

**NOTICE OF INTENT AND
PREVENTION OF SIGNIFICANT
DETERIORATION
AIR QUALITY APPLICATION FOR
580 MEGAWATT COMBINED-CYCLE
POWER PLANT
SEVIER POWER COMPANY
VOLUME 1**

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Project No. 091110137

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**NOTICE OF INTENT AND PREVENTION OF SIGNIFICANT DETERIORATION
AIR QUALITY APPLICATION FOR
580 MEGAWATT COMBINED CYCLE POWER PLANT
SEVIER POWER COMPANY**

1.0 INTRODUCTION

Sevier Power Company (SPC) proposes to construct and operate a new natural gas-fired combined-cycle power generating plant to be located approximately 8 miles northeast of Richfield Utah in Sevier County, Utah. The proposed plant upon completion will include a single power block, fired exclusively on pipeline-quality natural gas, and will consist of either two General Electric (GE) Frame 7FA or Siemens Westinghouse 5000-F(4) gas turbines, two heat recovery steam generators (HRSGs) with supplemental firing, and one steam turbine in a combined-cycle configuration, with associated equipment including an air-cooled condenser, a natural gas-fired auxiliary boiler, two natural gas-fired fuel heaters, a diesel engine-driven fire pump, and a diesel engine emergency generator. The combined cycle plant will have a nominal electrical generating capacity output of approximately 580 megawatts (MWe).

The proposed plant is considered to be a major Prevention of Significant Deterioration (PSD) source and is listed as one of the 28 major categories as defined in 40 CFR Part 52.21. The criteria pollutants that will be emitted from the facility are nitrogen oxides (NO_x), carbon monoxide (CO), volatile organic compounds (VOCs), particulate matter (PM₁₀ and PM_{2.5}), and sulfur dioxide (SO₂). The proposed electric generating facility has the potential to emit (PTE) regulated pollutants in amounts above significant levels as 40 CFR Part 52.21 (b) 23 for the following: NO_x, PM₁₀ and PM_{2.5}, CO, and VOC.

This permit application includes information required to approve the construction of a new major source such as the one being proposed by SPC. This permit application is organized into the following sections:

- **Section 2.0 – Project Description.** This section contains information describing the proposed facility and equipment; the site location; the project contact person for this permit application, and the applicable National American Industry Classification System (NAICS).
- **Section 3.0 – Project Emissions.** This section presents a detailed review of the potential emissions during normal or steady state operations and startup/shutdown operations. Emissions from all other proposed ancillary equipment and fugitives from roads are included in this section.
- **Section 4.0 – Regulatory Review.** This section presents an assessment of applicable state and federal regulations. This section focuses on establishing which regulations are directly applicable to the proposed combined-cycle turbines and the ancillary equipment and for which compliance must be demonstrated.
- **Section 5.0 – Best Available Control Technology Demonstration.** This section is a substantial requirement of the Notice of Intent (NOI)/PSD application. Since the proposed project will be a new major source, a detailed evaluation of control technologies and emission rates is provided. EPA’s “top down” best available control technology (BACT) approach was used for these determinations
- **Section 6.0 – Near-Field Dispersion Modeling Analyses.** This section summarizes the near-field dispersion modeling conducted to evaluate the potential impacts from the proposed SPC facility against the Significant Impact Levels (SILs), National Ambient Air Quality Standards (NAAQS) and to PSD Class II increments. Specifically, this section discusses the modeling input data and the various modeling scenarios evaluated. This section also presents the results of the Class II area analyses performed and compares the calculated impacts to the applicable standards.

- **Section 7.0 – Far-Field Dispersion Modeling Analysis.** This section presents the results of the Class I Area air dispersion modeling analysis performed for the project. This includes the results of the Class I concentration analyses and compliance with the PSD Class I increments. It also discusses the results of the initial screening test (Q/D) to determine if further visibility (regional haze) and deposition modeling were required.
- **Section 8.0 – Other Air Quality Issues.** This section contains supplemental information regarding the potential impacts of the project; specifically, the potential for impacts to soils, vegetation, and growth.
- **Section 9.0 – References.** This section includes a list of the documents relied upon during the preparation of this document.

Class F combustion turbines manufactured by GE or Siemens were considered for this permit application. The emissions for each combustion turbine vendor, BACT requirements, and dispersion modeling impacts have been addressed in this permit application. Final vendor selection is anticipated after receipt of air approval order.

2.0 PROJECT DESCRIPTION

The following sections contain information on the project location, the county air quality designation, the contact person for this permit application, the North American Industry Classification System (NAICS) code for the proposed facility, and detailed descriptions on the proposed facility and equipment.

2.1 Project Location

The proposed SPC plant site is an approximate 54-acre parcel surrounded by an additional 241 acres located approximately 8 miles northeast of Richfield, Utah near the town of Sigurd, Utah. Sigurd is located in Sevier County, Utah near the mouth of a northeast-southwest oriented canyon. The Universal Transverse Mercator (UTM) coordinates for the facility, in WGS84 are: 414332 meters East and 4300261 meters North. The site is accessible via Highway 118. The site is directly across from Rocky Mountain Power's Sigurd substation. SPC will be using pipeline-quality natural gas supplied through Kern River Gas Company. Figure 2.1 presents a Google Earth map showing the general location of the proposed power plant.

2.2 Air Quality Designation

Sevier County is designated as attainment for all existing National Ambient Air Quality Standards (NAAQS). The closest non-attainment area, Utah County, which is located approximately 67 miles north of the proposed facility, is in non-attainment for PM_{10} and $PM_{2.5}$. The closest PSD Class I area to the proposed facility is Capitol Reef National Park at a distance of 61.6 kilometers (38.3 miles) to the southeast of the proposed plant.

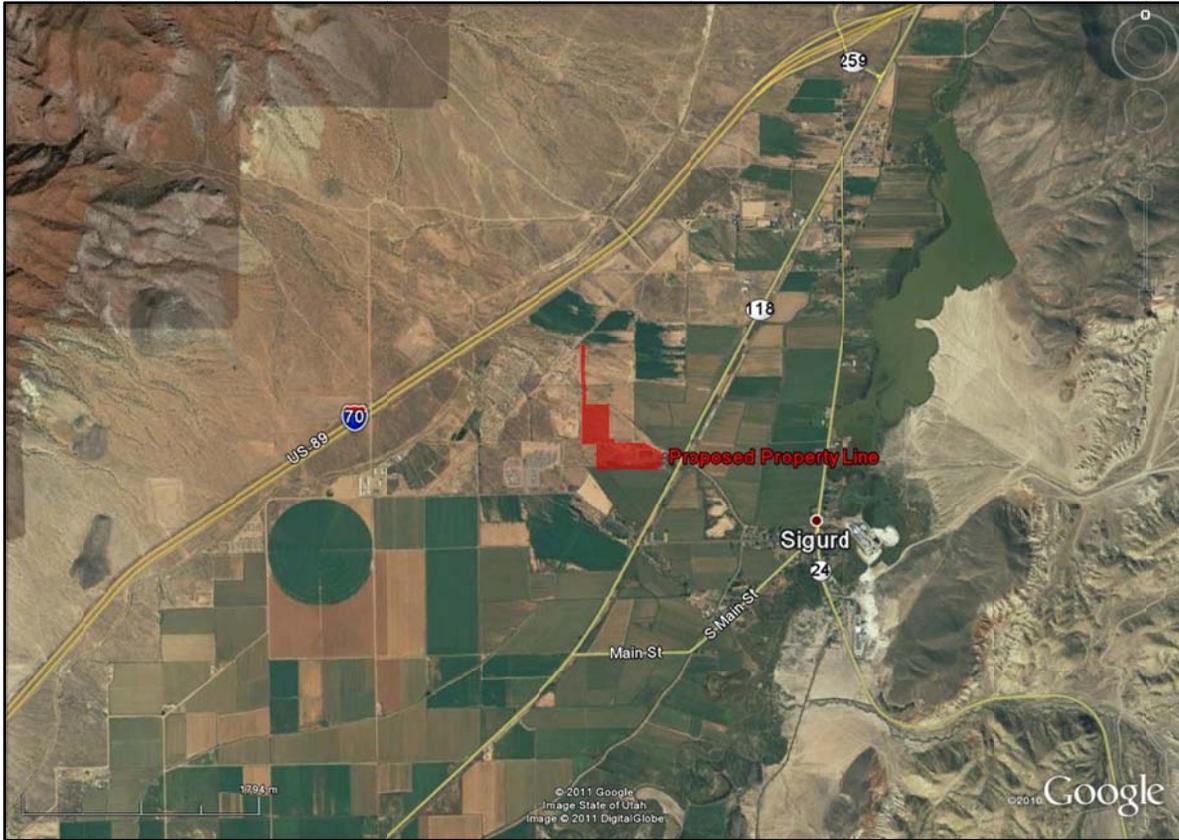


Figure 2.1 Google Earth Image Showing Location of Proposed SPC Power Plant

2.3 Applicant Information

To facilitate review of this document, the contact for this permit application is:

Mr. Bruce Taylor
Sevier Power Company
620 South Main Street
Bountiful, Utah 84010
(801) 916-7341

2.4 National American Industry Classification System

The NAICS is the standard used by federal statistical agencies in classifying business establishments for the purpose of collecting, analyzing, and publishing statistical data related to the U.S. business economy. Sector 22, Utilities, is comprised of establishments engaged in the provision of the following utility services: electric power, natural gas, steam supply, water supply, and sewage removal. Within this sector, the specific activities associated with the utility services provided vary by utility: electric power includes generation, transmission, and distribution; natural gas includes distribution; steam supply includes provision and/or distribution; water supply includes treatment and distribution; and sewage removal includes collection, treatment, and disposal of waste through sewer systems and sewage treatment facilities.

2.5 Facility Equipment

The proposed facility will be a combined-cycle natural gas power plant with a nominal electrical generating capacity of approximately 570 megawatts (MWe). The major components of the proposed power plant include:

- two F-class (either GE Frame 7FA or Siemens 5000-F(4)) combustion gas turbines (CT) equipped with dry low NO_x combustors designed for natural gas;
- two multi-pressure heat recovery steam generators (HRSGs) with duct burners and a selective catalytic reduction system (SCR) and catalytic oxidation system;
- one steam turbine-generator (STG) system with multi-cell air cooled condenser and associated auxiliary system and equipment (i.e., lubrication oil system including oil coolers and filters, and generator coolers);
- fuel gas cleaning and heating system;
- two convection fuel gas heaters;
- an auxiliary boiler to supply steam to maintain HRSG and steam turbine temperatures in order to reduce plant start times;

- an emergency standby diesel generator to supply power to the plant in the event of a utility power failure or extended utility outages during maintenance and shutdowns; and
- an emergency diesel-fueled fire pump engine for fire protection.

The general facility layout, including the location of the major pieces of equipment and the location of all proposed emission sources are presented in Figures 2.2 and 2.3. Figures 2.4 and 2.7 present the conceptual elevation views for each cardinal direction for the proposed plant.

2.5.1 Combustion Turbines

The proposed SPC power block will include two (2) F-class combustion turbines (CT) each in a two-over-one combined cycle configuration and one steam turbine. Each combustion turbine will be equipped with a HRSG that will include supplemental natural gas firing (duct firing). The CTs will be fired by pipeline-quality natural gas and annual operation of each combined-cycle CT will be 8,760 hours per year. The combined cycle turbines will be equipped with selective catalytic reduction (SCR) to minimize NO_x emissions and an oxidation catalyst to minimize CO and VOC emissions.

In a combined cycle power system, the gas CT is the main component. Within each combustion turbine, combustion air is compressed and mixed with fuel, then fired in the dry low-NO_x combustor to produce compressed hot combustion gases. Expansion of these gases in the turbine rotates the turbine shaft, which turns a generator to produce electricity. The exhaust gas exiting the power turbine from the combined-cycle turbines is ducted to a HRSG where steam is produced to generate additional electricity in the steam turbine generator. Natural gas-fired duct burners located within the HRSGs are used for supplemental firing to increase steam output.

The CTs are designed to operate in the dry low-NO_x mode at loads from approximately 50 up to 100 percent rating. The CTs will periodically be taken out of service for scheduled maintenance or as dictated by electric or economic demand conditions.

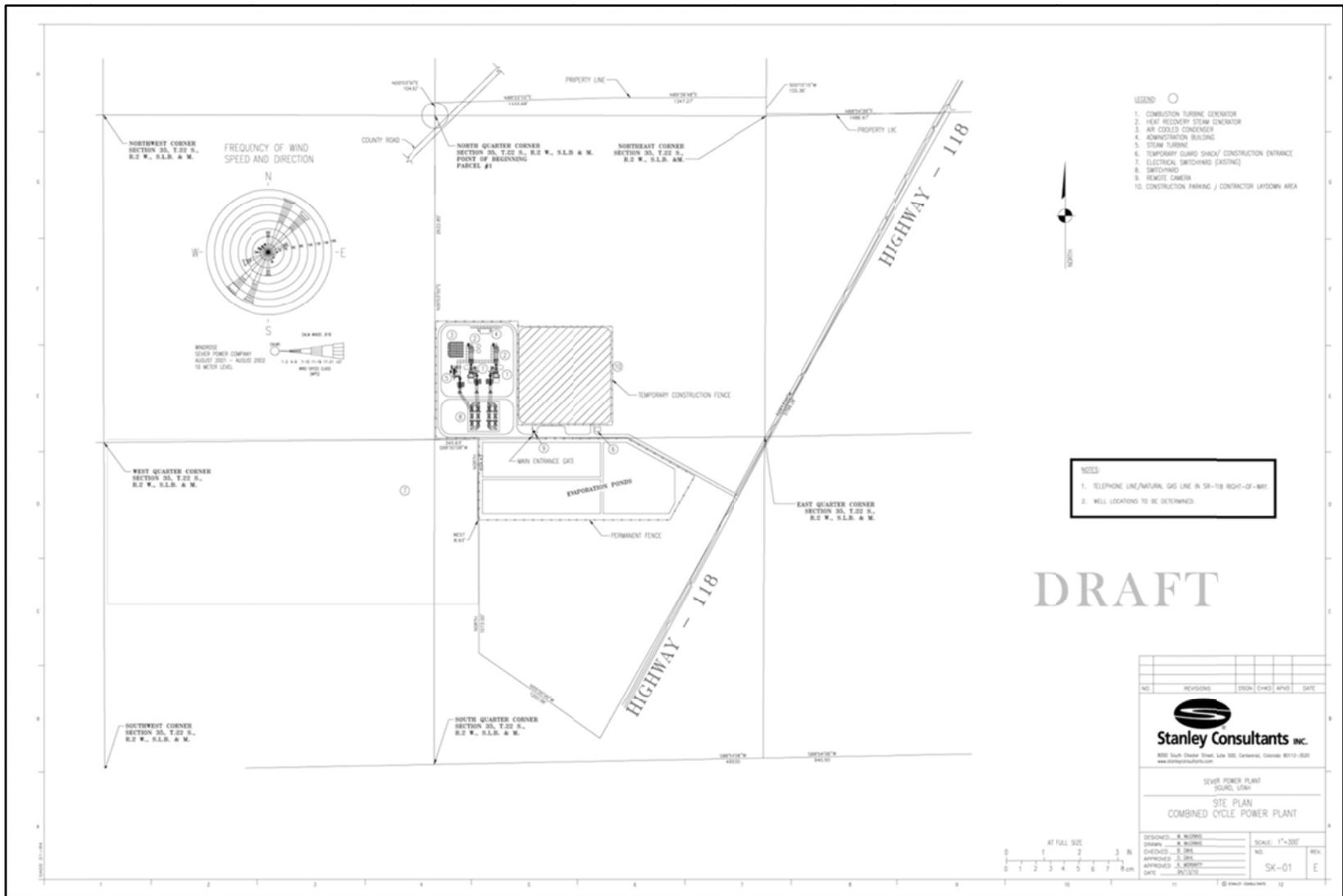


Figure 2.2 Preliminary SPC Plant Site Layout

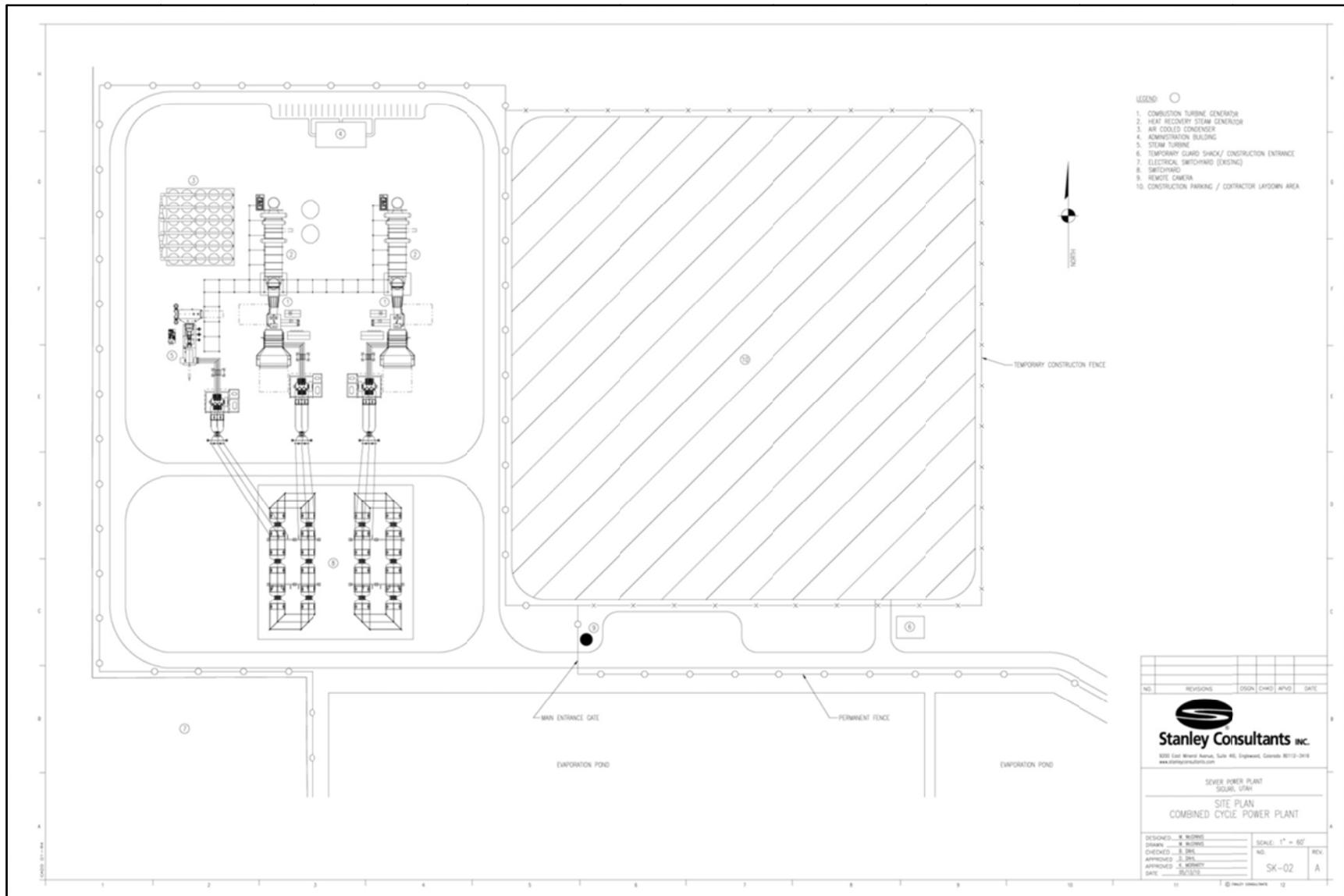


Figure 2.3 Enhanced View of SPC Combined-Cycle Plant Layout

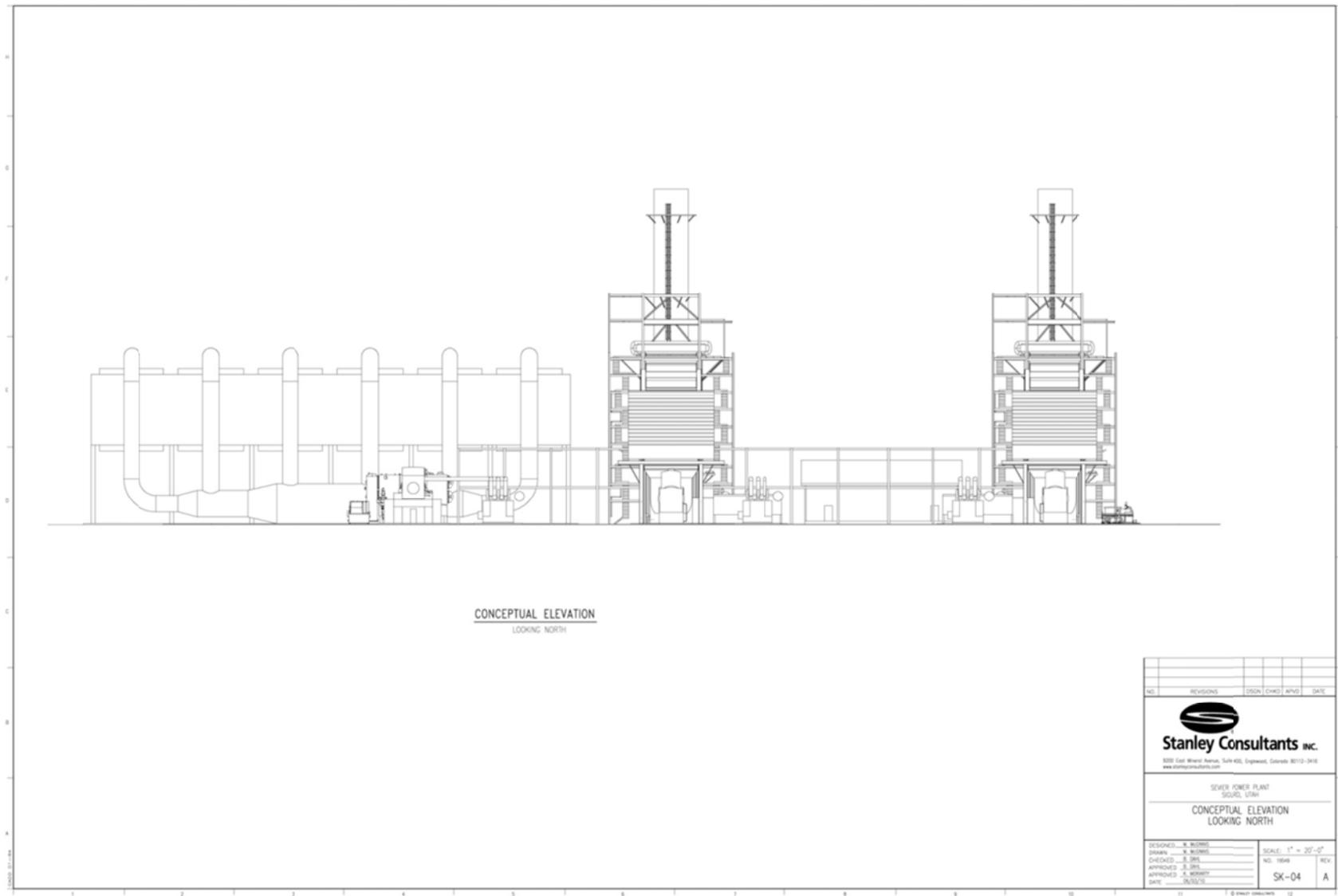


Figure 2.4 Conceptual Elevation View Looking North

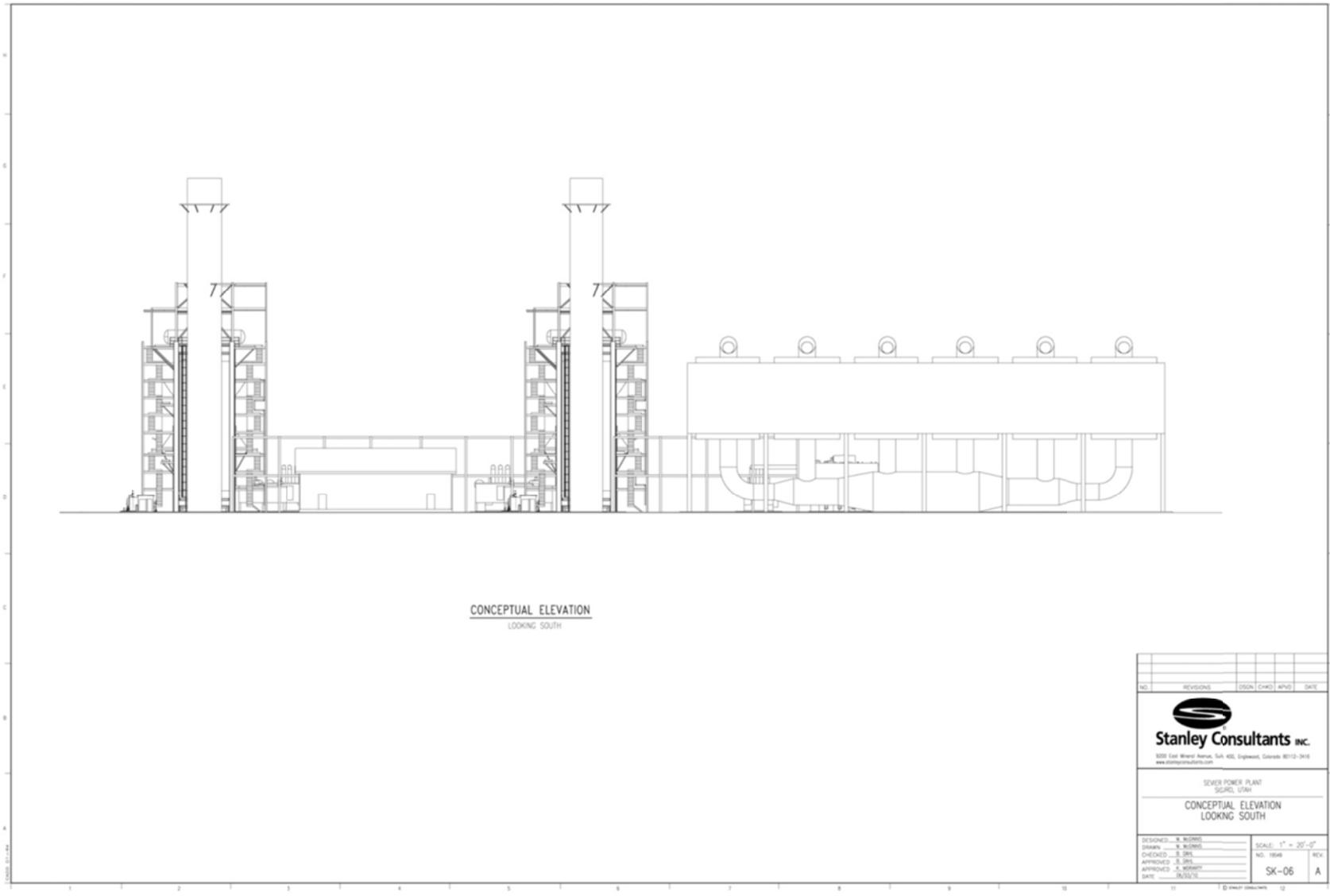


Figure 2.5 Conceptual Elevation View Looking South

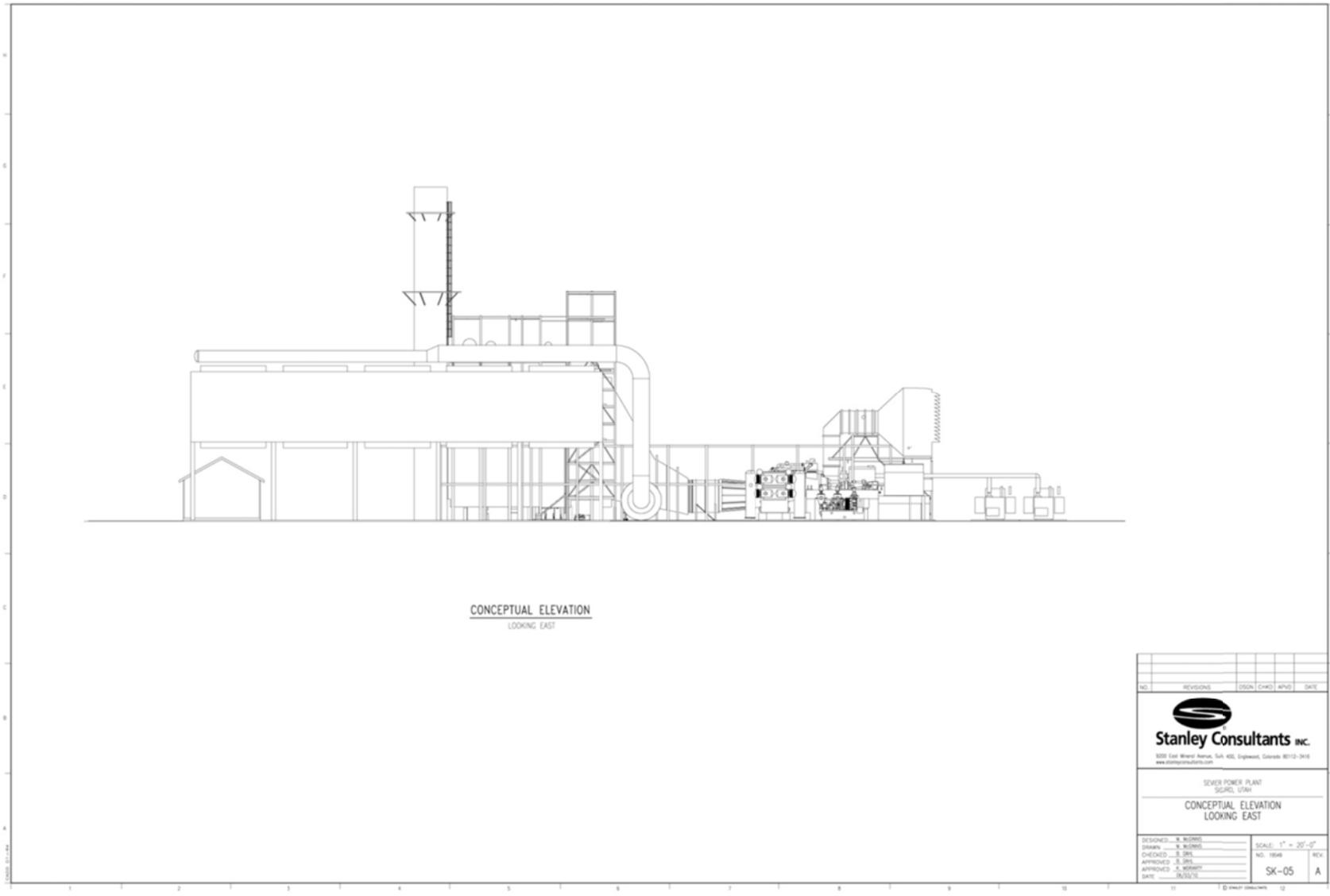


Figure 2.6 Conceptual Elevation View Looking East

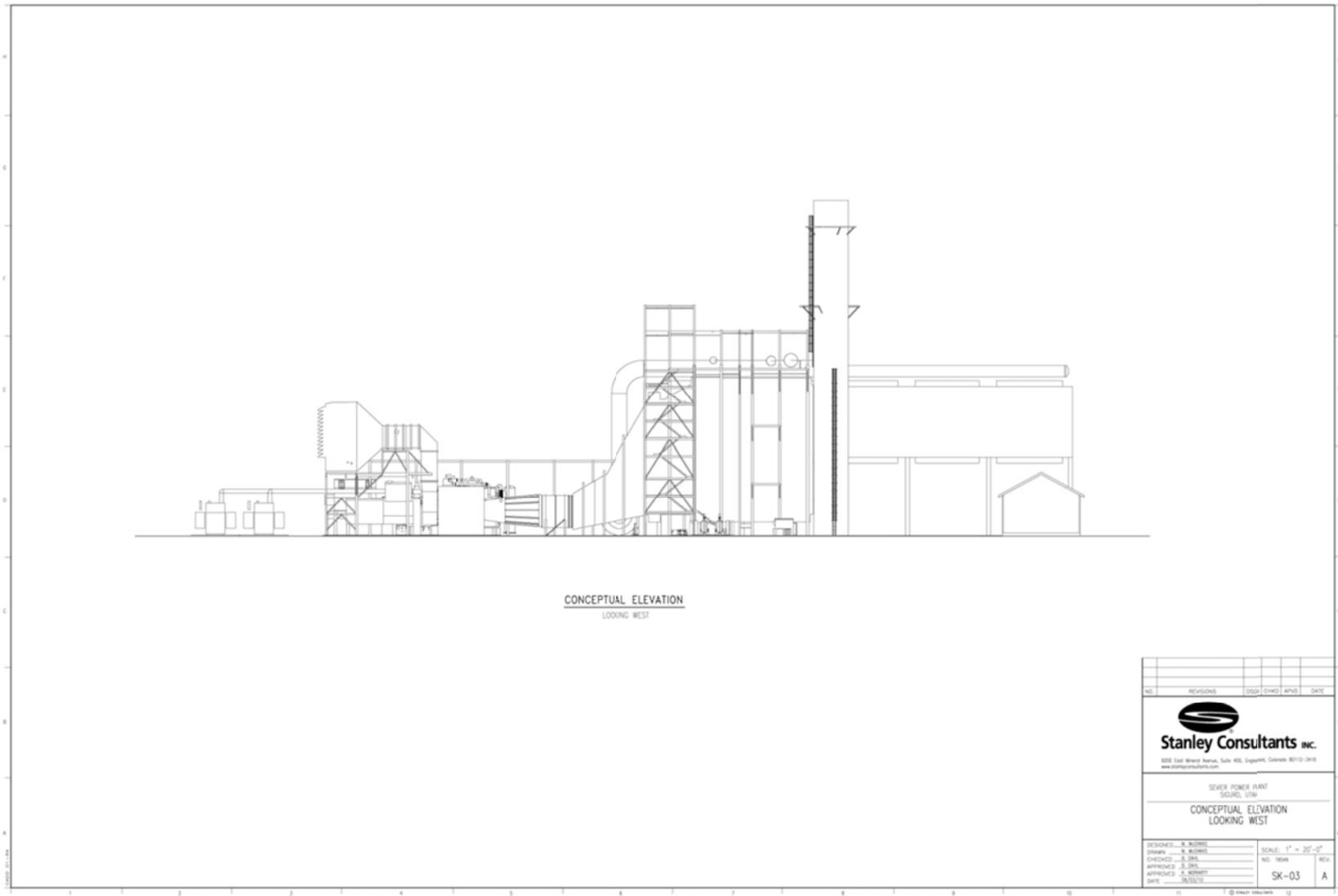


Figure 2.7 Conceptual Elevation View Looking West

2.5.1.1 GE Frame 207FA

For this project, each GE Frame 207FA CT is designed to produce a nominal of 182 MWe of gross electrical power at full load without duct burner firing at an average annual temperature of 48°F. CT power output will decrease somewhat when ambient air temperature increases and the output will increase as temperature decreases. This change in power output is related to the mass flow of combustion air through the turbine.

