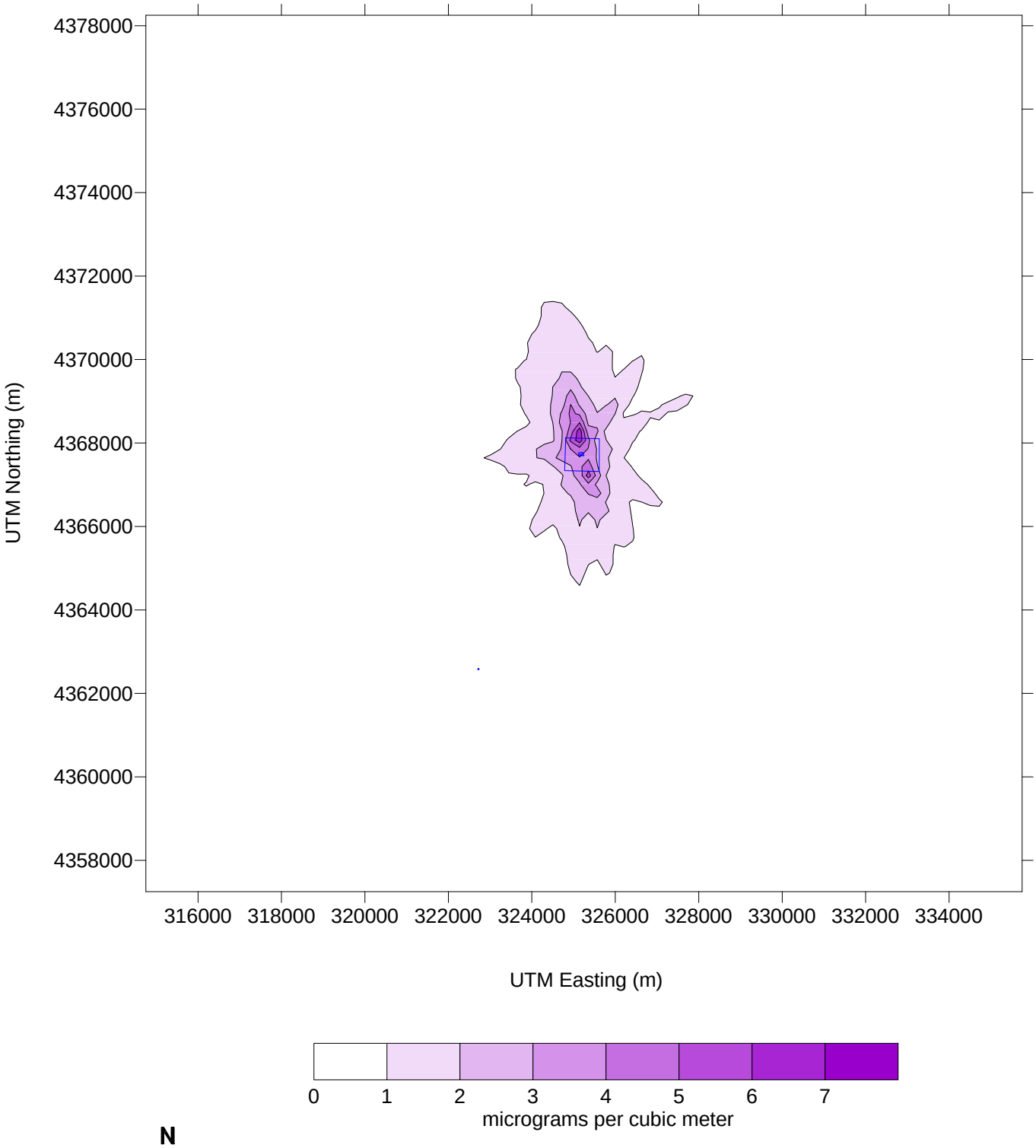
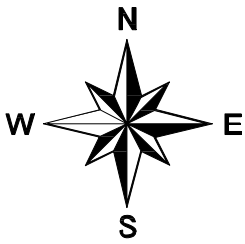
# Figure 7-13: PM10 24-hour Increment

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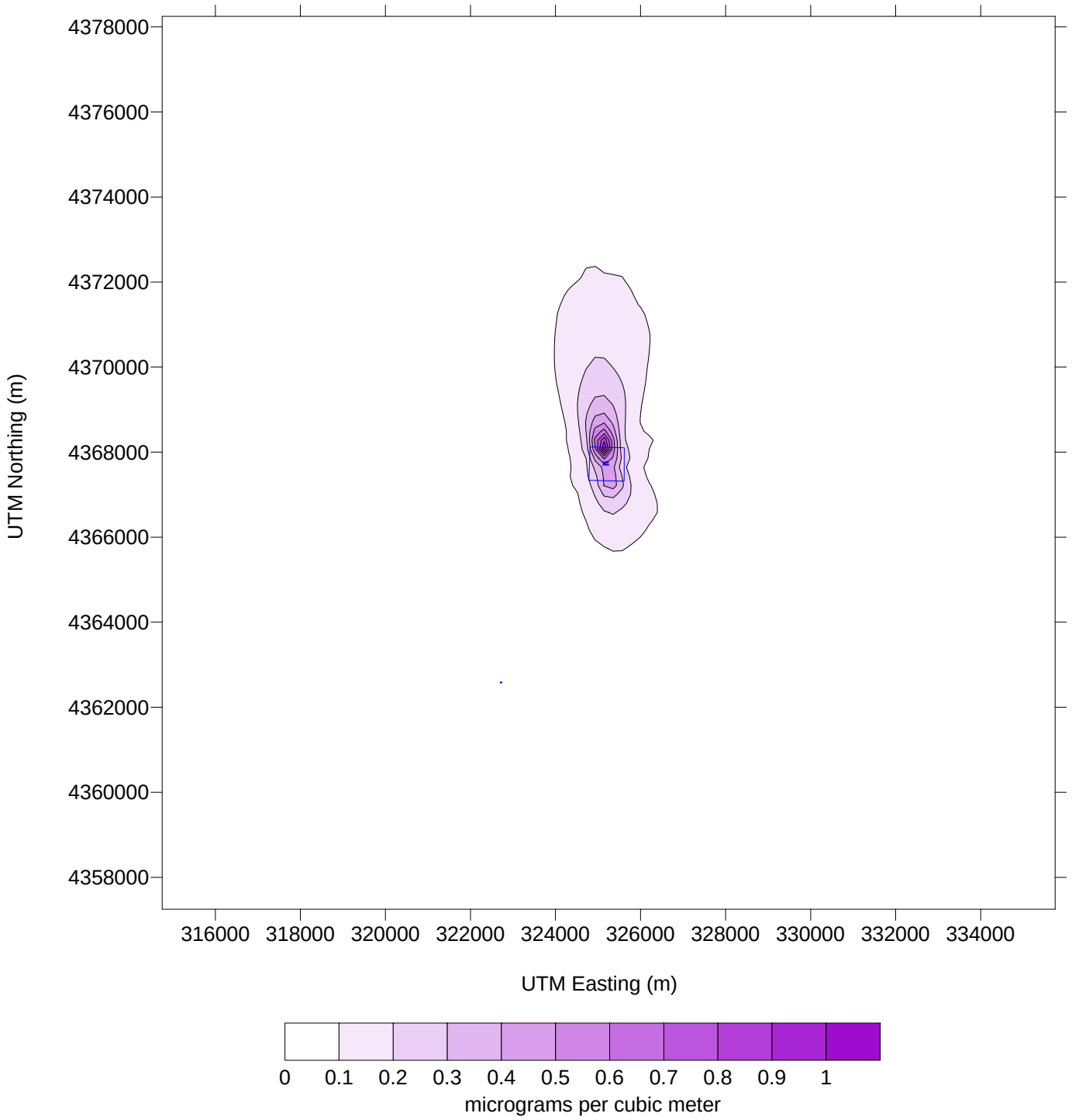
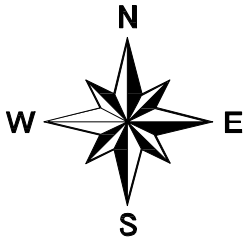
# Figure 7-14: PM2.5 Annual Increment

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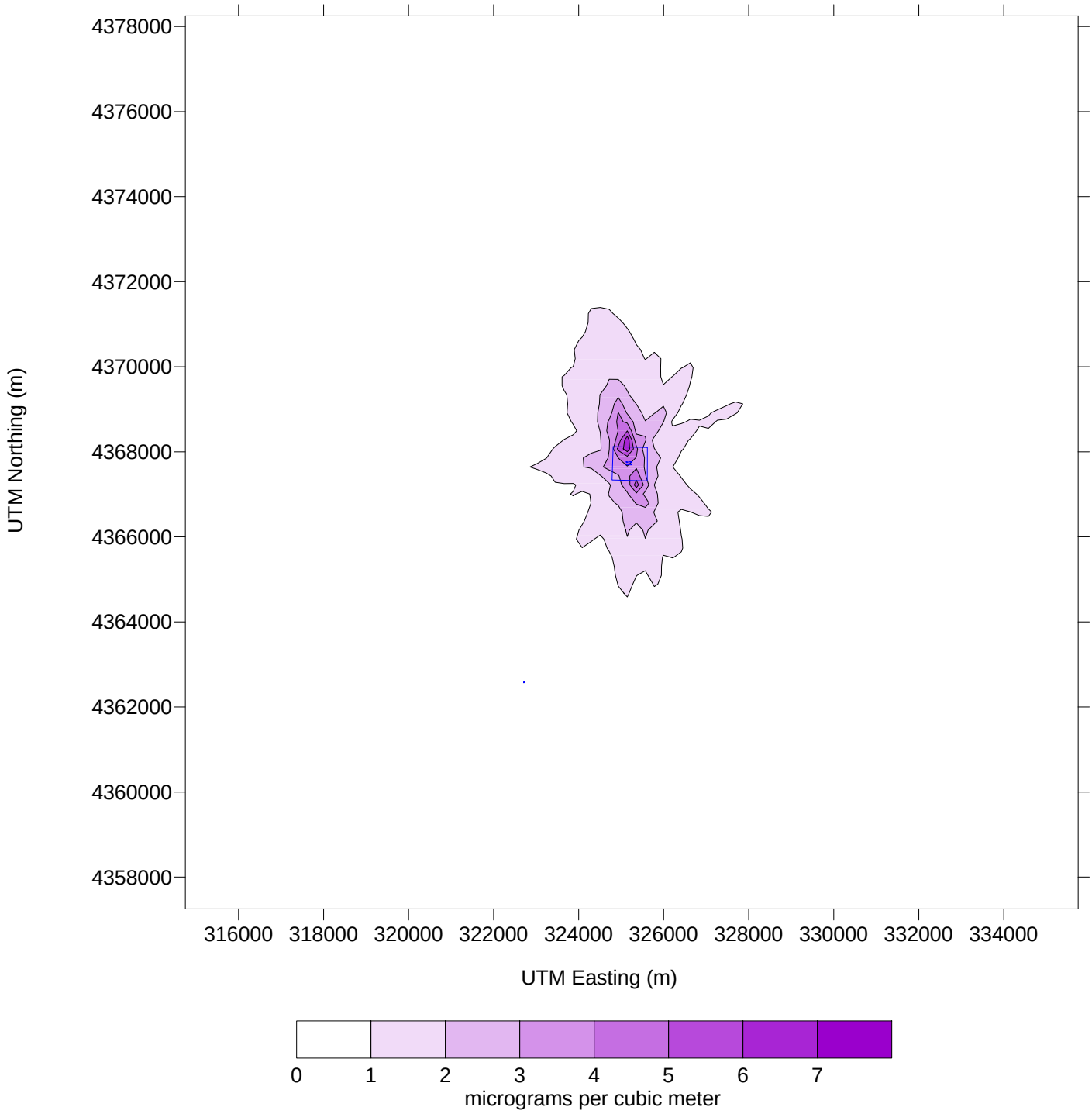
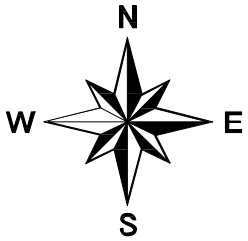
# Figure 7-15: PM2.5 24-hour Increment

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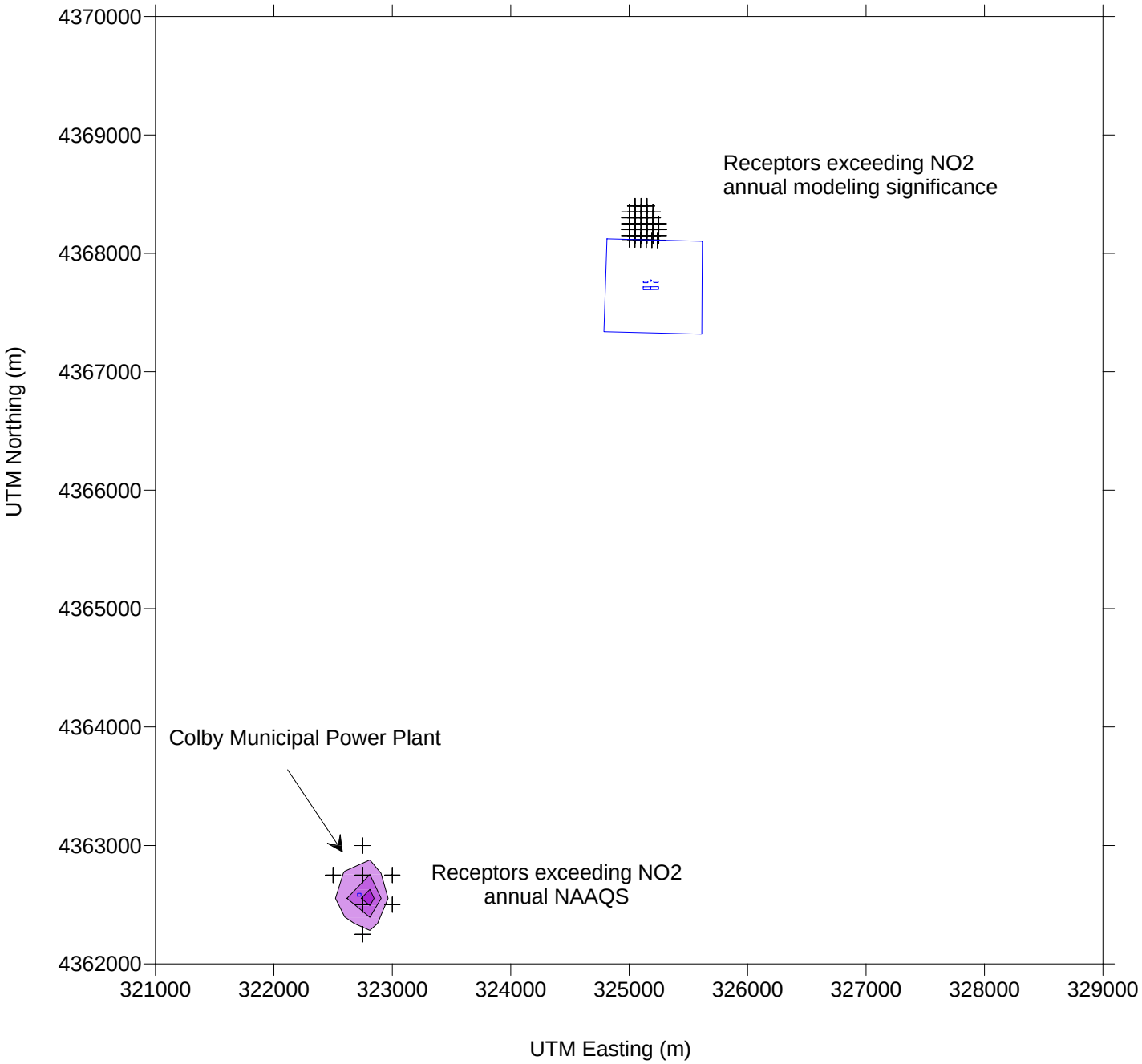
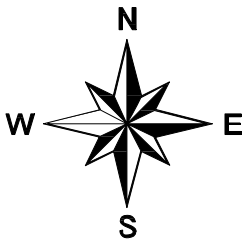
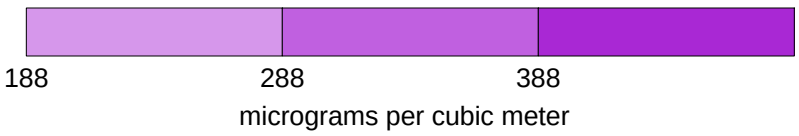
# Figure 7-16: NO2 Annual NAAQS




Background Included in Contours

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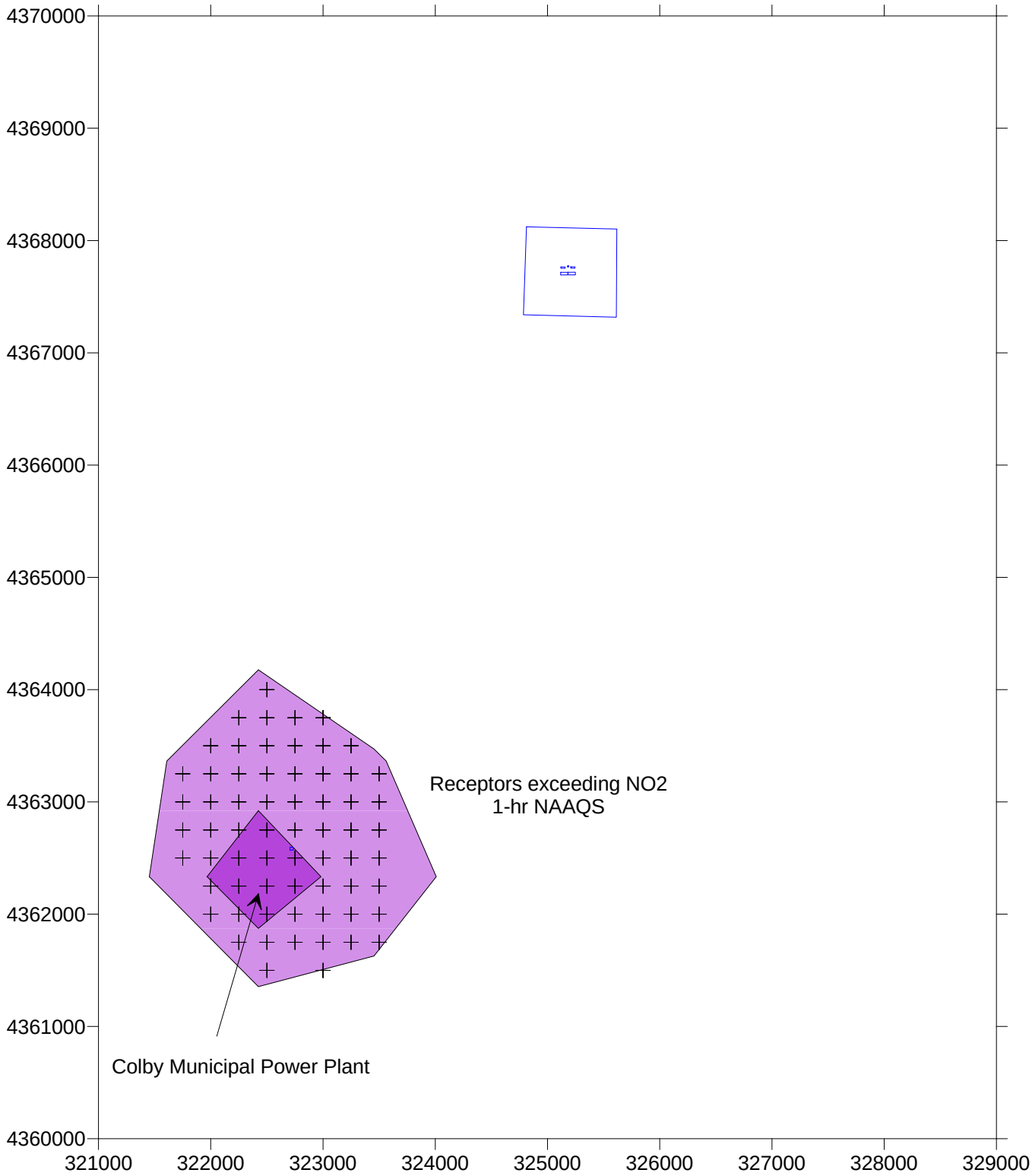
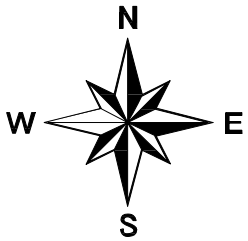
# Figure 7-17: NO2 1-hour NAAQS



micrograms per cubic meter

Background Included in Contours

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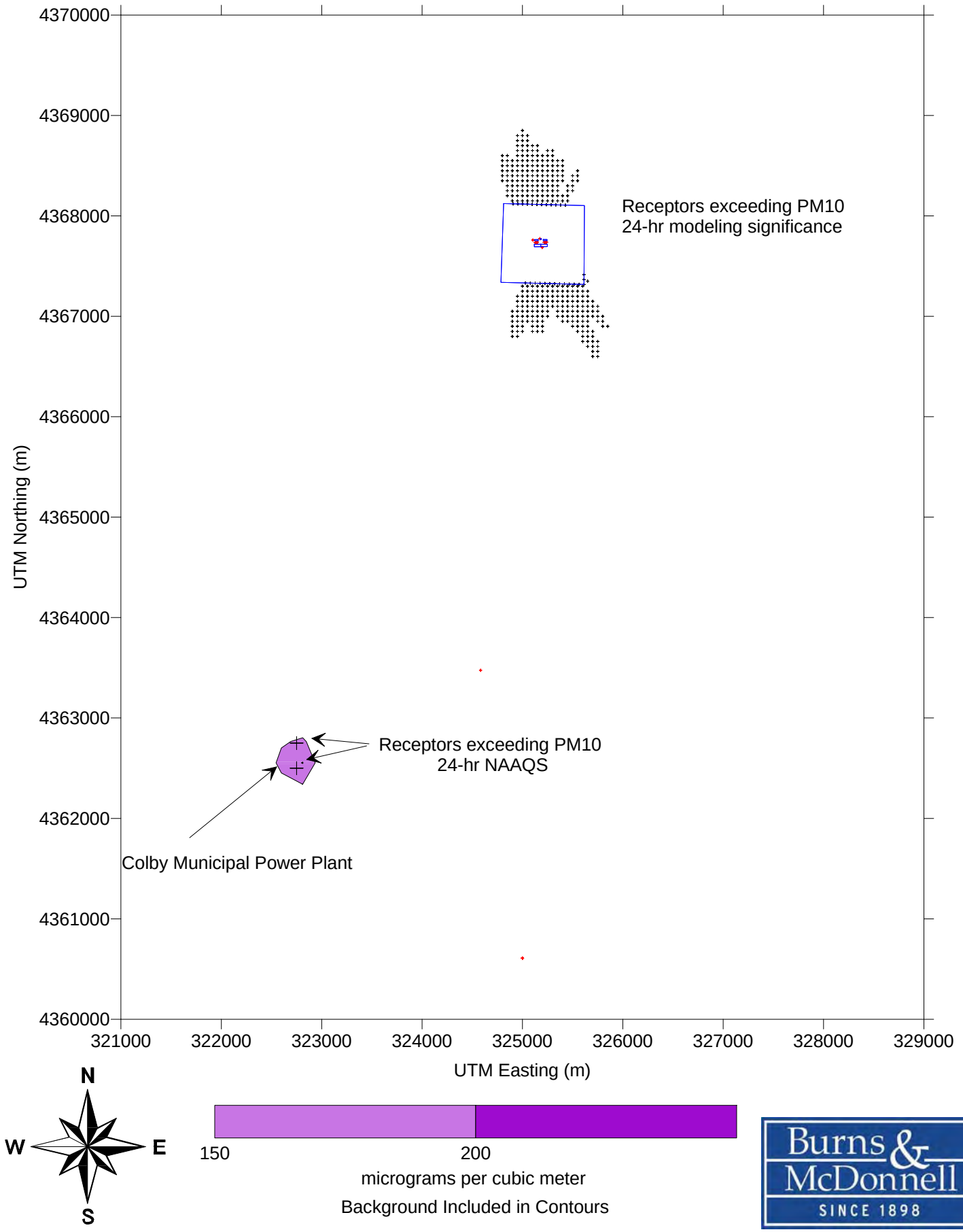
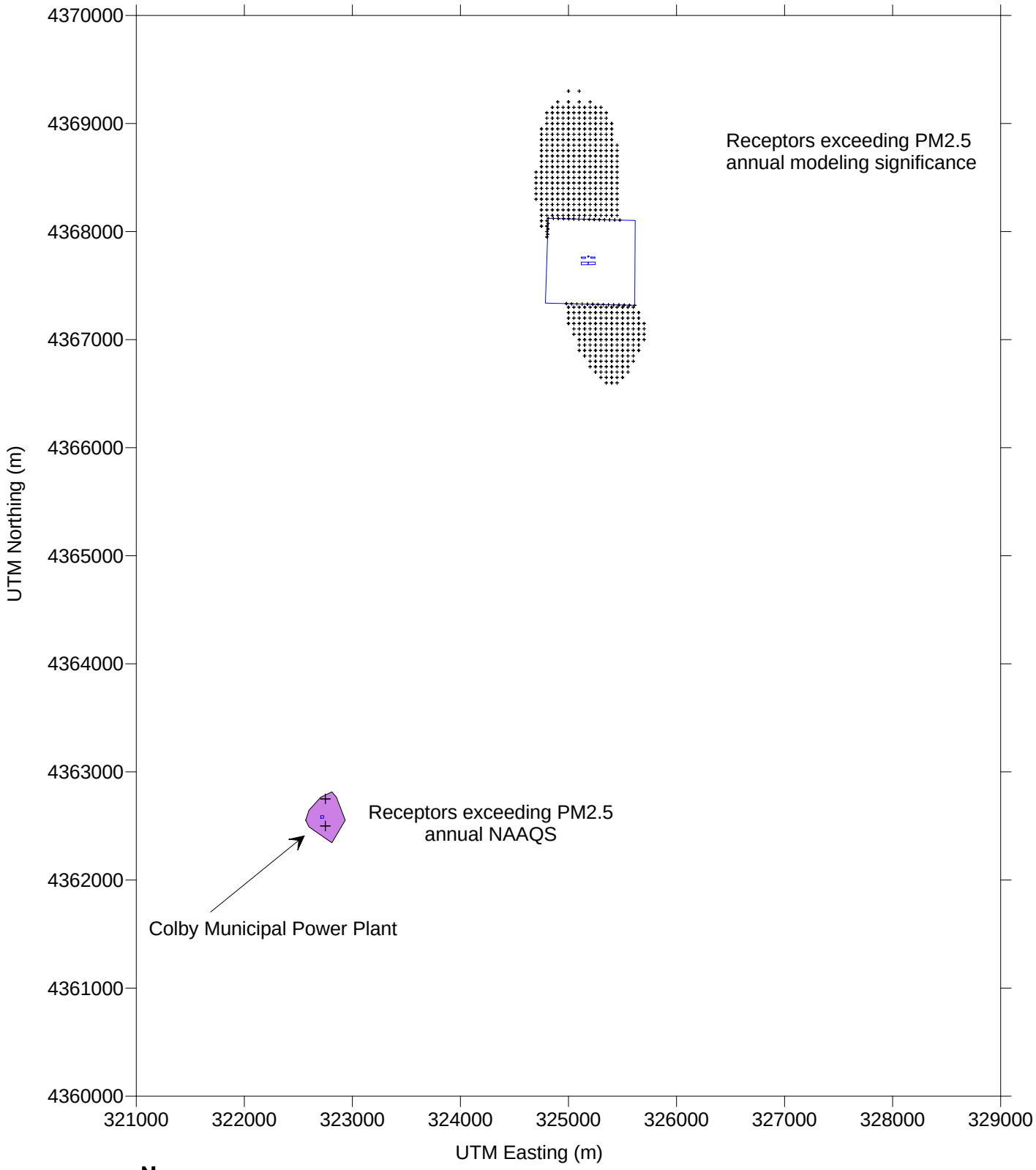
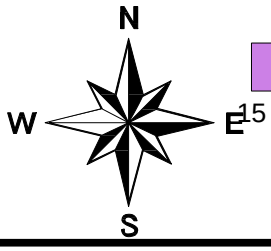
# Figure 7-18: PM10 24-hour NAAQS