The proposed GE CTs combined power output at full load will be approximately 333 MWe (gross power output) at a summer extreme ambient temperature of 104°F and the power output will increase to approximately 395 MWe (gross power output) at a winter extreme temperature of -17°F. Figure 2.8 presents an illustration of a GE Frame 207FA CT.

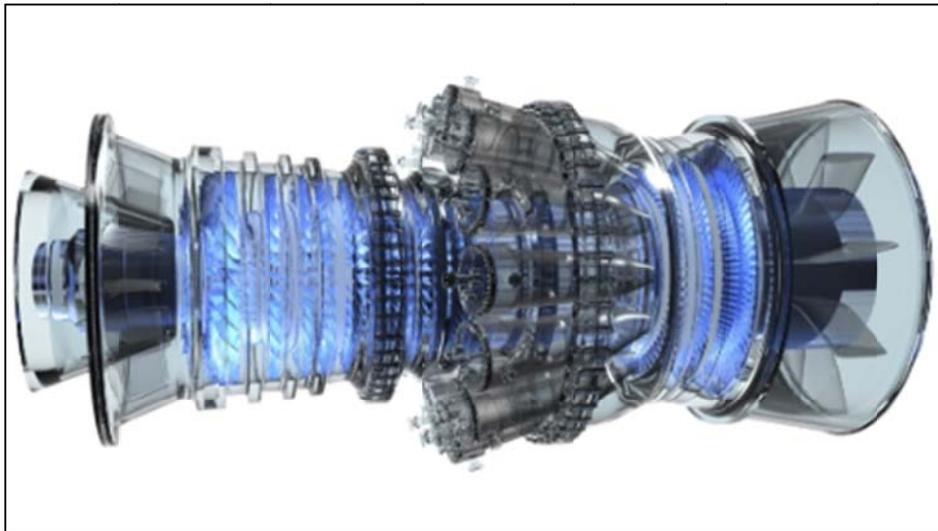


Figure 2.8 GE Frame 207FA Combustion Turbine

2.5.1.2 Siemens 5000-F(4)

Each proposed Siemens 5000-F(4) CT is designed to produce a nominal of 173 MWe of gross electrical power at full load and an average annual temperature of 48°F. Combined CT power output at full load will be approximately 305 MWe at a summer extreme ambient temperature of 104°F and increase to approximately 407 MWe at a winter extreme temperature of -17°F. An illustration of the Siemens 5000-F(4) CT is presented in Figure 2.9.

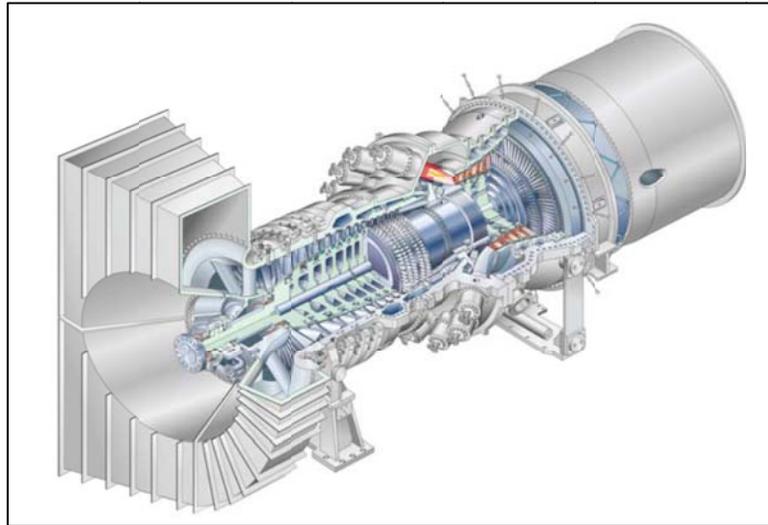


Figure 2.9 Siemens 5000-F(4) Combustion Turbine

2.5.2 Heat Recovery Steam Generators

Regardless of vendor, each CT will be equipped with a duct-fired HRSG. HRSG's are used to recover waste heat from the exhaust of the CT in the useful form of steam. The steam generated can be used for the production of power from a steam turbine. A horizontal, natural circulation, three-pressure HRSG system will extract heat from the exhaust of each proposed CT. Exhaust gas entering the HRSG at approximately 1,100°F will be cooled to approximately 185°F by the time it leaves the HRSG exhaust stack.

Steam production in the HRSGs will be augmented using natural gas-fired duct burners. The heat recovered is used in the combined-cycle plant for additional steam generation. Steam from the HRSG is used to drive a steam turbine connected to an electrical generator. Exhaust gas from the HRSG passes through additional emission control equipment prior to being discharged to the atmosphere through a stack.

Each HRSG will include high-, intermediate-, and low-pressure superheaters, a high-, intermediate-, and low-pressure evaporators, high- intermediate-, and low-pressure economizers, and reheat sections. The air-cooled condenser will condense the steam exhausting through the steam turbine generator. As the steam is condensed, the condensate flows to the condensate tank and will be reused.

Heat input from the duct burners will vary depending on steam requirements and ambient conditions. Based on heat balance performance calculations prepared for this project, heat input from the duct burners can be as high as 540 MMBtu/hr during summer ambient conditions. Based on heat balances prepared for this project, steam production at average annual ambient conditions from the HRSG is estimated to be approximately 800,000 lb/hr without duct firing and 1,000,000 lb/hr with duct firing. SPC has assumed 5,000 hours of duct burning per year.

Each HRSG will exhaust to a metal exhaust stack which is approximately 165 feet tall. Exhaust gas entering the HRSG at approximately 1,100°F will be cooled to approximately 185°F by the time it leaves the HRSG exhaust stacks. In addition to the use of combustion controls, post-combustion control devices such as selective catalytic reduction (SCR) and oxidation catalysts will be installed to control NO_x, CO, and VOC emissions, respectively.

2.5.3 Steam Turbine Generator

The proposed project includes one reheat, condensing steam turbine generator (STG) designed for variable pressure operation. The high-pressure portion of the steam turbine receives high-pressure super-heated steam from the HRSGs, and exhausts to the reheat section of the HRSGs. The steam from the reheat section for the HRSGs is supplied to the intermediate-pressure section of the turbine, which expands to the low-pressure section. The low-pressure turbine also receives excess low-pressure superheated steam from the HRSGs and exhausts to the air cooled condenser. The steam turbine set is designed to produce up to 253 MWe of nominal gross power output with duct firing and 182 MWe without duct firing at the annual average temperature of 48°F.

2.5.4 Air Cooled Condenser

Steam from the low pressure section of the steam turbine will be condensed in an air cooled condenser prior to being recycled. The proposed air cooled condenser is comprised of fin tube bundles grouped together into modules and mounted on an A-frame configuration on a steel support structure. To achieve efficient and reliable condensation, a two-stage single pressure condensing process will be employed.

In this process, steam is first ducted from the steam turbine to the air cooled condenser where it enters parallel low fin tube bundles from the top. The steam is only partially condensed in the parallel flow modules and the remaining steam is ducted in a lower heater to counterflow fin tube bundles. The steam enters from the bottom and rises in the fin tubes to a point where condensation is completed. The condensate drains by gravity to a condensate tank and is then sent back to the feed water system to be recycled.

There are both advantages and disadvantages to using an air cooled condensing system. Advantages include a significant reduction in water use (compared to wet cooling systems) and the elimination of particulate matter emissions (from cooling towers). Because ambient air is used as the cooling medium, and the air cools the steam without coming into contact with the condensate or any other potential contaminants, there are no emissions associated with an air cooled condensing system. Therefore, the ACC has not been identified as an emissions source at SPC. The primary disadvantage of utilizing an air cooled condensing system is related to the auxiliary power requirement associated with the fans used to move ambient air past the heat exchangers in addition to the higher capital cost for the system.

2.5.5 Auxiliary Boiler

SPC is proposing to add an 85 MMBtu/hr auxiliary boiler that would provide auxiliary steam when the plant is off-line and during startups. This auxiliary steam will be used for condensate sparging and to maintain the seals and prevent loss of vacuum in the steam turbine and condenser, so that the steam turbine is maintained in a ready state and can start up as quickly as possible. The auxiliary boiler will combust pipeline-quality natural gas only. The steam from the auxiliary boiler will not be used to augment the power generation of the CT or STG. SPC's proposed operating schedule is 8,760 hours per year.

2.5.6 Convection Fuel Heaters

Two (2) 22.3 MMBtu/hr convection fuel gas heaters will be operated in conjunction with the combustion turbines. The purpose of this heater is to superheat the natural gas prior to its introduction into the combustion turbines in order to provide the optimum combustion efficiency in addition to increasing the plants overall efficiency. These heaters will fire pipeline-quality natural gas. SPC proposed operating schedule for the convection fuel gas heaters is 8,760 hours per year.

2.5.7 Fuel Gas System

Pipeline quality natural gas will be used by SPC. The fuel delivered to the gas turbine must be liquid free and contain a specified level of super heat above the higher of the hydrocarbon or moisture dew points. A coalescing filter skid will be utilized to protect the downstream gas fuel system against the entry of both liquid phase and particulate contaminants. At rated flow, the efficiency of the filter is 100% for solid and liquid particulates 0.3 microns or larger. The skid consists of two 100% gas flow coalescing filters. Each filter is designed for performing maintenance without removing the gas turbine from service.

A gas fuel scrubber provides the final level of filtration directly upstream of the turbine. The gas fuel scrubber is a vertical, multi-cyclone, high-efficiency dry-type separator. The scrubber vessel is made of carbon steel. The scrubber removes water droplets from the gas stream following the event of a heater tube leak or failure. The scrubber has an automatic drain system that discharges to a drain tank.

2.5.8 Electric Startup Fuel Gas Superheater

Two (2) electric startup fuel gas superheaters are required at ignition when the fuel supply does not meet the minimum required superheat level such as during startup. The heated fuel needs to meet the Modified Wobbe Index requirement of the gas turbine's combustion system. The heater's capacity is sized to provide the minimum temperature rise for fuel flows up to the point where the convection fuel gas heaters can take over and increase the temperature for optimal plant efficiency.

2.5.9 Emergency Diesel Generator

SPC is proposing a 1250 kWe emergency diesel generator to supply essential power during an interruption of the electrical power supply to the site. This generator will be operated up to 500 hours per year, including monthly testing and maintenance, and will provide power in emergency situations. The diesel engine will be designed to fire low-sulfur diesel fuel. The proposed generator will be EPA Tier II compliant.

2.5.10 Emergency Fire Water Pump

SPC is proposing a 300 kWe diesel-fired fire water pump operated as a fire water pump driver. The unit will be limited to 500 hours per year, including monthly testing and maintenance. This proposed fire water pump diesel engine is designed to fire low-sulfur diesel fuel and will meet EPA Tier 3 emission levels.

3.0 PROJECT EMISSIONS

This section presents a discussion of the project emissions and the methodologies used to calculate the emissions. Emissions from the SPC facility will be primarily the products of natural gas combustion in the CTs/HRSGs, convection fuel gas heaters, and auxiliary boiler. The emergency generator and fire-water pump will have limited use, but are also sources of emissions associated with fuel combustion.

Emission calculations were prepared for each proposed SPC source to determine: (1) the potential to emit (PTE) emission rates of sources during normal operation; (2) the PTE emission rates of the CTs/HRSGs emissions during periods of start/up and shut down; and (3) annual PTE emission rates. In determining the potential emissions from the SPC Project, emission calculations were based on manufacturer data provided by combustion turbine suppliers, other vendor equipment data, emission factors found in EPA's *Compilation of Air Pollutant Emission Factors* (AP-42), and BACT emission limits. Operational limitations have been accounted for in estimating potential emissions to make the emission estimates more representative of actual on-site equipment operations.

For the natural gas fired sources, SO₂ emissions were assumed to be directly attributed to fuel sulfur content. Thus, for SPC, SO₂ emissions were based on a worst-case fuel sulfur content of 0.75 grains sulfur per 100 standard cubic feet (0.75 gr/100 scf) of natural gas.

PM_{2.5} emission rates were requested from each CT vendor. However, direct, speciated PM_{2.5} emission rate projections were not available. The PM emissions provided by each vendor were based on EPA Methods 5 and 202 and included both condensable and filterable fractions. Because the fuel source for the CT's is natural gas, combustion emissions are likely to be only PM_{2.5} filterable and condensable. To speciate these filterable and condensable emissions, the following conservative assumptions were made:

- All PM emissions are PM₁₀,
- All PM₁₀ emissions are PM_{2.5}.

PM₁₀ emissions were provided by each CT vendor. These emissions were then scaled by fuel input to the CT to determine emissions at partial loads. In addition, all primary sulfate emitted from the CTs plus sulfate converted from SO₂ by the SCR and CO catalysts are assumed to fully react with available SCR ammonia to form ammonium sulfate which was treated as both PM₁₀ and PM_{2.5}.

3.1 Annual Potential to Emit

The annual potential-to-emit (PTE) criteria pollutant emissions presented in tons per year in Table 3-1 represent the highest projected emissions from each proposed CT vendor at average temperature and humidity (48°F and 61% RH) and at 100% load. These emissions are for the entire combined cycle power block (2 CTs/HRSGs) including 5,000 hours with supplemental duct firing. NO_x, CO, SO₂ and VOC emission estimates presented in Table 3-1 are based on Siemens supplied CT/HRSG data; PM₁₀ and PM_{2.5} emissions are based on GE supplied CT/HRSG data. The emissions from all other project affiliated equipment will not change, regardless of vendor chosen.

**Table 3-1
Potential-to-Emit Annual Emission Estimates for SPC Project**

Emission Source	NO_x (TPY)	CO (TPY)	SO₂ (TPY)	PM₁₀ (TPY)	PM_{2.5} (TPY)	VOC (TPY)	HAPS (TPY)
CT #1/HRSG ¹²³⁴	74.5	120.2	12.1	50.1	50.1	44	3.7
CT #2/HRSG ¹²³⁴	74.5	120.2	12.1	50.1	50.1	44	3.7
Auxiliary Boiler	6.3	14.0	0.9	3.7	3.7	2.2	0.69
Convection Heater #1	3.5	7.2	0.06	0.98	0.98	0.6	0.18
Convection Heater #2	3.5	7.2	0.06	0.98	0.98	0.6	0.18
Emergency Gen. & tank	4.7	0.7	0.19	0.04	0.04	0.19	0.005
Fire Pump & tank	1.3	0.1	0.25	0.02	0.02	0.03	0.003
Paved Roads	NA	NA	NA	0.06	0.01	NA	NA
Total Annual PTE	168.3	269.6	25.7	106.0	106.0	91.6	8.5

¹ Includes startup and shutdown emissions.

² NO_x, CO, SO₂ and VOC emission estimated based on Siemens supplied emissions data at average temperature and humidity, 100 load with duct firing.

³ PM₁₀ and PM_{2.5} emission estimates based on GE supplied emissions data at average temperature and humidity, 100 load with duct firing.

⁴ HAPS emissions based on HHV and Siemens performance data.

3.2 Combustion Turbines/HRSG Emissions

GE Power Systems and Siemens Westinghouse provided CT/HRSG exhaust emission estimates for this project. Each vendor provided volumetric concentration values and hourly emission rates based on those concentration and mass weight values. The estimates provided were based on steady-state operating conditions for a range of ambient temperatures and load conditions. The combined cycle emissions were based on vendor estimated concentration emissions following the duct burners and controls, based on turbine exhaust concentrations. Appendix A contains the normal operating CT/HRSG emission estimates from each vendor.

3.2.1 Normal Operating Emissions

Normal operation of the CTs is defined as continuous operation of the CTs at normal operating loads which ranges between 50% and 100%. A load of 50% was assumed to be emission compliant (both SCR and CO catalyst systems fully operating). Normal operations also include HRSG duct firing during base load operations.

The CT load levels, duct firing rates, and ambient conditions that were used to estimate potential emissions of NO_x, CO, VOC, PM, and SO₂ for the GE 207FA and Siemens 5000-F(4) CTs/HRSGs for each operating scenario are presented in Table 3-2 and in Appendices A and B, respectively. Emissions for each CT were based on 8,760 hours per year of operation which includes 5,000 hours per year of HRSG duct burner firing. The operating cases cover the expected range of conditions in which SPC may operate at full load and bracket the worst-case air pollutant emissions. Emissions of NO_x are based on a BACT emission rate of 2 ppmvd at 15% O₂. CO and VOC emissions are based on a BACT emission rate of 3 ppmvd at 15% O₂. Emissions of SO₂ and PM₁₀/PM_{2.5} are based on sulfur fuel content, CT design data and engineering estimates.

Table 3-2

Operating Scenarios and Maximum Hourly Emissions for Each Operating Load Case by Vendor

Operating Load Case		Duct Burner	Ambient Conditions	CT Load (%)	NO _x (lb/hr)	CO (lb/hr)	VOC (lb/hr)	PM ₁₀ /PM _{2.5} (lb/hr)	SO ₂ (lb/hr)
GE									
SPC #1	GE #1	Fired	104°F/41% RH	2 X 100%	13	12	7	14	2.9
SPC #3	GE #4	Unfired	104°F/41% RH	2 X 52%	8	7	4	11	1.8
SPC #4	GE #6	Fired	48°F/61% RH	2 X 100%	14	13	7	14	3.1
SPC #5	GE #8	Unfired	48°F/61% RH	2 X 100%	13	12	7	12	2.9
SPC #6	GE #9	Unfired	48°F/61% RH	2 X 49%	8	8	4	11	1.8
SPC #10	GE #7	Fired	48°F/61% RH	2 X 100%	14	12	7	13	3.0
SPC #11	GE #14	Fired	-17°F/100% RH	2 X 100%	15	14	8	14	3.3
SPC #13	GE #16	Unfired	-17°F/100% RH	2 x 56%	10	9	5	11	2.1
SPC #14	GE #18	Unfired	65°F/51% RH	2 X 100%	13	12	7	12	2.8
Siemens									
SPC #1	Siemens #1	Fired	104°F/41% RH	2 X 100%	14	9	5	11	3.2
SPC #2	Siemens #2	Unfired	104°F/41% RH	2 X 100%	12	7	2	8	2.7
SPC #3	Siemens #3	Unfired	104°F/41% RH	2 X 50%	7	5	2	8	1.7
SPC #4	Siemens #4	Fired	48°F/61% RH	2 X 100%	15	9	5	12	3.4
SPC #5	Siemens #5	Unfired	48°F/61% RH	2 X 100%	13	8	2	9	3.0
SPC #6	Siemens #6	Unfired	48°F/61% RH	2 X 50%	8	5	2	8	1.9
SPC #10	Siemens #9	Fired	48°F/61% RH	2 X 100%	13	8	2	9	3.0
SPC #12	Siemens #10	Unfired	-17°F/100% RH	2 x 100%	15	9	3	10	3.4
SPC #13	Siemens #11	Unfired	-17°F/100% RH	2 X 50%	10	6	2	8	2.1
SPC #14	Siemens #12	Unfired	65°F/51% RH	2 X 100%	13	8	2	9	2.9

Table 3-3 presents the steady-state maximum hourly emissions in pounds per by CT vendor based on annual average temperature and relative humidity (48°F and 61% RH), CT at 100% load, duct burner firing, and post-combustion controls operational. These emission rates correspond to SPC Operating Load Case #4.

Table 3-3
Maximum Hourly Controlled Emissions during Normal Operations for CT/HRSG

Pollutant	Emission Rate (lb/hr) GE 207FA	Emission Rate (lb/hr) Siemens 5000-F(4)
NO _x	14.0	15.0
CO	13.0	9.2
SO ₂	3.1	3.4
PM ₁₀	14.0	12.0
PM _{2.5}	14.0	12.0
VOC	7.0	5.3

3.2.2 Startup/Shutdown Emissions

Combustion turbines during start-up emit pollutants at a higher rate than the emission rates achieved during normal steady state operation. In addition, the proposed post-combustion control systems (SCR for NO_x control and CO catalyst for CO control) will not effectively remove these pollutants from the exhaust gas stream until after the control equipment has achieved operating temperature.

An advantage of using a combined-cycle unit is the relatively short startup time and it's ability to respond quickly to changes in load. However, to ensure safe operation of the CT's, time is needed to stabilize the unit. Multiple steps are used in the startup sequence. First, the CT is started and ramped-up to low load where it is maintained. Heat from the CT exhaust is used to bring the HRSG, steam piping, emissions control equipment, steam turbine and other equipment to specified operating temperatures. Once the HRSG reached proper temperature, the steam turbine and its auxiliaries can be started and gradually heated as steam becomes available. Increases in steam turbine speed are restricted by the temperature differential between the metal surfaces and the steam.

The time required to startup the CT will be dependent on the amount of time the unit has not been in operation. The HRSG and steam turbine require time to heat up so safe normal operation can be achieved. The duration of a individual startup event will depend upon the amount of time since the unit's last normal operating period. Depending on the length of time since the unit has operated, startups are classified as cold, warm, or hot starts.

Each vendor provided slightly different time breakdowns regarding startup and shut down. According to GE, a cold start is defined as any start following a plant shutdown of 72 hours or greater. A warm start is defined as any start following a plant shutdown of between 8 and 72 hours. The start-up sequence and associated emissions are based on an assumed shutdown of 48 hours. A hot start is any start following a plant shutdown of 8 hours or less.

Siemens specifies a cold start as any start following a plant shutdown of 64 hours or greater. A cold start assumes that the steam turbine rotor less than 505°F. A warm start is defined as any start following a plant shutdown of between 16 and 64 hours and assumes that the steam turbine rotor is at a temperature between 505°F and 705°F. A hot start is any start following a plant shutdown of 16 hours or less with the steam turbine rotor > 705°F.

In determining the maximum startup/shutdown emissions, it was assumed that each cold start using GE turbines would take 242 minutes before the GE turbine would reach full plant load, each warm start would take 134 minutes and each hot start would take 87 minutes. In addition, 24 minutes are needed to shutdown a CT. For the Siemens turbines, each cold start would take 250 minutes, each warm start would take 125 minutes and each hot start would take 87 minutes. Twenty-seven minutes is needed to shutdown a Siemens CT.

It was conservatively estimated in the emission calculations that each turbine would reach the maximum potential emissions (100% load with duct burning firing) immediately after the startup (warm/cold). Short-term emissions for the CTs were calculated based on the maximum of either startup/shutdown emissions or a combination of startup/shutdown and normal operation emissions. Table 3-4 presents the average emissions during startup/shutdown per CT/HRSG. The startup or shutdown durations are for the CTs only. The total SUSD emissions are for both CTs/HRSGs for all annual projected startup and shutdown periods. Table 3-5 presents the proposed startup/shutdown schedule. Startup/shutdown emission estimates are presented in Appendix B.

Regardless of vendor chosen, annual emissions resulting from startup/shutdown operations for the proposed CT's are based on 12 cold starts, 50 warm starts, and 230 hot starts per year. For each cold start, the CT's are offline for 48 hours and for each warm start, the turbine is off-line for 8 hours. Under this scenario, the CT's will remain off-line for 976 hours.

**Table 3-4
Startup and Shutdown Emissions**

	Cold Start		Warm Start		Hot Start		Shutdown	
	GE	Siemens	GE	Siemens	GE	Siemens	GE	Siemens
Time for Startup or Shutdown, minutes	242	250	134	125	87	87	24	27
Number of Starts Per Year	12	12	50	50	230	230	292	292
NO_x								
SUSD Emissions (per turbine), lb/hr	118	105	88	93	73	68	58	77
SUSD Emissions (per HRSG), lb/hr	0.85	3.6	0.85	3.6	0.85	3.6	0.85	3.6
Total NO _x SUSD Emissions (both CTs/HRSG's), tn/yr	5.7	5.3	9.8	9.7	24.4	22.6	6.8	10.1
CO								
SUSD Emissions (per turbine), lb/hr	281	600	172	261	203	268	225	242
SUSD Emissions (per HRSG), lb/hr	0.81	2.2	0.81	2.2	0.81	2.2	0.81	2.2
Total CO SUSD Emissions (both CTs/HRSG's), tn/yr	13.6	30	19.2	27.2	67.8	89.3	26.3	31.8
VOC								
SUSD Emissions (per turbine), lb/hr	33	110	14	99	16	92	27	97
SUSD Emissions (per HRSG), lb/hr	0.42	1.1	0.42	1.1	0.42	1.1	0.42	1.1
Total VOC SUSD Emissions (both CTs/HRSG's), tn/yr	1.6	5.5	1.6	10.3	5.5	30.8	2.6	12.7
PM₁₀/PM_{2.5}								
SUSD Emissions (per turbine), lb/hr	11	9	10	9	8	8	13	9
SUSD Emissions (per HRSG), lb/hr	0.96	3.1	0.96	3.1	0.96	3.1	0.96	3.1
Total PM ₁₀ /PM _{2.5} SUSD Emissions (both CTs/HRSG's), tn/yr	0.5	0.43	1.1	0.93	2.7	2.6	1.6	1.2
SO₂								
SUSD Emissions (per turbine), lb/hr	1.9	1.6	2.3	2.9	2.7	1.5	4.6	1.8
SUSD Emissions (per HRSG), lb/hr	0.19	0.81	0.19	0.81	0.19	0.81	0.19	0.81
Total SO ₂ SUSD Emissions (both CTs/HRSG's), tn/yr	0.09	0.08	0.26	0.30	0.89	0.49	0.54	0.24

Table 3-5
Proposed Startup and Shutdown Schedule

Period	Number of Starts			Non-Operating Hours Before Startup (Downtime)		
	Cold	Warm	Hot	Cold	Warm	Hot
1 Hour	0	1	0	0	0	0
3 Hours	1	0	0	0	0	0
8 Hours	1	0	4	0	0	0
24 Hours	1	0	20	0	0	0
Annual	12	50	230	48	8	0

3.2.3 CT/HRSG Hazardous Air Pollutant Emissions

Hazardous air pollutant (HAP) emissions for the CT/HRSG's were based on the emissions factors found in EPA's AP-42, Fifth Edition, Section 3.1 Stationary Gas Turbines and performance data including the total CT and HRSG fuel flow in thousand lb/hr (Mlb/hr) and high and low NG heating values (HHV and LHV) in Btu/hr that were used in the performance calculations. HAP's emissions presented in Table 3-6 are based SPC operating case #4 (48°F/61% RH, 100% load with duct firing) by vendor and heating values. Appendix C presents the CT/HRSG HAP emission estimates for each vendor.

Table 3-6
Annual Hazardous Air Pollutant Emissions from CTs/HRSGs

Pollutant	Emission Rate (tn/yr) GE		Emission Rate (tn/yr) Siemens	
	HHV	LLV	HHV	LLV
1,3 Butadiene	0.007	0.007	0.008	0.007
Acetaldehyde	0.67	0.61	0.70	0.63
Acrolein	0.11	0.10	0.11	0.10
Benzene	0.20	0.18	0.21	0.19
Ethylbenzene	0.54	0.48	0.56	0.51
Formaldehyde	1.79	1.61	1.88	1.69
Naphthalene	0.02	0.02	0.02	0.02
Propylene oxide	0.49	0.44	0.51	0.46
Toluene	2.19	1.97	2.29	2.06
Xylene	1.08	0.97	1.13	1.02

3.3 Auxiliary Equipment

The auxiliary equipment proposed for use at the SPC facility includes a 85 MMBtu/hr auxiliary boiler, two (2) 22.264 MMBtu/hr convection heaters, a 1250 kW emergency generator, and a 480 HP emergency fire pump. The auxiliary boiler and convection heaters will support gas turbine operations; the emergency generator and fire pump will meet the electricity demands of the SPC facility during power outages or other emergencies. Emissions for the auxiliary boiler and convection heaters were based on pipeline-quality natural gas fuel usage and 8,760 operating hours.

The emergency generator and fire pump emissions were based on the use of diesel fuel and are expected each to operate no more than 500 hours per year. The emergency generator and fire pump meet the emission requirements as found in 40 CFR Part 60 Subpart IIII. Criteria and HAP pollutant emissions from the auxiliary equipment is presented in Table 3-7. Auxiliary equipment emission estimates are presented in Appendix D.

Table 3-7
Hourly and Annual Criteria and Hazardous Air Pollutant Emissions for Auxiliary
Equipment

Pollutant	Auxiliary Boiler		Convection Heaters		Emergency Generator		Fire Pump	
	lb/hr	tn/yr	lb/hr ¹	tn/yr ²	lb/hr	tn/yr	lb/hr	tn/yr
NO _x	1.45	6.33	0.81	7.08	18.6	4.66	5.27	1.32
CO	3.19	13.96	1.64	14.39	2.78	0.70	0.49	0.12
SO ₂	0.20	0.89	0.01	0.12	0.75	0.19	0.98	0.25
PM ₁₀	0.85	3.72	0.22	1.95	0.17	0.04	0.07	0.02
PM _{2.5}	0.85	3.72	0.22	1.95	0.14	0.04	0.07	0.02
VOC	0.51	2.23	0.13	1.17	0.77	0.19	0.13	0.03
HAPS								
Benzene	1.8 E-04	7.7 E-04	4.6 E-05	4.0 E-04	9.6 E-03	2.4 E-03	2.9 E-03	7.2E-04
Toluene	2.9 E-04	1.2 E-03	7.4 E-05	6.5 E-04	3.5 E-03	8.7 E-04	1.3 E-03	3.2E-04
Xylene	---	---	---	---	2.4 E-03	6.0 E-04	8.8 E-04	2.2E-04
Formaldehyde	6.3 E-03	2.7 E-02	1.6 E-03	1.4 E-02	9.8 E-04	2.5 E-04	3.7 E-03	9.2E-04
Acetaldehyde	---	---	---	---	3.1 E-04	7.8 E-05	2.4 E-03	5.9E-04
Acrolein	---	---	---	---	9.8 E-05	2.4 E-05	2.9 E-04	7.2E-05
Naphthalene	5.1 E-05	2.2E-04	1.3 E-05	1.7 E-04	1.6 E-03	4.0 E-04	2.6 E-04	6.6E-05
1,3-Butadiene	---	---	---	---	---	---	1.2 E-04	3.0E-05
Hexane	1.5 E-01	6.6 E-01	3.9 E-02	3.4 E-01	---	---	---	---
Arsenic	1.7 E-05	7.3 E-05	4.4 E-06	3.8 E-05	---	---	---	---
Beryllium	1.0 E-06	4.4 E-06	2.6 E-07	2.3 E-06	---	---	---	---
Cadmium	9.2 E-05	4.0 E-04	2.4 E-05	2.1 E-04	---	---	---	---
Chromium	1.2 E-04	5.1 E-04	3.1 E-05	2.7 E-04	---	---	---	---
Cobalt	7.0 E-06	3.1 E-05	1.8 E-06	1.6 E-05	---	---	---	---
Manganese	3.2 E-05	1.4 E-04	8.3 E-06	7.3 E-05	---	---	---	---
Mercury	2.2 E-05	9.5 E-05	5.7 E-06	5.0 E-05	---	---	---	---
Nickel	1.8 E-04	7.7 E-04	4.6 E-05	4.0 E-04	---	---	---	---
Selenium	2.0 E-06	8.8 E-06	5.2 E-07	4.6 E-06	---	---	---	---

¹ Hourly emissions per heater.

² Annual emissions are for two heaters.

3.4 Greenhouse Gas Emissions

Natural gas has the lowest greenhouse gas (GHG) emission rate of all fossil fuels such as coal or fuel oil. In general, GHG emissions from a natural gas-fired power plant are less than 35% of those generated by an equivalent sized coal-fired power plant. Thus, the potential GHG footprint from the new SPC facility will be significantly smaller than that of other fossil-fuel fired energy plants of comparable size. Hence, the use of natural gas-firing by combustion turbines provides a significant benefit in reducing GHG emissions from power generation.

Greenhouse gas emissions were determined for the CTs and HRSG's and are based SPC operating case #4 (48°F/61% RH, 100% load with duct firing) by vendor, high heating values (most conservative), and emission factors and global warming potentials as presented in the Climate Registry General Reporting Protocol, Version 1.1, May 2008.

For the auxiliary boiler and convection heaters, GHG emissions were determined based on emission factors provided in AP-42 Section 1.4, 40 CFR Part 98, and the Climate Registry. Table 3-8 shows the estimates for CO₂, CH₄, and N₂O and the total in terms of CO₂ equivalents in metric tons (MT). GHG emission estimates are presented in Appendix E. GHG emissions are not included for emergency equipment per 40 CFR Part 98.

**Table 3-8
GHG Emissions and Total CO₂ Equivalents**

GHG	Emissions (MT/yr) GE	Emissions (MT/yr) Siemens	Auxiliary Boiler (MT/yr)	Convection Heaters¹ (MT/yr)
CO ₂	1784354	1870562	39735	20815
CH ₄	30197	31656	0.76	0.40
N ₂ O	93.95	98.48	0.21	0.11
CO ₂ e	2447609	2565862	39816	20858

¹Emissions for two convection heaters.

3.5 Paved Road Emissions

Fugitive PM₁₀ and PM_{2.5} emissions were determined for aqueous ammonia trucks traveling on on-site paved roads using emission factors found in Section 13.2.2 of EPA's AP-42 emission factor compilation and in accordance with UDAQ guidance¹. SPC will water and vacuum sweep the paved on-site roads as necessary to minimize fugitive emissions. PM₁₀ and PM_{2.5} emissions were estimated to 0.06 and 0.01 tons per year, respectively. Paved road emission estimates are presented in Appendix D.

3.6 H₂SO₄ Emissions

Sulfuric acid (H₂SO₄) emissions were estimated based on the methodology presented in Electric Power Research Institutes (EPRI) 2007 report, *Estimating Total Sulfuric Acid Emissions from Stationary Power Plants*. The highest H₂SO₄ emissions based on Siemens CT/HRSGs was 1.0 ton per year. H₂SO₄ emissions based on a GE CT/HRSG was slightly less at 0.99 tons per year. Sulfuric acid emission estimates are presented in Appendix D.