# Figure 7-19: PM2.5 Annual NAAQS



micrograms per cubic meter

Background Included in Contours

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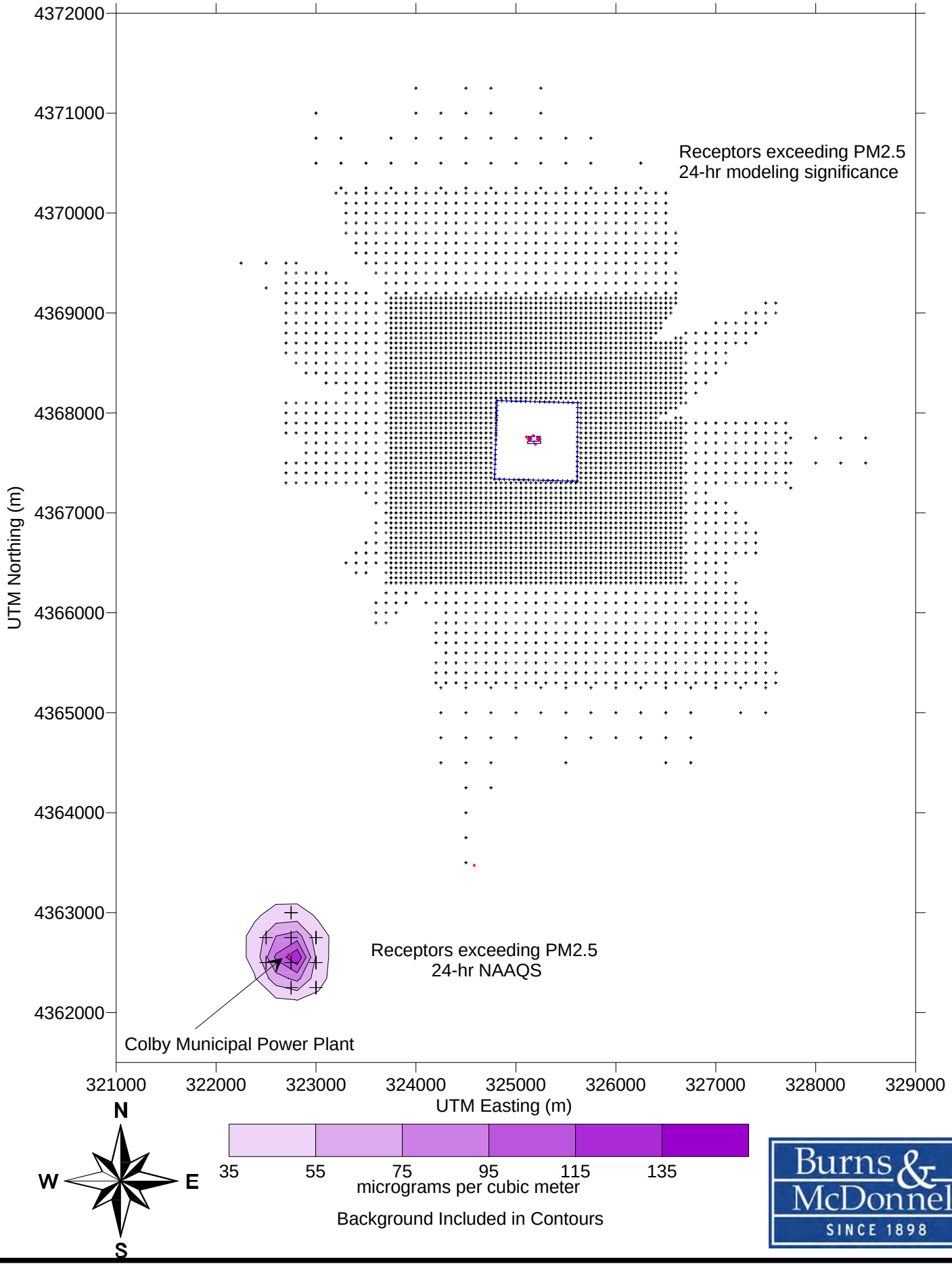
# Figure 7-20: PM2.5 24-hour NAAQS

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Path: V:\Tradewind Energy\72125-Lacey_Randall\GIS\DataFiles\ArcDocs\Figure_7_22_Lacey_Randall_Overview_Figure.mxd kstaver 12/10/2013

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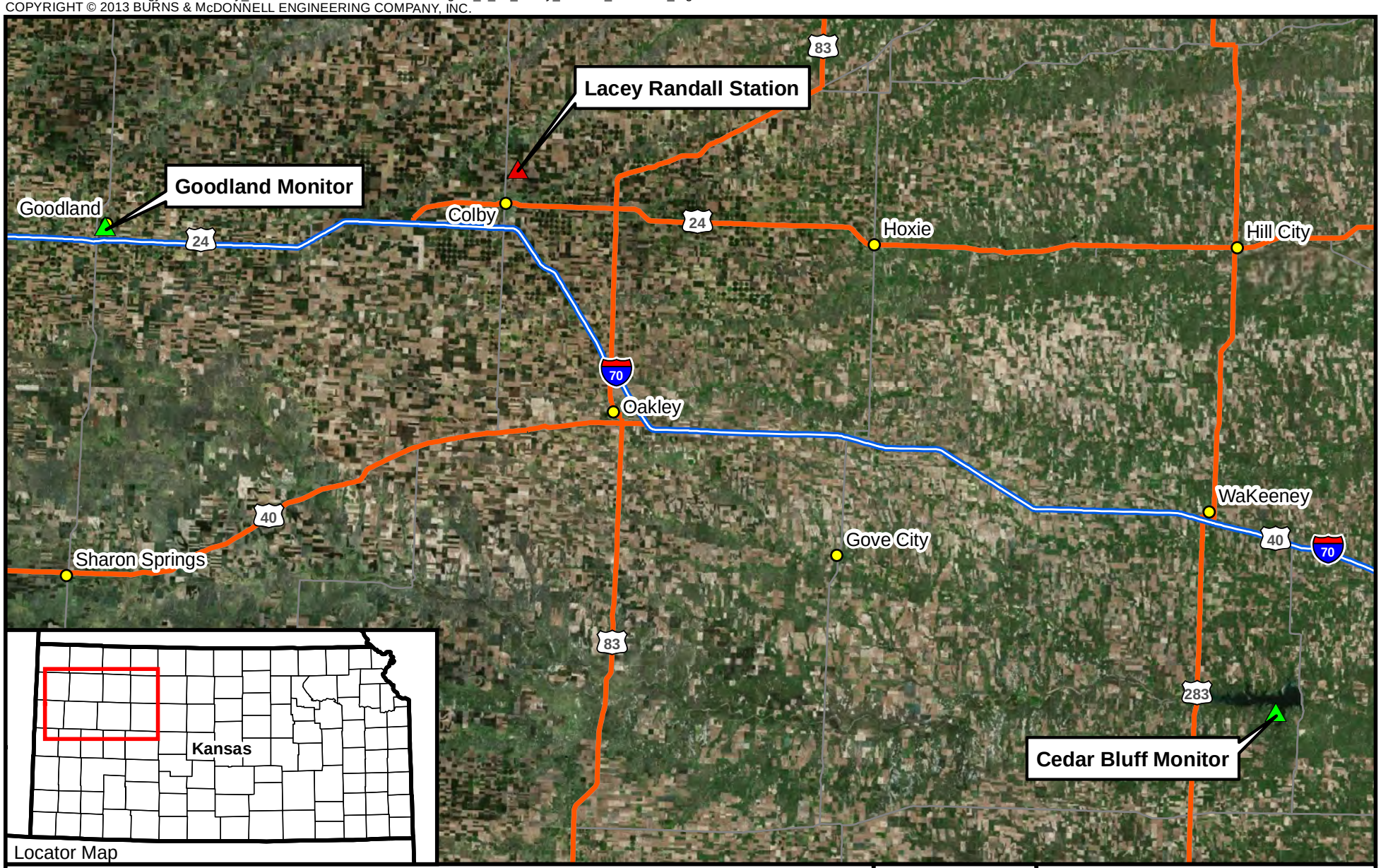


Monitoring Site
City
Limited Access
Highway
Major Road

NORTH

12 6 0 12
Miles

Figure 7-22
Lacey Randall Station
Tradewind Energy, Inc.

Overview of Monitoring Sites

Source: ESRI

Issued: 12/10/2013

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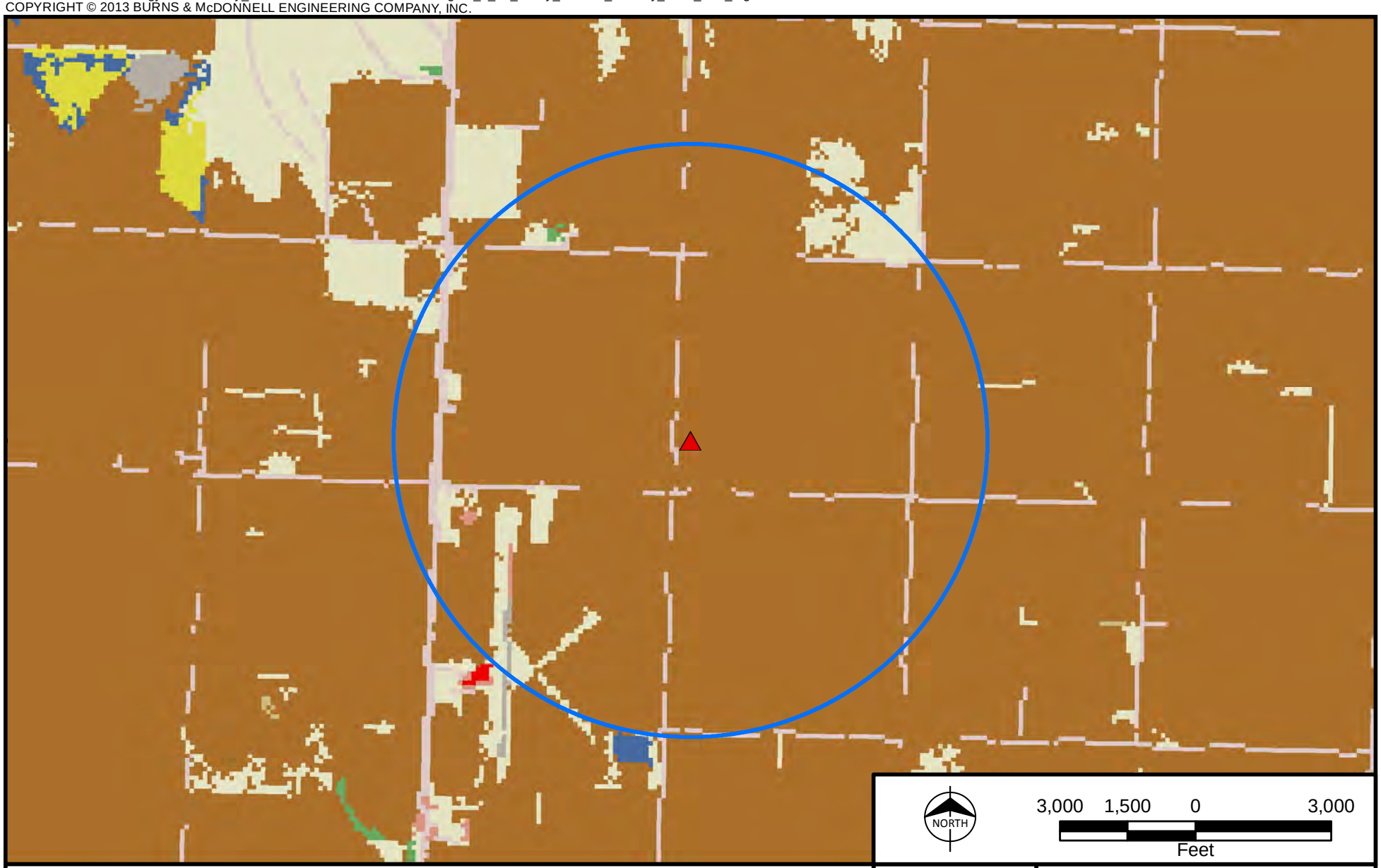


Lacey Randall Station

2km Buffer Around Lacey Randall Station

**Land Use Classification**

- Open Water
- Developed, Open Space
- Developed, Low Intensity
- Developed, Medium Intensity
- Developed, High Intensity
- Barren Land
- Deciduous Forest
- Evergreen Forest
- Mixed Forest
- Scrub/Shrub
- Grassland/Herbaceous
- Pasture/Hay
- Cultivated Crops
- Woody Wetlands
- Emergent Herbaceous Wetlands

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Figure 7-23
Primary Land Use

Lacey Randall Station

Source: USGS NLCD

Issued: 12/10/2013

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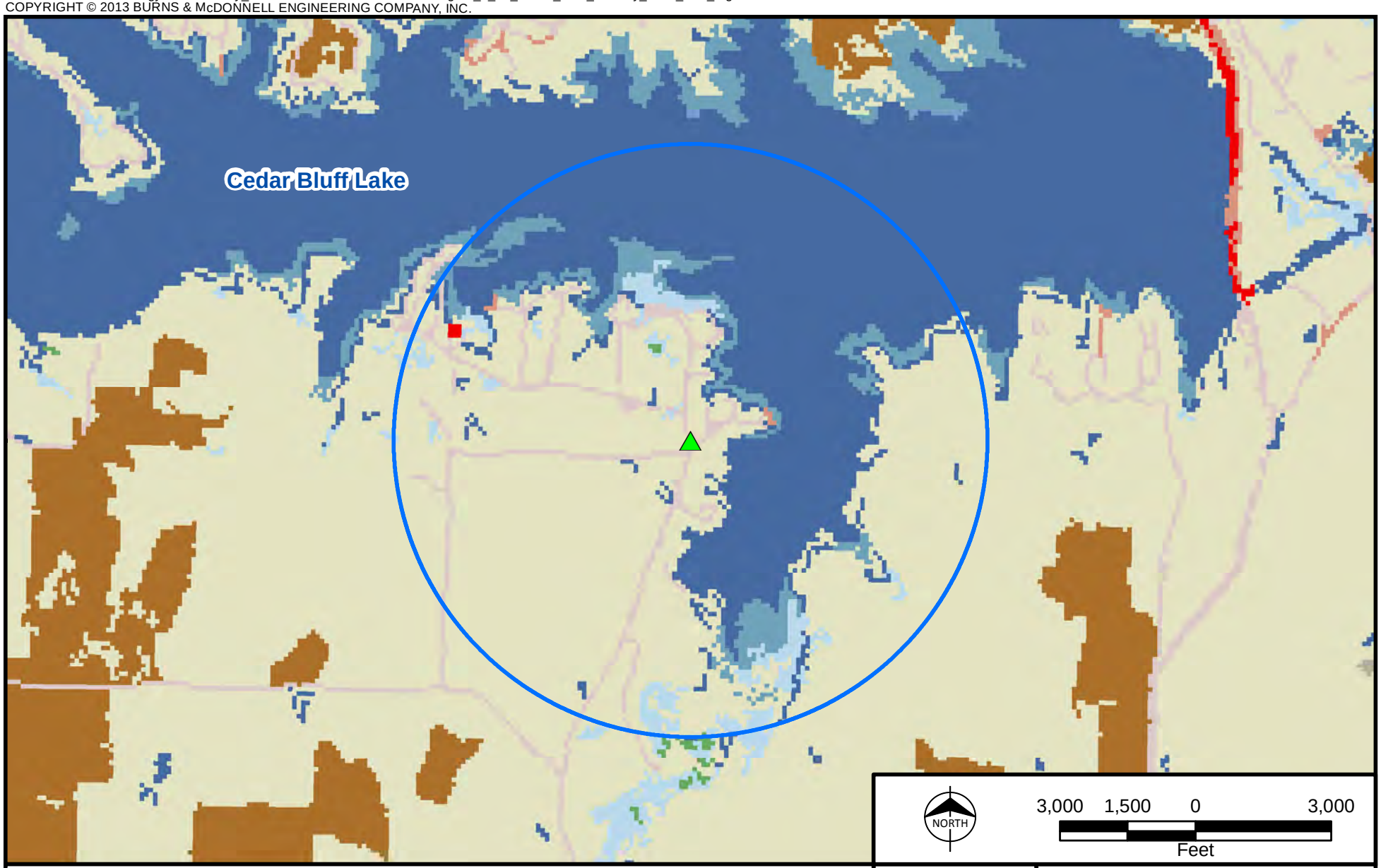