3.7 Fuel Oil Storage Tank Emissions

VOC emissions are anticipated from breathing and working losses from a 500 and 1000 gallon aboveground diesel fuel storage tanks associated with the emergency fire water pump and generator, respectively. VOC emissions from the tanks will not be controlled with add on control equipment. Tank emissions were estimated using EPA's TANKS software, version 4.09D and were estimated to be 1.12 pounds per year. A copy of the TANKS 4 reports are presented in Appendix D.

¹ UDAQ Memo titled Emission Factors for Paved and Unpaved Roads, March 10, 2008.

4.0 REGULATORY REVIEW

The following sections present a review of the air quality regulatory requirements that are potentially applicable for the proposed construction and operation of the SPC natural gas-fired combined-cycle power plant. Specifically, the following regulations were reviewed:

- Prevention of Significant Deterioration (PSD);
- Good Engineering Stack Height (GEP);
- New Source Performance Standards (NSPS);
- National Emissions Standards for Hazardous Air Pollutants (NESHAPS);
- Acid Rain Provisions (Title IV);
- Compliance Assurance Monitoring;
- Risk Management Program;
- Operating Permit Program (Title V); and
- Utah Administrative Code.

A review of each potentially application regulation is presented below.

4.1 National Ambient Air Quality Standards

The 1970 Clean Air Act (CAA) gave EPA authority to establish the minimum level of air quality that all states would be required to achieve. These minimum standards were developed to protect the public health and welfare. Thus, National Ambient Air Quality Standards (NAAQS) have been established for several pollutants (referred to as criteria pollutants) and are presented in Table 4-1. The NAAQS for criteria pollutants are expressed as total concentrations of pollutants in the air to which the public may be exposed. As part of this permit application, SPC is required to demonstrate that its facility and associated processes will not cause or contribute to a violation of the NAAQS.

Table 4-1

National Ambient Air Quality Standards ²

Pollutant	Averaging Period	Primary Standard (µg/m³)	Secondary Standard (µg/m³)
SO ₂	1-hour	197 ¹	NA ²
	3-hour	NA ²	1,300
	24-hour	365 ³	NA ²
	annual	80	NA ²
PM ₁₀	24-hour	150 ⁴	Same as primary
PM _{2.5}	24-hour	35 ⁵	Same as primary
	Annual	15 ⁶	Same as primary
CO	1-hour	40,000 ³	NA ²
	8-hour	10,000 ³	NA ²
NO ₂	1-hour	188 ⁹	None
	Annual	100	Same as primary
O ₃	8-hour (2008 standard)	0.075 ⁷	Same as primary
	8-hour (1997 standard)	0.08 ⁸	Same as primary
Lead	3-Month	1.5	NA ²

- 1) To attain this standard, the 3-year average of the 99th percentile of the daily maximum 1-hour average at each monitor within an area must not exceed 75 ppb.
- 2) No ambient standard for this pollutant and/or averaging time.
- 3) Not to be exceeded more than once per year.
- 4) Not to be exceeded more than once per year on average over three years.
- 5) To attain this standard, the three-year average of the 98th percentile of 24-hour concentrations at each population-oriented monitor within an area must not exceed 35 µg/m³.
- 6) To attain this standard, the three-year average of the weighted annual mean PM_{2.5} concentrations from single or multiple community-oriented monitors must not exceed 15 µg/m³.
- 7) To attain this standard, the three-year average of the fourth-highest daily maximum 8-hour average ozone concentrations measured at each monitor within an area over each year must not exceed 0.075 ppm.
- 8) To attain this standard, the three-year average of the fourth-highest daily maximum 8-hour average ozone concentrations measured at each monitor within an area over each year must not exceed 0.08 ppm.
- 9) To attain this standard, the 3-year average of the 98th percentile of the daily maximum 1-hour average at each monitor within an area must not exceed 100 ppb.

² <http://www.epa.gov/air/criteria.html>

The 1990 CAA amendments called for a review of the ambient air quality of all regions of the United States. States were required to file with EPA designations of all areas as attainment, non-attainment, and unclassifiable. An area that is in attainment indicates that air quality concentrations are less than the NAAQS; non-attainment areas are areas where monitoring data has indicated air quality concentrations that are greater than the standards. Unclassifiable areas are areas where there is insufficient monitoring data to prove that the area has attained the federal standards; however, these areas are treated as attainment areas.

The current air quality classification for Sevier County, the proposed location of the SPC facility is in attainment for all criteria pollutants. New major sources or major modifications to existing major sources in attainment areas are required to obtain a PSD permit prior to initiation of construction. SPC assumes that for the new one-hour NO₂ and SO₂ standards, Sevier County would be designated as unclassifiable due to limited data and as a result would be considered attainment.

4.2 Prevention of Significant Deterioration (PSD)

Major new sources located in attainment areas are required to obtain a PSD permit prior to construction. A “major” stationary source, as defined by 40 CFR 52.21(b)(1)(i)(a) is any stationary source with the potential to emit 250 tons per year of a regulated air pollutant or any stationary source defined as one of the 28 source categories listed in 40 CFR 52.21(b)(1)(i)(a) with the potential to emit 100 tons per year of any regulated pollutant. Combined-cycle turbines with HRSG are considered a fossil-fuel steam electric plant and for SPC, the combined-cycle plant will greater than 250,000,000 Btu/hr heat input. Thus, SPC would fall under one of the named 28 listed source categories and, as such, the applicable PSD threshold is 100 tons per year.

Once it is determined that a pollutant exceeds the PSD major source threshold, additional pollutants will be subject to PSD review if their Potential to Emit (PTE) exceeds the PSD major source threshold. The PSD significant emission rates are presented in Table 4-2.

**Table 4-2
PSD Significant Emission Rates**

Pollutant	Significant Emission Rate (TPY)
CO	100
NO _x	40
SO ₂	40
PM ₁₀	15
PM _{2.5}	10
O ₃	40 (VOCs)
Lead	0.6
Fluorides	3
Sulfuric acid mist (H ₂ SO ₄)	7
Total reduced sulfur (including H ₂ S)	10
Reduced sulfur compounds (including H ₂ S)	10
H ₂ S	10

The pollutants that will be emitted at the SPC facility that are subject to PSD are: NO₂, CO, PM₁₀, and PM_{2.5}.

The PSD application for this project includes the following analyses for each pollutant subject to PSD:

- Best Available Control Technology (BACT) analysis,
- Air Quality Monitoring Requirements,
- Air Quality Impact Analysis,
- Additional Impact analyses, and
- PSD Class I analysis.

4.2.1 Best Available Control Technology Analysis

A PSD source must conduct an analysis to ensure the application of the Best Available Control Technology (BACT) to emissions of pollutants subject to PSD review. To determine BACT, the “Top Down” methodology is recommended by EPA. A detailed explanation of the “Top Down” BACT analysis is presented in Section 5.0 of this permit application.

4.2.2 Air Quality Monitoring Requirements

In accordance with 40 CFR 52.21(m), a PSD permit application must contain an analysis of the existing ambient air quality data in the area which could be affected by the proposed project if the project would result in a net significant emissions increase. To define the existing air quality, a pre-construction monitoring program that is specifically designed to collect data in the area of the proposed source can be initiated or else data collected from either a state or privately-operated monitoring program may be used. The condition for monitoring can be waived if the proposed project would cause an impact less than EPA-specified de minimis monitoring levels as established by the EPA.

PSD de minimis monitoring concentration levels are presented in Table 4-3.

Table 4-3

PSD De Minimis Monitoring Concentrations

Pollutant	Averaging Period	Threshold Concentration ($\mu\text{g}/\text{m}^3$)
CO	8-hour	575
NO ₂	annual	14
SO ₂	24-hour	13
PM ₁₀	24-hour	10
PM _{2.5}	24-hour	4
O ₃	NA	Exempt if VOC emissions are less than 100 TPY
Lead	3-month	0.1
Fluorides	24-hour	0.25
Total reduced sulfur	1-hour	10
H ₂ S	1-hour	0.2
Reduced sulfur compounds	1-hour	10

4.2.3 Air Quality Impact Analysis

An air quality impact analysis must be performed for the proposed project subject to PSD review for each pollutant for which the increase in emissions exceeds the significant emission rate to demonstrate that the project will not cause or contribute to a exceedance of any applicable NAAQS or PSD increment. Usually, the analysis will involve: (1) the assessment of existing air quality which may include ambient monitoring data and air quality dispersion modeling results; and (2) using dispersion modeling, the prediction of ambient concentrations that will result from the applicants proposed project and future growth associated with the project. To determine the air quality impact, atmospheric dispersion modeling is performed in accordance with EPA's Guideline on Air Quality Models³ and Utah modeling requirements⁴.

³ 40 CFR Part 51, Appendix W

⁴ Utah Division of Air Quality Modeling Guidelines, Revised, December 17, 2008

Federal PSD increments have been established for SO₂, NO₂, PM₁₀ and PM_{2.5} for the Class I and Class II areas. Class I areas are those federally protected areas in which the least amount of incremental impact can occur such as National Parks and Wilderness areas. Nearly all other areas are defined as Class II where higher increments are specified. As part of the PSD regulations, an ambient air quality analysis is required to demonstrate that the PSD increment consumed for SO₂, NO₂, PM₁₀ and PM_{2.5} does not exceed or contribute to a concentration that exceeds allowable PSD increments.

As part of the air quality impact analysis, a preliminary dispersion modeling analysis was performed for those pollutants which were expected to be emitted in significant amounts. The pollutants for which preliminary modeling was performed are NO₂, PM₁₀, PM_{2.5}, and CO.

An impact analysis may be limited to SPC sources only if modeled impacts are below the significant impact levels (SILs). The preliminary modeling indicated that PM₁₀, PM_{2.5}, and NO₂ were above the PSD Class II SILs which required a full impact analysis to be performed for these pollutants. The allowable PSD increments and SILs are presented in Table 4-4. SIL's for the one-hour NO₂ and SO₂ standards have not been established.

Table 4-4
PSD Increments and Significant Impact Levels in Micrograms per Cubic Meter

Pollutant	Averaging Time	PSD Increments		SILs	
		Class 1	Class II	Class 1	Class II
NO ₂	Annual	2.5	25	0.1	1
SO ₂	3-hour	25	512	1	25
	24-hour	5	91	0.2	5
	annual	2	20	0.1	1
CO	1-hour	---	---	---	2000
	8-hour	---	---	---	500
PM ₁₀	24-hour	8	30	0.3	5
	annual	4	17	0.2	1
PM _{2.5}	24-hour	1	4	0.07	1.2
	annual	2	9	0.06	0.3

All air quality impact analyses were performed in accordance with an UDAQ approved modeling protocol which was designed specifically for the proposed project. A copy of the protocol as well as the protocol's agreement letter is presented in Appendix F.

4.2.4 Additional Impact Analyses

Per 40 CFR 52.21, a PSD permit application must contain an additional impacts analysis. These analyses provide an analysis of the impairment to visibility, acid deposition, soils and vegetation that would occur as a result of the source and general commercial, residential, industrial, and other growth associated with the source. The applicant need not provide an analysis of the impact on vegetation having no significant commercial or recreational value.

There are two types of visibility analyses that may be conducted and included in a PSD permit application. First, a visibility analysis may be conducted to evaluate visibility impacts due to plume impairment within 50 kilometers of a Class 1 using an initial screening model such as VISCREEN. If needed, a more refined model, such as PLUVUE2 may be used to address plume impairment. A second and distinct analysis is also required under PSD to evaluate regional haze.

In addition to the PSD Class I concentration increment analysis, a PSD Class I analysis may need to be conducted to address the impacts of SO₂ and NO₂ on acid deposition.

The impact on soils and vegetation in the source's impact area compared to the total air quality impacts to concentrations known to cause harmful effects to the resident species is also required of a PSD applicant. The soils and vegetation analysis was performed by MWH Americas Inc.

The growth analysis projects air pollutant emissions associated with industrial, commercial, and residential growth in direct support of the new source. Industrial and commercial growth includes new sources providing goods and services to new employees and to the proposed source; residential growth includes housing for employees entering the region.

4.3 Good Engineering Stack Height Analysis

The CAA requires that the degree of emission limitation required for control of any pollutant not be affected by a stack which exceeds good engineering practice (GEP) height. GEP stack height is defined as the highest of:

- 65 meters,
- A height established by applying the formula: $H_{GEP} = H + 1.5 L$ where H is the height of the structure or nearby structure and L is the lesser dimension (height or projected width) of the nearby structure, and
- A height demonstrated by fluid modeling or field study.

A structure is considered nearby a stack if it is within a distance of five times the structures height or maximum projected width. Only the smaller value of the height or projected width is used and the distance to the structure cannot be greater than 0.8 kilometers. Although GEP stack height regulations require that the stack height used in modeling not exceed GEP stack height, the actual stack height may be greater.

The regulations (40 CFR Part 51) also increase stack height beyond that resulting from the formula in cases where plume impaction occurs. Plume impaction occurs when a plume of exhaust gases emitted from a stack hits a higher hill or mountain (elevated terrain) downwind of the stack. Elevated terrain is terrain that exceeds the height calculated by the GEP stack height formula.

Per 40 CFR Part 51 and the results of BPIP-PRIME show there is no significant terrain that would induce downwash with ½ kilometer at least a 10% height relative to the distance from the source. Thus, plume impaction was not considered.

All stacks for the proposed SPC project will be less than 65 meters and will be modeled at their actual stack elevation. The modeling complies with GEP regulations.

4.4 New Source Performance Standards (NSPS)

The EPA has promulgated standards of performance for specific sources of air pollution. These standards have been codified in 40 CFR Part 60, Subparts A through WWW. The following Subparts are determined to be applicable to the proposed project:

- Subpart A - General Provisions;
- Subpart Dc - Standard of Performance for Small Industrial-Commercial-Institutional Steam Generating Units;
- Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines; and
- Subpart KKKK – Standards of Performance for Stationary Combustion Turbines.

4.4.1 Subpart A - General Provisions

Certain provisions of 40 CFR Part 60 Subpart A apply to the owner or operator of any stationary source subject to a NSPS. Since the proposed facility will be subject to a NSPS, the SPC Project will be required to comply with all applicable provisions of Subpart A. The provisions of Subpart A which are applicable to the proposed facility are presented in Table 4-5.

Table 4-5

Summary of Regulatory Requirements of NSPS Subpart A - General Provisions

40 CFR 60 Subpart A	Requirement	Compliance Action
60.7	Initial notification and record keeping	SPC will submit all NSPS related notifications to the UDAQ and EPA Region VIII for the proposed project in a timely manner.
60.8	Performance tests	SPC will conduct all required performance tests in accordance with the designated reference methods.
60.11	Compliance with standards and maintenance requirements	SPC will operate and maintain the facility using good air pollution control practices.
60.13	Monitoring requirements	Required pollutant monitoring pursuant to NSPS will utilize the methods provided in Section 60.13.
60.19	General notification and reporting requirements	All NSPS reports and notification will follow the schedule and format outlined in Section 60.19.

4.4.2 Subpart Dc – Standard of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

40 CFR Part 60 Subpart DC, Standard of Performance for Small Industrial-Commercial-Institutional Steam Generating Units in which construction commenced after June 9, 1989 and that have a maximum design input capacity of greater than 10 MMBtu/hr but less than or equal to 100 MMBtu/hr will apply to the auxiliary boiler and the convection heaters at the proposed SPC facility. Per Subpart Dc, there are no emission standards, compliance, stack testing, or emission monitoring requirements for natural gas-fired boilers. The auxiliary boiler and convection heaters will comply with the reporting and recordkeeping requirements of Subpart Dc.

4.4.3 Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

40 CFR Part 60, Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (CI ICE) will apply to the emergency generator and fire pump. The emission standards established in this rule depend on the engines mode of operation (continuous or emergency) and the engine's horsepower class. Based on Subpart IIII, both the diesel generator and fire pump are classified as emergency stationary internal combustion engines.

Subpart IIII includes emission standards for model year 2007 and later emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 kW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pumps. The emergency generator falls under this classification. This rule requires that emergency stationary CI ICE meet the Tier 2 or Tier 3 nonroad CI engine standards, and Tier 4 nonroad CI engine standards that do not require add-on control. The proposed 1250 kW emergency generator at the SPC facility will meet Tier 2 standards.

Since 2008, emergency fire pumps need to be certified to meet the standards presented in Table 4 of Subpart IIII. The proposed 480 kW emergency fire pump engine at the SPC facility will meet Tier 3 standards.

4.4.4 Subpart KKKK – Standards of Performance for Stationary Combustion Turbines

40 CFR 60 Subpart KKKK applies to stationary combustion turbines with a heat input at peak load greater than 10MMBtu/hr that commences construction, modification or reconstruction after February 18, 2005.

A stationary combustion turbine is defined as all equipment, including but not limited to the combustion turbine, fuel, air, lubrication and exhaust systems, heat recovery systems and any ancillary equipment, any combined-cycle combustion turbine and any combined heat and power combustion system. The HRSG and duct burners are subject to Subpart KKKK; thus, exempting them from the NSPS requirements found in 40 CFR Part 60, Subparts Da, Db, and Dc.

The proposed turbines will be subject to the NO_x emission standards in KKKK which are 15 ppm @ 15% O₂ or 0.43 lb/MWh when fired on natural gas. If the turbines operate at partial load (less than 75% of peak load) or if the turbines operate at temperatures less than 0°F, a NO_x emission standard of 96 ppm @ 15% O₂ (4.7 lb/MWh) will apply. If the HRSG's run independently of the combustion turbines, the NO_x emission standard that the turbines will be subject to is 54 ppm @ 15% O₂ (0.86 lb/MWh) when fired on natural gas. SPC will comply with concentration-based NO_x emission standards. The proposed NO_x emissions are 2 ppm @ 15% O₂ using low-NO_x combustors and SCR firing on natural gas.

The proposed turbines will also be subject to an emission limit of 0.9 lb/MWh gross output or the turbines must not burn any fuel that contains the total potential sulfur emissions in excess of 0.06 lb SO₂/MMBtu heat input. The proposed SPC turbines will be fired on pipeline-quality natural gas. The SO₂ emission rate from the proposed turbines is expected to be in compliance with the NSPS limit.

4.5 National Emissions Standards for Hazardous Air Pollutants (NESHAPS)

National Emissions Standards for Hazardous Air Pollutants (NESHAPS) is codified under 40 CFR Part 61 and 63. NESHAPS regulate specific categories of stationary sources with the potential to emit one or more hazardous air pollutants (HAP). Applicability of the rules regulating HAP emissions from source categories is limited to emission sources located at a major source (single HAP 10 TPY or more, or a combination of HAP of 25 TPY or more) of HAP emissions.

As presented in Section 3.0, the proposed SPC sources will emit less than 10 tons of a single HAP; thus, SPC sources are below the major source category. As such, the Combustion Turbine MACT (40 CFR 63 Subpart YYYY) will not apply.

The emergency generator and fire pump, however, will be subject to 40 CFR Part 63, Subpart ZZZZ since this standard is applicable to area sources of HAPS. An area source of HAP emissions is a source that is not a major source. An affected source that meets any of the criteria of §63.6590 in paragraphs (c)(1) through (7) must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition. SPC meets the requirement of a new or reconstructed stationary RICE located at an area source as found in the above mentioned §63.6590 (c)(1). Thus, no further requirements apply for the emergency generator and fire pump under 40 CFR Part 63, Subpart ZZZZ.

4.6 Acid Rain Provisions (Title IV)

Per Title IV of the 1990 CAA amendments, the EPA established a program to control emissions of certain pollutants that contribute to the formation of acid rain. As a “new utility unit” the SPC CTs/HRSGs meet the definition of an affected Phase II “utility unit” under 40 CFR 72(a)(3). Thus, the proposed SPC facility will be subject to the acid rain program. As a source that is subject to the acid rain program, SPC is required to do the following:

- Apply for a Phase II acid rain permit to include the new utility units;
- Install continuous emission monitoring systems (CEMS) to demonstrate compliance with the acid rain requirements as found in 40 CFR Part 75; and
- Purchase and hold allowances equivalent to annual SO₂ emissions.

For new units, an acid rain permit application must be submitted at least 24 months before the date of initial operation of the unit. This application must include the date that the units will commence commercial operation and the deadline for monitoring certification which is 90 days after commencement of commercial operation. SPC will operate in compliance with all applicable provisions of the Title IV Acid Rain program.

4.7 Compliance Assurance Monitoring

The EPA has promulgated requirements for sources to provide detailed monitoring plans that will ensure compliance with all applicable requirements. These monitoring requirements are contained in 40 CFR Part 64. Section 64.2 specifies that these monitoring requirements apply to a “pollutant-specific emissions at a major source” if all of the following are satisfied:

- 1) The unit is subject to an emission limitation or standard;
- 2) The unit uses a control device to achieve compliance with any such emission limitation or standard; and
- 3) The unit has potential pre-control device (uncontrolled) emissions equal to or greater than 100 percent of the amount, in tons per year, required for a source to be classified as a major source.

The combustion turbines and HRSG with duct burners use selective catalytic reduction and an oxidation catalyst to control NO_x, CO, and VOC emissions. CAM is applicable for these pollutants because (1) emission limitations are proposed for these emissions; (2) a control device will be utilized to meet the emission limitation; and (3) without the control device, the emissions from each unit would exceed the major source thresholds (100 tons per year for NO_x and CO). SPC will be required to submit a CAM plan with the Title V application within 1 year after the facility commences commercial operation.

4.8 Risk Management Program

Title III of the CAA contains requirements for subject facilities that store and/or process certain hazardous substances to ensure their safe use. 40 CFR Part 68 - Chemical Accident Prevention Provisions, sets forth the requirements of stationary sources to prevent accidental releases of regulated substances and requires sources that exceed threshold quantities of a regulated substance to prepare a Risk Management Plan. Per Table 1 of §68.130, aqueous ammonia is a regulated substance.

However, the concentration of ammonia proposed to be used by SPC is 19% which is below the threshold value of Table 1 of §68.130. Therefore, the requirements of 40 CFR Part 68 will not apply.

4.9 Operating Permit Program (Title V)

In accordance with the CAA of 1990, the proposed SPC project sources will be subject to the requirements of 40 CFR Part 70. The SPC Facility will be required to submit a Title V operating permit application no later than 12 months after the commencement of operation. The application and permit will essentially incorporate the requirement for operation encompassed by the PSD permit.

4.10 Utah Administrative Codes

The air quality regulations, codified in Title R307 of the Utah Administrative Code, which are potentially applicable to this project, are as follows:

- R307-101 - General Requirements
- R307-107 - General Requirements: Unavoidable Breakdown
- R307-150 - Emission Inventories.
- R307-165 - Emission Testing.
- R307-170 - Continuous Emission Monitoring Program.
- R307-201 - Emission Standards: General Emission Standards.
- R307-205 - Emission Standards: Fugitive Emissions and Fugitive Dust.
- R307-210 - Stationary Sources.
- R307-214 - National Emission Standards for Hazardous Air Pollutants (NESHAPS).
- R307-401 - Permit: New and Modified Sources.
- R307-405 - Permits: Major Sources in Attainment or Unclassified Areas (PSD).
- R307-406 - Visibility.
- R307-410 - Permits: Emissions Impact Analysis.

- R307-414 - Permits: Fees for Approval Orders.
- R307-415 - Permits: Operating Permit Requirements.
- R307-417 - Permits: Acid Rain Sources

4.10.1 R307-101 General Requirements

The definitions and general requirements found in E307-101 including R307-101-3, version of code of federal regulations incorporated by reference, will apply to the SPC project.

4.10.2 R307-107 General Requirements: Unavoidable Breakdown

The unavoidable breakdown provisions of R307-107 will apply to the SPC Project. A breakdown for any period longer than 2 hours will be reported to the Executive Secretary within 3 hours of the beginning of the breakdown if reasonable, but in no case longer than 18 hours after the beginning of the breakdown.

During times other than normal office hours, breakdowns for any period longer than 2 hours shall be initially reported to the Environmental Health Emergency Response Coordinator.

Within 7 calendar days of the beginning of any breakdown of longer than 2 hours, a written report will be submitted to the Executive Secretary which shall include the cause and nature of the event, estimated quantity of pollutant (total and excess), time of emissions and steps taken to control the emissions and to prevent recurrence. The submittal of such information shall be used by the Executive Secretary in determining whether a violation has occurred and/or the need of further enforcement action.

Breakdowns that are caused entirely or in part by poor maintenance, careless operation, or any other preventable upset condition or preventable equipment breakdown will not be considered unavoidable and are not covered by R307-107.

4.10.3 R307-150 Emission Inventories

The emission inventory provision of R307-150 will apply to the proposed SPC project since it is anticipated that the proposed project will be considered a major source as defined in R307-415-3. SPC shall submit an inventory every third year for all emissions units including fugitive emissions. The inventory shall include PM₁₀, PM_{2.5}, oxides of sulfur, oxides of nitrogen, CO, VOC, ammonia, other chargeable pollutants, and non-exempted HAPS. For each pollutant, the emissions inventory data shall include the rate and period of emissions, startup and shut down emissions, the specific emissions unit which is the source of the air pollution, composition of air contaminant, type and efficiency of the air pollution control equipment, and other information necessary to quantify operation and emissions and to evaluate pollution control. The emissions of a pollutant shall be calculated using the source's actual operating hours, production rates, and types of materials processed, stored, or combusted during the inventoried time period.

4.10.4 R307-165 Emission Testing

The proposed SPC project will be subject to the emission testing requirements that are listed in R307-165. Emission testing will be required of the SPC project sources within six months of start-up and at least once every five years or more frequently as determined by the Executive Secretary.

4.10.5 R307-170 Continuous Emission Monitoring Program

The proposed SPC project will be required to install continuous monitoring systems to demonstrate compliance with the NO_x and CO emission standards.

4.10.6 R307-201 Emission Standards: General Emission Standards

The SPC Project will be subject to the visible emission standards presented in R307-201. Emissions from the diesel engines (which includes the emergency generator and fire pump) shall be of a shade or density no darker than 20% opacity. Visible emissions exceeding the opacity standards for short time periods as the result of initial warm up, start-up or shutdown of a facility, installation or operation, or unavoidable combustion irregularities which do not exceed three minutes in length shall not be deemed a violation provided that the Executive Secretary finds that adequate control technology has been applied. SPC shall minimize visible and non-visible emissions during start-up or shutdown of a facility, installation, or operation through the use of adequate control technology and proper procedures. Emissions shall be brought into compliance with these requirements by reduction of the total weight of contaminants discharged per unit of time rather than by dilution of emissions with clean air. EPA Method 9 will be utilized to determine opacity from stationary sources.

4.10.7 R307-205 Emission Standards: Fugitive Emissions and Fugitive Dust

SPC will take steps when clearing or leveling of land greater than one-quarter acre in size, earthmoving, excavation, or movement of trucks or construction equipment over cleared land greater than one-quarter acre in size or access haul roads to minimize fugitive dust from such activities. Such control may include watering and chemical stabilization of potential fugitive dust sources or other equivalent methods or techniques approved by the Executive Secretary.

Any land area greater than one-quarter acre in size that has been cleared or excavated by SPC, steps shall take measures to prevent fugitive particulate matter from becoming airborne. Such measures may include: planting vegetative cover, providing synthetic cover, watering, chemical stabilization, wind breaks, or other equivalent methods or techniques approved by the Executive Secretary.

4.10.8 R307-210 Stationary Sources

As stated above, the SPC project will be subject to New Source Performance Standards as found in 40 CFR Part 60, Subparts A, Dc, IIII, and KKKK.

The provisions of 40 CFR Part 60 Subpart A applies to each affected facility as specified in the relevant NSPS regulation for that source type. Subpart A contains general requirements for notifications, monitoring, performance testing, reporting, recordkeeping, and operation and maintenance provisions.

The provisions of 40 CFR Part 60 Dc will apply to the auxiliary boiler and convection heaters since they are proposed to have a heat input capacity from fuels equal to or less than 100 MMBtu/hr but greater than or equal to 10 MMBtu/hr heat input.

The auxiliary boiler is proposed to have a maximum rated heat input of 85 MMBtu/hr; the convection heaters are proposed to have a maximum rated heat input of 22.26 MMBtu/hr. Since this equipment will only burn natural gas, no emission limits are applicable in this subpart.

Subpart IIII applies to the emergency generator and fire pump. The proposed generator will meet Tier 2 emission standards; the fire pump will meet Tier 3 emission standards. The diesel fuel used in this equipment will meet the requirements of 40 CFR 80.510 (b) and will be ultra low sulfur diesel with a maximum sulfur content of 15 ppm. The NSPS also requires that:

- A non-resettable hour meter be installed prior to start-up of the engines; and
- Hours of operation will be recorded.

SPC is limiting the operation of each engine to 500 hours per year.

Subpart KKKK applies to the combustion turbines since the proposed turbines will have a heat input capacity greater than 10.7 gigajoules or 10 MMBtu/hr. The proposed CT/HRSGs will comply with the NSPS emission limits of 15 ppm NO_x (15% O₂) and 0.060 lb SO₂/MMBTU.

4.10.9 R307-214 National Emission Standards for Hazardous Air Pollutants (NESHAPS)

The emergency generator and fire pump will be subject to 40 CFR Part 63, Subpart ZZZZ since this standard is applicable to area sources of HAPS. An affected source that meets any of the criteria of §63.6590 in paragraphs (c)(1) through (7) must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition. SPC meets the requirement of a new or reconstructed stationary RICE located at an area source as found in the above mentioned §63.6590 (c)(1).

4.10.10 R307-401 Permit: New and Modified Sources

This rule, which applies to the proposed SPC project, establishes the application and permitting requirements for new installations and modifications to existing installations throughout the State of Utah. According to R307-401 any person intending to construct a new installation which will or might reasonably be expected to become a source or an indirect source of air pollution shall submit to the executive secretary a NOI and receive an approval order prior to initiation of construction. The NOI shall include the information described in R307-401-5 to determine whether the proposed construction will be in accord with applicable requirements of these rules. Within 30 days after receipt of a NOI, or any additional information necessary to the review, the executive secretary shall advise the applicant of any deficiency in the NOI or the information submitted.

4.10.11 R307-405 Permits: Major Sources in Attainment or Unclassified Areas (PSD).

R307-405 implements the federal PSD permitting program for major sources and major modifications in attainment areas and maintenance areas as required by 40 CFR 51.166. This rule does not include the routine maintenance, repair and replacement provisions that were vacated by the DC Circuit Court of Appeals on March 17, 2006.

The proposed SPC project meets the definition of a “major source” as found in R307-405 and will be subject to PSD requirements. A major source is defined as: (1) any of the listed categorical sources of air pollutants which emits, or has the potential to emit, 100 tons per year or more of any pollutant subject to regulation under the Clean Air Act; (2) any other source which emits, or has the potential to emit, 250 tons per year or more of any air pollutant; (3) a source which does not otherwise qualify as a major source as defined in this paragraph, but which is physically changed, where the change itself would constitute a major source; or (4) a source which is major for volatile organic compounds is major for ozone.

Every new major source must be reviewed by the Executive Secretary to determine the air quality impact of the source to include a determination whether the source will cause or contribute to a violation of the maximum allowable increases or the NAAQS in any area. The determination of air quality impact will be made as of the source's projected start-up date.

Such determination shall take into account all allowable emissions of approved sources and, to the extent practicable, the cumulative effect on air quality of all sources and growth in the affected area. An analysis of the air quality related impact of the source will include an analysis of the impairment to visibility, soils, and vegetation and the projected air quality impact from general commercial, residential, industrial, and other growth associated with the source. The owner or operator need not provide an analysis of the impact on vegetation having no significant commercial or recreational value.

4.10.12 R307-406 Visibility

Since the proposed SPC Project will be considered as a new major source, the visibility requirements of R307-406 will apply to this project. In accordance with R307-406, any new major source proposed in either an attainment area or area of non-attainment is required to determine the impact of its emissions on visibility in any mandatory Class I area. As a condition of any approval order issued to a source under R307-401, the Executive Secretary shall require the use of air pollution control equipment, technologies, methods or work practices deemed necessary to mitigate visibility impacts in Class I areas that would occur as a result of emissions from such source. The Federal Land Managers (FLMs) will be notified since the FLMs have jurisdiction over Class I and Wilderness areas. In determining visibility impact by a major new source or major modification, the Executive Secretary shall use, the procedures identified in the EPA publication "Workbook for Estimating Visibility Impacts" (EPA 450-4- 80-031) November 1980, or equivalent. In addition, the Executive Secretary shall insure that source emissions will be consistent with making reasonable progress toward the national visibility goal referred to in 40 CFR, 51.300(a).

4.10.13 R307-410 Permits: Emissions Impact Analysis

R307-410 establishes the procedures and requirements for evaluating the emissions impact of new or modified sources that require an approval order under R307-401 to ensure that the source will not interfere with the attainment or maintenance of any NAAQS. The rule also establishes the procedures and requirements for evaluating the emissions impact of hazardous air pollutants. The rule also establishes the procedures for establishing an emission rate based on the good engineering practice stack height as required by 40 CFR 51.118.

Prior to receiving an approval order under R307- 401, a new source in an attainment area with a total controlled emission rate per pollutant greater than or equal to amounts specified in Table 4-1 above, or a modification to an existing source located in an attainment area which increases the total controlled emission rate per pollutant of the source in an amount greater than or equal to those specified in Table 4-1, shall conduct air quality modeling, as identified in R307-410-3, to estimate the impact of the new or modified source on air quality unless previously performed air quality modeling for the source indicates that the addition of the proposed emissions increase would not violate a National Ambient Air Quality Standard, as determined by the Executive Secretary.

The estimated emissions from the proposed SPC project for NO₂, CO, PM₁₀, and PM_{2.5} exceed the modeling requirements of Table 4-1; hence, dispersion modeling was conducted to satisfy R307-410 and is presented in Sections 6.0 and 7.0 of this application. In addition, per R307-310, SPC shall provide documentation of increases in emissions of hazardous air pollutants following the requirements presented in R307-401-5.

4.10.14 R307-414 Permits: Fees for Approval Orders

The owner and operator of each new major source or major modification is required to pay a fee to the Department sufficient to cover the reasonable costs of reviewing and acting upon the notice of intent required pursuant to R307-401 for each new major source or major modification and implementing and enforcing requirements placed on such source by any approval order issued pursuant to such notice (not including any court costs associated with any enforcement action). R307-414 will apply to SPC since a NOI will be submitted prior to construction.

4.10.15 R307-415 Permits: Operating Permit Requirements

Title V of the CAA requires States to develop and implement a comprehensive air quality permitting program. Title V does not impose new substantive requirements. Title V does require that sources subject to R307-415 pay a fee and obtain a renewable operating permit that clarifies, in a single document, which requirements apply to a source and assures the source's compliance with those requirements.

R307-415 establishes the procedures and elements of the Title V program. Since the SPC project is a major and a Part 70 source, the SPC project will be subject to R307-415.

4.10.16 R307-417 Permits: Acid Rain Sources

The provisions of 40 CFR Part 72, for purposes of implementing an acid rain program that meets the requirements of Title IV of the Clean Air Act, are incorporated into these rules by reference. If the provisions or requirements of 40 CFR Part 72 conflict with or are not included in R307-415 (Operating Permits), the requirements of 40 CFR Part 72 shall apply and take precedence.

5.0 BEST AVAILABLE CONTROL TECHNOLOGY DEMONSTRATION

As presented in Utah Air Quality Rule R307-401-2 (d), "Best available control technology (BACT)" means an emissions limitation (including a visible emissions standard) based on the maximum degree of reduction for each air contaminant which would be emitted from any proposed stationary source or modification which the executive secretary, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. The BACT analysis was conducted in accordance with EPA's recommended "top-down" methodology which is:

- Step 1 – Identify All Control Technologies
- Step 2 – Eliminate Technically Infeasible Options
- Step 3 – Rank Remaining Control Technologies by Control Effectiveness
- Step 4 – Evaluate Most Effective Controls
- Step 5 – Select BACT.

In Step 1 in a "top down" analysis, all available control options for the emission unit in question are identified. Identifying all potential available control options consists of those air pollution control technologies or control techniques with a practical potential for application to the emission unit and the regulated pollutant being evaluated.

In Step 2, the technical feasibility of the control options identified in Step 1 are evaluated and the control options that are determined to be technically infeasible are eliminated. Technically infeasible is defined where a control option, based on physical, chemical, and engineering principles, would preclude the successful use of the control option on the emissions unit under review due to technical difficulties. Technically infeasible control options are then eliminated from further consideration in the BACT analysis.

The third step of the “top-down” analysis is to rank all the remaining control options not eliminated in Step 2, based on control effectiveness for the pollutant under review. If the BACT analysis proposes the top control alternative, there would be no need to provide cost and other detailed information.

Once the control effectiveness is established in Step 3 for all feasible control technologies identified in Step 2, additional evaluations of each technology, based on energy, environmental, and economic impacts, are considered to make a BACT determination in Step 4. The energy impact of each evaluated control technology is the energy benefit or penalty resulting from the operation of the control technology at the source. The costs of the energy impacts either in additional fuel costs or the cost of lost power generation impacts the cost-effectiveness of the control technology.

The second evaluation to be reviewed for each control technology remaining in Step 4 is the environmental evaluation. Non-air quality environmental impacts are evaluated to determine the cost to mitigate the environmental impacts caused by the operation of a control technology.

The third evaluation addresses the economic evaluation of the remaining control technologies. The cost to purchase and to operate the control technology is analyzed. The capital and annual operating costs are estimated based on established design parameters or documented assumptions in the absence of established designed parameters. The cost-effectiveness describes the potential to achieve the required emissions reduction in the most economical way. It also compares the potential technologies on an economic basis.

In Step 5, BACT is selected for the pollutant and emission unit under review. BACT is the highest ranked control technology not eliminated in Step 4.

5.1 Gas Combustion Turbine BACT for NO_x

Nitrogen oxides (NO_x) are formed during the combustion of fuel and generally classified as thermal NO_x, prompt NO_x, or fuel-related NO_x. Typically, the NO_x that is formed in combustion turbines consists of 60 percent NO with the remaining balance as NO₂. NO_x emissions formed through the oxidation of a portion of the nitrogen contained in the combustion air are called thermal NO_x and are a function of combustion temperature. Prompt NO_x forms within the combustion flame and is usually negligible when compared to the amount of thermal NO_x formed. Fuel NO_x emissions are formed by the oxidation of the chemically bound nitrogen in the fuel.

5.1.1 Step 1 - Identify All Control Technologies

The following control options were evaluated for controlling NO_x emissions from combustion turbines in a combined cycle configuration. They are categorized as combustion controls where the amount of NO_x formed in the combustion process is reduced and post-combustion controls where NO_x is removed from the flue gas stream. Pre-combustion controls include: dry low-NO_x combustors, XONON, and steam/water injection. Post-combustion controls include: Selective Non-Catalytic Reduction (SNCR), NO_xOUT, Selective Catalytic Reduction (SCR), and EM_x.

Combustion Controls

5.1.1.1 Dry Low-NO_x Combustors

In the past several years, manufacturers have offered and installed combustion turbines with dry low-NO_x combustors (DLN). These burners are offered by GE and Siemens Westinghouse and can achieve NO_x concentrations of as low as 9 ppmvd or less when firing natural gas. DLN combustors reduce the formation of thermal NO_x through:

- (1) lean combustion that uses excess air to reduce the primary combustion temperature;
- (2) reduced combustor residence time to limit exposure in a high temperature environment;
- (3) lean premixed combustion that reduces the peak flame temperature by mixing fuel and air in an initial stage to produce a lean and uniform fuel/air mixture to the next stage where combustion takes place; and/or
- (4) two-stage rich/lean combustion using a primary fuel-rich combustion stage to limit the amount of oxygen available to combine with nitrogen.

For the combined cycle units being considered for this project, the standard combustion chamber design includes the use of DLN combustor technology.

5.1.1.2 XONON

XONON, developed by Catalytica Combustion Systems, is another form of in-combustor control. XONON prevents the formation of NO_x emissions by keeping the temperature of flame (below 2700°F) and combustion below the level that permits nitrogen and oxygen to combine and form NO_x . XONON uses a proprietary flameless catalytic combustion module followed by completion of combustion (at lower temperatures) downstream of the catalyst. XONON is an emerging technology which has been used successfully on gas turbines < 15 MW but have not been demonstrated on large-scale utility gas turbines such as the units being considered for this project.

5.1.1.3 Steam/Water Injection

The injection of water or steam to the high temperature zones of the CT flame is a combustion technique that reduces the peak flame temperature, thus lowering the quantity of thermal NO_x formed. The amount of NO_x reduction is a function of the combustor design and the water-to-fuel ratio employed. An increase in the steam/water-fuel ratio causes a decrease in NO_x emissions.

However, the lower peak flame temperature can also reduce combustion efficiency and prevent complete combustion potentially causing CO and precursor organic compound (POC) emissions to increase as steam/water-fuel ratios increase. The injected water or steam exits the turbine as part of the exhaust. Water or steam injection systems have been demonstrated to control NO_x emissions to 35 ppmvd @ 15% O₂ or 0.13 lb/MMBtu.

In addition, duct burners are comprised of several small modular burners located in the cross-sectional area of the duct. It is not feasible to inject steam/water since the flame is not concentrated on one area. For these reasons, steam/water injection technology cannot be used for the duct-burners.

Post-Combustion Controls

5.1.1.4 Selective Non-Catalytic Reduction

Selective Non-Catalytic Reduction (SNCR) involves the injection of ammonia or urea with proprietary chemicals into the exhaust stream without a catalyst. SNCR technology requires gas temperatures in the range of 1,600°F to 2,100°F⁵ and is most commonly used in boilers because gas turbines do not have exhaust temperatures in that range. The exhaust temperature from the proposed turbines averages approximately 1,100°F so SNCR is technically infeasible.

5.1.1.5 NO_xOUT™ SNCR Process

Fuel Tech's NO_xOUT™ process is a urea-based SNCR process for reduction of NO_x from stationary sources. The NO_xOUT™ process requires precisely engineered injection of stabilized urea liquor into combustion flue gas. NO_x reduction occurs in the temperature range of 1,650°F to 2,100°F.

⁵ *Air Pollution Control Fact Sheet*, EPA-452/F-03-031, available at <http://www.epa.gov/ttn/catc/dir1/fsncr.pdf>.

The NO_xOUT™ process has been successfully applied commercially on coal, oil and gas-fired boilers, biomass-fired boilers, process heaters, certain cement kilns, various steel industry boilers to name a few. However, the commercial application of a NO_xOUT™ system was not identified as being demonstrated on any CT/HRSG unit.

5.1.1.6 Selective Catalytic Reduction

Selective Catalytic Reduction (SCR) is a technology that react the NO_x in the turbine exhaust with ammonia or urea and oxygen in the presence of a catalyst to form nitrogen and water. SCR technology requires optimal gas temperatures in the range of 480°F to 800°F⁶. NO_x conversion is sensitive to exhaust temperature and performance can be limited by contaminants in the exhaust gas that may poison the catalyst. A small amount of ammonia is not consumed in the reaction and is emitted in the exhaust stream. The SCR catalyst required periodic replacement. SCR is a widely used post-combustion NO_x control technique on utility-scale gas turbines/HRSGs in conjunction with combustion controls and has been demonstrated to achieve NO_x emission limits of 2.0 ppm.

5.1.1.7 EM_x™

Formerly SCONOX™, EM_x™ is a catalytic oxidation and absorption control technology that uses a platinum-based oxidation catalyst coated with potassium carbonate (K₂CO₃) to oxidize and remove both NO_x, CO, and VOC without a reagent such as ammonia.

The K₂CO₃ coated catalyst oxidized CO to CO₂, NO to NO₂, and hydrocarbons to CO₂ and water. CO₂ generated in the catalyst bed is exhausted to the atmosphere with the flue gas while NO₂ absorbs onto the catalyst to form potassium nitrite (KNO₂) and potassium nitrate (KNO₃).

⁶ *Air Pollution Control Fact Sheet*, EPA-452/F-03-032, available at <http://www.epa.gov/ttn/catc/dir1/fscr.pdf>.

The EMx™ system utilizes hydrogen as the basis for a propriety catalyst regeneration process. The regeneration step converts KNO₂ and KNO₃ into K₂CO₃, water, and nitrogen gas. In order to maintain continuous operation during catalyst regeneration, the system is furnished in arrays of five-module catalyst sections. During operation, four of the five modules are online and treating the flue gas while one module is not in use. NO_x reduction in the system occurs in an operating temperature range of 300°F to 700°F. The EM_x™ catalytic oxidation and absorption control technology must be installed in the appropriate temperature section of the HRSG.

When exposed to sulfur oxides, the EMx™ system catalyst is subject to reduced performance and deactivation. For this reason, an additional catalytic oxidation/absorption system that removes sulfur compounds is installed upstream of the EMx™ catalyst.

The EMx™ catalyst must be recoated or washed every six months to one year. The frequency of washing is dependent on the sulfur content in the fuel and the effectiveness of the sulfur oxides catalytic oxidation/absorption system.

Commercial experience with the EMx™ catalytic oxidation and absorption control technology is limited. The largest turbine identified which included an EMx™ pollutant reduction system was a 45 MW turbine installation for the City of Redding, California. EmeraChem states that the process is scalable. However, commercial experience on the size turbines that SPC is proposing has not been demonstrated.

5.1.2 Step 2 – Eliminate Technically Infeasible Options

DLN combustors are available, demonstrated, and are technically feasible and will be further considered for BACT.

After review of EPA and State databases, no data were found to suggest that XONON has been used successfully on gas turbines larger than 15 MW. Thus, since this technology has not been demonstrated on large-scale utility gas turbines such as the units being considered for this project, it is not considered technically feasible and has been eliminated from further consideration.

Steam/water injection can also be eliminated since it is found to be less effective in gas firing applications than other control systems, and while technically feasible, it is not used in modern gas-fired combined cycle units because DLN combustors offer better control for no additional cost.

In addition, since the duct burners are comprised of several small modular burners located in the cross-sectional area of the duct and the flame is not concentrated in one area, it is not feasible to inject steam/water into the flame. Thus, for these reasons, steam/water injection technology was eliminated from further consideration.

Based on available information, the NO_xOUT™ process has been demonstrated on a 90 MW GE Frame 7 FA gas turbine at a combined cycle facility and was able to achieve a controlled NO_x emission rate of 5 ppm. However, the NO_xOUT™ process was considered technically not feasible for SPC since NO_x reductions using the NO_xOUT™ system requires flue gas temperatures in the range of 1,600°F to 1,950°F. This temperature range is significantly above the maximum exhaust temperature of approximately 1,100°F for the gas turbines proposed by SPC.

SNCR is eliminated because it also required temperatures between 1,600°F to 2,100°F for reactions to occur. In addition, there are no examples found where this technology has been installed on combined cycle gas turbines.

SCR is available, demonstrated, and is technically feasible with large scale combined cycle turbines and will be further considered for BACT.

EmeraChem states that the process is scalable and thus, in theory, can be considered applicable. Commercial experience with the EMx™ catalytic oxidation and absorption control technology has been limited to only a few operating turbines that are 45 MW or smaller in size. No large natural gas combined-cycle applications of the size SPC is proposed were identified using EMx™. Since there is no commercial experience of the use of EMx™ on the size turbines that SPC is proposing, it is not considered technically feasible and has been eliminated from further consideration.

5.1.3 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Based on the results of Step 2, the only remaining technically feasible control technology available for gas-fired combustion turbines is SCR used in conjunction with DLN combustors.

5.1.4 Step 4 – Evaluate Most Effective Controls

The use of a SCR system requires an ammonia storage, handling and delivery system which includes vaporizers and blowers to vaporize and dilute the aqueous ammonia reagent for injection. The SCR system catalyst will also increase with backpressure on each combustion turbine which will slightly reduce the power output of each combustion turbine. Thus, the use of a SCR system will impact the energy requirements of the facility.

The use of a SCR system introduces some environmental risk due to ammonia being classified as a hazardous substance, the vanadium content of the SCR catalyst classification as a hazardous waste, and the ammonia emissions or ammonia slip from the SCR system.

Under Title III Section 302 of the Superfund Amendments and Reauthorization Act (SARA), ammonia is listed as a hazardous substance. Ammonia is also regulated by US EPA's Chemical Accident Prevention Provisions. SPC will utilize aqueous ammonia which can be stored and used more safely than anhydrous ammonia.

SPC will prepare and maintain a Risk Management Plan (RMP) and implement a Risk Management Program to prevent accidental releases of ammonia. The RMP will provide information on the hazards of ammonia handled at the facility and the programs that will be put into place to prevent and respond to accidental releases.

The vanadium content of the SCR catalyst is what classifies the spent catalyst as a hazardous waste and as such it must be handled and disposed of according to hazardous waste procedures. Recycling of SCR catalysts may be performed also.

Some ammonia slip from the exhaust stacks is unavoidable due to the imperfect distribution of the reagent and catalyst deactivation. The maximum expected emission of ammonia will typically be less than 5 ppmvd, corrected to 15% O₂. The amount of ammonia slip will increase over the life of the catalyst.

Lastly, the oxidation of ammonia and SO₂ can lead to the formation of ammonium sulfate salts. A fraction of the SO₂ in the flue gas will oxidize to SO₃ in the presence of the SCR catalyst. SO₃ can react with water to form sulfuric acid mist (H₂SO₄). Sulfuric acid mist and ammonium sulfate are considered to be condensable particulate which can lead to increased PM₁₀/PM_{2.5} emissions.

Thus, while there are economic, environmental and energy impacts that occur with the use of a SCR, these impacts are not considered significant enough to preclude the use of a SCR for NO_x control. Hence, the highest ranking control technology, SCR with DLN combustors is proposed for this project; a cost analysis is not required.

5.1.5 Step 5 – Select BACT

State-by-state reviews as well as the EPA's RACT/BACT/LAER Clearinghouse databases were searched for recently permitted natural gas-fired combined-cycle power generation facilities. Table 5-1 presents a summary of recent NO_x determinations for natural gas-fired combined-cycle power generation facilities. This table is not exhaustive, rather lists the emission rates and control technologies utilized in the past five years from select plants.

Based on Table 5-1, BACT is being achieved through the use of DLN combustors and SCR control of NO_x emissions. SPC is proposing the use of dry low-NO_x combustors, HRSGs equipped with low NO_x duct burners, and SCR as BACT for the GE or Siemens CTs. This is the most effective combustion and post-combustion control technologies identified as available and proven for reducing NO_x emissions for this type of facility. SPC is proposing a NO_x emissions limit of 2.0 ppm_{dv} @ 15% O₂ (based on a three-hour average) for each turbine/HRSG stack.

Table 5-1

Gas Turbine NO_x Emission Limits for Combined Cycle Plants from EPA's RACT/BACT/LAER Clearinghouse

RBLC ID	Facility Name	County	State	Permit Date	Size	Basis	Emission Limit	Comments
OR-0048	Carty Plant	Morrow	Oregon	12/29/2010	2866 MMBtu/hr	BACT-PSD	2 ppm _{dv} @ 15% O ₂ (3-hr rolling limit)	SCR
AK-0071	International Station Power Plant	Mun. of Anchorage	Alaska	12/21/2010	59900 hp ISO	BACT-PSD	5 ppm _{dv} (4-hr average)	SCR, DLN burners, 90% SCR efficiency. Includes duct burner emissions
ID-0018	Langley Gulch Power Plant	Payette	Idaho	10/5/2010	2375.28 MMBtu/hr	BACT-PSD	2 ppm _{dv} @ 15% O ₂ (3-hr rolling limit)	Siemens SGT6-5000F Combustion turbine with duct burners. SCR, DLN burners, good combustion practices
GA-0138	Live Oaks Power Plant	Glynn	Georgia	9/10/2010	600 MW	BACT-PSD	2.5 ppm _{dv} @ 15% O ₂ (3-hr rolling limit)	Siemens SGT6-5000F combustion turbines, HRSG, duct burners. SCR, DLN burners
TX-0548	Madison Bell Energy Center	Madison	Texas	11/6/2009	275 MW	BACT-PSD	2 ppm _{dv} @ 15% O ₂ (24-hr rolling limit)	GE PG7121 combustion turbines, HRSG, duct burners. SCR
TX-0547	NG Power Generation Facility	Lamar	Texas	6/22/2009	250 MW	BACT-PSD	2 ppm _{dv} @ 15% O ₂ (24-hr rolling limit)	Either GE 7FAS or Mitsubishi 501GS, HRSG, duct burners. SCR
TX-0546	Pattillo Branch Power Plant	Fannin	Texas	6/17/2009	350 MW	BACT-PSD	2 ppm _{dv} @ 15% O ₂ (24-hr rolling limit)	Either GE 7FA or FB or Siemens SCT6-5000F, HRSG, duct burners. SCR
CA-1179	Applied Energy LLC	San Diego	California	3/20/2009		BACT-PSD	2 ppm 1-hour	SCR
OK-0129	Chouteau Power Plant	Mayes	Oklahoma	1/23/2009	1882 MMBtu/hr	BACT-PSD	2 ppm _{dv} @ 15% O ₂ (1-hr rolling limit)	Siemens V84.3A, SCR and DLN burners
FL-0304	Cane Island Power Park	Osceola	Florida	9/8/2008	300 MW	BACT-PSD	2 ppm _{dv} @ 15% O ₂ (24-hr rolling limit)	SCR
FL-0303	FPL West County Energy Center Unit 3	Palm Beach	Florida	7/30/2008	2333 MMBtu/hr	BACT-PSD	2 ppm _{dv} @ 15% O ₂ (24-hr rolling limit)	Three 250 MW CTG with HRSG, duct burners, SCR and DLN burners
LA-0224	Arsenal Hill Power Plant	Caddo	Louisiana	3/20/2008	2110 MMBtu/hr	BACT-PSD	30.15 lb/hr or 4 ppm _{dv} @15% O ₂ (annual avg.)	Low NO _x , SCR
CT-0151	Kleen Energy Systems LLC	Middlesex	Connecticut	2/25/2008	580 MW Nominal	LAER	2 ppm _{dv} @ 15% O ₂ (1-hr block)	Siemens SGT6-5000F Combustion turbine with duct burners. SCR, DLN burners
VA-0308	Warren County Facility	Warren	Virginia	1/14/2008	1717 MMBtu/hr	BACT-PSD	2 ppm _{dv}	GE Model 7FA with HRSG and duct burner. Two stage pre-NO _x combustion and SCR
VA-0308	Warren County Facility	Warren	Virginia	1/14/2008	1944 MMBtu/hr	BACT-PSD	2 ppm _{dv} or 17.9 lb/hr with burner firing	GE Model 7FA with HRSG and duct burner. Two stage pre-NO _x combustion and SCR
VA-0308	Warren County Facility	Warren	Virginia	1/14/2008	2204 MMBtu/hr	BACT-PSD	2 ppm _{dv}	GE Model 7FA with HRSG and duct burner. Two stage pre-NO _x combustion and SCR

Table 5-1 (Continued)

Gas Turbine NO_x Emission Limits for Combined Cycle Plants from EPA's RACT/BACT/LAER Clearinghouse

RBLC ID	Facility Name	County	State	Permit Date	Size	Basis	Emission Limit	Comments
CA-1114	Blythe Energy Project II	Riverside	California	4/25/2007	170 MW	BACT-PSD	2 ppmdv @ 15% O ₂ (3-hr average)	SCR
NY-0098	Athens Generating Plant	Greene	New York	1/19/2007	3100 MMBtu/hr	LAER	2 ppmdv @ 15% O ₂ (3-hr average)	3 Westinghouse 501G turbines with HRSG and duct burners. DLN burners and SCR
FL-0286	FPL West County Energy Center	Palm Beach	Florida	1/10/2007	2333 MMBtu/hr	BACT-PSD	2 ppmdv @ 15% O ₂ (24-hr average)	Combined cycle with HRSG and duct burners, DLN burners and SCR
NY-0095	Caithnes Bellport Energy Center	Suffolk	New York	5/10/2006	2221 MMBtu/hr	BACT-PSD	2 ppmdv @ 15% O ₂	Combined cycle with HRSG and duct firing. SCR
NV-0035	Tracy Substation Expansion Project	Storey	Nevada	8/16/2005	306 MW	BACT-PSD	2 ppmdv @ 15% O ₂ (3-hr average)	Combined cycle with HRSG and duct firing. SCR
OR-0041	Wanapa Energy Center	Umatilla	Oregon	8/8/2005	2384.1 MMBtu/hr	BACT-PSD	2 ppmdv @ 15% O ₂ (3-hr average)	GE 7241FA Turbine, combined cycle with HRSG and duct firing. DLN burners and SCR
NY-0100	Empire Power Plant	Rensselaer	New York	6/23/2005	2099 MMBtu/hr	LAER	2 ppmdv @ 15% O ₂ (3-hr average)	GE 7FA turbine with HRSG and duct firing. DLN burners and SCR.
FL-0263	FPL Turkey Point Power Plant	Dade	Florida	2/8/2005	170 MW	BACT-PSD	2 ppmdv @ 15% O ₂ (24-hr average)	Combined cycle with HRSG and duct burners, DLN burners and SCR

5.2 Gas Combustion Turbine BACT for CO and VOC

Both CO and unburned hydrocarbons (as VOC's) are products of incomplete combustion which occurs when there is incomplete oxidation of the carbon contained in the fuel. CO and VOC formation is limited by ensuring complete and efficient combustion of the fuel in the combustion turbine. High combustion temperatures, good air/fuel mixing, and adequate excess air minimize CO and VOC emissions.

High combustion temperatures also increase NO_x emissions due to thermal NO_x formation, as discussed previously. A good combustor design will minimize the formation of CO and VOC emissions while reducing the combustion temperature to minimize NO_x emissions.

5.2.1 Step 1 - Identify All Control Technologies

Potentially available control technologies were identified based on a comprehensive review of available literature. Carbon monoxide and VOC control methods are categorized into two methods: combustion controls and post-combustion control. The combustion controls for CO/VOC formation minimize the amount of CO formed from the CT and duct burner; the post-combustion controls reduce the CO/VOC emissions in the fuel gas stream after CO/VOC has been formed in the combustion process. Both of these methods can be used alone or in combination to achieve various degrees of CO/VOC control.

Several different types of emission controls were identified for this CO/VOC BACT analysis and include: (1) good combustion practice (GCP); (2) DLN burners; (3) oxidation catalysts; (4) EMx™; and (5) XONON.

Combustion Controls

5.2.1.1 Good Combustion Practice

Proper combustion practices include operation of the combustion turbines and duct burners at high combustion efficiencies which reduces the formation of CO and VOC's as products of incomplete combustion. Combustion technology/design is a function of the efficient operation and design of the gas turbines and duct burners. With combustion technology/design control, formation of CO and VOC is minimized through optimum design and operation. This includes proper air-to-fuel ratios, and a turbine design that provides the necessary temperature, mixing conditions and residence time in the combustion zone. Good combustion practice utilizes "lean combustion" where a large amount of excess air is used to produce a cooler flame temperature to minimize NO_x formation which, at the same time insures good air/fuel mixing with excess air to achieve complete combustion, thus minimizing CO emissions. Good combustion practice can be used with DLN combustors which will be utilized for minimizing NO_x emissions.

5.2.1.2 Dry Low-NO_x Combustors

CO emissions generated during the combustion process are dependent upon the design of the combustion system including fuel-to-air ratios and staging of combustion air. The use of good combustion practices with state of the art DLN burners will reduced CO emissions. For this reason, the proposed GE or Siemens turbines will be equipped with DLN burners. This technology provides low emission rates of CO.

Post-Combustion Controls

5.2.1.3 Oxidation Catalyst

The use of an oxidation catalyst to convert CO to CO₂ and that will not impact NO_x emissions is a control technology that is available to reduce CO emissions. Oxidation catalysts are a proven post-combustion control technology widely in use on large gas turbines to reduce CO emissions.

Up to 80% CO reduction, can be achieved with a noble metal enriched catalyst operating in a temperature range of 300°F to 700°F. Operation outside of this temperature range will result in lower reduction efficiencies. Residence time is another critical operating parameter for the catalyst enhanced oxidation process. System design requires adequate residence time for the flue gas stream in the active catalyst zones. It is expected that reduction efficiencies will not be maintained during periods of operation, i.e. startup and shutdown, when the catalyst operating temperature cannot be maintained.

5.2.1.4 EM_xTM

EM_xTM is a catalytic oxidation and absorption control technology that uses a platinum-based oxidation catalyst coated with potassium carbonate (K₂CO₃) to oxidize and remove both NO_x and CO without a reagent such as ammonia. The EM_xTM system reduces CO emissions by oxidizing the CO to CO₂. The demonstrated application for this technology is currently limited to combined cycle combustion turbines less than 50 MW.

5.2.1.5 XONON

As mentioned previously in Section 5.1.1.2, the XONON catalytic combustion system potentially can lower CO emissions by operating at lower temperatures. XONON is a catalytic combustion system that uses catalysts within the combustor to oxidize a lean air-to-fuel mixture rather than burning with a flame.

5.2.2 Step 2 – Eliminate Technically Infeasible Options

The development of good combustion practices with state-of-the art DLN combustors are available, demonstrated, and are technically feasible technologies that will be further considered for BACT.

CO oxidation catalysts are also an available, demonstrated, and technically feasible control technology for controlling CO and VOC emissions and will also be further considered for BACT.

EmeraChem states that the EMx™ process is scalable and thus, in theory, can be considered applicable for CO reduction. Commercial experience with the EMx™ catalytic oxidation and absorption control technology has been limited to only a few operating turbines that are 45 MW or smaller in size.

Since there is no commercial experience of the use of EMx™ on the size turbines that SPC is proposing, it is not considered technically feasible and has been eliminated from further consideration. Similarly, XONON has not been demonstrated on large scale utility gas turbines such as are being proposed by SPC and is not considered technically feasible.

5.2.3 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

CO and VOC control by good combustion practices and using DLN combustors is the least stringent control technology considered. The performance of a oxidation catalyst system on combustion turbines results in 90% or greater control for CO emissions.

5.2.4 Step 4 – Evaluate Most Effective Controls

There are three potential environmental impacts with the use of an oxidation catalyst system. First, the use of an oxidation catalyst will require the replacement of the catalyst bed after several years. The waste catalyst will have to be disposed of in accordance with state and federal regulations regarding normal waste disposal. Because of the precious metal content of the catalyst, the oxidation catalyst may also be recycled to recover the precious metals.

A second potential environmental impact in using an oxidation catalyst to reduce CO emissions, is that a percentage of SO₂ in the flue gas will oxidize to SO₃. The higher the operating temperature, the higher the SO₂ to SO₃ oxidation potential. The SO₃ will react with moisture in the flue gas to form H₂SO₄. The increase in H₂SO₄ emission may increase PM₁₀ emissions.

The third potential environmental impact of using an oxidation catalyst is the oxidation of CO can result in increased CO₂ emissions. CO₂ is considered a greenhouse gas which is thought to contribute to global climate change.

The installation of an oxidation catalyst system will also have an energy impact. The oxidation catalyst system located downstream of the CT exhaust will increase the backpressure on the CT which results in decreased output. This decreased output will lead to increased emissions of all pollutants on a unit power output basis.

Although there are environmental and energy impacts associated with the use of an oxidation catalyst system, these impacts are not considered significant enough to preclude the use of this system for CO control. Since SPC is proposing CTs with DLN combustors and a catalytic oxidation system to reduce CO and VOC emissions, a cost analysis for these controls is not required.

5.2.5 Step 5 – Select BACT

State-by-state reviews as well as the EPA's RACT/BACT/LAER Clearinghouse databases were searched for recently permitted natural gas-fired combined-cycle power generation facilities. Tables 5-2 and 5-3 present summaries of recent CO and VOC determinations for natural gas-fired combined-cycle power generation facilities. These tables are not exhaustive, rather list the emission rates and control technologies utilized in the past five years from select plants.

Based on Table 5-2, BACT is being achieved through the good combustion practices, DLN combustors, and an oxidation catalyst system. SPC is proposing good combustion practices, DLN combustors, and a oxidation catalyst system and a CO emission rate of 2.0 ppmvd @ 15% O₂ (based on a three-hour average) for each turbine/HRSG stack which is considered BACT. This limit includes those periods with and without supplemental duct firing.

For VOC emissions, SPC is proposing good combustion practices, DLN burners, an oxidation catalyst system, and a VOC emission rate of 3.0 ppmvd @ 15% O₂ (based on a three-hour average) for each turbine/HRSG stack. This limit includes those periods with and without supplemental duct firing and is considered BACT.

Table 5-2

Gas Turbine CO Emission Limits from EPA's RACT/BACT/LAER Clearinghouse

RBLC ID	Facility Name	County	State	Permit Date	Size	Basis	Emission Limit	Comments
ID-0018	Langley Gulch Power Plant	Payette	Idaho	10/5/2010	2375.28 MMBtu/hr	BACT-PSD	2 ppm _{dv} @ 15% O ₂ (3-hr rolling limit)	Combustion turbine, HRSG with duct burners. CATOX ¹ , DLN burners, good combustion practices
GA-0138	Live Oaks Power Plant	Glynn	Georgia	9/10/2010	600 MW	BACT-PSD	2 ppm _{dv} @ 15% O ₂ (3-hr rolling limit)	Combustion turbines, HRSG with duct burners, CATOX, good combustion practices
TX-0548	Madison Bell Energy Center	Madison	Texas	11/6/2009	275 MW	BACT-PSD	17.5 ppm _{dv} @ 15% O ₂ (1-hr rolling limit)	Combustion turbines, HRSG with duct burners, good combustion practices.
TX-0547	NG Power Generation Facility	Lamar	Texas	6/22/2009	250 MW	BACT-PSD	15 ppm _{dv} @ 15% O ₂ (24-hr rolling limit)	Combustion turbines, HRSG with duct burners, good combustion practices.
TX-0546	Pattillo Branch Power Plant	Fannin	Texas	6/17/2009	350 MW	BACT-PSD	2 ppm _{dv} @ 15% O ₂ (3-hr rolling limit)	Combustion turbines, HRSG with duct burners, CATOX and good combustion practices.
OK-0129	Chouteau Power Plant	Mayes	Oklahoma	1/23/2009	1882 MMBtu/hr	BACT-PSD	8 ppm _{dv} @ 15% O ₂ (1-hr rolling limit)	Good combustion practices
FL-0304	Cane Island Power Park	Osceola	Florida	9/8/2008	300 MW	BACT-PSD	8 ppm _{dv} @ 15% O ₂ (24-hr rolling limit)	Good combustion practices
FL-0303	FPL West County Energy Center Unit 3	Palm Beach	Florida	7/30/2008	2333 MMBtu/hr	BACT-PSD	6 ppm _{dv} @ 15% O ₂ (24-hr rolling limit)	Three 250 MW CTG with HRSG with duct burners. Good combustion practices
LA-0224	Arsenal Hill Power Plant	Caddo	Louisiana	3/20/2008	2110 MMBtu/hr	BACT-PSD	143.31 lb/hr or 10 ppm _{dv} @ 15% O ₂ (annual average)	Proper operating practices
CT-0151	Kleen Energy Systems LLC	Middlesex	Connecticut	2/25/2008	580 MW Nom.	BACT-PSD	0.9 ppm _{dv} @ 15% O ₂ (1-hr block) without duct burner	Combustion turbine, HRSG with duct burners. CATOX.
VA-0308	Warren County Facility	Warren	Virginia	1/14/2008	1717 MMBtu/hr	BACT-PSD	1.3 ppm _{dv} without power augmentation or 12.8 lb/hr with duct burner	Combustion turbine, HRSG and duct burners, CATOX and good combustion practices.
VA-0308	Warren County Facility	Warren	Virginia	1/14/2008	1944 MMBtu/hr	BACT-PSD	1.2 ppm _{dv} with duct burner	Combustion turbine, HRSG and duct burners, CATOX and good combustion practices..
VA-0308	Warren County Facility	Warren	Virginia	1/14/2008	2204 MMBtu/hr	BACT-PSD	1.8 ppm _{dv} without duct burner; 2.5 ppm _{dv} with duct burner	Combustion turbine, HRSG and duct burners, CATOX and good combustion practices..
CA-1114	Blythe Energy Project II	Riverside	California	4/25/2007	170 MW	BACT-PSD	4 ppm _{dv} @ 15% O ₂ (3-hr average)	
FL-0286	FPL West County Energy Center	Palm Beach	Florida	1/10/2007	2333 MMBtu/hr	BACT-PSD	6 ppm _{dv} @ 15% O ₂ (24-hr average)	Combined cycle with HRSG and duct burners, CATOX
NY-0095	Caithnes Bellport Energy Center	Suffolk	New York	5/10/2006	2221 MMBtu/hr	BACT-PSD	2 ppm _{dv} @ 15% O ₂	Combined cycle with HRSG and duct firing, CATOX

¹ CATOX = catalytic oxidation

Table 5-2 (Continued)

Gas Turbine CO Emission Limits from EPA's RACT/BACT/LAER Clearinghouse

RBLC ID	Facility Name	County	State	Permit Date	Size	Basis	Emission Limit	Comments
NV-0035	Tracy Substation Expansion Project	Storey	Nevada	8/16/2005	306 MW	BACT-PSD	3.5 ppmdv @ 15% O ₂ (3-hr average)	Combined cycle with HRSG and duct firing. CATOX ¹
OR-0041	Wanapa Energy Center	Umatilla	Oregon	8/8/2005	2384.1 MMBtu/hr	BACT-PSD	2 ppmdv @ 15% O ₂ (3-hr rolling limit)	GE 7241FA Turbine, combined cycle with HRSG and duct firing. CATOX
FL-0263	FPL Turkey Point Power Plant	Dade	Florida	2/8/2005	170 MW	BACT-PSD	8.0 ppmdv @ 15% O ₂ (24-hr average with duct burner)	Combined cycle with HRSG and duct burners. Efficient combustion of NG

¹ CATOX = catalytic oxidation

Table 5-3

Gas Turbine VOC Emission Limits from EPA's RACT/BACT/LAER Clearinghouse

RBLC ID	Facility Name	County	State	Permit Date	Size	Basis	Emission Limit	Comments
ID-0018	Langley Gulch Power Plant	Payette	Idaho	10/5/2010	2375.28 MMBtu/hr	BACT-PSD	2 ppmdv @ 15% O ₂ (3-hr rolling limit)	Combustion turbine, HRSG with duct burners. CATOX ¹ , DLN burners, good combustion practices
GA-0138	Live Oaks Power Plant	Glynn	Georgia	9/10/2010	600 MW	BACT-PSD	2 ppmdv @ 15% O ₂ (3-hr rolling limit)	Combustion turbines, HRSG with duct burners, CATOX, good combustion practices
TX-0548	Madison Bell Energy Center	Madison	Texas	11/6/2009	275 MW	BACT-PSD	2.5 ppmdv @ 15% O ₂ (1-hr rolling limit)	Combustion turbines, HRSG with duct burners, good combustion practices.
TX-0547	NG Power Generation Facility	Lamar	Texas	6/22/2009	250 MW	BACT-PSD	4 ppmdv @ 15% O ₂ (24-hr rolling limit)	Combustion turbines, HRSG with duct burners, good combustion practices.
TX-0546	Pattillo Branch Power Plant	Fannin	Texas	6/17/2009	350 MW	BACT-PSD	2 ppmdv @ 15% O ₂ (3-hr rolling limit)	Combustion turbines, HRSG with duct burners, CATOX and good combustion practices.
CA-1179	Applied Energy LLC	San Diego	California	4/11/2011		BACT-PSD	2 ppm 1-hour	CATOX
FL-0303	FPL West County Energy Center Unit 3	Palm Beach	Florida	7/30/2008	2333 MMBtu/hr	BACT-PSD	1.2 ppmvd	Three 250 MW CTG with HRSG with duct burners. Good combustion practices
LA-0224	Arsenal Hill Power Plant	Caddo	Louisiana	3/20/2008	2110 MMBtu/hr	BACT-PSD	12.06 lb/hr or 4.9 ppmdv @ 15% O ₂ (annual average)	Proper operating practices
CT-0151	Kleen Energy Systems LLC	Middlesex	Connecticut	2/25/2008	580 MW Nom.	BACT-PSD	5 ppmdv @ 15% O ₂ (1-hr block)	Combustion turbine, HRSG with duct burners. CATOX.