Cedar Bluff Monitoring Site

2km Buffer Around Cedar Bluff Monitoring Site

**Land Use Classifications**

- Open Water
- Developed, Open Space
- Developed, Low Intensity
- Developed, Medium Intensity
- Developed, High Intensity
- Barren Land
- Deciduous Forest
- Evergreen Forest
- Mixed Forest
- Scrub/Shrub
- Grassland/Herbaceous
- Pasture/Hay
- Cultivated Crops
- Woody Wetlands
- Emergent Herbaceous Wetlands

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Figure 7-24
Primary Land Use

Cedar Bluff Reservoir
Monitoring Location
AIRS No 20-195-0001

Source: USGS NLCD

Issued: 12/10/2013

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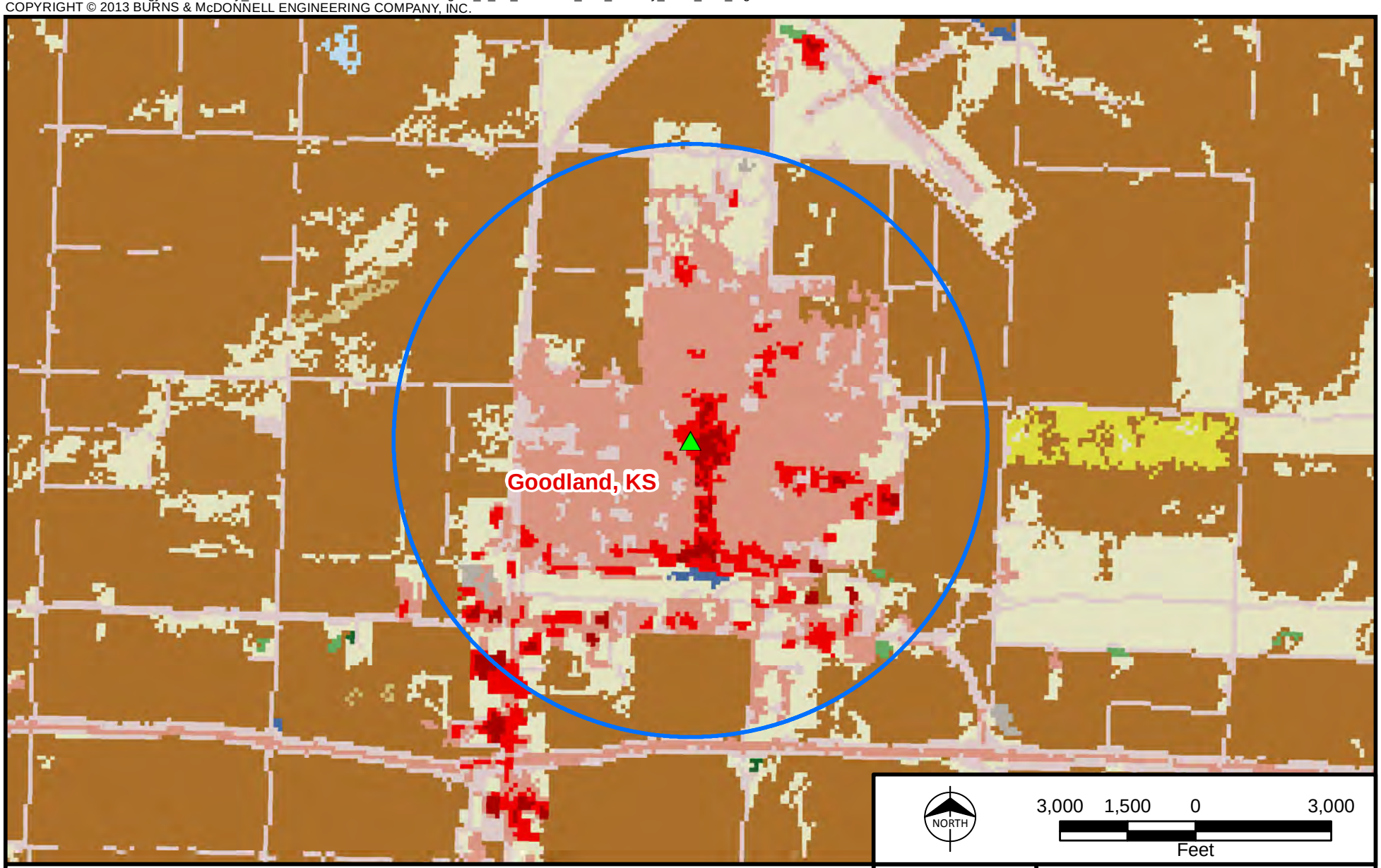


Goodland Site

2km Buffer Around Goodland Monitoring Site

**Land Use Classifications**

- Open Water
- Developed, Open Space
- Developed, Low Intensity
- Developed, Medium Intensity
- Developed, High Intensity
- Barren Land
- Deciduous Forest
- Evergreen Forest
- Mixed Forest
- Scrub/Shrub
- Grassland/Herbaceous
- Pasture/Hay
- Cultivated Crops
- Woody Wetlands
- Emergent Herbaceous Wetlands

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Figure 7-25
Primary Land Use

Goodland Site
Monitoring Location
AIRS No 20-181-0001

Source: USGS NLCD

Issued: 12/10/2013

Path: V:\Tradewind Energy\72125-Lacey_Randall\GIS\DataFiles\ArcDocs\Figure_7_26_Lacy_Randall_NOx_Sources.mxd kstaver 12/10/2013

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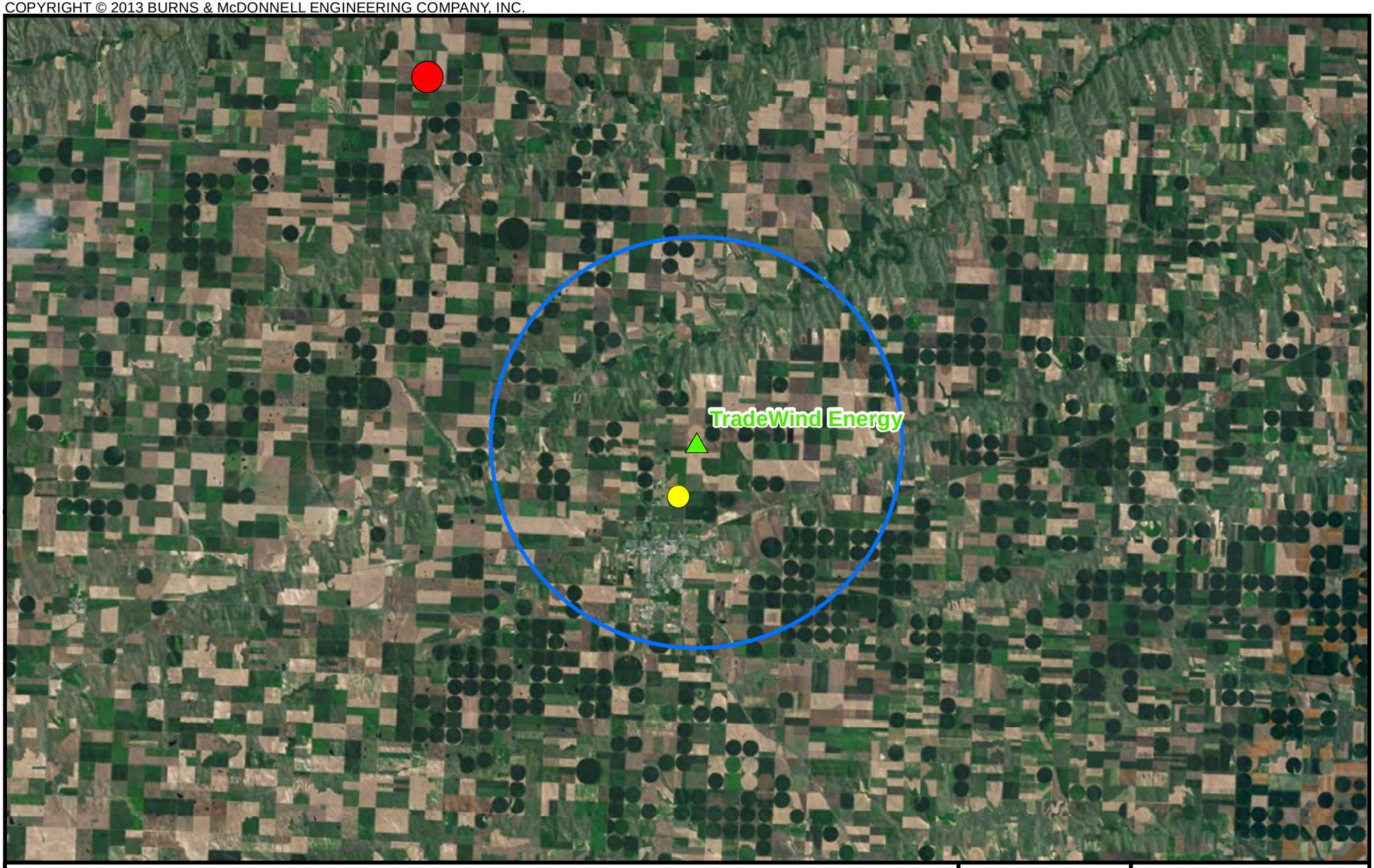


NOx Sources >50 tpy

NOx Sources <50 tpy

TradeWind Energy Site

10 km Buffer Around Site

4 2 0 4 Miles

NORTH

Burns & McDonnell SINCE 1898

Figure 7-26
NOx Sources
Surrounding TradeWind
Energy

Source: ESRI, Burns & McDonnell

Path: V:\Tradewind Energy\72125-Lacey_Randall\GIS\DataFiles\ArcDocs\Figure_7_27_Monitor_NOx_Sources.mxd kstaver 12/10/2013

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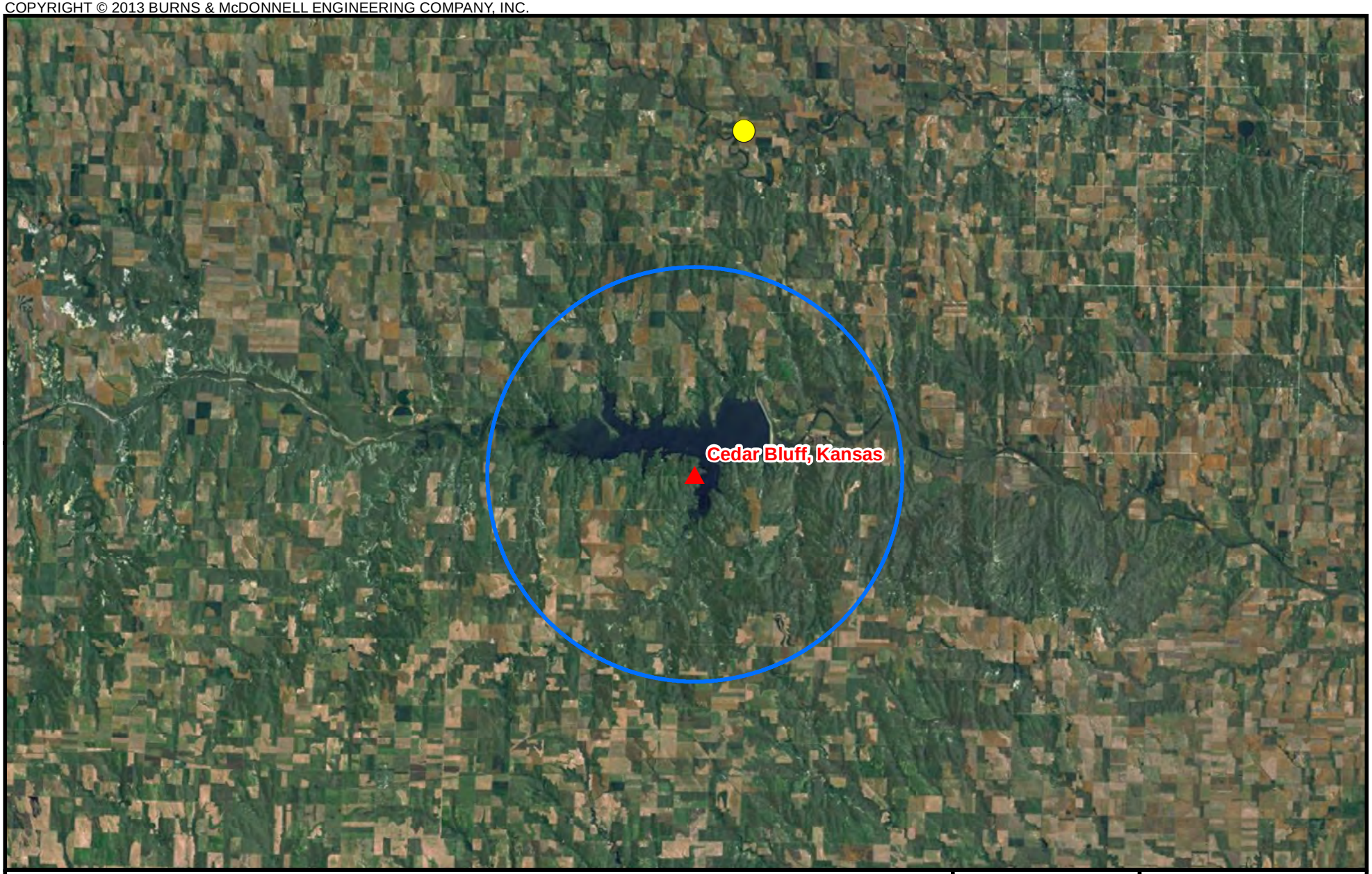