Table 5-3 (Continued)

Gas Turbine VOC Emission Limits from EPA's RACT/BACT/LAER Clearinghouse

RBLC ID	Facility Name	County	State	Permit Date	Size	Basis	Emission Limit	Comments
VA-0308	Warren County Facility	Warren	Virginia	1/14/2008	1717 MMBtu/hr	BACT-PSD	1.4 ppm _{dv} with power augmentation or 1 ppm _{dv} with duct burner	Combustion turbine, HRSG and duct burners, CATOX and good combustion practices.
VA-0308	Warren County Facility	Warren	Virginia	1/14/2008	1944 MMBtu/hr	BACT-PSD	0.7 ppm _{dv} with duct burner or 1 ppm _{dv} without duct burner	Combustion turbine, HRSG and duct burners, CATOX and good combustion practices..
VA-0308	Warren County Facility	Warren	Virginia	1/14/2008	2204 MMBtu/hr	BACT-PSD	0.7 ppm _{dv} without duct burner or 1 ppm _{dv} with duct burner	Combustion turbine, HRSG and duct burners, CATOX and good combustion practices..
NY-0098	Athens Generating Plant	Greene	New York	1/19/2007	1080 MW	LAER	4 ppm _{dv} @ 15% O ₂ (3-hr average)	Combustion turbines, HRSG with duct burners, good combustion practices.
FL-0286	FPL West County Energy Center	Palm Beach	Florida	1/10/2007	2333 MMBtu/hr	BACT-PSD	1.5 ppm _{dv} @ 15% O ₂	Combined cycle with HRSG and duct burners, CATOX
NV-0035	Tracy Substation Expansion Project	Storey	Nevada	8/16/2005	306 MW	BACT-PSD	4 ppm _{dv} @ 15% O ₂ (3-hr average)	Combined cycle with HRSG and duct burners, CATOX
NY-0100	Empire Power Plant	Rensselaer	New York	6/23/2005	2099 MMBtu/hr	LAER	1 ppm _{dv} @ 15% O ₂	Combined cycle with HRSG and duct burners
FL-0263	FPL Turkey Point Power Plant	Dade	Florida	2/8/2005	170 MW	BACT-PSD	1.9 ppm _{dv} @ 15% O ₂ (with duct burner)	Combined cycle with HRSG and duct burners. Efficient combustion of NG

5.3 Gas Combustion Turbine BACT for PM₁₀ and PM_{2.5}

PM_{2.5} emission information was sought from the proposed combustion turbine vendors but direct speciated PM_{2.5} information is not available. Therefore, for this BACT analysis, because the fuel source for the turbines is natural gas, combustion emissions are likely in the size range of PM_{2.5} filterable and condensable and all PM₁₀ emissions were assumed to be PM_{2.5}. PM₁₀ emission information was provided by the proposed combustion turbine vendors.

There are several sources of particulate matter, in the form of PM₁₀/PM_{2.5}, from the CT and HRSG with duct burners. Source of PM₁₀/PM_{2.5} result from condensable hydrocarbons from incomplete combustion, trace particulate and other inert contaminants in the natural gas, fuel sulfur, dust drawn in from the ambient air, and metal and carbon particles from equipment wear. As mentioned previously, all of the particulate matter emitted from the proposed project is believed to be less than 10 microns in diameters with most of it being less than 2.5 microns in diameter.

5.3.1 Step 1 - Identify All Control Technologies

Three types of control technologies were reviewed for the reduction of PM₁₀/PM_{2.5}. These technologies include: (1) pre-combustion controls such as the inlet air filter; (2) combustion controls which includes good combustion practice, clean burning fuels, and DLN combustors; and (3) post-combustion controls such as electrostatic precipitators and baghouses.

Pre-Combustion Control

5.3.1.1 Inlet Air Filter

To protect the turbine from contaminants in the air which can damage the CT, each proposed CT vendor suggest a turbine inlet air filter is used to filter out particulate matter 10 microns or less.

There are two main types of filters – static filters and self-cleaning filters. Self-cleaning filters are cleaned by a pulse of backflow air that dislodges the layer of dust collected on the outside surface of the filter. Self-cleaning filters require less maintenance than static filters. Any particulate that passes through the inlet filter and combustion chamber will be exhausted to the atmosphere.

Combustion Controls

5.3.1.2 Good Combustion Practice

Good combustion practices ensure proper air/fuel mixing to achieve complete combustion which minimizes emissions of unburned hydrocarbons that can lead to formation of particulate matter (PM₁₀/PM_{2.5}).

5.3.1.3 Clean Burning Fuels

SPC will utilize pipeline-quality natural gas which is an inherently clean fuel. Natural gas has only trace amounts of sulfur that can form particulate matter during combustion. This particulate matter can also combine with other compounds in the atmosphere after it is emitted to form secondary particulate matter such as sulfates.

5.3.1.4 Dry Low-NO_x Combustors

The use of DLN combustors provides efficient combustion to ensure complete combustion. Complete combustion minimizes the emissions of unburned fuel that can form condensable PM₁₀/PM_{2.5}. Condensable particulate matter is the portion of the total particulate matter that exists as a gas in the stack but condenses in the cooler ambient air to form particulate matter.

Post-Combustion Controls

5.3.1.5 Electrostatic Precipitators

An electrostatic precipitator (ESP) is a particle control device that uses electrical forces to move the particles out of the gas stream and onto collection plates. ESP's use a high-voltage direct-current corona to electrically charge particles in the gas stream. The suspended particles are attracted to collecting electrodes and deposited on collection plates. Particles are collected and disposed of by mechanically rapping the electrodes and plates and dislodging the particulate matter into collection hoppers. ESP's are commonly used on incinerators and solid fuel boilers.

5.3.1.6 Fabric Filter Baghouses

Fabric filter (baghouse) systems consist of a structure containing tubular bags made of a woven fabric. A baghouse removes $PM_{10}/PM_{2.5}$ from the exhaust gas by drawing the dust laden air through a bank of filter tubes suspended inside a structural housing. $PM_{10}/PM_{2.5}$ is collected on the upstream side of the fabric. Particulates collect on the outside of filter bags that are periodically shaken to release the particulate matter into hoppers. Fabric filter baghouses are typically used in high-particulate emission producing applications.

5.3.2 Step 2 – Eliminate Technically Infeasible Options

Pre- and post-combustion control technologies including inlet air filters, good combustion practices with state-of-the art DLN combustors, and the use of clean burning fuels such as natural gas are available, demonstrated, and are technically feasible technologies that will be further considered for BACT.

State-by-state reviews as well as the EPA's RACT/BACT/LAER Clearinghouse databases were searched to identify facilities that were using post-combustion control devices, such as ESPs and baghouses, for removal of PM₁₀/PM_{2.5} for natural gas-fired combined-cycle power generation facilities. No facilities were identified in the search. These devices are designed to be applied to gas streams with higher particulate emissions (high grain loading) to operate correctly and would have little effect on the low PM₁₀/PM_{2.5} emissions expected in the flue gas. This low level of PM₁₀/PM_{2.5} abatement efficiency (if any) also indicates that these types of control devices would not be cost-effective even if they were feasible. Since these post-combustion controls technologies have not been demonstrated in practice for use on natural gas-fired turbines, it was determined that these post-combustion control devices are technically not feasible and were eliminated from further consideration.

5.3.3 Steps 3 – 5

Inlet air filters, good combustion practices with state-of-the art DLN combustors, and the use of a clean burning fuel such as natural gas are the only feasible control technologies. They will be used in combination with each other and are top ranking in terms of control effectiveness. There are no adverse energy, environmental or cost impact associated with the use of these control technologies. Thus, no further analysis is required under EPA's top-down BACT approach.

Thus, given the high combustion efficiency of the CT and the use of natural gas, PM₁₀/PM_{2.5} emissions will be low. The SPC facility will utilize only pipeline quality natural gas, an air inlet filter, and proper combustion design and operation with state-of-the-art DLN combustors which represents BACT. The proposed PM₁₀/PM_{2.5} BACT limit is 14 lb/hr at ambient conditions at 100% load with supplemental duct firing based on a 30-day rolling average for each CT/HRSG stack.

5.4 Gas Combustion Turbine BACT for SO₂ and Sulfuric Acid Mist

SO₂ emissions from combustion turbines result from the oxidation of trace amounts of sulfur in the natural gas. The SPC combined-cycle power block will be fired exclusively with pipeline-quality natural gas. Typically, natural gas has only trace amounts of sulfur that is used as an odorant.

Sulfuric acid mist emissions can also form as a result of a small percentage of the SO₂ in the flue gas oxidizing to SO₃ that combines with water to form H₂SO₄.

5.4.1 Step 1 - Identify All Control Technologies

There are two primary mechanisms to reduce SO₂ emissions from combustion sources which are: (1) reduce the amount of sulfur in the fuel and (2) remove the sulfur from the CT/HRSG exhaust gas with post-combustion control device such as flue gas desulfurization utilizing wet or dry scrubbers.

5.4.1.1 Reducing the Amount of Sulfur in Fuel

SPC will be using Kern River Gas pipeline-quality natural gas which has a maximum sulfur content of 0.75 grains/100 standard cubic feet (scf) of sulfur. The use of a fuel containing low sulfur content is considered a control technology.

5.4.1.2 Post-Combustion Control Devices for Sulfur Removal

Two main types of SO₂ post-combustion control technologies, wet and dry scrubbing, were identified to reduce SO₂ in the exhaust gas. In wet scrubbers chemical reagents, usually an alkali material such as calcium in the form of lime or limestone, are mixed with water and used in the scrubber.

SO₂ is absorbed by the scrubbing liquid in the scrubber and the chemicals in the water react with the SO₂ producing sulfite and sulfate compounds. The scrubbing liquid which contains the SO₂ falls to the bottom of the scrubber and enters a holding tank where chemical reactions continue to form solids from the SO₂.

Dry scrubbing is any scrubbing process that produces wastes with less than 5% water. The main types of dry scrubbing include spray drying, dry injection, or a combination of the two. For dry scrubbing, as flue gas flows through a scrubber, a fine mist of dissolved and partially dissolved alkalis such as lime is sprayed in the scrubber. Enough moisture is added in the process to partially saturate the flue gas, but the amount of moisture is kept low enough so that the final product remains dry. The lime slurry absorbs and reacts with the sulfur dioxide and is removed by a particulate control device.

5.4.2 Step 2 – Eliminate Technically Infeasible Options

The requirement for low-sulfur natural gas is a control technique that has been achieved in practice and is technically feasible and cost-effective and will be further considered for BACT.

Post-combustion devices such as wet or dry scrubbers are typically installed on coal-fired power plants that burn fuels with much higher sulfur contents. The SO₂ concentrations in the natural gas combustion exhaust gases are too low for scrubbing technologies to work effectively or to be technically feasible and cost effective. These control technologies require much higher sulfur concentrations in the exhaust gases to be feasible as a control technology.

Thus, post-combustion SO₂ control devices, such as wet and dry scrubbing have not been achieved in practice at natural gas-fired power plants, are not technically feasible, and have been eliminated from further consideration.

5.4.3 Steps 3 – 5

The use of pipeline quality natural gas and fuel sulfur limits are the only feasible SO₂ control technology for natural gas combustion sources. There are no adverse energy, environmental or cost impact associated with the use of these control technologies. Thus, no further analysis is required under EPA's top-down BACT approach.

SPC will use Kern River Gas pipeline quality natural gas with a sulfur limit of 0.75 grains/100 scf. With extremely low emission rates of SO₂ and H₂SO₄ it proposed that the use of pipeline-quality natural gas be considered BACT. The proposed SO₂ BACT limit is 3.4 lb/hr.

5.5 Natural-Gas Fired Auxiliary Boiler and Convection Heaters BACT for NO_x

The auxiliary equipment to be utilized by SPC includes a 85 MMBtu/hr auxiliary boiler and two 22.3 MMBtu/hr convection heaters. Both the auxiliary boiler and fuel gas conditioning heaters will utilize only pipeline-quality natural gas.

As mentioned previously, there are two ways that NO_x are primarily formed in a combustion process. The first way NO_x is formed is within the high temperature environment of the combustor with the combination of elemental nitrogen and oxygen in the combustion air (thermal NO_x). The second way NO_x is formed is through the oxidation of nitrogen contained in the fuel (fuel NO_x). The majority of NO_x emissions from the auxiliary boiler and convection heaters will be the result of thermal NO_x. The rate of formation of thermal NO_x is a function of the residence time and free oxygen and is exponential with peak flame temperature.

5.5.1 Step 1 - Identify All Control Technologies

The following control options were evaluated for controlling NO_x emissions from the auxiliary boiler and convection heaters. They are categorized as combustion and post-combustion controls.

Combustion controls include: good combustion practices, low NO_x burners (LNB), ultra low NO_x burners (UNLB), staged air/fuel combustion or overfire air injection, and flue gas recirculation. Post-combustion controls include: SNCR, SCR, and EM_x or a combination of combustion and post-combustion controls.

Combustion Controls

5.5.1.1 Good Combustion Practices

Good combustion practices generally include the following components: (1) Proper air/fuel mixing in the combustion zone; (2) High temperatures and low oxygen levels in the primary combustion zone; (3) Overall excess oxygen levels high enough to complete combustion while maximizing boiler thermal efficiency, and (4) Sufficient residence time to complete combustion. Good combustion practices is accomplished through boiler design as it relates to time, temperature, and turbulence, and boiler operation as it relates to excess oxygen levels.

5.5.1.2 Low NO_x Burners

Low-NO_x burner technology uses advanced burner design to reduce NO_x formation through the restriction of oxygen, flame temperature, and/or residence time. There are two general types of LNB: staged fuel and staged air burners. In a staged fuel LNB, the combustion zone is separated into two regions. The first region is a lean combustion region where a fraction of the fuel is supplied with the total quantity of combustion air. Combustion in this zone takes place at substantially lower temperatures than a standard burner. In the second combustion region, the remaining fuel is injected and combusted with left over oxygen from the first region. This technique reduces the formation of thermal NO_x.

Staged fuel LNBs are well suited for boilers burning natural gas which generate higher thermal NO_x. By increasing residence times, staged-air LNBs provide reducing conditions which has a greater impact on fuel NO_x than staged fuel burners.

5.5.1.3 Ultra Low NO_x Burners

Ultra low NO_x burners may incorporate a variety of techniques including flue gas recirculation, steam injection, or a combination of techniques. These burners combine the benefits of flue gas recirculation and low-NO_x burner control technologies. The ULNB is designed to recirculate hot, oxygen depleted flue gas from the flame or firebox back into the combustion zone. By doing this, the average oxygen concentration is reduced in the flame without reducing the flame temperatures below which is necessary for optimal combustion efficiency. Reducing oxygen concentrations in the flame impacts the amount of fuel NO_x generated.

5.5.1.4 Staged Air/Fuel Combustion or Overfire Air Injection

Overfire air (OFA) is a combustion staging processes typically used in conjunction with low NO_x burners. A portion of the combustion air is redirected from the LNB to a higher elevation in the furnace to reduce peak flame temperatures by reducing the concentration of oxygen in portions of the furnace. This technique is used to create an oxygen depleted zone where unburned hydrocarbon species act to reduce the NO_x that was formed near the burner. The overfire air creates an oxidation zone to complete combustion. NO_x formation is minimized by completing combustion in an air-lean environment.

5.5.1.5 Flue Gas Recirculation

Flue gas recirculation is another combustion control used to reduce NO_x. FGR involves the recycling of fuel gas into the air-fuel mixture at the burner to help cool the burner flame. Internal FGR, used primarily in ULNB, involves recirculating the hot O₂-depleted flue gas from the heater into the combustion zone using burner design features. External FGR, usually used with LNB, requires the use of hot-side fans and ductwork to route a portion of the flue gas in the stack back to the burner windbox.

Post-Combustion Controls

5.5.1.6 Selective Non-Catalytic Reduction

SNCR is a post-combustion control system that involves the injection of ammonia or urea with proprietary chemicals into the exhaust stream without a catalyst. SNCR technology requires gas temperatures in the range of 1,600°F to 2,100°F and is most commonly used in boilers.

5.5.1.7 Selective Catalytic Reduction

SCR is a post combustion technology that reacts the NO_x in the boiler exhaust with ammonia or urea and oxygen in the presence of a catalyst to form nitrogen and water. The ammonia injection grid is located upstream of the catalyst. SCR technology requires optimal gas temperatures in the range of 480°F to 800°F. NO_x conversion is sensitive to exhaust temperature and performance can be limited by contaminants in the exhaust gas that may poison the catalyst. A small amount of ammonia is not consumed in the reaction and is emitted in the exhaust stream.

5.5.1.8 EM_xTM

EM_xTM is a catalytic oxidation and absorption control technology that uses a platinum-based oxidation catalyst coated with K₂CO₃ to oxidize and remove both NO_x, CO, and VOC without a reagent such as ammonia. NO_x reduction using EM_xTM occurs most effectively at temperatures ranging from 300°F to 700°F. The demonstrated application for this technology is currently limited to combined cycle combustion turbines less than 50 MW and diesel-fired boilers.

5.5.2 Step 2 – Eliminate Technically Infeasible Options

State-by-state reviews as well as the EPA’s RACT/BACT/LAER Clearinghouse databases were searched to identify facilities that were using post-combustion control devices, such as SNCR, SCR, and EM_xTM for removal of NO_x for natural gas-fired auxiliary boilers and fuel gas conditioning heaters used at combined-cycle plants. No facilities were identified in the search that utilized the post-combustion controls of SNCR and EM_x on natural gas fired auxiliary boilers and/or convection heaters. SNCR technology has exhaust gas temperatures and/or oxygen content constraints that would prevent these technologies from being applied to the auxiliary boiler and convection heaters. EM_xTM has not been demonstrated in practice on natural gas fired boilers and heaters. Thus, these technologies were eliminated from further review. The remaining control technologies are technically feasible and will be further considered for BACT.

5.5.3 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Based on the results of Step 2, several control technologies remain and have been ranked in decreasing order by the approximate level of emissions reduction:

- LNB with SCR 0.011 lb/MMBtu
- ULNB with FGR 0.011 lb/MMBtu
- LNB with FGR 0.020 lb/MMBtu
- LNB with GCP 0.036 lb/MMBtu
- LNB 0.070 lb/MMBtu
- FGR 0.20 lb/MMBtu
- Staged air/fuel combustion or overfire air injection 0.25 lb/MMBtu
- GCP with conventional burners 0.30 lb/MMBtu

5.5.4 Step 4 – Evaluate Most Effective Controls

While all the control technologies ranked in Step 3 are technically feasible, three control technologies were identified that offered the top level of control. They include LNB with SCR, ULNB with FGR, and LNB with FGR.

SPC is proposing ULNB with FGR for the auxiliary boiler and LNB and FGR for the convection heaters which are two of the leading NO_x control technologies identified. By using these controls, no adverse economic, energy, or collateral environmental impacts were identified that preclude the use of these technologies. For the remaining top control technology, LNB with SCR, the use of SCR would involve economic, energy and environmental impacts. The costs of applying an SCR for the auxiliary boiler and a convection heater are presented in Tables 5-4 and 5-5. It should be noted that the cost per ton of NO_x reduction is for each convection heater. Based on Table 5-5, SCR is not BACT for either the auxiliary boiler and the convection heater due to the very high cost, which is in excess of \$38,800 and \$29,680, respectively, per ton of NO_x emissions controlled.

Table 5-4

Selective Catalytic Reduction Capitol Costs for Auxiliary Boiler and Convection Heater

	Auxiliary Boiler	Convection Heater	Factor	Basis for Cost and Factor
Capacity (MMBtu/hr)	85	22.264		
Direct Costs:				
Purchased Equipment:				
Primary and Auxiliary Equipment (PE)	\$ 350,000	\$ 275,000	Vendor Data	
Instrumentation and Controls	\$ 35,000	\$ 27,500	10% of PE	EPA ¹
Sales Tax	\$ 10,500	\$ 8,250	3% of PE	EPA ¹
Freight	\$ 17,500	\$ 13,750	5% of PE	EPA ¹
Total Purchased Equipment Cost (PEC)	\$ 413,000	\$ 324,500		
Direct Installation				
Foundations	\$ 33,040	\$ 25,960	8% of PEC	EPA ¹
Handling and Erection	\$ 57,820	\$ 45,430	14% of PEC	EPA ¹
Electrical	\$ 16,520	\$ 12,980	4% of PEC	EPA ¹
Piping	\$ 8,260	\$ 6,490	2% of PEC	EPA ¹
Insulation and Ductwork	\$ 4,130	\$ 3,245	1% of PEC	EPA ¹
Painting	\$ 4,130	\$ 3,245	1% of PEC	EPA ¹
Total Direct Installation (DI)	\$ 123,900	\$ 97,350		
Total Direct Cost (DC)	\$ 536,900	\$ 421,850		
Indirect Installation Costs				
Engineering and Project Management	\$ 41,300	\$ 32,450	10% of PEC	EPA ¹
Construction and Field Expenses	\$ 20,650	\$ 16,225	5% of PEC	EPA ¹
Contractor Fees	\$ 41,300	\$ 32,450	10% of PEC	EPA ¹
Startup Expenses	\$ 8,260	\$ 6,490	2% of PEC	EPA ¹
Performance Tests	\$ 4,130	\$ 3,245	1% of PEC	EPA ¹
Contingencies	\$ 12,390	\$ 9,735	3% of PEC	EPA ¹
Total Indirect Cost	\$ 128,030	\$ 100,595		
Total Installed Cost (TIC)	\$ 664,930	\$ 522,445		
Assumptions:				
EPA ¹ - EPA Air Pollution Control Cost Manual, Sixth Edition, Section 4, EPA/452/B-002-001, Jan. 2002.				

Table 5-5

Selective Catalytic Reduction Annual Costs for Auxiliary Boiler and Convection Heater

	Auxiliary Boiler	Convection Heater	Basis for Cost and Factor
Capacity (MMBtu/hr)	85	22.264	
Capitol Cost			
Total Installed Cost	\$ 664,930	\$ 522,445	
NO _x Emissions Before Control, lb/MMBtu	0.017	0.036	ULNB (aux. boiler) and LNB (convection heater)
Annual Capacity Factor	100%	100%	
NO _x Emissions Before Control, tn/yr	6.33	7.08	
NO _x Emissions After Control, lb/MMBtu	0.0034	0.0072	
Control Efficiency (%)	80	80	
NO _x Emissions After Control, tn/yr	1.266	1.416	
NO _x Emission Reduction, tn/yr	5.064	5.664	
Annual Costs, \$/year			
Catalyst Annual Cost			
Catalyst Replacement Cost	\$ 206,500	\$ 162,250	50% of primary equipment cost (includes capitol and labor)
Catalyst Life	5	5	EPA ²
Annual Costs, \$/year	\$ 50,363	\$ 39,571	7% Interest - EPA ¹
Aqueous Ammonia	\$ 7,090	\$ 7,930	4 tons aqueous ammonia needed per ton NO _x removed at \$350/tn
Operating Labor	\$ 12,775	\$ 12,775	1 hour per day @ \$35/hr
Supervisor	\$ 1,916	\$ 1,916	15% of operating labor - EPA ²
Maintenance Labor	\$ 12,775	\$ 12,775	1 hour per day @ \$35/hr
Maintenance Materials	\$ 12,775	\$ 12,775	100% of maintenance labor - EPA ²
Electricity	\$ 5,212	\$ 1,365	0.1 kW/MMBtu/hr for pressure drop at \$0.07/KWh
Overhead	\$ 24,145	\$ 24,145	60% of oper., maint.& supervisor labor plus main.costs
Taxes, Insurance, and Administration	\$ 26,597	\$ 20,898	4% of total installed cost - EPA ²
Capitol Recovery	\$ 43,271	\$ 33,999	7%, 20 years, (TIC-catalyst) - EPA ¹
Total Annual Cost	\$ 196,919	\$ 168,149	
Cost Effectiveness, \$ per ton NO _x reduction	\$ 38,886.16	\$ 29,687.25	
Assumptions:			
EPA ¹ - EPA Air Pollution Control Cost Manual, Sixth Edition, Section 4, EPA/452/B-002-001, Jan. 2002. Table A.2			
EPA ² - EPA Air Pollution Control Cost Manual, Sixth Edition, Section 4, EPA/452/B-002-001, Jan. 2002. Cost is for one convection heater.			

Data from EPA's RACT/BACT/LAER Clearinghouse shows typical BACT NO_x emission rates for natural gas fired boilers less than 100 MMBtu/hr range from 0.011 to 0.14 lb/MMBtu range and for the convection heaters, NO_x emission rates range from 0.14 lb/MMBtu to 0.013 lb/MMBtu. Table 5-6 presents a summary of NO_x emission limits and the control techniques utilized to achieve the listed emission rate. This table is not exhaustive, rather lists the emission rates and control technologies utilized in the past five years from select plants.

5.5.5 Step 5 – Select BACT

SPC is proposing the use of pipeline quality natural gas as well as ULNB and FGR for the auxiliary boiler. Based on manufacturer provided data, the proposed SPC auxiliary boiler will achieve an emission rate of 0.017 lb/MMBtu or 1.45 lb/hr. The proposed use of ULNB and FGR represents BACT for the auxiliary boiler.

The proposed SPC convection heaters will be equipped with LNB utilizing low excess air and FGR to minimize NO_x emissions. Based on manufacturer supplied data, the SPC convection heaters will achieve a NO_x emission rate of 0.036 lb/MMBtu or 0.81 lb/hr. The use of LNB with FGR is considered BACT.

Table 5-6

Auxiliary Boiler and Convection Heaters NO_x Emission Limits from EPA's RACT/BACT/LAER Clearinghouse

RBLCID	Facility Name	County	State	Permit Date	Process Name	Size	Basis	Emission Limit	Comments
OR-0048	Carty Plant	Morrow	Oregon	12/29/2010	NG-fired boiler	91 MMBtu/hr	BACT-PSD	4.5 lb/hr	Low NO _x burners
AK-0071	International Station Power Plant	Mun. of Anchorage	Alaska	12/21/2010	Auxiliary boiler	12.5 MMBtu/hr	BACT-PSD	32 lb/MMSCF (3-hr avg.)	Low NO _x burners and FGR
OH-0310	American Municipal Power Gen. Station	Meigs	Ohio	10/8/2009	Auxiliary Boiler	150 MMBtu/hr	BACT-PSD	0.14 lb/MMBtu	
NV-0049	Harrahs Operating Company	Clark	Nevada	8/20/2009	NG-fired Boiler	35.4 MMBtu/hr	BACT-PSD	0.035 lb/MMBtu	Low NO _x burners
NV-0049	Harrahs Operating Company	Clark	Nevada	8/20/2009	NG-fired Boiler	21.0 MMBtu/hr	BACT-PSD	0.037 lb/MMBtu	Low NO _x burners
OK-0129	Chouteau Power Plant	Mayes	Oklahoma	1/23/2009	Auxiliary Boiler	33.5 MMBtu/hr	BACT-PSD	0.07 lb/MMBtu or 2.3 lb/hr	Low NO _x burners
OK-0129	Chouteau Power Plant	Mayes	Oklahoma	1/23/2009	Fuel Gas Heater	18.8 MMBtu/hr	BACT-PSD	2.7 lb/hr	
AL-0251	CER Generation Hillabee Energy Center	Tallapoosa	Alabama	9/24/2008	Fuel Heater	11.64 MMBtu/hr	BACT-PSD	0.013 lb/MMBtu	Low NO _x burners
FL-0303	FPL West County Energy Center Unit 3	Palm Beach	Florida	7/30/2008	Fuel Gas Heater	10 MMBtu/hr	BACT-PSD	0.095 lb/MMBtu	Good combustion
VA-0308	Warren County Facility	Warren	Virginia	1/14/2008	Auxiliary Boiler	97 MMBtu/hr	BACT-PSD	0.0110 lb/MMBtu	Ultra low NO _x burners
VA-0308	Warren County Facility	Warren	Virginia	1/14/2008	Auxiliary Boiler	62 MMBtu/hr	BACT-PSD	0.0110 lb/MMBtu	
AL-0230	Thyssenkrupp Steel and Stainless USA	Mobile	Alabama	8/17/2007	NG-fired Boiler	64.9 MMBtu/hr	BACT-PSD	0.012 lb/MMBtu	Ultra low NO _x burners and FGR
FL-0286	FPL West County Energy Center	Palm Beach	Florida	1/10/2007	Auxiliary Boiler	99.8 MMBtu/hr	BACT-PSD	0.05 lb/MMBtu	
FL-0286	FPL West County Energy Center	Palm Beach	Florida	1/10/2007	Fuel Gas Heater	10 MMBtu/hr	BACT-PSD	0.095 lb/MMBtu	
NY-0095	Caithnes Bellport Energy Center	Suffolk	New York	5/10/2006	Auxiliary Boiler	29.4 MMBtu/hr	BACT-PSD	0.0110 lb/MMBtu	Low NO _x burners and FGR
NV-0035	Tracy Substation Expansion Project	Storey	Nevada	8/16/2005	Auxiliary Boiler	37.7 MMBtu/hr	BACT-PSD	0.037 lb/MMBtu (3-hr avg.)	Best combustion practices
LA-0192	Crescent City Power	Orleans	Louisiana	6/6/2005	Fuel Gas Heater	19 MMBtu/hr	BACT-PSD	1.81 lb/hr and 0.095 lb/MMBtu (ann. avg)	Low NO _x burners and good combustion practices

5.6 Natural-Gas Fired Auxiliary Boiler and Convection Heaters BACT for CO

EPA's top-down process was used to determine the best available control technology for control of CO emissions from the proposed auxiliary boiler and convection heaters. Carbon monoxide is a product of the chemical reaction between carbonaceous fuels and oxygen. The primary factors influencing generation of CO are temperature and residence time in the combustion zone. Higher combustion zone temperatures and residence times lead to more complete combustion and lower CO emissions.

5.6.1 Step 1 - Identify All Control Technologies

The following options were identified for the control of CO emissions from the auxiliary boiler and convection heaters. These control options include combustion and post-combustion controls of GCP and catalytic oxidation, respectively.

Combustion Controls

5.6.1.1 Good Combustion Practices

The first control technology identified to reduce CO emissions is through good engineering design of the equipment utilizing GCP. Good combustion practices for CO include adequate fuel residence times, proper fuel-air mixing, and temperature control. For the proposed auxiliary boiler and convection heaters, there will be adequate turbulence in the flue gas which will ensure good mixing, a high temperature zone (greater than 1800°F) that will ensure complete burnout along with a sufficient residence time (one to two seconds) at high temperature which will lead to minimized CO emissions. Higher combustion zone temperatures favor the complete oxidation of carbon-containing compounds to CO₂ and water. Therefore, emissions of CO would be expected to decrease at higher temperatures.