NOx Sources <50 tpy

Monitor 20-195-0001

10 km Buffer Around Site

4 2 0 4 Miles

NORTH

Burns & McDonnell SINCE 1898

Figure 7-27
NOx Sources
Surrounding Monitor
20-195-0001

Source: ESRI, Burns & McDonnell

Path: V:\Tradewind Energy\72125-Lacey_Randall\GIS\DataFiles\ArcDocs\Figure_7_28_Lacy_Randall_VOC_Sources.mxd kstaver 12/10/2013

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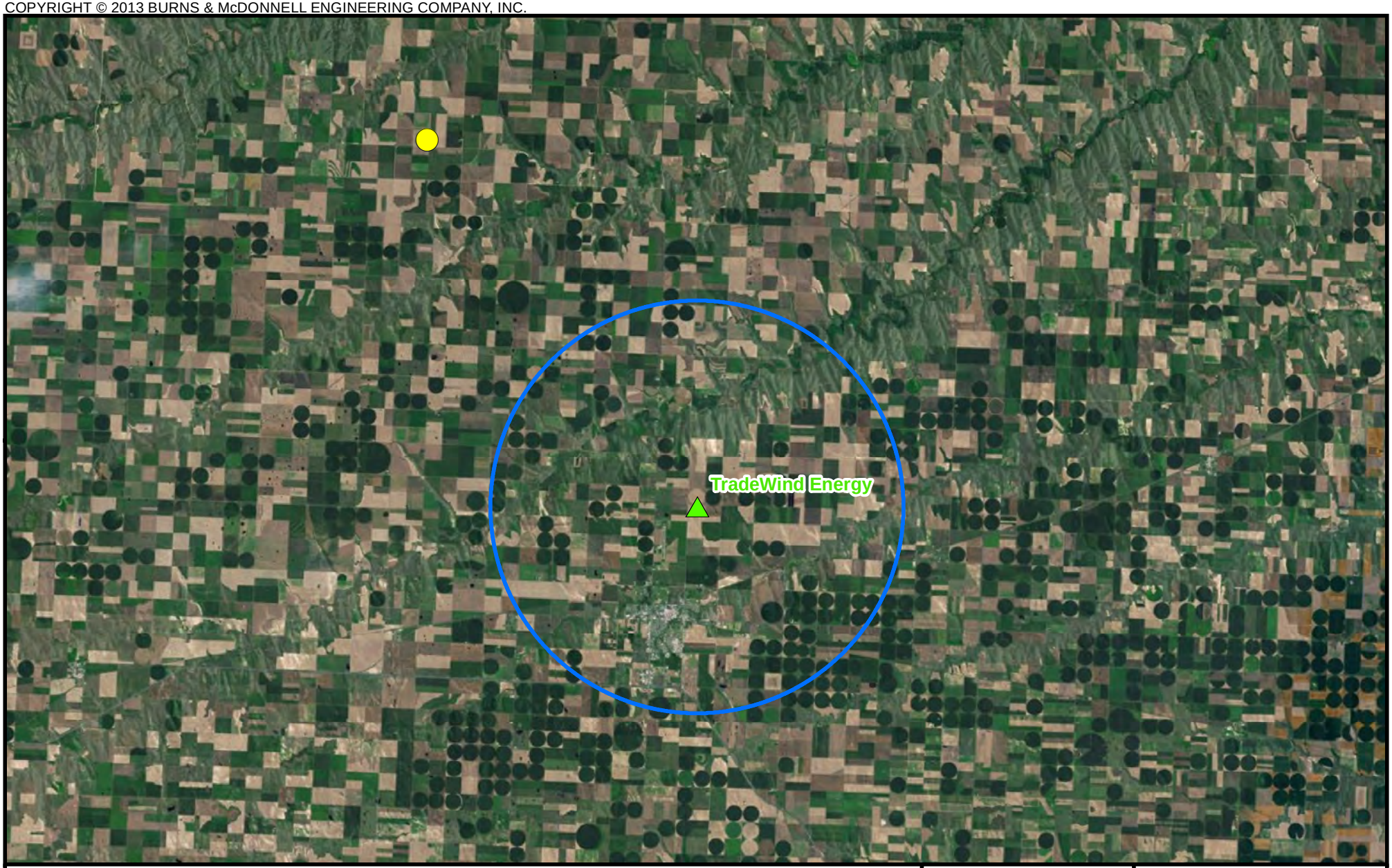


VOC Sources <50 tpy

TradeWind Energy

10 km Buffer Around Site

4 2 0 4 Miles

NORTH

Burns & McDonnell SINCE 1898

Figure 7-28
VOC Sources
Surrounding TradeWind
Energy

Source: ESRI, Burns & McDonnell

Path: V:\Tradewind Energy\72125-Lacey_Randall\GIS\DataFiles\ArcDocs\Figure_7_29_Monitor_VOC_Sources.mxd kstaver 12/10/2013

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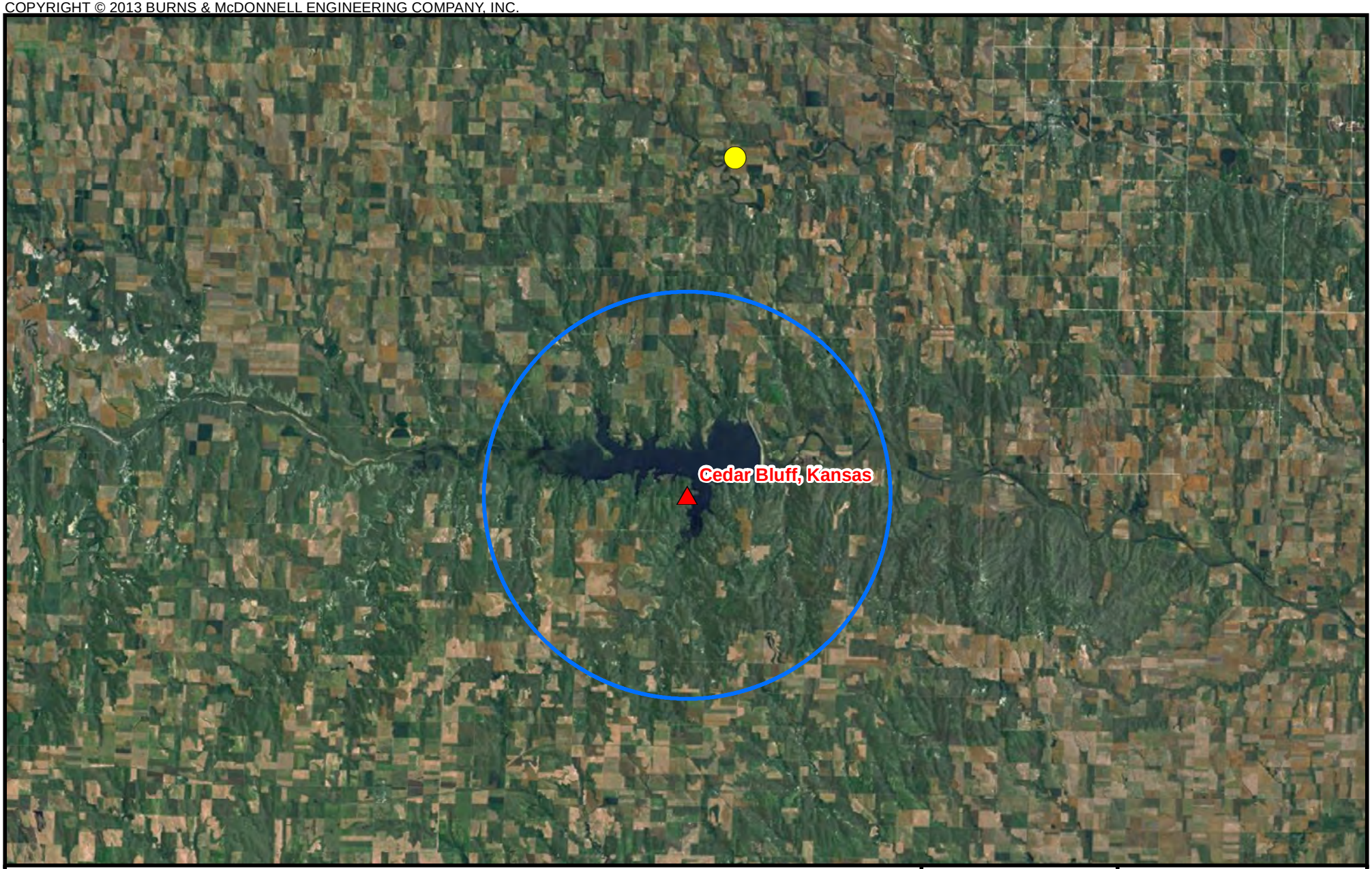


VOC Sources <50 tpy

Monitor 20-195-0001

10 km Buffer Around Site

4 2 0 4 Miles

NORTH

Burns & McDonnell SINCE 1898

Figure 7-29
VOC Sources
Surrounding Monitor
20-195-0001

Source: ESRI, Burns & McDonnell

Path: V:\Tradewind Energy\72125-Lacey_Randall\GIS\DataFiles\ArcDocs\Figure7_30_Lacy Randall_PM10_Sources.mxd kstaver 12/10/2013

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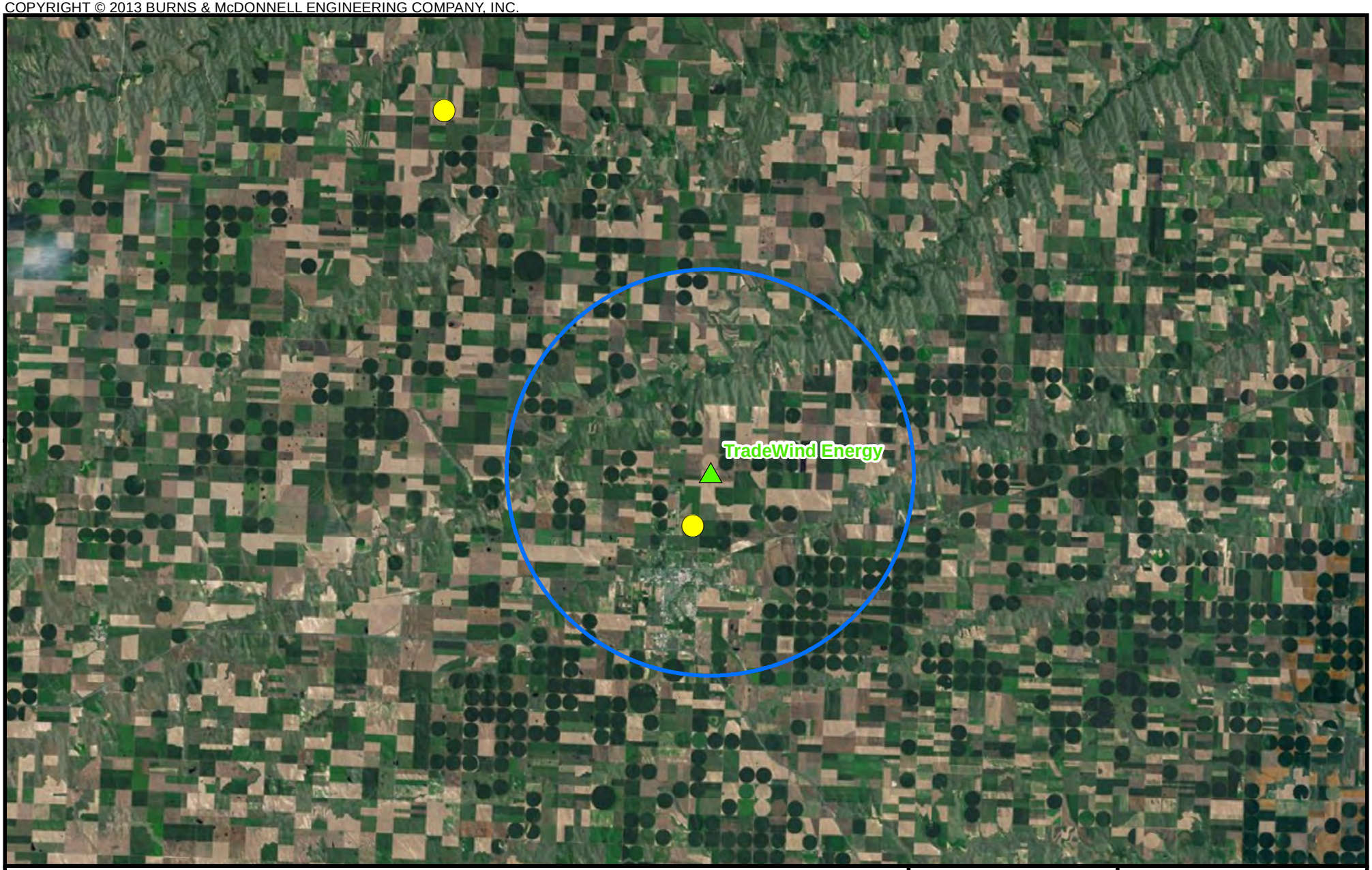


PM10 Sources <50 tpy

10 km Buffer Around Site

TradeWind Energy

4 2 0 4 Miles

NORTH

Burns & McDonnell SINCE 1898

Figure 7-30
PM10 Sources
Surrounding TradeWind
Energy

Source: ESRI, Burns & McDonnell

Path: V:\Tradewind Energy\72125-Lacey_Randall\GIS\DataFiles\ArcDocs\Figure_7_31_Monitor_PM10_Sources.mxd kstaver 12/10/2013