Post-Combustion Controls

5.6.1.2 Catalytic Oxidation

Catalytic oxidation allows complete oxidation to take place at a faster rate and a lower temperature than is possible with thermal oxidation. In a typical catalytic oxidizer, the gas stream is passed through a flame area and then through a catalyst bed at a velocity in the range of 10 to 30 feet per second (fps). Catalytic oxidizers typically operate at a narrow temperature range of approximately 600°F to 1100°F. At lower temperatures, the CO conversion efficiency decreases rapidly.

Catalytic oxidizers are similar to a SCR system in that a catalyst bed facilitates the conversion of a CO to CO₂. Unlike SCR, catalytic oxidizers do not use additional chemicals such as ammonia to facilitate the conversion.

5.6.2 Step 2 – Eliminate Technically Infeasible Options

Both control options identified for reducing CO emissions from the proposed natural-gas auxiliary boiler and convection heaters are available, demonstrated, and are technically feasible and will be further considered for BACT.

5.6.3 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The identified control technologies, GCP and oxidation catalyst, are considered technically feasible for natural gas fired boilers and heaters. In top-down order of decreasing stringency, the feasible CO controls are listed with the approximate level of control that could be achieved:

- Oxidation catalyst and GCP - 85%
- GCP - BACT baseline

5.6.4 Step 4 – Evaluate Most Effective Controls

With the use of GCP, no adverse economic, energy, or collateral environmental impacts are identified that preclude the use of this control option. For the top control option, oxidation catalyst and GCP, with respect to energy, there will be a noticeable reduction in the thermal efficiency of the proposed auxiliary boiler and convection heaters. Depending upon the design, catalyst modules increase the back-pressure downstream of the combustion chamber by several tenths of an inch of water. An environmental factor associated with post-combustion oxidation catalyst systems involves the increased generation and disposal of the spent catalyst as a solid waste.

The EPA's RBLC and recent issued permits were reviewed. Catalytic combustion is rarely used to control CO emissions from natural gas auxiliary boilers and convection heaters in the size capacity that SPC is proposing. The cost of applying an catalytic oxidation system for the auxiliary boiler and a convection heater are presented in Tables 5-7 and 5-8. It should be noted that the cost per ton CO reduction is for each convection heater. Based on the projected costs, \$12,544 per ton and \$10,645 per ton (estimated) of additional CO reduction for the auxiliary boiler and convection heater, respectively, the use of oxidation catalyst was eliminated from further consideration.

CO emissions data from EPA's RACT/BACT/LAER Clearinghouse and other state databases are summarized in Table 5-9. This table is not exhaustive, rather lists the emission rates and control technologies utilized in the past five years from select plants. Table 5-9 shows typical BACT CO emission rates and control technologies utilized to achieve the listed emission rates for natural gas fired boilers less than 100 MMBtu/hr range. As can be seen, the use of GCP is standard for this type of equipment.

Table 5-7

Oxidation Catalyst Capitol Costs for Auxiliary Boiler and Convection Heater

	Auxiliary Boiler	Convection Heater	Factor	Basis for Cost and Factor
Capacity (MMBtu/hr)	85	22.264		
Direct Costs:				
Purchased Equipment:				
Primary and Auxiliary Equipment (PE)	\$ 100,000	\$ 60,000	Vendor Data	
Instrumentation and Controls	\$ 10,000	\$ 6,000	10% of PE	EPA ¹
Sales Tax	\$ 3,000	\$ 1,800	3% of PE	EPA ¹
Freight	\$ 5,000	\$ 3,000	5% of PE	EPA ¹
Total Purchased Equipment Cost (PEC)	\$ 118,000	\$ 70,800		
Direct Installation				
Foundations	\$ 9,440	\$ 5,664	8% of PEC	EPA ¹
Handling and Erection	\$ 16,520	\$ 9,912	14% of PEC	EPA ¹
Electrical	\$ 4,720	\$ 2,832	4% of PEC	EPA ¹
Piping	\$ 2,360	\$ 1,416	2% of PEC	EPA ¹
Insulation and Ductwork	\$ 1,180	\$ 708	1% of PEC	EPA ¹
Painting	\$ 1,180	\$ 708	1% of PEC	EPA ¹
Total Direct Installation (DI)	\$ 35,400	\$ 21,240		
Total Direct Cost (DC)	\$ 153,400	\$ 92,040		
Indirect Installation Costs				
Engineering and Project Management	\$ 11,800	\$ 7,080	10% of PEC	EPA ¹
Construction and Field Expenses	\$ 5,900	\$ 3,540	5% of PEC	EPA ¹
Contractor Fees	\$ 11,800	\$ 7,080	10% of PEC	EPA ¹
Startup Expenses	\$ 2,360	\$ 1,416	2% of PEC	EPA ¹
Performance Tests	\$ 1,180	\$ 708	1% of PEC	EPA ¹
Contingencies	\$ 3,540	\$ 2,124	3% of PEC	EPA ¹
Total Indirect Cost	\$ 36,580	\$ 21,948		
Total Installed Cost (TIC)	\$ 189,980	\$ 113,988		
Assumptions:				
EPA ¹ - EPA Air Pollution Control Cost Manual, Sixth Edition, Section 4, EPA/452/B-002-001, Jan. 2002.				
Estimated cost for primary and aux. equipment for conv. heater. Vendor data not available. Cost is for one heater.				

Table 5-8

Oxidation Catalyst Annual Costs for Auxiliary Boiler and Convection Heater

	Auxiliary Boiler	Convection Heater	Basis for Cost and Factor
Capacity (MMBtu/hr)	85	22.264	
Capitol Cost			
Total Installed Cost	\$ 189,980	\$ 113,988	
CO Emissions Before Control, lb/MMBtu	0.0375	0.074	GCP
Annual Capacity Factor	100%	100%	
CO Emissions Before Control, tn/yr	13.96	14.39	
CO Emissions After Control, lb/MMBtu	0.0056	0.0111	
Control Efficiency (%)	85	85	
CO Emissions After Control, tn/yr	1.396	2.159	
CO Emission Reduction, tn/yr	12.564	12.232	
Annual Costs, \$/year			
Catalyst Annual Cost			
Catalyst Replacement Cost	\$ 118,000	\$ 70,800	100% of primary equipment cost (includes capitol and labor)
Catalyst Life	5	5	EPA ²
Annual Costs, \$/year	\$ 28,779	\$ 17,267	7% Interest - EPA ¹
Operating Labor	\$ 12,775	\$ 12,775	1 hour per day @ \$35/hr
Supervisor	\$ 1,916	\$ 1,916	15% of operating labor - EPA ²
Maintenance Labor	\$ 12,775	\$ 12,775	1 hour per day @ \$35/hr
Maintenance Materials	\$ 12,775	\$ 12,775	100% of maintenance labor - EPA ²
Electricity	\$ 5,212	\$ 1,365	0.1 kW/MMBtu/hr for pressure drop at \$0.07/KWh
Overhead	\$ 24,145	\$ 24,145	60% of oper., maint.& supervisor labor plus main.costs
Taxes, Insurance, and Administration	\$ 7,599	\$ 4,560	4% of total installed cost - EPA ²
Capitol Recovery	\$ 51,625	\$ 42,631	7%, 20 years, (TIC-catalyst) - EPA ¹
Total Annual Cost	\$ 157,601	\$ 130,209	
Cost Effectiveness, \$ per ton CO reduction	\$ 12,543.87	\$ 10,645.38	
Assumptions:			
EPA ¹ - EPA Air Pollution Control Cost Manual, Sixth Edition, Section 4, EPA/452/B-002-001, Jan. 2002. Table A.2			
EPA ² - EPA Air Pollution Control Cost Manual, Sixth Edition, Section 4, EPA/452/B-002-001, Jan. 2002. Cost is for one convection heater.			

Table 5-9

Auxiliary Boiler and Fuel Gas Heater CO Emission Limits from EPA's RACT/BACT/LAER Clearinghouse

RBLCID	Facility Name	County	State	Permit Date	Process Name	Size	Basis	Emission Limit	Comments
NV-0049	Harrahs Operating Company	Clark	Nevada	8/20/2009	NG-fired Boiler	35.4 MMBtu/hr	Case-by-case	0.028 lb/MMBtu	Operate in accordance with manufacturers specifications
NV-0049	Harrahs Operating Company	Clark	Nevada	8/20/2009	NG-fired Boiler	21.0 MMBtu/hr	Case-by-case	0.111 lb/MMBtu	Operate in accordance with manufacturers specifications
OK-0129	Chouteau Power Plant	Mayes	Oklahoma	1/23/2009	Auxiliary Boiler	33.5 MMBtu/hr	BACT-PSD	5.02 lb/hr	Good combustion practices
OK-0129	Chouteau Power Plant	Mayes	Oklahoma	1/23/2009	Fuel Gas Heater	18.8 MMBtu/hr	BACT-PSD	0.39 lb/hr	Good combustion practices
AL-0251	CER Generation Hillabee Energy Center	Tallapoosa	Alabama	9/24/2008	Fuel Heater	11.64 MMBtu/hr	BACT-PSD	0.081 lb/MMBtu	Good combustion practices
FL-0303	FPL West County Energy Center Unit 3	Palm Beach	Florida	7/30/2008	Fuel Gas Heater	10 MMBtu/hr	BACT-PSD	0.08 lb/MMBtu	Good combustion practices
VA-0308	Warren County Facility	Warren	Virginia	1/14/2008	Auxiliary Boiler	97 MMBtu/hr	BACT-PSD	0.036 lb/MMBtu	
VA-0308	Warren County Facility	Warren	Virginia	1/14/2008	Auxiliary Boiler	62 MMBtu/hr	BACT-PSD	0.036 lb/MMBtu	
GA-0127	Plant McDonough Combined Cycle	Cobb	Georgia	1/7/2008	Auxiliary Boler	200 MMBtu/hr	BACT-PSD	0.037 lb/MMBtu	
AL-0230	Thyssenkrupp Steel and Stainless USA	Mobile	Alabama	8/17/2007	NG-fired Boiler	64.9 MMBtu/hr	BACT-PSD	0.040 lb/MMBtu	
FL-0285	Progress Bartow Power Plant	Pinellas	Florida	1/26/2007	Auxiliary Boiler	99 MMBtu/hr	BACT-PSD	0.08 lb/MMBtu	400 ppmdv
FL-0286	FPL West County Energy Center	Palm Beach	Florida	1/10/2007	Auxiliary Boiler	99.8 MMBtu/hr	BACT-PSD	0.08 lb/MMBtu	
FL-0286	FPL West County Energy Center	Palm Beach	Florida	1/10/2007	Fuel Gas Heater	10 MMBtu/hr	BACT-PSD	0.08 lb/MMBtu	
NY-0095	Caithnes Bellport Energy Center	Suffolk	New York	5/10/2006	Auxiliary Boiler	29.4 MMBtu/hr	BACT-PSD	0.036 lb/MMBtu	Good combustion practices
NV-0035	Tracy Substation Expansion Project	Storey	Nevada	8/16/2005	Auxiliary Boiler	37.7 MMBtu/hr	BACT-PSD	0.036 lb/MMBtu (3-hr avg.)	Best combustion practices
LA-0192	Crescent City Power	Orleans	Louisiana	6/6/2005	Fuel Gas Heater	19 MMBtu/hr	BACT-PSD	1.52 lb/hr and 0.08 lb/MMBtu (ann. avg)	Good combustion practices

5.6.5 Step 5 – Select BACT

Based on manufacturer provided data, the proposed SPC auxiliary boiler will achieve a CO emission rate of 0.0375 lb/MMBtu; the proposed emission rate for each convection heater is 0.074 lb/MMBtu. Thus, the use of GCP is considered BACT for minimizing CO emissions from the proposed auxiliary boiler and convection heaters.

5.7 Natural-Gas Fired Auxiliary Boiler and Convection Heaters BACT for PM₁₀ and PM_{2.5}

According to EPA's AP-42, Section 1.4, since natural gas is a gaseous fuel, filterable PM emissions are typically low. Particulate matter from natural gas combustion has been estimated to be less than one micrometer in size and has filterable and condensable fractions. Particulate matter in natural gas combustion are usually larger molecular weight hydrocarbons that are not fully combusted. Increased particulate matter emissions can result from poor air/fuel mixing or maintenance problems. For this BACT analysis, all particulate emissions were considered PM_{2.5} which is a subset of PM₁₀.

5.7.1 Step 1 - Identify All Control Technologies

The following is a list of combustion and post-combustion control technologies which were identified for controlling PM₁₀/PM_{2.5} emissions:

- GCP;
- use of clean burning fuels;
- proper design and operation;
- wet gas scrubber;
- electrostatic precipitator (ESP);
- cyclone; and
- baghouse/fabric filters.

Combustion Control

5.7.1.1 Good Combustion Practices

By maintaining the auxiliary boiler and convection heaters in good working order per manufacturer specifications with low sulfur gaseous fuels, PM₁₀/PM_{2.5} emissions will be reduced.

Post-Combustion Controls

5.7.1.2 Wet Gas Scrubber

A wet gas scrubber is an air pollution control device that removes PM and acid gases from waste streams from stationary point sources. PM and acid gases are primarily removed through the impaction, diffusion, interception and/or absorption of the pollutant onto droplets of liquid. Wet scrubbers have some advantages over ESPs and baghouses in that they are particularly useful in removing PM with the following characteristics:

- Sticky and/or hygroscopic materials;
- Combustible, corrosive or explosive materials;
- Particles that are difficult to remove in dry form;
- PM in the presence of soluble gases; and
- PM in gas stream with high moisture content.

5.7.1.3 Electrostatic Precipitator

An ESP is a particle control device that uses electrical forces to move the particles out of the gas stream onto collector plates. This process is accomplished by the charging of particles in the gas stream using positively or negatively charged electrodes. The particles are then collected as they are attracted to oppositely opposed electrodes. Once the particles are collected on the plates, they are removed by knocking them loose from the plates, allowing the collected layer of particles to fall down into a hopper.

Some precipitators remove the particles by washing with water. ESP's are used to capture coarse particles at high concentrations. Small particles at low concentrations are not effectively collected by an ESP.

5.7.1.4 Cyclone

A cyclone operates on the principle of centrifugal separation. The exhaust enters the top and spirals around towards the bottom. As the particles proceed downward, the heavier material hits the outside wall and drops to the bottom where it is collected. The cleaned gas escapes through an inner tube. Cyclones are generally used to reduce dust loading and collect large particles.

5.7.1.5 Fabric Filter Baghouse

A fabric filter unit (or baghouse) consists of one or more compartments containing rows of fabric bags. Particle-laden gases pass along the surface of the bags then through the fabric. Particles are retained on the upstream face of the bags and the cleaned gas stream is vented to the atmosphere. Fabric filters collect particles with sizes ranging from submicron to several hundred microns in diameter. Fabric filters are used for medium and low gas flow streams with high particulate concentrations.

5.7.2 Step 2 - Eliminate Technically Infeasible Options

None of the add-on post-combustion control devices (wet gas scrubber, ESP, cyclone, baghouse/fabric filters) were identified as being suitable for the auxiliary boiler or convection heaters burning gaseous fuels due to both the extremely low concentration of small particulates expected in gas streams from this type of equipment. Therefore, wet scrubbers, EPS's, cyclones, and fabric filtration (baghouses) were rejected as BACT for PM₁₀/PM_{2.5} emissions from the boiler and heaters.

5.7.3 Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The remaining control options are the utilization of GCP and use of clean burning fuels such as natural gas.

5.7.4 Step 4 - Evaluate Most Effective Controls

Combustion controls or “proper combustion” to minimize $PM_{10}/PM_{2.5}$ emissions includes adequate fuel residence time, proper fuel-air mixing, and temperature control to ensure the maximum amount of fuel is combusted. The use of clean-burning fuels, such as natural gas which has only trace amounts of sulfur that can form particulates, will result in minimal formation of $PM_{10}/PM_{2.5}$ during combustion. Thus, the only control technology identified in the RBLC database for the natural gas-fired auxiliary boiler and convection heaters is a work practice requirement to adhere to GCP and use of low sulfur gaseous fuels such as natural gas. This control strategy is technically feasible and will not cause any adverse energy, environmental, or economic impacts.

5.7.5 Step 5 - Select BACT

Good combustion practices and limiting fuel use to only pipeline quality natural gas are proposed as BACT for $PM_{10}/PM_{2.5}$ emissions from SPC’s proposed auxiliary boiler and convection heaters. The proposed $PM_{10}/PM_{2.5}$ emission rates for the auxiliary boiler and convection heaters is 0.010 lb/MMBtu. Table 5-10 presents a summary of previous BACT determinations for PM. This table is not exhaustive, rather lists the emission rates and control technologies utilized in the past five years from select plants.

Table 5-10

Auxiliary Boiler and Convection Heaters PM Emission Limits from EPA's RACT/BACT/LAER Clearinghouse

RBLCID	Facility Name	County	State	Permit Date	Process Name	Size	Basis	Emission Limit	Comments
OR-0048	Carty Plant	Morrow	Oregon	12/29/2010	NG-fired boiler	91 MMBtu/hr	BACT-PSD	2.5 lb/MMCF	Good combustion practices using natural gas
AK-0071	International Station Power Plant	Mun. of Anchorage	Alaska	12/21/2010	Auxiliary boiler	12.5 MMBtu/hr	BACT-PSD	7.6 lb/MMSCF (3-hr avg. as PM ₁₀)	Good combustion practices using natural gas
OK-0129	Chouteau Power Plant	Mayes	Oklahoma	1/23/2009	Fuel Gas Heater	18.8 MMBtu/hr	BACT-PSD	0.1 lb/hr	
FL-0303	FPL West County Energy Center Unit 3	Palm Beach	Florida	7/30/2008	Fuel Gas Heater	10 MMBtu/hr	BACT-PSD	2 grains/100 scf	
FL-0286	FPL West County Energy Center	Palm Beach	Florida	1/10/2007	Auxiliary Boiler	99.8 MMBtu/hr	BACT-PSD	2 grains/100 scf	As PM ₁₀
FL-0286	FPL West County Energy Center	Palm Beach	Florida	1/10/2007	Fuel Gas Heater	10 MMBtu/hr	BACT-PSD	2 grains/100 scf	
NY-0095	Caithnes Bellport Energy Center	Suffolk	New York	5/10/2006	Auxiliary Boiler	29.4 MMBtu/hr	BACT-PSD	0.033 lb/MMBtu	Low sulfur fuel
NV-0035	Tracy Substation Expansion Project	Storey	Nevada	8/16/2005	Auxiliary Boiler	37.7 MMBtu/hr	BACT-PSD	0.004 lb/MMBtu (3-hr avg.)	Best combustion practices
LA-0192	Crescent City Power	Orleans	Louisiana	6/6/2005	Fuel Gas Heater	19 MMBtu/hr	BACT-PSD	0.14 lb/hr and 0.007 lb/MMBtu (ann. avg)	Low sulfur fuel - pipeline quality natural gas

5.8 Natural-Gas Fired Auxiliary Boiler and Convection Heaters BACT for SO₂

SO₂ emissions from the auxiliary boiler and convection heaters will be a result of oxidation of fuel sulfur.

5.8.1 Step 1 - Identify All Control Technologies

There are two primary mechanisms to reduce SO₂ emissions from combustion sources which are: (1) reduce the amount of sulfur in the fuel and (2) remove the sulfur from the auxiliary boiler and/or convection heaters exhaust gases with post-combustion control device such as flue gas desulfurization utilizing wet scrubbers or dry scrubbers.

Combustion Control

5.8.1.1 Reducing the Amount of Sulfur in Fuel

SPC will be using Kern River Gas pipeline-quality natural gas which has a maximum sulfur content of 0.75 grains/100 scf of sulfur. The use of a fuel containing low sulfur content is considered a control technology.

Post-Combustion Control

5.8.1.2 Wet Scrubbing

Two main types of SO₂ post-combustion control technologies, wet and dry scrubbing, were identified to reduce SO₂ in the exhaust gas. In wet scrubbers chemical reagents, usually an alkali material such as calcium in the form of lime or limestone, are mixed with water and used in the scrubber. SO₂ is absorbed by the scrubbing liquid in the scrubber and the chemicals in the water react with the SO₂ producing sulfite and sulfate compounds. The scrubbing liquid which contains the SO₂ falls to the bottom of the scrubber and enters a holding tank where chemical reactions continue to form solids from the SO₂.

5.8.1.3 Dry Scrubbing

Dry scrubbing is any scrubbing process that produces wastes with less than 5% water. The main types of dry scrubbing include spray drying, dry injection, or a combination of the two. For dry scrubbing, as flue gas flows through a scrubber, a fine mist of dissolved and partially dissolved alkalis such as lime is sprayed in the scrubber. Enough moisture is added in the process to partially saturate the flue gas, but the amount of moisture is kept low enough so that the final product remains dry. The lime slurry absorbs and reacts with the sulfur dioxide and is removed by a particulate control device.

5.8.2 Step 2 – Eliminate Technically Infeasible Options

The requirement for low-sulfur natural gas is a control technique that has been achieved in practice and is technically feasible and cost-effective and will be further considered for BACT.

Post-combustion devices such as wet or dry scrubbers are typically installed on coal-fired power plants that burn fuels with much higher sulfur contents. The SO₂ concentrations in the natural gas combustion exhaust gases from the auxiliary boiler and convection heaters are too low for scrubbing technologies to work effectively or to be technically feasible and cost effective. These control technologies require much higher sulfur concentrations in the exhaust gases to be feasible as a control technology.

Thus, post-combustion SO₂ control devices, such as wet and dry scrubbing have not been achieved in practice on auxiliary boilers and convection heaters at the proposed size capacity and utilizing natural gas, are not technically feasible, and have been eliminated from further consideration.

5.8.3 Steps 3 – 5

The use of pipeline-quality natural gas and fuel sulfur limits are the only feasible SO₂ control technology for the auxiliary boiler and convection heaters. There are no adverse energy, environmental or cost impact associated with the use of these control technologies. Thus, no further analysis is required under EPA's top-down BACT approach.

SPC will use Kern River Gas pipeline-quality natural gas with a sulfur limit of 0.75 grains/100 scf. The use of pipeline quality natural gas is considered BACT.

5.9 Emergency Diesel Generator and Diesel Fire Water Pump BACT for NO_x

The emergency diesel generator will be operated only during interruptions in normal electrical power supply or for maintenance, testing, and operator training. The emergency fire pump will only be operated in the event of a plant fire or for maintenance, testing, and operator training. Each unit is limited to 500 hours of operation per year.

Diesel engines are classified as compression ignition (CI) internal combustion engines. In diesel engines, air is drawn into a cylinder as the piston creates space for it by moving away from the intake valve. The piston's subsequent upward swing then compresses the air, heating it at the same time. Next, fuel is injected under high pressure as the piston approaches the top of its compression stroke, igniting spontaneously as it contacts the heated air. The hot combustion gases expand, driving the piston downward. During its return swing, the piston pushes spent gases from the cylinder, and the cycle begins again with an intake of fresh air. The primary pollutants in the exhaust gases include NO_x, CO, VOC, and particulate matter.

The predominant mechanism for NO_x formation from internal combustion engines is thermal NO_x which arises from the thermal dissociation and subsequent reaction of nitrogen and oxygen molecules in the combustion air.

Combustion Modifications

5.9.1 Step 1 - Identify All Control Technologies

The following control options were evaluated for controlling NO_x emissions from the CI combustion engines. They are categorized as combustion modifications and post-combustion controls. Combustion modifications include: ignition timing retard, air-to-fuel ratio, and derating. Post combustion controls include SCR, NSCR catalyst, and NO_x absorption systems.

5.9.1.1 Ignition Timing Retard

As described above, the injection of diesel fuel into the cylinder of a CI engine initiates the combustion process. With ignition timing retard, this combustion modification lowers NO_x emissions by moving the ignition event to later in the power stroke when the piston is in the downward motion and combustion chamber volume is increasing. Because the combustion chamber volume is not at its minimum, the peak flame temperature is reduced which reduces the formation of thermal NO_x.

5.9.1.2 Air-to-Fuel Ratio

Diesel engines are inherently lean-burn engines. The air-to-fuel ration can be adjusted by controlling the amount of fuel that enters each cylinder. By reducing the air-to-fuel ratio to near stoichiometric, combustion will occur under conditions of less excess oxygen and reduced combustion temperatures. Lower oxygen levels and combustion temperature reduce NO_x formation.

5.9.1.3 Derating

Derating involves restricting engine operation to lower than normal levels of power production. Derating reduces cylinder pressure and temperatures which reduces NO_x formation.

Post-Combustion Controls

5.9.1.4 Selective Catalytic Reduction

Selective catalytic reduction systems introduce a liquid reducing agent such as ammonia or urea into the flue gas stream before the catalyst. The catalyst reduces the temperature needed to initiate the reaction between the reducing agent and NO_x to form nitrogen and water.

For SCR systems to function effectively, exhaust temperatures must be high enough (200°C to 500°C) to enable catalyst activation. For this reason, SCR control efficiencies are expected to be relatively low during the first 20 to 30 minutes after engine start up, especially during maintenance and testing. There are also complications controlling the excess ammonia (ammonia slip) from SCR use.

5.9.1.5 Non-Selective Catalytic Reduction

Non-selective catalytic reduction systems are used to reduce emissions from rich-burn engines that are operated stoichiometrically or fuel-rich stoichiometric. In the engine exhaust, NSCR catalysts convert NO_x to nitrogen and oxygen. NSCR catalytic reactions require that O₂ levels be kept low and that the engine be operated at fuel-rich air-to-fuel ratios. Lean-burn engines are characterized by an oxygen-rich exhaust which minimizes the potential for NO_x reduction.

5.9.1.6 NO_x Absorption Systems (Lean NO_x Traps)

NO_x absorber development is a new catalyst advance for removing NO_x in a lean (i.e., oxygen rich) exhaust environment for both diesel and gasoline lean-burn direct-injection engines. With this developing technology, NO is catalytically oxidized to NO₂ and stored in an adjacent chemical trapping site as a nitrate. The stored NO_x is removed in a two-step reduction step by temporarily inducing a rich exhaust condition. NO_x adsorbers (sometimes referred to as lean NO_x traps) employ precious metal catalyst sites to carry out the first NO to NO₂ conversion step. The NO₂ then is adsorbed by an adjacent alkaline earth oxide site where it chemically reacts and is stored as a nitrate. When this storage media nears capacity it must be regenerated. This is accomplished in by creating a rich atmosphere with injection of a small amount of diesel fuel. The released NO_x is quickly reduced to N₂ by reaction with CO on a rhodium catalyst site or another precious metal that is also incorporated into this unique single catalyst layer.

5.9.2 Step 2 – Eliminate Technically Infeasible Options

Combustion modifications and SCR have been demonstrated and are technically feasible technologies that will be further considered for BACT. NSCR catalysts are effective to reduce NO_x emission when applied to rich-burn engines fired on natural gas, propane or gasoline. The proposed diesel engines are inherently lean-burn engines; thus, NSCR is eliminated from further consideration.

In addition, NO_x absorbers were eliminated from further consideration since NO_x adsorbers are experimental technology and no commercial applications of NO_x absorbers were identified in state or EPA's RBLC RACT/BACT/LAER Clearinghouse databases as being employed on stationary emergency generators or fire pumps. Also, the literature indicates that testing of these NO_x absorbers has raised issues about sustained performance of the catalyst. Current lean NO_x catalysts are prone to poisoning by both lube oil and fuel sulfur⁷.

⁷ http://www.poweronsite.org/AppGuide/Chapters/Chap4/4-1_Recip_Engines.htm

5.9.3 Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The remaining control options, combustion modification and the post-combustion control, SCR will be examined further. Combustion controls have been demonstrated to reduce NO_x emissions from CI engines by approximately 50%; the use of a SCR can reduce emissions in the range from 70 to 90%.

5.9.4 Step 4 - Evaluate Remaining Most Effective Controls

The top control option, SCR, uses a reducing-agent like ammonia or urea (which is usually preferred) with a special catalyst to reduce NO_x in diesel exhaust to N₂. The SCR catalyst sits in the exhaust stream and the reducing agent is injected into the exhaust ahead of the catalyst. Once injected the urea becomes ammonia and the chemical reduction reaction between the ammonia and NO takes place across the SCR catalyst. With the use of an SCR, there is the potential for some ammonia to “slip” through the catalyst.

There are several downsides with using an SCR. First, an improperly functioning SCR system can create excess ammonia emissions. SCR systems also add significant equipment to the engine system which increases the possibility of failures and increasing on-going maintenance costs. In addition, cost evaluations were performed to determine the cost of control per ton of NO_x removed from an SCR for the emergency generator and fire water pump. Per EPA’s cost effectiveness evaluation⁸, costs per ton of NO_x removed is \$242,493 for the emergency generator and \$396,886 for the fire pump. Thus, based on the economic impact prepared by EPA, the post-combustion NO_x control utilizing SCR is not cost effective for the emergency generator or the fire water pump and has been eliminated from further consideration.

Thus, the only control technology for the emergency generator and fire pump is a work practice requirement to adhere to GCP. This control strategy is technically feasible and will not cause any adverse energy, environmental, or economic impacts.

⁸ Memorandum from Tanya Parise, Alpha-Gamma Technologies to Sims Roy, EPA OAQPS ESD Combustion Group, June 9, 2005.

5.9.5 Step 5 - Select BACT

SPC is proposing a generator and fire water pump that incorporates in its design injection timing retard, turbocharging and aftercooling. The generator and fire water pump will be operated and maintained in accordance with GCP. The house of operation will be restricted to 500 hours per year. The combustion controls, ultra low sulfur diesel fuel and limited annual hours of operation as BACT for the emergency diesel generator and fire water pump. The emergency generator will be Tier II compliant for non-road compression ignition engine generators larger than 900 kW and will meet the emission standard of 6.4 g/kW-hr (NO_x + NMHC). The fire water pump will be Tier III compliant and will meet an emission standard of 4.0 g/kW-hr (NO_x + NMHC). The use of good combustion controls including ignition timing retard, air-to-fuel ratio, and derating will be based on manufacturer recommendations.

5.10 Emergency Diesel Generator and Diesel Fire Water Pump BACT for CO and VOC

Carbon monoxide and VOC emissions are primarily the result of incomplete combustion of the diesel fuel. These emissions occur when there is a lack of available oxygen, the combustion temperature is too low, or if the residence time in the cylinder is too short.

5.10.1 Step 1 - Identify All Control Technologies

The following control options were evaluated for controlling CO and VOC emissions from the CI combustion engines. They include: good combustion practices and the post-combustion control technologies of diesel oxidation catalysts and NSCR catalysts.

Combustion Control

5.10.1.1 Good Combustion Practices

Good combustion practices refer to the operation of engines at high combustion efficiency which reduces the products of incomplete combustion. The proposed emergency generator and fire water pump engines are designed to achieve maximum combustion efficiency. The manufacturers will provide operation and maintenance manuals that detail the required methods to achieve the highest levels of combustion efficiency.

Post-Combustion Control

5.10.1.2 Diesel Oxidation Catalyst

A diesel oxidation catalyst is a flow-through metal or ceramic substrate coated with platinum or other precious metals. The diesel oxidation catalyst sits in the exhaust stream and all exhaust from the engine passes through it. The catalyst promotes the oxidation of unburned CO and HC (as VOC) in the exhaust producing CO₂ and water. Diesel oxidation catalysts are commercially available and reliable for controlling CO and HC emissions from diesel engines.

5.10.1.3 Non-Selective Catalytic Reduction

A NSCR system is used to reduce emissions from rich-burn engines that are fueled by natural gas, propane, gasoline and are operated stoichiometrically or fuel-rich stoichiometric. In the presence of CO and NMHC in the engine exhaust, NSCR catalysts convert CO to O₂ and NMHC to CO₂. NSCR catalytic reactions require that O₂ levels be kept low and that the engine be operated at fuel-rich air-to-fuel-ratios. The proposed emergency generator and fire water pump are lean-burn engines which are characterized by an oxygen-rich exhaust which minimizes the potential for CO reduction.

5.10.2 Step 2 – Eliminate Technically Infeasible Options

Good combustion practices and diesel oxidation catalysts have been demonstrated and are technically feasible technologies that will be further considered for BACT. NSCR catalysts are effective to reduce CO and VOC emissions when applied to rich-burn engines that are fired on natural gas, propane or gasoline. The proposed diesel engines are inherently lean-burn engines; thus, NSCR is eliminated from further consideration.

5.10.3 Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The remaining control options, good combustion practices and the post-combustion control using an diesel oxidation catalyst will be examined further. Combustion controls have been demonstrated to reduce CO emissions from CI engines by approximately 50%; the use of an diesel oxidation catalyst can reduce CO emissions in the range of 60 to 85% and 35 to 50% for VOC emissions.

5.10.4 Step 4 - Evaluate Most Effective Controls

Diesel oxidation catalysts can significantly reduce CO and VOC emissions. However, due to the limited hours of proposed operation for the emergency generator and fire water pump, this add-on control is not practical. The cost effectiveness of installing and operating standard diesel oxidation catalysts on each of the proposed engines was evaluated. The cost effectiveness of a standard diesel oxidation catalyst on the emergency generator was estimated to be over \$110,000 per tons of CO removed and approximately \$650,000 per ton of VOC removed. The costs for the installation of diesel oxidation catalysts on the 480 HP firepump were in excess of the \$500,000 per ton for both CO and VOC removed⁸. Thus, based on the economic impact, the post-combustion CO and VOC control utilizing diesel oxidation catalysts is not cost effective for the emergency generator or the fire water pump and has been eliminated from further consideration.

5.10.5 Step 5 - Select BACT

SPC is proposing combustion controls, ultra low sulfur diesel fuel and limited annual hours of operation as BACT for the emergency diesel generator and fire water pump. The emergency generator will be Tier II compliant for non-road compression ignition engine generators larger than 900 kW and will meet the CO emission standard of 3.5 g/kW-hr. The fire water pump will be Tier III compliant and will meet an CO emission standard of 3.5 g/kW-hr. Both the emergency generator and fire water pump hours of operation will be restricted to 500 hours per year. The use of good combustion controls will be based on manufacturer recommendations.

5.11 Emergency Diesel Generator and Diesel Fire Water Pump BACT for PM₁₀/PM_{2.5}

Diesel particulate emissions are composed of a variety of liquid phase hydrocarbons and solid phase soot (carbon). The literature suggests that the majority of particulate emissions from diesel combustion are in the PM_{2.5} size or smaller range.

5.11.1 Step 1 - Identify All Control Technologies

The following control options were evaluated for controlling PM₁₀/PM_{2.5} emissions from the CI combustion engines. They include: GCP, use of low sulfur fuels, diesel particulate filters, and diesel oxidation catalysts.

Combustion Controls

5.11.1.1 Good Combustion Practices

Good combustion practices refer to the operation of engines at high combustion efficiency which reduces the products of incomplete combustion.

The proposed emergency generator and fire water pump engines are designed to achieve maximum combustion efficiency. The manufacturers will provide operation and maintenance manuals that detail the required methods to achieve the highest levels of combustion efficiency.

5.11.1.2 Ultra Low Sulfur Diesel

Limiting the sulfur content of diesel fuel is a pollution prevention method to reduce the sulfate fraction (25-25%) of diesel particulate matter. The literature suggests that the use of low sulfur fuels, such as ultra low sulfur diesel, can reduce particulate emissions by 10-20%.

Post-Combustion Control

5.11.1.3 Diesel Particulate Filters

Diesel particulate filters are add-on devices that filter out particulate matter. Diesel particulate filters are add-on devices that include both passive and active diesel particulate filters, depending on the method used to clean the filters. Some filters are single-use, while others are designed to burn off the accumulated particulate, either through the use of a catalyst (passive), or through an active technology, such as a fuel burner which heats the filter to soot combustion temperatures, through engine modifications. The use of diesel particulate filters has been demonstrated to reduce particulate emissions by up to 85%.

5.11.1.4 Diesel Oxidation Catalyst

A diesel oxidation catalyst utilizes metal catalysts to oxidize particulate matter in the diesel exhaust. Diesel oxidation catalysts are commercially available and are reliable for reducing particulate matter emissions up to 30% from diesel engines.

5.11.2 Step 2 – Eliminate Technically Infeasible Options

All proposed control options are technically feasible and will be reviewed further.

5.11.3 Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The proposed control options are ranked in descending order based on control efficiency:

- Diesel particulate filters – 85%
- Diesel oxidation catalysts – 30%
- Low sulfur fuels – 10-20%
- Good combustion practices - baseline

5.11.4 Step 4 - Evaluate Most Effective Controls

The top ranked control options, diesel particulate filters and diesel oxidation catalysts can significantly reduce PM₁₀/PM_{2.5} emissions. However, due to the limited hours of proposed operation for the emergency generator and fire water pump, these add-on controls are not practical. Per EPA's cost effectiveness evaluation, the cost per ton of PM removed from an emergency generator and fire pump in the sizes proposed by SPC equipped with a catalyzed diesel particulate filter were \$969,121 and \$348,278, respectively. EPA also determined the cost effectiveness utilizing an oxidation catalyst to reduce particulate matter emissions. Per EPA's cost effectiveness evaluation, the cost per ton of PM removed from an emergency generator and fire pump in the sizes proposed by SPC equipped with diesel oxidation catalysts were \$355,344 and \$163,458, respectively⁸. Thus, based on the economic impact prepared by EPA, the post-combustion add-on devices are not cost effective for the emergency generator or the fire water pump and have been eliminated from further consideration.

5.11.5 Step 5 - Select BACT

SPC is proposing GCP, ultra low sulfur diesel fuel, and limited annual hours of operation as BACT for the emergency diesel generator and fire water pump. The emergency generator will be Tier II compliant for non-road compression ignition engine generators larger the 900 kW and will meet the PM emission standard of 0.2 g/kW-hr. The fire water pump will be Tier III compliant and will meet an PM emission standard of 0.2 g/kW-hr. Both the emergency generator and fire water pump hours of operation will be restricted to 500 hours per year.

The use of GCP will be based on manufacturer recommendations; ultra low sulfur diesel fuel (15 ppm sulfur) will also be utilized.

5.12 Emergency Diesel Generator and Diesel Fire Water Pump BACT for SO₂

Sulfur dioxide emissions occur from the reaction of various elements in the diesel fuel. Sulfur in diesel fuel oxidizes during combustion to SO₂ and sulfur trioxide (SO₃). In the presence of water vapor, these hydrolyze to H₂SO₄.

5.12.1 Step 1 - Identify All Control Technologies

Only one control option was found to reduce SO₂ emissions from the proposed CI combustion engines which is the use of low-sulfur diesel fuel.

5.12.2 Step 2 – Eliminate Technically Infeasible Options

All proposed control option is technically feasible and will be reviewed further.

5.12.3 Steps 3 – 5

The use of ultra low sulfur diesel fuel containing no more than 15 parts per million by weight of sulfur is the only feasible SO₂ control technology for the proposed IC combustion engines. There are no adverse energy, environmental or cost impact associated with the use of these control technologies. Thus, no further analysis is required under EPA's top-down BACT approach.

5.13 Gas Turbine Startup and Shutdown BACT

A normal part of the operation of combined-cycle natural gas-fired power plants are startup and shutdown periods. During these periods, emission rates are greater and highly variable than emissions during steady state operations. Emissions are greater during startup and shutdown for several reasons including: (1) the turbines are not operating at full load where they are most efficient; (2) exhaust temperatures are lower than during steady-state emissions; and (3) pollution control systems such as SCR catalyst and oxidation catalysts are not functioning optimally at lower temperature and pollutant abatement may be partial or none at all for a portion of the startup period.

For startups, the duration of the startup depends on the temperature of the equipment at the beginning of the startup period. Equipment that is warm, will come up to full operating temperature quicker than equipment that is started cold. The longest startups occur after a “cold start” in which case the startup can take up to approximately 8 hours until the equipment has achieved its steady-state emission rates. At SPC, cold starts are expected to occur up to 12 times per year. The majority of startups will occur when the equipment is already warm “warm starts” or hot “hot starts” which will take between 1 and 3 hours for the equipment to come to its full operating temperature. For SPC, it was estimated there would be 50 warm starts and 230 hot starts annually.

Because emissions are greater during startup and shutdown periods than during steady-state operation, the BACT limits established in previous sections will not be technically feasible during these periods.

5.13.1 Step 1 - Identify All Control Technologies

The following technologies were identified to potentially reduce startup and shutdown emissions from the combustion turbines. They include: best work practices, pre-heater (to reduce startup duration), fast-start technology, and catalytic control with good engineering practices.

5.13.1.1 Best Work Practices

Best work practices are designed to minimize the amount of emissions that occur during startup. This is accomplished by optimizing the start-up sequence so that the unit reaches the point when its emissions control technologies are functioning at an optimal level. Power plant operators can limit the duration of each startup and shutdown to the minimum duration achievable by following the equipment manufacturer's recommendations. Plant operators can also use their operational experience with the particulate turbine and auxiliary equipment to optimize startup and shutdown times and reduce emissions.

5.13.1.2 Pre-Heater (Auxiliary Boiler)

SPC is proposing an auxiliary boiler in order to minimize combustion turbine startup time and emissions. Before a cold start of a CT, the auxiliary boiler will provide steam to raise the steam turbine temperature to minimize startup time. After CT ignition, the turbine is ramped up to partial load and held at this load a sufficient time to heat the HRSG. The auxiliary boiler continues to provide steam to the steam turbine until the CT/HRSG can provide the required steam temperature, flow, and pressure, etc.

5.13.1.3 Fast Start Technology

Several of the turbine manufacturers being considered for this project have made design improvements that allow combined-cycle facilities to start up more quickly and efficiently. These improvements allow combined-cycle facilities to by-pass the steam turbine during the early stages of start-up. With a conventional combined-cycle design, the combustion turbine has to be held at low load while the steam turbine heats up. This is done to minimize thermal stresses and maintain the necessary clearances between the stationary and rotating parts of the steam turbine. With the new designs, the gas turbine is decoupled from the steam turbine during plant startup, reducing gas turbine startup emissions, enabling faster steam turbine output and enhancing steam turbine operational flexibility.

5.13.1.4 Catalytic Control with Good Engineering Practices

During a startup, emissions increase and then dramatically decrease as the CT ramps up to normal operating loads. During a startup, emissions are elevated as the combustion controls make adjustments for additional fuel firing while the CT proceeds to operating conditions in the normal range of the unit.

For this project, SPC is proposing the post-combustion controls of SCR (to reduce NO_x emissions) and oxidation catalyst (to reduce CO and VOC) emissions. SCR systems are designed to inject ammonia when the temperature of the SCR catalyst is approximately 500°F. Oxidation catalyst efficiency is also a function of catalyst temperature (which is directly related to CT exhaust gas temperature). During startup, the production of hot exhaust gas is controlled by the dynamics of the CT startup progress and is regulated by the process control system. With the oxidation catalyst, VOC removal efficiency below a catalyst temperature of 500°F is minimal. CO removal efficiency is relatively higher but well below maximum control efficiency during steady state operations.

5.13.2 Step 2 – Eliminate Technically Infeasible Options

Using best work practices and use of an auxiliary boiler to reduce startup and shutdown times is a feasible way to minimize emissions during these periods.

Fast-start technology is also technically feasible; however, SPC is not proposing fast-start technology for this project which would require a redesign of the project. Thus, the fast-start technology was eliminated from further consideration. SPC is proposing catalytic post-combustion controls which are technically feasible for this project.

5.13.3 Steps 3 - 5

Best work practices, the use of the auxiliary boiler, and post-combustion catalytic controls (SCR and oxidation catalysts) are proposed and are feasible in varying degrees during startup and shutdown periods. The best method for the control of startup emissions from combined-cycle operation is to operate the CT such that heat is applied to the HRSG from the turbine exhaust in a safe and expedient manner and to allow the SCR catalyst to reach operating temperature (500°F) as fast as practical without damaging the equipment. For this project, a four-hour time period is identified as the minimum safe time to accomplish the HRSG and SCR heating and the system to reach steady-state operating conditions. The SCR will not be effective until the SCR catalyst has reached minimum operational temperature. The oxidation catalyst for CO and VOC reduction is also not effective until its operational temperature has been reached (300°F).

External heating of the SCR and oxidation catalysts are not technically feasible. In order to externally heat the SCR and oxidation catalyst, they would be required to be removed from the optimal performance location within the HRSG. The additional heat generated from external heating would overheat the HRSG steam drum potentially damaging the equipment.

For the shutdown process, the same logic applies. The equipment must be cooled at a controlled rate to avoid thermal stresses. Maximum control of combined cycle shutdown emissions is accomplished by cooling the HRSG steam drum at the maximum allowable temperature and pressure ramp rate. Emissions during shutdown result from fuel combustion. Best work practices would indicate that fuel cutoff occur as soon as safely possible.

SPC is proposing the following startup and shutdown limits for each CT/HRSG:

- NO_x - 118 lb/hr
- CO - 600 lb/hr

These limits would apply during any hour when the generating unit is in a combined cycle startup or shutdown conditions.

5.14 BACT for CT/HRSG for Greenhouse Gases

Potential GHG emissions from the natural gas fired CTs/HRSGs, include carbon dioxide (CO₂), nitrous oxide (N₂O), and methane (CH₄). The majority of the total GHG emissions, expressed at CO₂e are CO₂ emissions. CO₂ is a product of combustion of fuel containing carbon, such as natural gas. Since CO₂ is created as part of the chemical reaction between oxygen and the fuel when burned, there is no way to reduce the amount of CO₂ generated from combustion.

5.14.1 Step 1 - Identify All Control Technologies

Four potential control technologies were identified for reducing GHG emissions which include energy efficient processes and technologies which reduce the amount of fuel required to produce the necessary energy output, and three types of carbon capture (pre-combustion, post-combustion, and oxy-combustion) and subsequent sequestration.

5.14.1.1 Energy Efficient Processes and Technologies

The combined-cycle technologies being considered by SPC are among the most energy efficient electrical generating technology on the market today. Combined-cycle turbines are more efficient and are a clean burning source of electricity when compared to other fossil fuel technologies. When compared to the average air emissions from coal-fired electric generation facilities, EPA has found that natural gas produces half the amount of CO₂.

5.14.1.2 Carbon Capture and Sequestration

There are emerging technologies to capture GHG emissions created from power generation. There were three types of carbon capture approached identified which include pre-combustion, post-combustion, and oxy-combustion.

In pre-combustion carbon capture, the carbon in the fuel is converted to CO₂ and removed before the combustion process. A post-combustion control system generally consists of capturing CO₂ by separating the CO₂ from the other components of the flue gas stream at a lower pressure after combustion. Oxy-combustion involves the combustion of fossil fuels in an oxygen-rich environment (nearly pure oxygen as the oxidant) so that the flue gas consists primarily of CO₂ and water vapor.

After capture, a compression system to compress the CO₂ is needed and prepare it for transport to a permanent geological storage site such as oil and gas reserves and underground saline formations and injecting the captured CO₂ into the storage site.

5.14.2 Step 2 – Eliminate Technically Infeasible Options

The identified control options are technically feasible and will be reviewed further.

5.14.3 Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Energy-efficient power generation is a feasible and proven technology. In contrast, carbon capture technologies have been applied at small scales to point sources of CO₂ and these emerging technologies are in their infancy. With pre-combustion, post-combustion, and oxy-combustion carbon capture processes, if commercially feasible, CO₂ target capture rates range from 90-99%.⁹

⁹ Carbon Capture Approaches for Natural Gas Combined Cycle Systems, National Energy Technology Laboratory, December 20, 2010 Revision 2.

5.14.4 Step 4 - Evaluate Most Effective Controls

The National Energy Technology Laboratory (NETL) evaluated future developmental technologies for CO₂ capture from natural gas combined cycle plants. Three main approaches were reviewed for CO₂ capture. These include pre-combustion, post-combustion, and oxy-combustion.

In the pre-combustion approach, an auto-thermal reactor or high pressure partial oxidation reactor are used to convert the natural gas feed primarily to hydrogen, carbon monoxide, carbon dioxide, and water. The reformed gas is removed in a methyldiethanolamine (MDEA) acid gas removal process. The high hydrogen content fuel is then utilized in the combustion turbine. Because of the additional equipment required for the pre-combustion CO₂ capture technologies, there is an economic impact associated with this type of capture system. The total as spent capital costs more than double by using pre-combustion capture technologies when compared to a combined-cycle plant with no CO₂ capture technology¹⁰. The CO₂ avoided cost (\$/ton) for the pre-combustion carbon capture approaches ranged from 89.8 to 93.12.¹¹

Post-combustion capture requires the addition of a capture system to separate the CO₂ from the other flue gas components and concentrate, compress, and prepare the CO₂ for transport to a permanent geological storage site. Exhaust gas recycle (EGR) and chemical adsorption into a solution for separating CO₂ from the flue gases at low concentrations was examined by NETL. Three cases were examined by NETL and include NGCC plants with 35 percent EGR and amine absorption; 50 percent EGR and amine absorption; and 35 percent EGR, amine absorption, and a lower amine system reboiler steam requirement. The amine system used is monoethanolamine (MEA), which Fluor utilizes in its Econamine FG Plus process.

¹⁰ Carbon Capture Approaches for Natural Gas Combined Cycle Systems, National Energy Technology Laboratory, December 20, 2010 Revision 2, Exhibit ES-5 Plant Capital Costs.

¹¹ Carbon Capture Approaches for Natural Gas Combined Cycle Systems, National Energy Technology Laboratory, December 20, 2010 Revision 2, Exhibit ES-9 Summary and Comparison of CO₂ Avoided Costs for All Cases

According to NETL, CO₂ concentrations of 6.7 and 8.8 volume percent can be achieved by recycling 35 and 50 percent of the flue gas, respectively. The CO₂ concentration without EGR is 4.0 volume percent. For a conventional natural gas combined cycle system, EGR will reduce the flue gas oxygen concentration from about 12 percent to about 8 and 4 volume percent for EGRs of 35 and 50 percent, respectively. The oxygen content of the gas stream exiting the CT combustor will be lower than the flue gas because additional air is added downstream of the combustor. A combustor study conducted by General Electric (GE) indicates a minimum combustor exhaust oxygen concentration of about 4 percent is needed without a negative impact on the combustor efficiency or CO emissions.

Because of major design modifications that are required for a post-combustion carbon capture system, there is an economic impact associated with this type of capture system. The total as spent capitol costs double by using these post-combustion capture technologies when compared to a combined-cycle plant with no CO₂ capture technology¹⁰. The CO₂ avoided cost (\$/ton) for the post-combustion carbon capture approaches ranges from 65.32 to 71.64.¹¹

In the oxy-combustion based process, natural gas is combusted in the combustion turbine using high purity oxygen as the oxidant. The flue gas exiting the HRSG is recycled to the CT to act as a diluent. Most of the water is condensed in the HRSG prior to recycle and the portion of the stream not recycled is sent to CO₂ compression for sequestration. A second oxy-combustion process is based on technology developed by Clean Energy Systems. Using high purity oxygen, natural gas is combusted in a high pressure gas generator with recycled water/steam acting as diluents. Power is recovered in a high pressure expander. The exhaust enters a reheat combustor where additional natural gas and oxygen are combusted. Additional power is recovered in subsequent turbine expanders before the working fluid enters a partial condenser that recovers water for recycling. The remaining gas is sent to CO₂ compression.

The oxy-combustion system is the most capital intensive of the carbon capture systems. The total as spent capitol cost more than triple by using oxy-combustion system technologies when compared to a combined-cycle plant with no CO₂ capture technology¹⁰. The CO₂ avoided cost (\$/ton) for the oxy-combustion system carbon capture approaches ranges from 103.63 to 146.27¹¹.

There are several environmental impacts which need to be considered in using any of the above listed carbon capture systems. One impact is that 85% more water is needed with a CO₂ capture system. In general, the water demand doubles on average. Additional water demand comes from the large cooling loads in the post-combustion cases using the Econamine process, from water gas shift and humidification requirements in the pre-combustion cases, and from lower net power output in the oxy-combustion cases.

A second environmental impact is the significant parasitic energy loss or energy penalty associated with carbon capture systems. The energy penalty means that either a facility would have to be resized to combust additional fossil fuels in order to make up for lost energy output or additional generation capacity would have to be constructed to make up for any lost output. The IPCC Special Report: Carbon Dioxide Capture and Storage estimated using current technologies would result in an increased fuel consumption from 2-11 percent for natural gas combined-cycle plants without CO₂ capture and compression¹².

A third environmental impact is disposal of the solvent or sorbent used in the carbon capture systems. Solid waste will be generated and will need to be disposed of in accordance with the appropriate local and federal solid and hazardous waste regulations.

If CO₂ were captured, it would have to be transported for subsequent sequestration. CO₂ can be transported in three states: gas, liquid, and solid. Applicable commercial-scale transport of CO₂ for SPC would consist of tanker trucks and/or pipeline.

¹² <http://www.ipcc-wg3.de/publications/special-reports/special-report-on-carbon-dioxide-capture-and-storage>

Transport by tanker trucks is not practical due to the large number of trucks needed and their associated exhaust emissions which include CO₂. Also, tank truck and rail options cost more than twice as much as a pipeline.¹² Pipelines routinely carry large volumes of natural gas, oil, and water, for example, over large distances. Pipelines would be the best avenue for transport of CO₂ to a sequestration site although safety issues are of concern with a pipeline especially in populated areas. Pipeline leak or rupture would have significant safety, environmental and health impacts.

Currently, the pipeline infrastructure in the area of the SPC plant does not exist for CO₂ transport. The nearest CO₂ pipeline in northeastern Utah is over 225 miles from the proposed SPC plant location. The cost to build a pipeline would be extreme; the labor and steel costs alone are estimated to be \$57,500 per mile per inch pipeline diameter.¹³

CO₂ injection and storage into geological formations is a mitigation option. Injecting CO₂ into deep geological formations at carefully selected sites can store it underground for long periods of time. The cost of geological storage of CO₂ is highly site-specific, depending on factors such as the depth of the storage formation and the number of wells needed for injection. Costs for storage, including monitoring, appear to lie in the range of 0.6–8.3 US\$/tCO₂ stored¹². However, current and planned CO₂ geological storage locations in the United States are limited. The closest CO₂ storage project is proposed near Teapot Dome, Wyoming. CO₂ injection is also being used to enhance oil recovery in western and central Wyoming.

Since current cost and energy penalties are relatively high, CO₂ capture has not been utilized at power plants at full scale, CO₂ transport infrastructure in the vicinity of the proposed plant is not available, and the experience with large-scale geological CO₂ storage is limited, CO₂ capture, transport, and sequestration is not considered BACT and has been eliminated from further consideration.

¹³ http://www.powerplantccs.com/ccs/tra/tra_pipe_cost.html

5.14.5 Step 5 - Select BACT

Thus, at this point in time, the only practical way to reduce the amount of CO₂ generated is to minimize the amount of fuel combustion required to produce the desired amount of electricity. This is achieved by operating the equipment efficiently in accordance with manufacturer standards and conducting periodic maintenance on the equipment to keep it at its optimum performance. In comparison to other fuels, natural gas generates a lower amount of CO₂ and will be used exclusively by SPC for the CTs/HRSGs.

To determine an appropriate CO₂ emissions limit for the CT/HRSGs, a search of state and EPA's RBLC databases for recent issued permits was conducted to proposed a BACT emission limit for the CTs/HRSGs, the auxiliary boiler, and convection heaters. Two permits were identified, PacifiCorp Lakeside in Utah County, Utah and Russell Energy Center in Alameda County, California with a CO₂ BACT limit which was 1,100 pounds CO₂ per net megawatt-hour. This CO₂ limit is comparable to the average emissions rate for all natural gas fired power plants of 1135 lbs/MW-hr that was published by EPA¹⁴. Thus, SPC is proposing a CO₂ BACT emission limit of 1,100 lbs/MW-hr for the CTs/HRSGs.

5.15 BACT for Auxiliary Boiler and Convection Heaters for Greenhouse Gases

Potential GHG emissions from the natural gas fired auxiliary boiler and convection heaters include CO₂, N₂O, and CH₄. The majority of the total GHG emissions, expressed at CO₂e are CO₂ emissions. CO₂ is a product of combustion of fuel containing carbon, such as natural gas. Since CO₂ is created as part of the chemical reaction between oxygen and the fuel when burned, there is no way to reduce the amount of CO₂ generated from combustion. Methane (CH₄) emissions result from incomplete combustion. Nitrous oxide (N₂O) emission results primarily from low temperature combustion.

¹⁴ <http://www.epa.gov/cleanenergy/energy-and-you/affect/natural-gas.html>

5.15.1 Step 1 - Identify All Control Technologies

Three control options identified as potential CO₂, CH₄, and N₂O controls include low carbon fuels, energy efficient processes and technologies including good combustion practices, and carbon capture and sequestration.

5.15.1.1 Energy Efficient Processes and Technologies

EPA has found that natural gas, a low carbon fuel, produces half the amount of CO₂ when compared to other fossil fuels.

Good combustion practices generally include the following components: (1) Proper air/fuel mixing in the combustion zone; (2) High temperatures and low oxygen levels in the primary combustion zone; (3) Overall excess oxygen levels high enough to complete combustion while maximizing boiler thermal efficiency, and (4) Sufficient residence time to complete combustion. Good combustion practices is accomplished through boiler design as it relates to time, temperature, and turbulence, and boiler operation as it relates to excess oxygen levels.

5.15.1.2 Carbon Capture and Sequestration

Carbon capture and sequestration is considered an add-on technology. Carbon sequestration is an engineering technique where CO₂ is removed from the exhaust gas, injected and stored permanently underground in a geological formation of some type for a long period of time.

5.15.2 Step 2 – Eliminate Technically Infeasible Options

The identified control options low carbon fuels and energy efficient processes and technologies including good combustion practices are technically feasible and will be reviewed further.

Carbon capture and sequestration from the auxiliary boiler and the convection heaters is not technically feasible for the reasons stated in Section 5.14.4 above and have been eliminated from further consideration.

5.15.3 Steps 3 – 5

Natural gas will be utilized by both the auxiliary boiler and convection heaters and has the lowest CO₂ emission rate of all fossil fuels. According to AP-42, natural gas has a CO₂ emission rate of 120 lb/MMBtu compared to distillate oil which has a CO₂ emission rate of 150 lb/MMBtu. Thus, natural gas is a top ranked low carbon containing fuel.

Good combustion practice includes operational and design elements to control the amount and distribution of excess air in the flue gas. This ensures that there is enough oxygen present for complete combustion. If sufficient combustion air supply, temperature, residence time, and mixing are incorporated in the combustion design and operation, CH₄ and N₂O emissions will be minimized.

Available control technologies for the control of CH₄ and N₂O emissions are the same controls used for CO and VOC emissions (Section 5.6). These controls include good combustion practices including the use of ULNB and FGR and LNB and FGR for the auxiliary boiler and convection heaters, respectively. ULNB and LNB are designed to control the mixing of air and fuel to reduce the peak temperatures of combustion.

As stated in Section 5.5.5, the auxiliary boiler will be equipped with ULNB and FGR and the convection heaters will be equipped with LNB using low excess air and FGR. Good combustion practices include the use of ULNB and FGR and LNB and FGR. The use of ULNB and FGR for the auxiliary boiler is expected to achieve a CH₄ emission rate of 0.00023 lb/MMBtu and a N₂O emission rate of 0.00064 lb/MMBtu. For the convection heaters utilizing LNB using low excess air and FGR a emission rates of 0.00023 lb/MMBtu and 0.00064 lb/MMBtu for CH₄ and N₂O, respectively will be achieved.

With the above-listed controls, no adverse economic, energy, or collateral environmental impacts were identified that would preclude using these technologies.

The use of low carbon containing fuels including natural gas in combination with the use of efficient auxiliary boiler and convection heaters and good combustion practices represents BACT for control of GHG.

6.0 PSD CLASS II AREA AMBIENT AIR QUALITY ANALYSIS

This section presents the air quality impacts associated with the emissions from the proposed SPC combined cycle power plant. Consistent with the procedures presented in 40 CFR Part 51 Appendix W *Guideline on Air Quality Models*, the air dispersion model used to demonstrate compliance with the NAAQS and PSD Class II area increments was the EPA approved model AERMOD. A modeling protocol developed for this project was accepted by the UDAQ and forwarded to the FLMs. The near-field modeling and full-impact analysis input and output files are contained on an external hard drive that accompanies this permit application.

6.1 Near-Field Dispersion Modeling Analyses

Analyses of air quality impacts within designated Class II areas were performed in accordance with Utah Titles R307-405 and R307-410. These analyses consisted of dispersion modeling of criteria and hazardous air pollutants.

6.1.1 Regional Description

The SPC Project will be located in a northeast-southwest oriented valley. The Pahvant Range is located west of the proposed site. The terrain rises from approximately 5,220 feet at the site to elevations in excess of 10,000 feet approximately 16 miles to the northwest. High terrain is also located south and southeast of the site in the Sevier Plateau with elevations in excess of 11,000 feet. Mt. Terrill and Mt. Marvine are located approximately 22 and 24 miles to the southeast, respectively. The terrain surrounding the facility and used in the modeling analyses is presented in Figure 6.1.

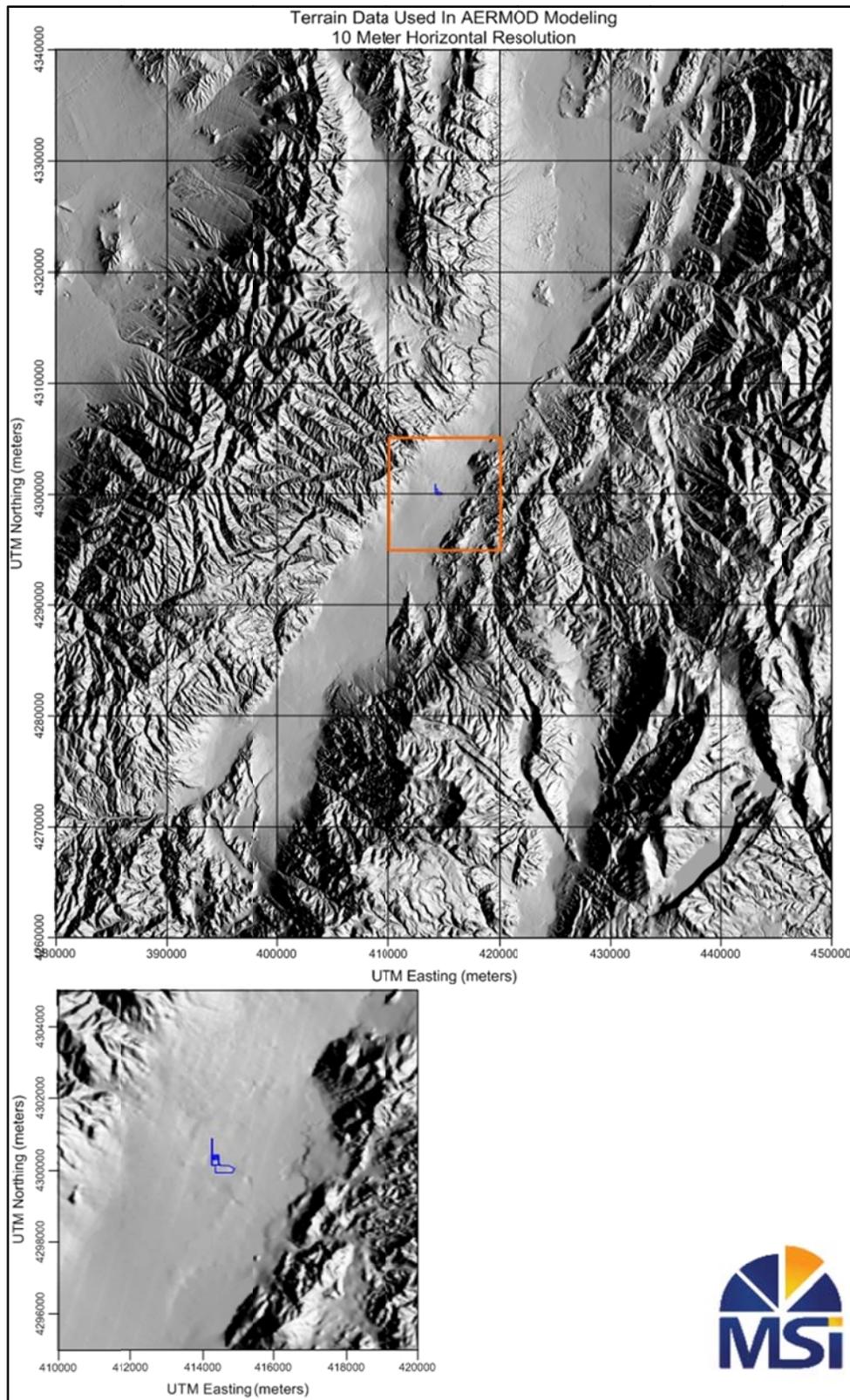


Figure 6.1 Terrain Data used in AERMOD

6.2 Background Ambient Air Quality

Background air quality includes pollutant concentrations due to natural sources, nearby sources other than the one(s) currently under consideration, and unidentified sources. Sevier County, where the proposed facility will be located, is in attainment for all pollutants.

Background concentrations of NO₂, SO₂, PM₁₀, PM_{2.5} and CO for Sevier County were obtained from the UDAQ in a June 16, 2011 email. The background values used for the NAAQS analyses are presented in Table 6-1.

Table 6-1
Background Pollutant Concentrations

Pollutant	Averaging Period	Background Concentration (µg/m³)
NO ₂	1-hour	38
	Annual	23
SO ₂	1-hour	31
	3-hour	31
	24-hour	7
	annual	4
PM ₁₀	24-hour	72
PM _{2.5}	24-hour	16
	annual	13
CO	1-hour	4810
	8-hour	3208

6.3 Model Selection

To address the near-field impacts from the proposed SPC combined-cycle project, the latest version of the AERMOD modeling system (AERMOD 11103, AERMET 11059, AERSURFACE 11059, AERMAP 09040) was utilized.

AERMOD is a steady-state plume dispersion model that is used for assessment of pollutant concentrations from a variety of sources. AERMOD uses Gaussian distributions in the vertical and horizontal for stable conditions, and in the horizontal for convective conditions. The vertical concentration distribution for convective conditions results from an assumed bi-Gaussian probability density function of the vertical velocity. AERMOD accounts for plume downwash based on the PRIME building downwash algorithms. The model uses hourly sequential preprocessed meteorological data to estimate pollutant concentrations for various averaging times.

The AERMOD modeling system consists of two pre-processors and the dispersion model. AERMET is the meteorological pre-processor and AERMAP is the terrain pre-processor that characterizes the terrain and generates receptor elevations. These pre-processors were utilized to generate the required AERMOD files. In addition, in 2008 EPA released AERSURFACE which prepares required land-use information inputs for AERMET.

6.3.1 AERMET

The AERMET preprocessor was used to prepare the meteorological data for AERMOD. AERMET is designed to accept National Weather Service (NWS) one-hour surface observations, NWS twice-daily upper air soundings, and data from an on-site meteorological measurement system. These data are processed in three steps. The first step extracts data from the archive data files and performs various quality assessment checks. The second step merges all available data (both NWS and on-site). These merged data are stored together in a single file. The third step reads the merged meteorological data and estimates the boundary layer parameters needed by AERMOD. AERMET writes two files for input to AERMOD: a file of hourly boundary layer parameter estimates and a file of multiple-level (when the data are available) observations of wind speed and direction, temperature, and standard deviation of the fluctuating components of the wind direction.

6.3.2 AERMAP

The AERMAP terrain preprocessor was used to extract elevation data from 7.5-minute USGS digital elevation data (DEM). Elevations were based on WGS-84 datum. AERMAP produces receptor heights and related parameters that are input into AERMOD. AERMAP determines the base elevation at each receptor and source. For complex terrain situations, AERMOD captures the essential physics of dispersion in complex terrain and needs elevation data that convey the features of the surrounding terrain. To satisfy this need, AERMAP searches for the terrain height and location that has the greatest influence on dispersion for each individual receptor, within a 10% slope of the facility. This height is then referred to as the hill height scale. Both the base elevation and hill height scale data are produced by AERMAP as a file or files which can be directly accessed by AERMOD.

6.3.3 AERSURFACE

The AERMOD Implementation Guide recommends that the surface characteristics be determined using digital land cover data. The current version of AERSURFACE supports the use of land cover from the United States Geological Survey (USGS) National Land Cover archives. These data were used to determine site characteristics. AERSURFACE was used to calculate the surface roughness, albedo and Bowen ratio for 12 sectors around a one-kilometer radius centered at the prior SPC meteorological tower location. The surface roughness length is related to the height of obstacles to the wind flow. The surface roughness length influences the surface shear stress and is an important in the determination of the magnitude of mechanical turbulence and the stability of the boundary layer. Albedo is the fraction of total incident solar radiation reflected by the surface back to space without absorption. The daytime Bowen ratio, an indicator of surface moisture, is the ratio of sensible heat flux to latent heat flux and was used for determining planetary boundary layer parameters for convective conditions driven by the surface sensible heat flux. Table 6-2 presents the albedo, Bowen ratio, and surface roughness, by month that was used for the SPC power plant near-field dispersion modeling analysis.