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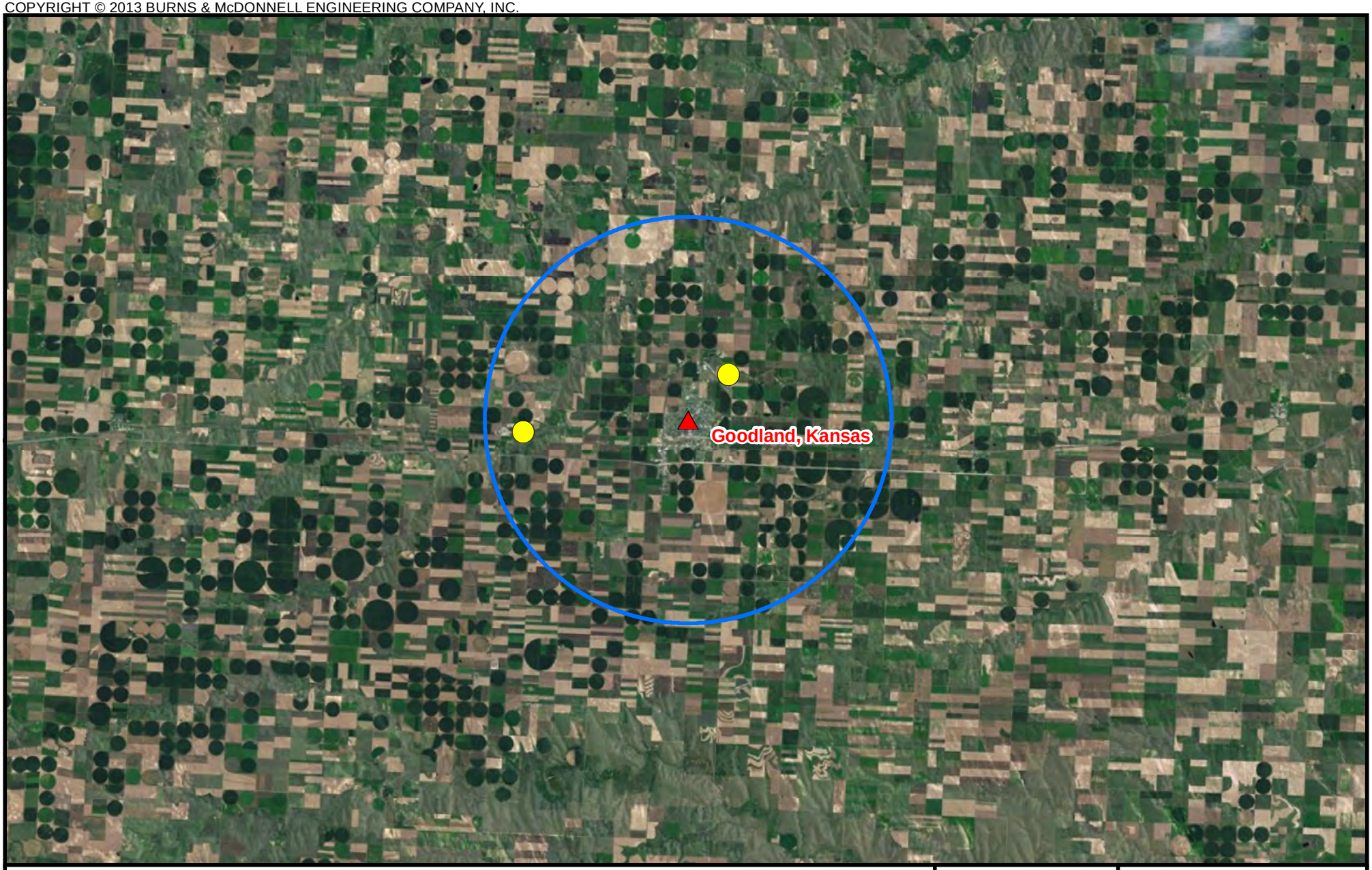


PM10 Sources <50 tpy

Monitor 20-181-0001

10 km Buffer Around Site

4 2 0 4 Miles

NORTH

Burns & McDonnell SINCE 1898

Figure 7-31
PM10 Sources
Surrounding Monitor
20-181-0001

Source: ESRI, Burns & McDonnell

Path: V:\Tradewind Energy\72125-Lacey_Randall\GIS\DataFiles\ArcDocs\Figure_7_32_Lacy Randall_PM2.5_Sources.mxd kstaver 12/10/2013

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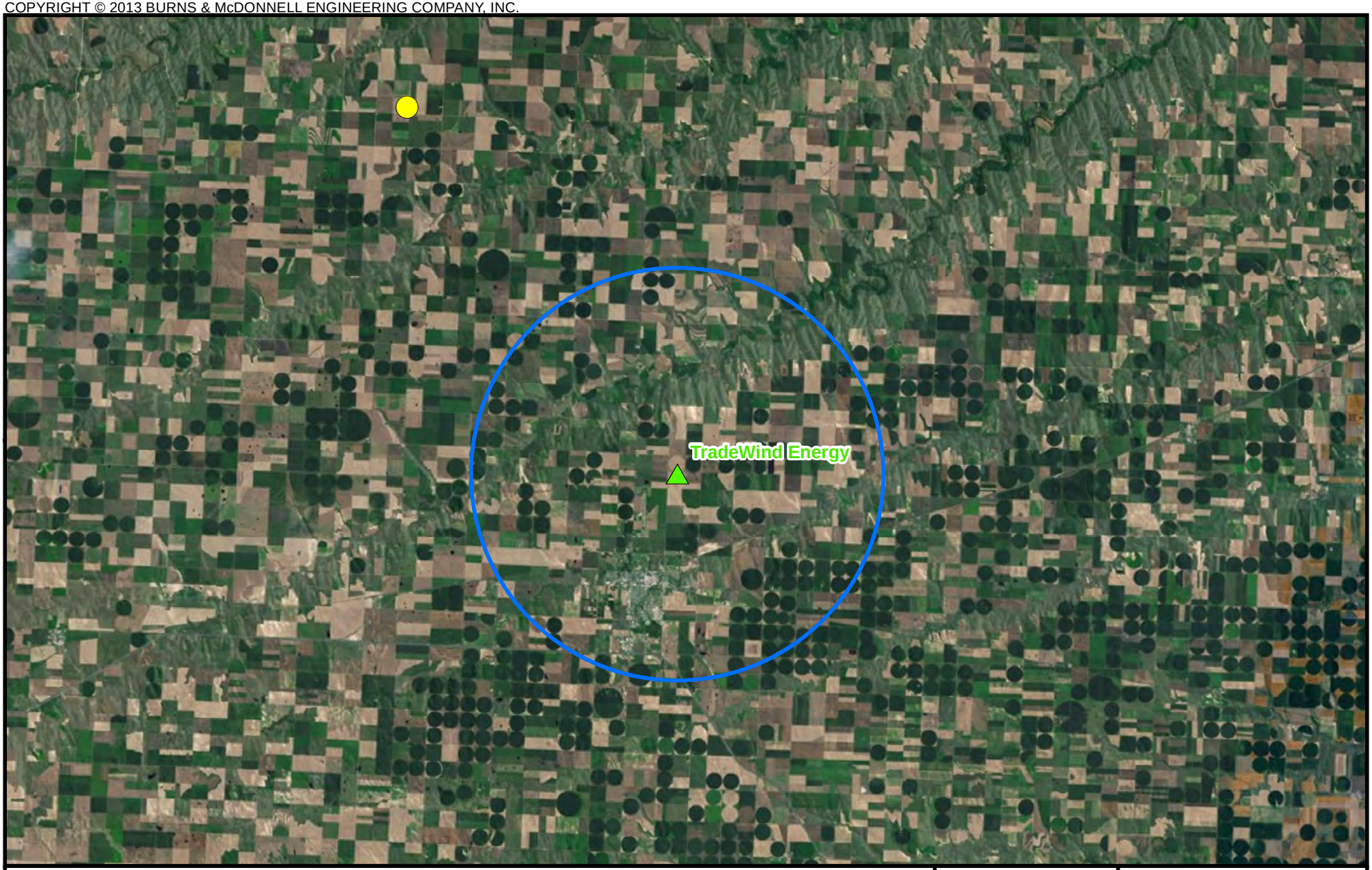


PM2.5 Sources <50 tpy

TradeWind Energy

10 km Buffer Around Site

4 2 0 4 Miles

NORTH

Burns & McDonnell SINCE 1898

Figure 7-32
PM2.5 Sources Surrounding TradeWind Energy

Source: ESRI, Burns & McDonnell

Path: V:\Tradewind Energy\72125-Lacey_Randall\GIS\DataFiles\ArcDocs\Figure_7_33_Monitor_PM2.5_Sources.mxd kstaver 12/10/2013

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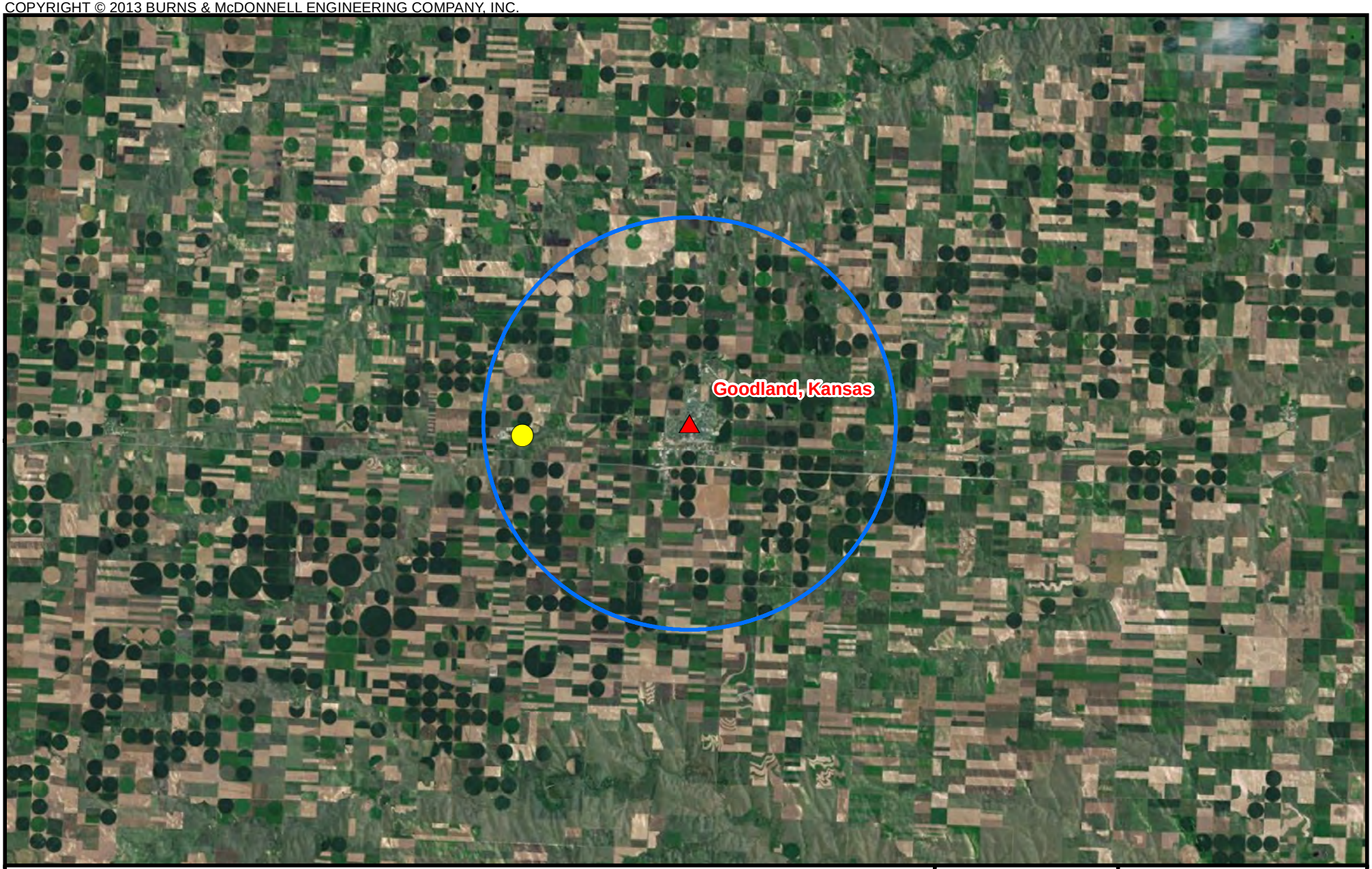


PM2.5 Sources <50 tpy

Monitor 20-181-0001

10 km Buffer Around Site

4 2 0 4 Miles

NORTH

Burns & McDonnell SINCE 1898

Figure 7-33
PM2.5 Sources
Surrounding Monitor
20-181-0001

Source: ESRI, Burns & McDonnell

# APPENDIX H - MODELING FILES

Viscreen

Visual Effects Screening Analysis for
Source: Tradewind Energy
Class I Area: Scott State Park

*** Level-1 Screening ***

Input Emissions for

| | | |
|---|---|---|
| Particulates | 100.59 | TON/YR |
| NOx (as NO2) | 141.57 | TON/YR |
| Primary NO2 | .00 | TON/YR |
| Soot | .00 | TON/YR |
| Primary SO4 | .00 | TON/YR |

**** Default Particle Characteristics Assumed

Transport Scenario Specifications:

| | |
|---|---|
| Background Ozone: | .04 ppm |
| Background Visual Range: | 60.00 km |
| Source-Observer Distance: | 80.00 km |
| Min. Source-Class I Distance: | 80.00 km |
| Max. Source-Class I Distance: | 80.00 km |
| Plume-Source-Observer Angle: | 11.25 degrees |
| Stability: 6 | |
| Wind Speed: 1.00 m/s | |

R E S U L T S

Asterisks (*) indicate plume impacts that exceed screening criteria

Maximum Visual Impacts INSIDE Class I Area
Screening Criteria ARE NOT Exceeded

| | | | | | Delta E | | Contrast | |
|---|---|---|---|---|---|---|---|---|
| Backgrnd | Theta | Azi | Distance | Alpha | Crit | Plume | Crit | Plume |
| SKY | 10. | 84. | 80.0 | 84. | 2.00 | .209 | .05 | .002 |
| SKY | 140. | 84. | 80.0 | 84. | 2.00 | .055 | .05 | -.002 |
| TERRAIN | 10. | 84. | 80.0 | 84. | 2.00 | .118 | .05 | .001 |
| TERRAIN | 140. | 84. | 80.0 | 84. | 2.00 | .022 | .05 | .001 |

Maximum Visual Impacts OUTSIDE Class I Area
Screening Criteria ARE NOT Exceeded

| | | | | | Delta E | | Contrast | |
|---|---|---|---|---|---|---|---|---|
| Backgrnd | Theta | Azi | Distance | Alpha | Crit | Plume | Crit | Plume |
| SKY | 10. | 20. | 52.7 | 149. | 2.00 | .280 | .05 | .003 |
| SKY | 140. | 20. | 52.7 | 149. | 2.00 | .051 | .05 | -.002 |
| TERRAIN | 10. | 40. | 65.9 | 129. | 2.00 | .154 | .05 | .002 |
| TERRAIN | 140. | 40. | 65.9 | 129. | 2.00 | .032 | .05 | .001 |

Modeling Inventory from KDHE

| Facility ID | Pollutant | Facility Name | Primary SIC Code | UTM Zone | UTM Vertical (KM) | UTM Horizontal (KM) | Reg Source Classification Code (SCC) | Group Number | Process Number | Stack Number | Stack Height (Feet) | Stack Diameter (Feet) | Stack Gas Exit Velocity (Feet per Second) | Stack Exit Gas Temperature (°F) | Distance (m) | PTE (lbs/hour) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1930001 | NO2 | MIDWEST ENERGY, INC. | 4911 | 14 | 4,363,475 | 324,583 | 20100201 | 001 | 1.00 | | 64.76492 | 11.42772 | 61.94023 | 650.00614 | 4,599 | 97.7 |
| 1930007 | NO2 | COLBY MUNICIPAL POWER PLANT | 4911 | 14 | 4,362,583 | 322,725 | 20200402 | 001 | 1.00 | | 33.50515 | 2.12706 | 59.47876 | 623.02576 | 5,952 | 535.4 |
| 1530014 | NO2 | SOUTHERN STAR CENTRAL GAS PIPELINE, INC. | 4922 | 14 | 4,385,966 | 311,329 | 20200252 | 001 | 1.00 | 1.00 | 37.00000 | 2.00000 | 53.10000 | 700.00000 | 22,592 | 64.5 |
| 1530014 | NO2 | SOUTHERN STAR CENTRAL GAS PIPELINE, INC. | 4922 | 14 | 4,385,966 | 311,329 | 20200253 | 002 | 1.00 | 3.00 | 12.00000 | 0.33000 | 240.00000 | 1000.00000 | 22,592 | 3.4 |
| 1530014 | NO2 | SOUTHERN STAR CENTRAL GAS PIPELINE, INC. | 4922 | 14 | 4,385,966 | 311,329 | 10200603 | 003 | 1.00 | 2.00 | 30.00000 | 1.30000 | 9.00000 | 350.00000 | 22,592 | 0.2 |
| 1530014 | NO2 | SOUTHERN STAR CENTRAL GAS PIPELINE, INC. | 4922 | 14 | 4,385,966 | 311,329 | 10300603 | 005 | 1.00 | 4.00 | 12.00000 | 0.50000 | 4.10000 | 350.00000 | 22,592 | 0.0 |
| 0630019 | NO2 | WESTERN PLAINS ENERGY, L.L.C. | 2869 | 14 | 4,331,748 | 349,842 | 30205021 | 003 | 1.00 | | 116.00000 | 2.35000 | 39.09000 | 85.00000 | 43,936 | 4.0 |
| 0630019 | NO2 | WESTERN PLAINS ENERGY, L.L.C. | 2869 | 14 | 4,331,748 | 349,842 | 10200602 | 003 | 2.00 | | 58.21322 | 3.40341 | 27.61026 | 436.40925 | 43,936 | 5.9 |
| 0630019 | NO2 | WESTERN PLAINS ENERGY, L.L.C. | 2869 | 14 | 4,331,748 | 349,842 | 30205040 | 005 | 1.00 | | 13.20000 | 1.60000 | 7.80000 | 91.10000 | 43,936 | 0.5 |
| 0630019 | NO2 | WESTERN PLAINS ENERGY, L.L.C. | 2869 | 14 | 4,331,748 | 349,842 | 20200102 | 009 | 1.00 | | 26.48779 | 1.41820 | 60.21177 | 489.92882 | 43,936 | 9.3 |

| Facility ID | Pollutant | Facility Name | Primary SIC Code | UTM Zone | UTM Vertical (KM) | UTM Horizontal (KM) | Reg Source Classification Code (SCC) | Group Number | Process Number | Stack Number | Stack Height (Feet) | Stack Diameter (Feet) | Stack Gas Exit Velocity (Feet per Second) | Stack Exit Gas Temperature (°F) | Distance | PTE (lbs/hour) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 0630019 | PM10 | WESTERN PLAINS ENERGY, L.L.C. | 2869 | 14.00 | 4,331,748 | 349,842 | 30200505 | 001 | 1.00 | | 33.3 | 1.1 | 14.5 | 69.1 | 43,936 | 0.5 |
| 0630019 | PM10 | WESTERN PLAINS ENERGY, L.L.C. | 2869 | 14.00 | 4,331,748 | 349,842 | 30200817 | 001 | 3.00 | | 46.0 | 1.5 | 58.1 | 85.0 | 43,936 | 0.6 |
| 0630019 | PM10 | WESTERN PLAINS ENERGY, L.L.C. | 2869 | 14.00 | 4,331,748 | 349,842 | 30205014 | 001 | 5.00 | | 39.2 | 1.2 | 7.8 | 77.1 | 43,936 | 3.5 |
| 0630019 | PM10 | WESTERN PLAINS ENERGY, L.L.C. | 2869 | 14.00 | 4,331,748 | 349,842 | 38500101 | 002 | 1.00 | | 41.4 | 16.0 | 26.2 | 97.4 | 43,936 | 1.0 |
| 0630019 | PM10 | WESTERN PLAINS ENERGY, L.L.C. | 2869 | 14.00 | 4,331,748 | 349,842 | 30205020 | 003 | 3.00 | | 39.2 | 1.2 | 7.8 | 77.1 | 43,936 | 8.9 |
| 0630019 | PM10 | WESTERN PLAINS ENERGY, L.L.C. | 2869 | 14.00 | 4,331,748 | 349,842 | 20200102 | 009 | 1.00 | | 26.5 | 1.4 | 60.2 | 489.9 | 43,936 | 0.0 |
| 1530014 | PM10 | SOUTHERN STAR CENTRAL GAS PIPELINE, INC. | 4922 | 14.00 | 4,385,966 | 311,329 | 20200252 | 001 | 1.00 | 1.00 | 37.0 | 2.0 | 53.1 | 700.0 | 22,592 | 0.8 |
| 1530014 | PM10 | SOUTHERN STAR CENTRAL GAS PIPELINE, INC. | 4922 | 14.00 | 4,385,966 | 311,329 | 20200253 | 002 | 1.00 | 3.00 | 12.0 | 0.3 | 240.0 | 1000.0 | 22,592 | 0.0 |
| 1530014 | PM10 | SOUTHERN STAR CENTRAL GAS PIPELINE, INC. | 4922 | 14.00 | 4,385,966 | 311,329 | 10200603 | 003 | 1.00 | 2.00 | 30.0 | 1.3 | 9.0 | 350.0 | 22,592 | 0.0 |
| 1530014 | PM10 | SOUTHERN STAR CENTRAL GAS PIPELINE, INC. | 4922 | 14.00 | 4,385,966 | 311,329 | 10300603 | 005 | 1.00 | 4.00 | 12.0 | 0.5 | 4.1 | 350.0 | 22,592 | 0.0 |
| 1930001 | PM10 | MIDWEST ENERGY, INC. | 4911 | 14.00 | 4,363,475 | 324,583 | 20100201 | 001 | 1.00 | | 64.8 | 11.4 | 61.9 | 650.0 | 4,599 | 8.5 |
| 1930007 | PM10 | COLBY MUNICIPAL POWER PLANT | 4911 | 14.00 | 4,362,583 | 322,725 | 20200402 | 001 | 1.00 | | 33.5 | 2.1 | 59.5 | 623.0 | 5,952 | 14.3 |
| 1930026 | PM10 | RED RIVER COMMODITIES | 0723 | 14.00 | 4,360,609 | 325,000 | 30200505 | 001 | 3.00 | | 33.3 | 1.1 | 14.5 | 69.1 | 7,438 | 0.0 |
| 1930026 | PM10 | RED RIVER COMMODITIES | 0723 | 14.00 | 4,360,609 | 325,000 | 30200503 | 001 | 4.00 | | 43.1 | 1.6 | 38.5 | 73.7 | 7,438 | 0.6 |
| 1930026 | PM10 | RED RIVER COMMODITIES | 0723 | 14.00 | 4,360,609 | 325,000 | 30200502 | 001 | 5.00 | | 116.0 | 2.4 | 39.1 | 85.0 | 7,438 | 0.1 |
| 1930026 | PM10 | RED RIVER COMMODITIES | 0723 | 14.00 | 4,360,609 | 325,000 | 30200506 | 001 | 6.00 | | 26.6 | 1.0 | 10.8 | 69.2 | 7,438 | 0.0 |

| Facility ID | Pollutant | Facility Name | Primary SIC Code | UTM Zone | UTM Vertical (KM) | UTM Horizontal (KM) | Reg Source Classificatio n Code (SCC) | Group Number | Process Number | Stack Number | Stack Height (Feet) | Stack Diameter (Feet) | Stack Gas Exit Velocity (Feet per Second) | Stack Exit Gas Temperature (°F) | Distance | PTE (lbs/hour) | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 0630019 | PM25-FIL | WESTERN PLAINS | 2869 | 14.00 | 4,331,748 | 349,842 | 30200505 | 001 | 1.00 | | 33.3 | 1.1 | 14.5 | 69.1 | 43,936 | 0.5 | 30200505 |
| 0630019 | PM25-FIL | WESTERN PLAINS | 2869 | 14.00 | 4,331,748 | 349,842 | 30200817 | 001 | 3.00 | | 46.0 | 1.5 | 58.1 | 85.0 | 43,936 | 0.6 | 30200817 |
| 0630019 | PM25-FIL | WESTERN PLAINS | 2869 | 14.00 | 4,331,748 | 349,842 | 30205014 | 001 | 5.00 | | 39.2 | 1.2 | 7.8 | 77.1 | 43,936 | 3.5 | 30205014 |
| 0630019 | PM25-FIL | WESTERN PLAINS | 2869 | 14.00 | 4,331,748 | 349,842 | 38500101 | 002 | 1.00 | | 41.4 | 16.0 | 26.2 | 97.4 | 43,936 | 1.0 | 38500101 |
| 0630019 | PM25-FIL | WESTERN PLAINS | 2869 | 14.00 | 4,331,748 | 349,842 | 30205020 | 003 | 3.00 | | 39.2 | 1.2 | 7.8 | 77.1 | 43,936 | 8.9 | 30205020 |
| 0630019 | PM25-FIL | WESTERN PLAINS | 2869 | 14.00 | 4,331,748 | 349,842 | 20200102 | 009 | 1.00 | | 26.5 | 1.4 | 60.2 | 489.9 | 43,936 | 0.0 | 20200102 |
| 1530014 | PM25-FIL | SOUTHERN STAR ( | 4922 | 14.00 | 4,385,966 | 311,329 | 20200252 | 001 | 1.00 | 1.00 | 37.0 | 2.0 | 53.1 | 700.0 | 22,592 | 0.8 | 20200252 |
| 1530014 | PM25-FIL | SOUTHERN STAR ( | 4922 | 14.00 | 4,385,966 | 311,329 | 20200253 | 002 | 1.00 | 3.00 | 12.0 | 0.3 | 240.0 | 1000.0 | 22,592 | 0.0 | 20200253 |
| 1530014 | PM25-FIL | SOUTHERN STAR ( | 4922 | 14.00 | 4,385,966 | 311,329 | 10200603 | 003 | 1.00 | 2.00 | 30.0 | 1.3 | 9.0 | 350.0 | 22,592 | 0.0 | 10200603 |
| 1530014 | PM25-FIL | SOUTHERN STAR ( | 4922 | 14.00 | 4,385,966 | 311,329 | 10300603 | 005 | 1.00 | 4.00 | 12.0 | 0.5 | 4.1 | 350.0 | 22,592 | 0.0 | 10300603 |
| 1930001 | PM25-FIL | MIDWEST ENERGY | 4911 | 14.00 | 4,363,475 | 324,583 | 20100201 | 001 | 1.00 | | 64.8 | 11.4 | 61.9 | 650.0 | 4,599 | 8.5 | 20100201 |
| 1930007 | PM25-FIL | COLBY MUNICIPAL | 4911 | 14.00 | 4,362,583 | 322,725 | 20200402 | 001 | 1.00 | | 33.5 | 2.1 | 59.5 | 623.0 | 5,952 | 13.8 | 20200402 |

Secondary $PM_{2.5}$ Information

# Air Quality Modeling
# Final Rule Technical Support Document

U.S. Environmental Protection Agency
Office of Air Quality Planning and Standards
Air Quality Assessment Division
Research Triangle Park, NC 27711
June 2011

| | | | Annual $PM_{2.5}$ Design Values ($\mu g/m^3$) | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Site ID** | **State** | **County** | **2003-2007 Average Ambient Values** | **2003-2007 Maximum Ambient Values** | **2012 Base Case Average Values** | **2012 Base Case Maximum Values** | **2014 Base Case Average Values** | **2014 Base Case Maximum Values** | **2014 Remedy Average Values** | **2014 Remedy Maximum Values** |
| 191032001 | Iowa | Johnson | 12.08 | 12.26 | 11.04 | 11.20 | 10.73 | 10.88 | 9.97 | 10.11 |
| 191130037 | Iowa | Linn | 10.79 | 10.95 | 9.78 | 9.92 | 9.48 | 9.63 | 8.75 | 8.88 |
| 191370002 | Iowa | Montgomery | 10.02 | 10.33 | 9.09 | 9.37 | 8.84 | 9.11 | 8.13 | 8.37 |
| 191390015 | Iowa | Muscatine | 12.92 | 13.29 | 11.85 | 12.20 | 11.50 | 11.83 | 10.66 | 10.96 |
| 191471002 | Iowa | Palo Alto | 9.53 | 9.53 | 8.72 | 8.72 | 8.51 | 8.51 | 7.99 | 7.99 |
| 191530030 | Iowa | Polk | 10.41 | 10.54 | 9.44 | 9.55 | 9.17 | 9.29 | 8.52 | 8.63 |
| 191532510 | Iowa | Polk | 9.95 | 10.14 | 9.01 | 9.19 | 8.76 | 8.93 | 8.13 | 8.31 |
| 191532520 | Iowa | Polk | 10.64 | 10.64 | 9.65 | 9.65 | 9.38 | 9.38 | 8.75 | 8.75 |
| 191550009 | Iowa | Pottawattamie | 11.13 | 11.52 | 10.08 | 10.44 | 9.82 | 10.17 | 9.25 | 9.57 |
| 191630015 | Iowa | Scott | 11.86 | 12.06 | 10.84 | 11.03 | 10.47 | 10.64 | 9.59 | 9.75 |
| 191630018 | Iowa | Scott | 11.64 | 11.89 | 10.64 | 10.87 | 10.27 | 10.48 | 9.38 | 9.58 |
| 191630019 | Iowa | Scott | 14.42 | 14.42 | 13.27 | 13.27 | 12.86 | 12.86 | 12.01 | 12.01 |
| 191770006 | Iowa | Van Buren | 10.84 | 10.84 | 9.94 | 9.94 | 9.65 | 9.65 | 8.92 | 8.92 |
| 191930017 | Iowa | Woodbury | 10.32 | 10.53 | 9.47 | 9.66 | 9.27 | 9.46 | 8.80 | 8.98 |
| 191970004 | Iowa | Wright | 10.37 | 10.51 | 9.47 | 9.59 | 9.22 | 9.34 | 8.59 | 8.70 |
| 200910007 | Kansas | Johnson | 10.59 | 10.86 | 9.60 | 9.84 | 9.33 | 9.56 | 8.59 | 8.81 |
| 200910009 | Kansas | Johnson | 11.10 | 11.10 | 10.08 | 10.08 | 9.79 | 9.79 | 8.97 | 8.97 |
| 200910010 | Kansas | Johnson | 9.68 | 9.74 | 8.81 | 8.86 | 8.56 | 8.61 | 7.82 | 7.86 |
| 201070002 | Kansas | Linn | 10.47 | 10.62 | 9.66 | 9.79 | 9.41 | 9.53 | 8.55 | 8.65 |
| 201730008 | Kansas | Sedgwick | 10.26 | 10.85 | 9.28 | 9.81 | 9.05 | 9.57 | 8.39 | 8.89 |
| 201730009 | Kansas | Sedgwick | 10.29 | 10.95 | 9.31 | 9.89 | 9.07 | 9.64 | 8.42 | 8.95 |
| 201730010 | Kansas | Sedgwick | 10.36 | 10.96 | 9.37 | 9.92 | 9.14 | 9.67 | 8.49 | 8.99 |
| 201770010 | Kansas | Shawnee | 10.79 | 10.79 | 9.86 | 9.86 | 9.61 | 9.61 | 8.87 | 8.87 |
| 201770011 | Kansas | Shawnee | 10.93 | 10.93 | 10.00 | 10.00 | 9.76 | 9.76 | 9.06 | 9.06 |
| 201910002 | Kansas | Sumner | 9.89 | 10.31 | 9.01 | 9.39 | 8.80 | 9.17 | 8.13 | 8.47 |
| 202090021 | Kansas | Wyandotte | 12.73 | 13.37 | 11.54 | 12.12 | 11.23 | 11.80 | 10.44 | 10.97 |

| | | | | | | | tot |
|---|---|---|---|---|---|---|---|
| | 2005cs | 2012cs | 2014cs | 2005ck | 2012ck | 2014ck2 | 2012cs - 2005cs |
| Alabama | 102,429 | 95,395 | 92,449 | 100,251 | 89,529 | 89,301 | -7,035 |
| Arizona | 81,645 | 74,219 | 73,186 | 77,753 | 74,624 | 75,818 | -7,426 |
| Arkansas | 64,593 | 62,736 | 62,302 | 63,257 | 63,993 | 63,740 | -1,857 |
| California | 258,113 | 248,519 | 245,542 | 264,333 | 251,932 | 250,089 | -9,594 |
| Colorado | 69,363 | 65,440 | 64,673 | 67,879 | 66,509 | 65,021 | -3,924 |
| Connecticut | 16,661 | 14,427 | 14,031 | 15,905 | 14,723 | 14,455 | -2,234 |
| Delaware | 7,447 | 5,246 | 3,605 | 8,357 | 7,810 | 7,634 | -2,202 |
| District of Columbia | 1,441 | 1,185 | 1,127 | 1,265 | 1,059 | 1,019 | -256 |
| Florida | 233,728 | 209,089 | 208,966 | 235,138 | 220,234 | 231,866 | -24,639 |
| Georgia | 147,278 | 135,441 | 125,760 | 141,573 | 125,600 | 124,333 | -11,838 |
| Idaho | 100,053 | 98,879 | 98,571 | 99,371 | 98,479 | 98,175 | -1,174 |
| Illinois | 132,740 | 122,771 | 112,565 | 126,721 | 120,305 | 122,179 | -9,969 |
| Indiana | 137,991 | 143,706 | 139,035 | 136,584 | 121,110 | 119,479 | 5,716 |
| Iowa | 80,139 | 70,812 | 69,867 | 78,519 | 72,544 | 73,856 | -9,328 |
| Kansas | 161,993 | 156,252 | 155,434 | 160,706 | 157,016 | 156,879 | -5,741 |
| Kentucky | 77,235 | 78,380 | 76,746 | 74,612 | 74,518 | 73,609 | 1,145 |
| Louisiana | 92,524 | 84,432 | 83,350 | 103,788 | 100,658 | 100,125 | -8,093 |
| Maine | 24,167 | 21,942 | 21,471 | 23,807 | 22,306 | 21,732 | -2,225 |
| Maryland | 55,116 | 40,230 | 38,958 | 53,921 | 42,841 | 57,584 | -14,887 |
| Massachusetts | 47,179 | 40,416 | 39,895 | 47,139 | 44,157 | 43,889 | -6,763 |
| Michigan | 95,078 | 82,883 | 81,741 | 89,372 | 83,415 | 81,512 | -12,195 |
| Minnesota | 112,365 | 105,355 | 103,911 | 109,663 | 111,407 | 110,058 | -7,010 |
| Mississippi | 70,175 | 66,414 | 65,693 | 69,011 | 65,998 | 65,117 | -3,761 |
| Missouri | 107,697 | 105,551 | 104,048 | 104,084 | 103,327 | 103,104 | -2,146 |
| Montana | 56,685 | 53,943 | 53,527 | 56,096 | 55,911 | 55,475 | -2,742 |
| Nebraska | 58,864 | 56,731 | 56,017 | 58,095 | 57,440 | 57,779 | -2,134 |
| Nevada | 39,846 | 36,760 | 37,368 | 39,448 | 37,044 | 47,166 | -3,087 |
| New Hampshire | 19,463 | 16,331 | 16,174 | 18,985 | 16,603 | 16,230 | -3,132 |
| New Jersey | 32,963 | 26,070 | 25,967 | 32,307 | 29,515 | 28,943 | -6,893 |
| New Mexico | 111,370 | 106,923 | 106,495 | 110,064 | 108,525 | 108,250 | -4,447 |
| New York | 84,972 | 74,800 | 73,370 | 83,620 | 77,459 | 83,650 | -10,172 |
| North Carolina | 104,421 | 93,487 | 90,754 | 104,628 | 98,322 | 98,939 | -10,933 |
| North Dakota | 55,001 | 52,107 | 51,618 | 54,617 | 51,462 | 50,936 | -2,894 |
| Ohio | 141,086 | 132,669 | 129,447 | 136,147 | 100,326 | 101,030 | -8,417 |
| Oklahoma | 112,803 | 111,454 | 110,634 | 109,390 | 110,713 | 111,129 | -1,350 |
| Oregon | 140,003 | 136,385 | 135,633 | 139,787 | 137,810 | 137,403 | -3,618 |
| Pennsylvania | 135,981 | 105,730 | 104,004 | 129,929 | 96,055 | 97,021 | -30,251 |
| Rhode Island | 2,568 | 2,233 | 2,158 | 2,620 | 2,454 | 2,418 | -335 |
| South Carolina | 63,791 | 58,932 | 59,534 | 63,381 | 56,141 | 56,928 | -4,859 |
| South Dakota | 48,037 | 45,954 | 45,455 | 47,599 | 45,238 | 44,832 | -2,083 |
| Tennessee | 85,454 | 84,530 | 81,370 | 82,182 | 72,593 | 71,366 | -924 |
| Texas | 327,200 | 302,881 | 299,213 | 311,718 | 299,720 | 303,066 | -24,319 |
| Tribal | 1,569 | 1,570 | 1,568 | 1,586 | 1,571 | 1,570 | 0 |
| Utah | 55,242 | 52,975 | 52,502 | 54,084 | 52,704 | 52,449 | -2,267 |
| Vermont | 9,137 | 8,668 | 8,572 | 8,984 | 8,630 | 8,433 | -469 |
| Virginia | 80,522 | 69,492 | 67,611 | 78,911 | 70,071 | 69,560 | -11,030 |
| Washington | 70,675 | 62,977 | 61,869 | 68,687 | 65,512 | 64,795 | -7,698 |
| West Virginia | 53,070 | 60,970 | 58,906 | 52,317 | 45,419 | 46,384 | 7,900 |
| Wisconsin | 64,446 | 59,853 | 59,041 | 62,055 | 62,719 | 62,677 | -4,593 |
| Wyoming | 68,388 | 64,770 | 64,555 | 67,888 | 66,662 | 66,589 | -3,617 |
| Total | 4,300,712 | 4,008,914 | 3,936,289 | 4,228,137 | 3,960,713 | 3,995,591 | -291,798 |

al

| 2014cs - 2012cs | 2012cs - 2012ck | 2014cs - 2014ck2 | 2014cs - 2012cs % | 2014ck2 - 2012ck % | 2012cs - 2005cs % | 2012ck - 2005ck % |
|---|---|---|---|---|---|---|
| -2,946 | 5,866 | 3,148 | -3.1% | -0.3% | -6.9% | -10.7% |
| -1,033 | -405 | -2,632 | -1.4% | 1.6% | -9.1% | -4.0% |
| -434 | -1,258 | -1,438 | -0.7% | -0.4% | -2.9% | 1.2% |
| -2,977 | -3,413 | -4,547 | -1.2% | -0.7% | -3.7% | -4.7% |
| -766 | -1,070 | -348 | -1.2% | -2.2% | -5.7% | -2.0% |
| -395 | -296 | -424 | -2.7% | -1.8% | -13.4% | -7.4% |
| -1,641 | -2,564 | -4,029 | -31.3% | -2.3% | -29.6% | -6.5% |
| -58 | 126 | 108 | -4.9% | -3.8% | -17.7% | -16.3% |
| -124 | -11,145 | -22,900 | -0.1% | 5.3% | -10.5% | -6.3% |
| -9,681 | 9,841 | 1,427 | -7.1% | -1.0% | -8.0% | -11.3% |
| -309 | 401 | 395 | -0.3% | -0.3% | -1.2% | -0.9% |
| -10,206 | 2,466 | -9,614 | -8.3% | 1.6% | -7.5% | -5.1% |
| -4,672 | 22,597 | 19,556 | -3.3% | -1.3% | 4.1% | -11.3% |
| -945 | -1,732 | -3,989 | -1.3% | 1.8% | -11.6% | -7.6% |
| -818 | -764 | -1,445 | -0.5% | -0.1% | -3.5% | -2.3% |
| -1,634 | 3,862 | 3,137 | -2.1% | -1.2% | 1.5% | -0.1% |
| -1,082 | -16,226 | -16,774 | -1.3% | -0.5% | -8.7% | -3.0% |
| -471 | -364 | -261 | -2.1% | -2.6% | -9.2% | -6.3% |
| -1,271 | -2,611 | -18,625 | -3.2% | 34.4% | -27.0% | -20.5% |
| -521 | -3,741 | -3,994 | -1.3% | -0.6% | -14.3% | -6.3% |
| -1,142 | -532 | 229 | -1.4% | -2.3% | -12.8% | -6.7% |
| -1,444 | -6,052 | -6,148 | -1.4% | -1.2% | -6.2% | 1.6% |
| -722 | 417 | 576 | -1.1% | -1.3% | -5.4% | -4.4% |
| -1,503 | 2,224 | 944 | -1.4% | -0.2% | -2.0% | -0.7% |
| -416 | -1,968 | -1,948 | -0.8% | -0.8% | -4.8% | -0.3% |
| -713 | -710 | -1,762 | -1.3% | 0.6% | -3.6% | -1.1% |
| 609 | -284 | -9,797 | 1.7% | 27.3% | -7.7% | -6.1% |
| -157 | -272 | -56 | -1.0% | -2.2% | -16.1% | -12.5% |
| -102 | -3,446 | -2,975 | -0.4% | -1.9% | -20.9% | -8.6% |
| -429 | -1,601 | -1,756 | -0.4% | -0.3% | -4.0% | -1.4% |
| -1,431 | -2,659 | -10,280 | -1.9% | 8.0% | -12.0% | -7.4% |
| -2,733 | -4,835 | -8,185 | -2.9% | 0.6% | -10.5% | -6.0% |
| -489 | 645 | 682 | -0.9% | -1.0% | -5.3% | -5.8% |
| -3,222 | 32,344 | 28,417 | -2.4% | 0.7% | -6.0% | -26.3% |
| -819 | 740 | -494 | -0.7% | 0.4% | -1.2% | 1.2% |
| -753 | -1,425 | -1,770 | -0.6% | -0.3% | -2.6% | -1.4% |
| -1,726 | 9,675 | 6,983 | -1.6% | 1.0% | -22.2% | -26.1% |
| -75 | -221 | -260 | -3.4% | -1.5% | -13.0% | -6.4% |
| 603 | 2,791 | 2,606 | 1.0% | 1.4% | -7.6% | -11.4% |
| -499 | 716 | 623 | -1.1% | -0.9% | -4.3% | -5.0% |
| -3,160 | 11,937 | 10,004 | -3.7% | -1.7% | -1.1% | -11.7% |
| -3,668 | 3,162 | -3,853 | -1.2% | 1.1% | -7.4% | -3.8% |
| -1 | -2 | -2 | -0.1% | -0.1% | 0.0% | -0.9% |
| -473 | 271 | 52 | -0.9% | -0.5% | -4.1% | -2.6% |
| -96 | 38 | 139 | -1.1% | -2.3% | -5.1% | -3.9% |
| -1,881 | -579 | -1,949 | -2.7% | -0.7% | -13.7% | -11.2% |
| -1,107 | -2,535 | -2,925 | -1.8% | -1.1% | -10.9% | -4.6% |
| -2,064 | 15,551 | 12,522 | -3.4% | 2.1% | 14.9% | -13.2% |
| -811 | -2,866 | -3,636 | -1.4% | -0.1% | -7.1% | 1.1% |
| -216 | -1,892 | -2,035 | -0.3% | -0.1% | -5.3% | -1.8% |
| -72,625 | 48,201 | -59,302 | -1.8% | 0.9% | -6.8% | -6.3% |

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