Table 6-2
Surface Characteristics used in AERMET for the SPC Facility

Months		Sectors											
		1	2	3	4	5	6	7	8	9	10	11	12
January	Alb.	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
	Bo	1.55	1.55	1.55	1.55	1.55	1.55	1.55	1.55	1.55	1.55	1.55	1.55
	Zo	0.021	0.028	0.03	0.041	0.057	0.06	0.023	0.03	0.057	0.046	0.029	0.027
February	Alb.	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
	Bo	1.55	1.55	1.55	1.55	1.55	1.55	1.55	1.55	1.55	1.55	1.55	1.55
	Zo	0.021	0.028	0.03	0.041	0.057	0.06	0.023	0.03	0.057	0.046	0.029	0.027
March	Alb.	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18
	Bo	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74
	Zo	0.037	0.057	0.058	0.065	0.089	0.104	0.056	0.058	0.092	0.078	0.05	0.051
April	Alb.	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18
	Bo	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74
	Zo	0.037	0.057	0.058	0.065	0.089	0.104	0.056	0.058	0.092	0.078	0.05	0.051
May	Alb.	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18
	Bo	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74
	Zo	0.037	0.057	0.058	0.065	0.089	0.104	0.056	0.058	0.092	0.078	0.05	0.051
June	Alb.	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18
	Bo	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74
	Zo	0.037	0.057	0.058	0.065	0.089	0.104	0.056	0.058	0.092	0.078	0.05	0.051
July	Alb.	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18
	Bo	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74
	Zo	0.037	0.057	0.058	0.065	0.089	0.104	0.056	0.058	0.092	0.078	0.05	0.051
August	Alb.	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18
	Bo	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74
	Zo	0.037	0.057	0.058	0.065	0.089	0.104	0.056	0.058	0.092	0.078	0.05	0.051

Table 6-2 (Continued)

Surface Characteristics used in AERMET for the SPC Facility

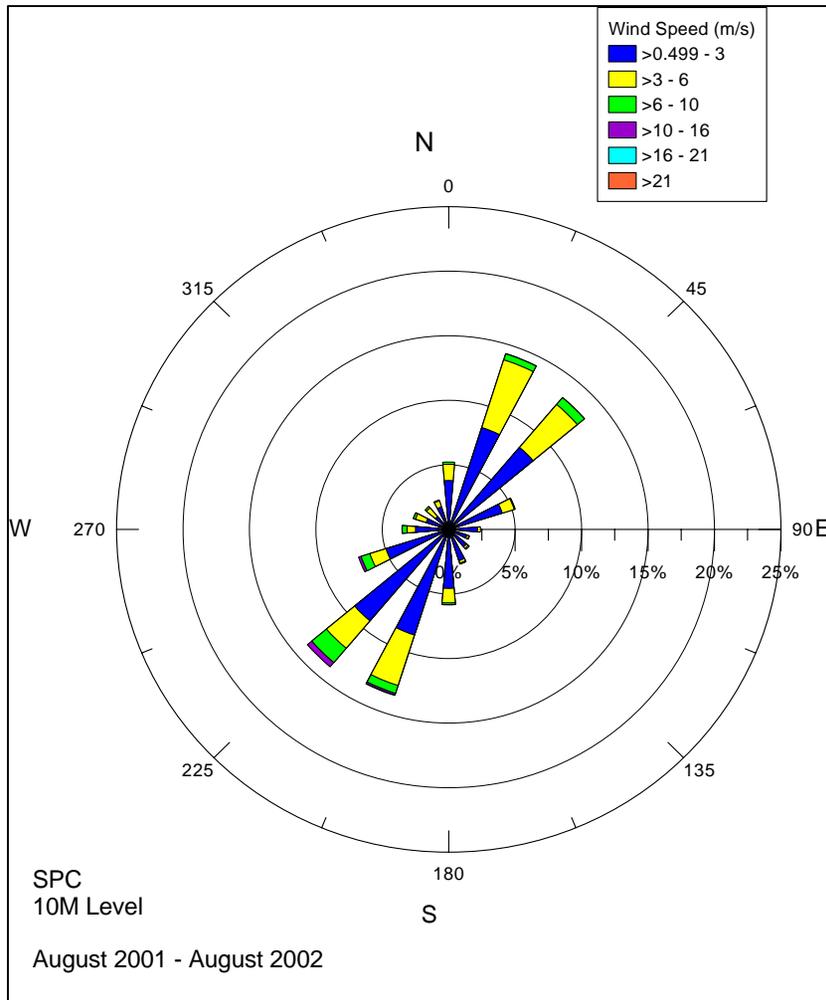
Months		Sectors											
		1	2	3	4	5	6	7	8	9	10	11	12
September	Alb.	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18
	Bo	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74
	Zo	0.037	0.057	0.058	0.065	0.089	0.104	0.056	0.058	0.092	0.078	0.05	0.051
October	Alb.	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
	Bo	1.55	1.55	1.55	1.55	1.55	1.55	1.55	1.55	1.55	1.55	1.55	1.55
	Zo	0.021	0.028	0.03	0.041	0.057	0.06	0.023	0.03	0.057	0.046	0.029	0.027
November	Alb.	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
	Bo	1.55	1.55	1.55	1.55	1.55	1.55	1.55	1.55	1.55	1.55	1.55	1.55
	Zo	0.021	0.028	0.03	0.041	0.057	0.06	0.023	0.03	0.057	0.046	0.029	0.027
December	Alb.	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
	Bo	1.55	1.55	1.55	1.55	1.55	1.55	1.55	1.55	1.55	1.55	1.55	1.55
	Zo	0.021	0.028	0.03	0.041	0.057	0.06	0.023	0.03	0.057	0.046	0.029	0.027

6.4 Meteorological Data

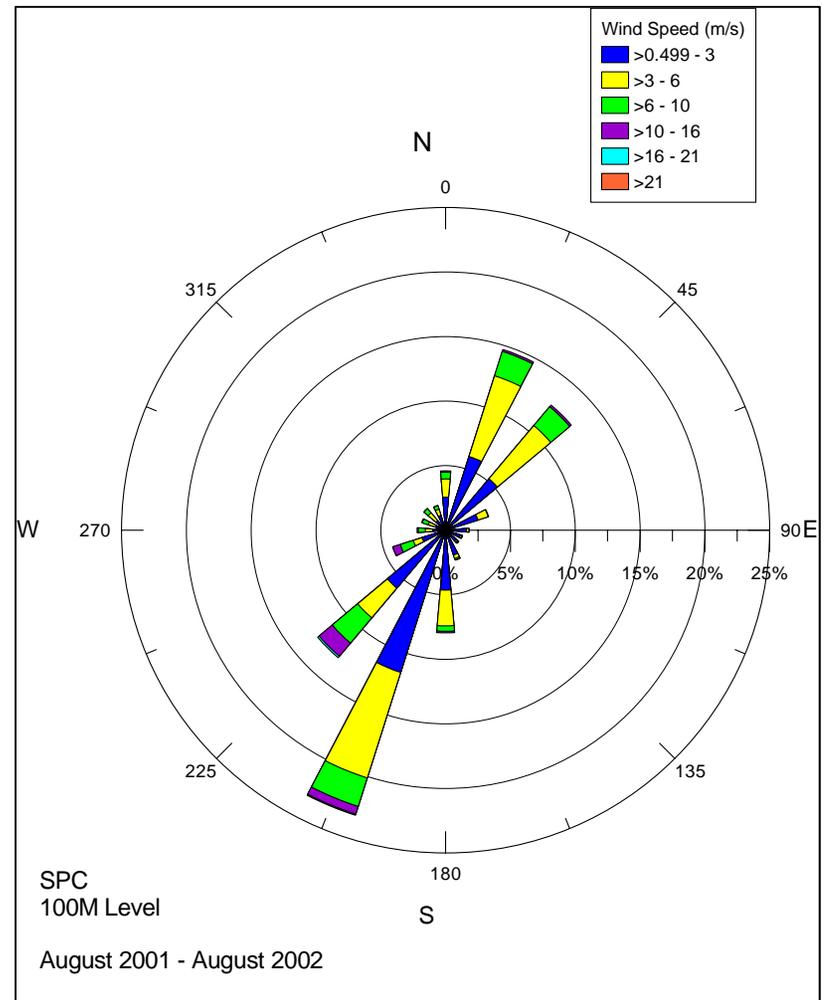
The near-field modeling was performed using on-site 100-meter meteorological data collected by SPC in 2001 and 2002. The meteorological data utilized in this modeling analysis were previously approved by the UDAQ for modeling purposes. Data collection at the SPC meteorological monitoring station began on August 6, 2001 at 17:15 Mountain Standard Time (MST) and consisted of wind speed and direction at 10 and 100 meters, vertical wind speed at 10 and 100 meters, temperature at 2, 10 and 100 meters, relative humidity, solar and net radiation at 2 meters, precipitation, and barometric pressure at the base of the tower.

The AERMET meteorological processor required full upper air soundings (radiosonde data) representing the vertical potential temperature profile near sunrise in order to calculate convective mixing heights. For SPC, the early morning soundings collected at 12Z (or UTC/GMT) by the NWS for the period coinciding with the surface meteorological data were used.

The on-site meteorological data collected from August 2001 through August 2002 and coincident upper air sounding data collected by the National Weather Service (NWS) in Salt Lake City, Utah were processed for use in AERMOD. Figures 6.2 and 6.3 present the annual wind roses for August 2001 through August 2002 for the 10 and 100-meter levels. Periods of invalid meteorological data were not used in the near-field modeling analysis.



**Figure 6.2 10-Meter Wind Rose
(August 2001-August 2002)**



**Figure 6.3 100-Meter Wind Rose
(August 2001 - August 2002)**

6.5 Treatment of Calms or Near-Calms

AERMOD contains algorithms for dealing with low wind speed (near calm) conditions. AERMOD can produce model concentrations for conditions when the wind speed may be less than 1 m/s but still greater than the instrument threshold. The threshold wind speed is typically the threshold of the instrument used to collect the wind information.

AERMET requires that a threshold wind speed and wind direction be input. The reference wind speed is selected by the model at the lowest level of non-missing wind speed and wind direction data where the speed is greater than the wind speed threshold and the height of the measurement is between seven times the local surface roughness and 100 meters. If the only valid observation of the reference wind speed between these heights is less than the threshold, the hour is considered calm and no concentration is calculated.

6.6 Receptor Grid for Near-Field Modeling

A 50 kilometer (km) by 50 km modeling domain was used for the near-field modeling. Discrete receptors based on Universal Transverse Mercator (UTM) coordinates were used for AERMOD. Elevations were derived using in-house 10-meter Digital Elevation Model (DEM) data. Receptor spacing adhered to UDAQ guidelines as discussed in UDAQ's Emissions Impact Assessment Guidelines. Receptors were placed every 25 meters around the fence line, every 50 meters from the fenceline to 500 meters, every 100 meters from 500 meters to 1 kilometer, every 200 meters from 1 to 5 kilometers and every 500 meters from 5 to 10 kilometers. From 10 kilometers to 25 kilometers, 1 kilometer (or 1000 meters) receptor spacing was used. Figure 6.4 presents the receptor grid that was used for the near-field modeling analyses.

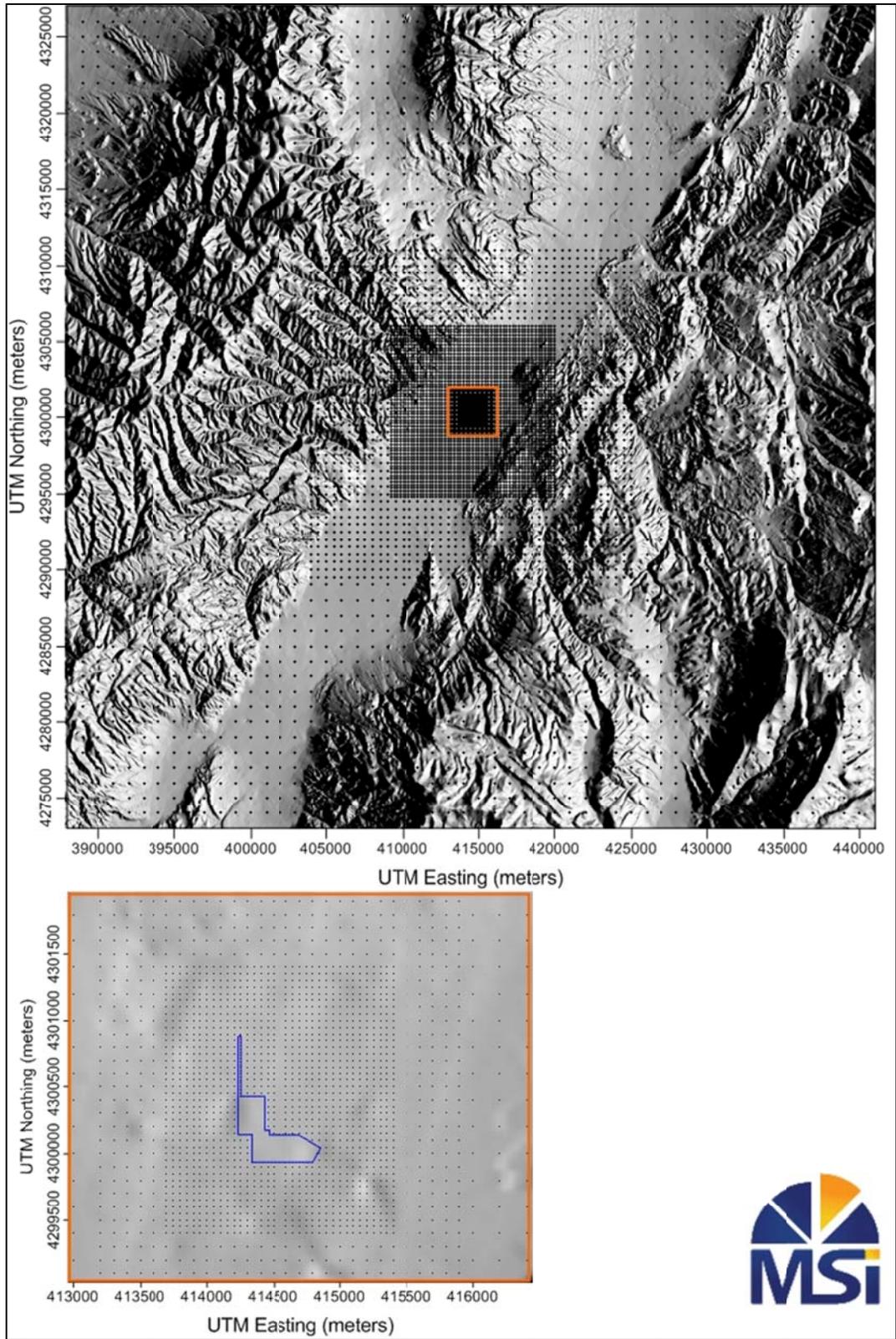


Figure 6.4 AERMOD Discrete Receptor Grid

6.7 Load Screening Analyses

Each CT vendor provided source parameters and corresponding emission rates for a range of operating scenarios. These operating scenarios include a range of loads (between 50 and 100 percent) and a range of ambient conditions. Corresponding stack parameters were provided by each vendor for each case.

For each vendor, the operating cases were modeled to determine under which operating conditions would yield the highest model-predicted ground-level concentrations. Emissions from the auxiliary boiler, convection heaters, emergency generator, and fire water pump were also used in these analyses. The emission rates and source information by operating scenario and vendor input to AERMOD are presented in Table 6-3. The results of the load screening analyses are presented in Appendix G.

**Table 6-3
AERMOD Source Parameters and Emission Rates For Load Screening Analyses**

Operating Scenario	Load (%)	Temp. (°F)	Rel. Hum. (%)	Duct Firing	Stack Hgt. (m)	Stack Dia. (m)	Stack Temp. (°K)	Exit Vel. (m/s)	NO ₂ (lb/hr)	CO (lb/hr)	PM _{2.5} (lb/hr)	PM ₁₀ (lb/hr)
GE												
GE Case 1	100	104	41	Fired	50.29	5.13	368.2	25.99	13	12	14	14
GE Case 2	100	104	41	Fired	50.29	5.13	365.9	24.68	13	12	14	14
GE Case 3a	52	104	41	Unfired	50.29	5.13	357.6	17.75	8	7	11	11
GE Case 3b	36	104	41	Unfired	50.29	5.13	353.2	14.83	6	6	11	11
GE Case 4	100	48	61	Fired	50.29	5.13	355.4	26.13	14	13	14	14
GE Case 5	100	48	61	Unfired	50.29	5.13	359.8	26.38	13	12	12	12
GE Case 6a	49	48	61	Unfired	50.29	5.13	347.0	16.76	8	8	11	11
GE Case 6b	36	48	61	Unfired	50.29	5.13	344.8	14.75	7	6	11	11
GE Case 10	100	48	61	Fired	50.29	5.13	357.0	26.23	14	12	13	13
GE Case 11	100	-17	100	Fired	50.29	5.13	357.6	28.03	15	14	14	14
GE Case 13a	56	-17	100	Unfired	50.29	5.13	354.3	19.22	10	9	11	11
GE Case 13b	39	-17	100	Unfired	50.29	5.13	349.3	15.42	8	7	11	11
GE Case 14	100	65	51	Unfired	50.29	5.13	359.3	26.00	13	12	12	12
Siemens												
Siemens Case 1	100	104	41	Fired	50.29	6.71	366.5	14.47	14	9	11	11
Siemens Case 2	100	104	41	Unfired	50.29	6.71	370.9	14.56	12	7	8	8
Siemens Case 3	50	104	41	Unfired	50.29	6.71	368.2	9.98	7	5	8	8
Siemens Case 4	100	48	61	Fired	50.29	6.71	364.3	15.70	14	9	12	12
Siemens Case 5	100	48	61	Unfired	50.29	6.71	368.2	15.77	13	8	9	9
Siemens Case 6	50	48	61	Unfired	50.29	6.71	367.0	11.14	8	5	8	8
Siemens Case 7	100	48	61	Unfired	50.29	6.71	362.6	15.55	13	8	9	9
Siemens Case 9	50	48	61	Unfired	50.29	6.71	360.4	10.94	8	5	8	8
Siemens Case 10	100	48	61	Fired	50.29	6.71	367.6	15.76	13	8	9	9
Siemens Case 12	100	-17	100	Unfired	50.29	6.71	369.3	17.47	15	9	10	10
Siemens Case 13	50	-17	100	Unfired	50.29	6.71	368.2	12.28	10	6	8	8
Siemens Case 14	100	65	51	Unfired	50.29	6.71	367.6	15.53	13	8	9	9
Emer. Gen.	All	All	All	NA	2.7	0.20	653.4	141.7	18.64	2.78	0.14	0.17
Fire Pump	All	All	All	NA	1.8	0.18	772.7	47.3	5.27	0.49	0.07	0.07
Aux. Boiler	All	All	All	NA	30.5	0.91	422.0	14.1	1.45	3.19	0.85	0.85
Heater 1	All	All	All	NA	6.1	0.61	519.3	15.0	0.80	1.64	0.22	0.22
Heater 2	All	All	All	NA	6.1	0.61	519.3	15.0	0.80	1.64	0.22	0.22

Note: Emissions are pounds per hour per turbine (lb/hr/CT)

6.8 Source Parameters and Technical Input Options

The stack parameters and emission rates used in AERMOD characterized the worst-case scenarios; thus, insuring that SPC operations would meet all applicable air quality standards. Based on the results of the load screening analyses, a representative set of stack parameters and pollutant emissions rates was determined which produced the worst-case plume dispersion conditions and highest model-predicted concentrations. The screening analyses showed GE Operating Case 11 produced the highest model-predicted concentrations for CO and NO₂; GE Operating Case 6b produced the highest model predicted concentrations for particulate matter (PM_{2.5} and PM₁₀). The short-term emission estimate rates and source parameters including UTM coordinates, stack base elevations, and source release parameters for each point source that was modeled are presented in Table 6-4 and 6-5. CT/HRSG stacks, auxiliary boiler, convection heaters, emergency diesel generator, and fire pump were modeled as point sources.

Long-term (annual) emission rates were also modeled. The annual emission rates for the CTs/HRSGs were based on 5000 hours with dust firing and 3760 hours without duct firing (GE operating cases 6 and 8). Table 6-6 present the annual emission rates for NO₂ and PM_{2.5}. The emissions from the emergency generator and fire pump were modeled using annualized rates in accordance with EPA's March 1, 2011 memo *Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO₂ National Ambient Air Quality Standard*¹⁵. Short-term and annual emissions from the paved road segments were modeled as volume sources per the procedures found in Table 3-1 of the User's Guide for the AMS/EPA Regulatory Model - AERMOD¹⁶ and the procedures presented in Table 6-7.

¹⁵ http://www.epa.gov/ttn/scram/Additional_Clarifications_AppendixW_Hourly-NO2-NAAQS_FINAL_03-01-2011.pdf

¹⁶ http://www.epa.gov/ttn/scram/dispersion_prefrec.htm#aermod

Table 6-4**Modeled Emission Rates and Stack Parameters for NO₂ and CO - Short Term**

Source Description	Easting (X) (m)	Northing (Y) (m)	Base Elevation (m)	Stack Height (m)	Temp (K)	Exit Velocity (m/s)	Stack Diameter (m)	NO₂ (g/s)	CO (g/s)
Stack 1	414316.2	4300373.6	1617.7	50.3	357.6	28.0	5.13	1.890	1.764
Stack 2	414377.3	4300373.4	1616.6	50.3	357.6	28.0	5.13	1.890	1.764
Fire Pump	414376.8	4300389.2	1616.7	1.8	772.7	47.3	0.18	3.79E-02	3.52E-03
Emergency Generator	414305.7	4300254.6	1617.0	2.7	653.4	141.7	0.20	1.34E-01	2.00E-02
Auxiliary Boiler	414347.3	4300340.4	1616.9	30.5	422.0	14.1	0.91	1.82E-01	4.02E-01
Convection Heater 1	414325.2	4300355.6	1617.5	6.1	519.3	15.0	0.61	1.01E-01	2.07E-01
Convection Heater 2	414386.3	4300355.4	1616.3	6.1	519.3	15.0	0.61	1.01E-01	2.07E-01

Note: Worst-Case Emissions and Stack Parameters for NO₂ and CO from GE Operating Case 11.

Table 6-5**Modeled Emission Rates and Stack Parameters for PM_{2.5} and PM₁₀ - Short Term**

Source Description	Easting (X) (m)	Northing (Y) (m)	Base Elevation (m)	Stack Height (m)	Temp (K)	Exit Velocity (m/s)	Stack Diameter (m)	PM_{2.5} (g/s)	PM₁₀ (g/s)
Stack 1	414316.2	4300373.6	1617.7	50.3	344.8	14.7	5.13	1.386	1.386
Stack 2	414377.3	4300373.4	1616.6	50.3	344.8	14.7	5.13	1.386	1.386
Fire Pump	414376.8	4300389.2	1616.7	1.8	772.7	47.3	0.18	5.03E-04	5.03E-04
Emergency Generator	414305.7	4300254.6	1617.0	2.7	653.4	141.7	0.20	1.01E-03	1.22E-03
Auxiliary Boiler	414347.3	4300340.4	1616.9	30.5	422.0	14.1	0.91	1.07E-01	1.07E-01
Convection Heater 1	414325.2	4300355.6	1617.5	6.1	519.3	15.0	0.61	2.81E-02	2.81E-02
Convection Heater 2	414386.3	4300355.4	1616.3	6.1	519.3	15.0	0.61	2.81E-02	2.81E-02

Note: Worst-Case Emissions and Stack Parameters for PM_{2.5} and PM₁₀ from GE Operating Case 6b.

Table 6-6**Modeled Emission Rates and Stack Parameters for NO₂ and PM_{2.5} – Annual**

Source Description	Easting (X) (m)	Northing (Y) (m)	Base Elevation (m)	Stack Height (m)	Temp (K)	Exit Velocity (m/s)	Stack Diameter (m)	NO₂ (g/s)	PM_{2.5} (g/s)
Stack 1	414316.2	4300373.6	1617.7	50.3	355.4	26.1	5.13	1.714	1.651
Stack 2	414377.3	4300373.4	1616.6	50.3	355.4	26.1	5.13	1.714	1.651
Fire Pump	414376.8	4300389.2	1616.7	1.8	772.7	47.3	0.18	3.79E-02	5.03E-04
Emergency Generator	414305.7	4300254.6	1617.0	2.7	653.4	141.7	0.20	1.34E-01	1.01E-03
Auxiliary Boiler	414347.3	4300340.4	1616.9	30.5	422.0	14.1	0.91	1.82E-01	1.07E-01
Convection Heater 1	414325.2	4300355.6	1617.5	6.1	519.3	15.0	0.61	1.01E-01	2.81E-02
Convection Heater 2	414386.3	4300355.4	1616.3	6.1	519.3	15.0	0.61	1.01E-01	2.81E-02

Note: Annual Emissions Based on GE Cases 6 and 8.

Table 6-7
Procedures Used for Estimating Lateral and Initial Vertical Dimensions for
Volume and Line Sources

Type of Source	Procedure for Obtaining Initial Dimension
Initial Lateral Dimensions (σ_{y0})	
Single volume source	σ_{y0} = length of side divided by 4.3
Line source represented by adjacent volume sources	σ_{y0} = length of side divided by 2.15
Line source represented by separated volume sources	σ_{y0} = center to center distance divided by 2.15
Initial Vertical Dimensions (σ_{z0})	
Surface-based source	σ_{z0} = vertical dimension of source divided by 2.15
Elevated source ($h_e > 0$) on or adjacent to a building	σ_{z0} = building height divided by 2.15
Elevated source ($h_e > 0$) not on or adjacent to a building	σ_{z0} = vertical dimension of source divided by 4.3

The AERMOD model was run with the regulatory default option which includes the following:

- Stack tip downwash,
- Calms and missing meteorological data routine,
- Direction-specific building downwash,
- Actual receptor elevations,
- Sequential date checking, and
- Complex/intermediate terrain algorithms.

Other selected input variables that were used in AERMOD include:

- 24-hour and annual averaging periods for $PM_{2.5}$,
- 24-hour averaging period for PM_{10} ,
- One-hour and annual averaging periods for NO_2 ,
- 1- and 8- hour averaging periods for CO,
- elevated terrain,

- rural mixing heights, and
- concentrations.

Modeled emissions of NO_x were assumed to completely convert to NO₂. The AERMOD non-default options of PVMRM and OLM were not used in the modeling analyses for SPC.

6.9 Good Engineering Practice (GEP) Stack Height

The GEP stack height is defined under Section 123 of the CAA as “the height necessary to insure that emissions from the stack do not result in excessive concentrations of any air pollutant in the immediate vicinity of the source as a result of atmospheric downwash, eddies, or wakes which may be created by the source itself, nearby structures or nearby terrain obstacles.” GEP stack height was calculated with the formulas presented in 40 CFR 51.100 (ii). The EPA’s refined formula height is defined as $H + 1.5 L$, where L is length.

6.10 Downwash

The BPIP-Prime algorithm in AERMOD was utilized to address downwash effects. The height, width, length and base elevation of proposed structures that will be constructed at the SPC facility were used. Preliminary structure dimensions are presented in Table 6-8. BPIP determines, in each of the 36 wind directions (10 degree sectors), which buildings will produce the greatest downwash effects for a stack.

Table 6-8
Building Dimensions used in BPIP-Prime

Building Name	Building Code	E-W Dimension (meters)	N-S Dimension (meters)	Height (meters)
Administration Building	ADMIN	24.3	12.1	9.7
Condenser	CNDSR	33.1	37.9	25.9
Gas Turbine 1	S1_CMB	8.3	8.8	16.2
Gas Turbine Cooling Fan	S1_FAN	16.7	4.9	21.0
Gas Turbine Cooling Fan	S1_FAN2	16.6	4.0	18.1
Heat Recovery Steam Generator 1	S1_RCV	13.0	60.0	7.8
Heat Recovery Steam Generator 1 Tier 2	S1_RCV	13.0	43.2	25.9
Gas Turbine 2	S2_CMB	8.3	8.8	16.2
Gas Turbine Cooling Fan	S2_FAN	16.7	4.9	20.1
Gas Turbine Cooling Fan	S2_FAN2	16.6	4.0	18.1
Heat Recovery Steam Generator 2	S2_RCV	13.0	60.0	7.8
Heat Recovery Steam Generator 2 Tier 2	S2_RCV	13.0	43.2	25.9
Steam Turbine Cooling Fan	STM_FAN	10.4	4.0	7.8
Steam Turbine Cooling Fan	STM_FAN2	10.4	3.0	7.8
Steam Turbine	STM_GEN	6.1	20.1	10.0
Tank 1	TANK1	9.4	9.4	11.6
Tank 2	TANK2	9.4	9.4	11.6

6.11 Near-Field Modeling Results

Near-field modeling was performed for those pollutants for which the SPC facility's proposed emissions were greater than the significant emission rates as defined in R307-410-3. Those pollutants modeled include NO₂, CO, PM₁₀, and PM_{2.5}. The results of the near-field modeling from only SPC sources are presented in Table 6-9 and in Appendix H. Figures 6.5 through 6.11 present the modeled concentration isopleth plots for NO₂, CO, PM₁₀ and PM_{2.5}. Maximum modeled values are presented for one- and eight-hour CO, annual NO₂, and annual PM_{2.5} concentrations. High second high (HSH) modeled values are presented for 24-hour PM₁₀. Modeled values for one-hour NO₂ and 24-hour PM_{2.5} represent the 98th percentile over the period (1-year).

Table 6-9

Modeled Maximum and High-Second-High Near-Field Pollutant Concentrations for SPC

Pollutant	Averaging Period	Modeled Impact ($\mu\text{g}/\text{m}^3$)	Location of Model Predicted Concentration	
			UTM East (meters)	UTM North (meters)
NO ₂	1-hour ¹	119.9	414228.6	4300386.1
	Annual	7.8	414404.0	4300428.2
CO	1-hour	330.6	414228.6	4300361.5
	8-hour	82.8	414404.0	4300428.2
PM ₁₀	24-hour (high)	7.1	414228.7	4300312.4
	24-hour (HSH)	6.8	414228.7	4300312.4
PM _{2.5}	24-hour	6.9	414228.7	4300312.4
	Annual	1.8	414228.7	4300312.4

¹98th percentile of the daily maximum one-hour average
HSH – High-Second-High

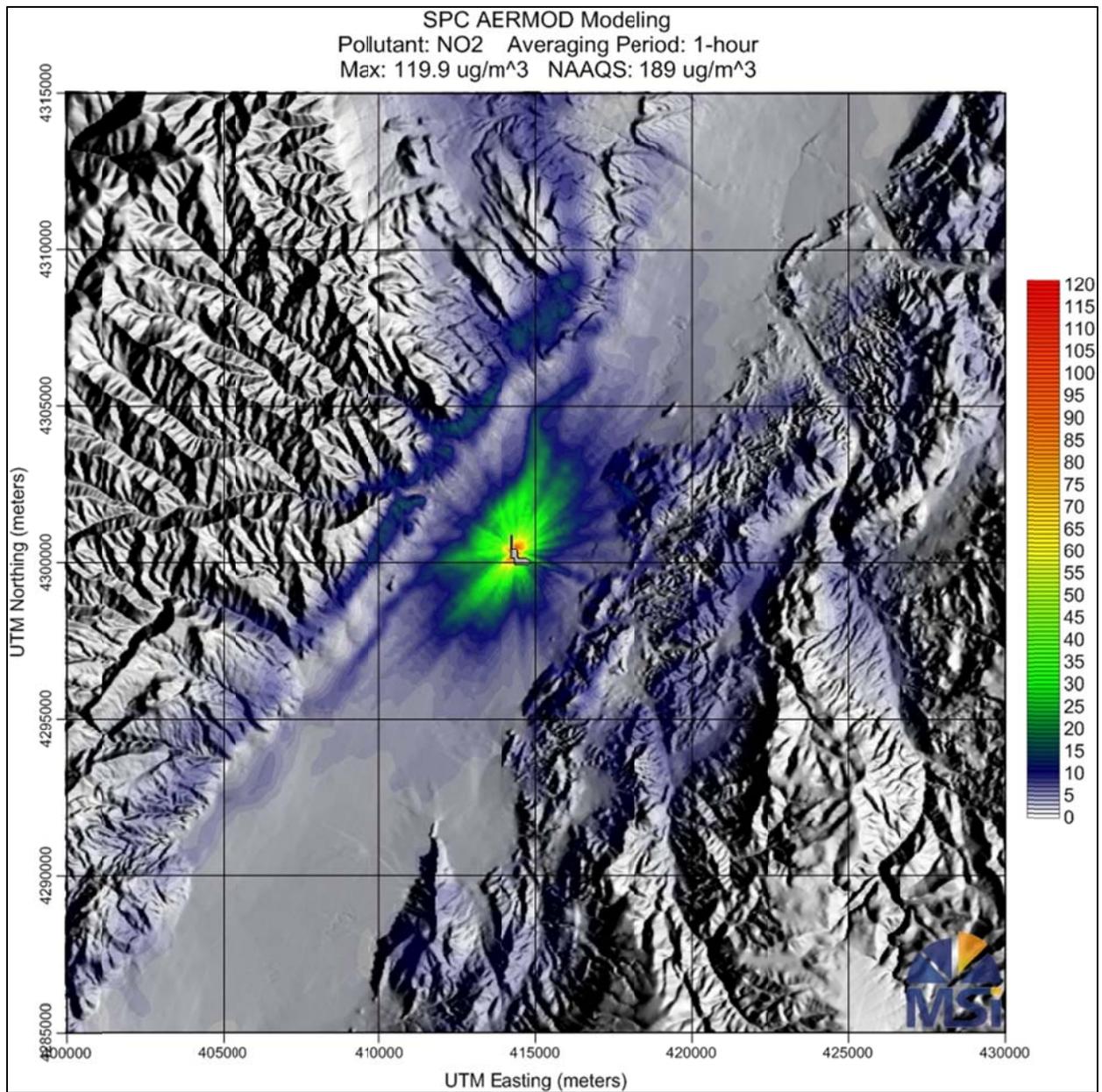


Figure 6.5 Modeled 98th Percentile One-hour NO₂ Concentration Isopleth Plot

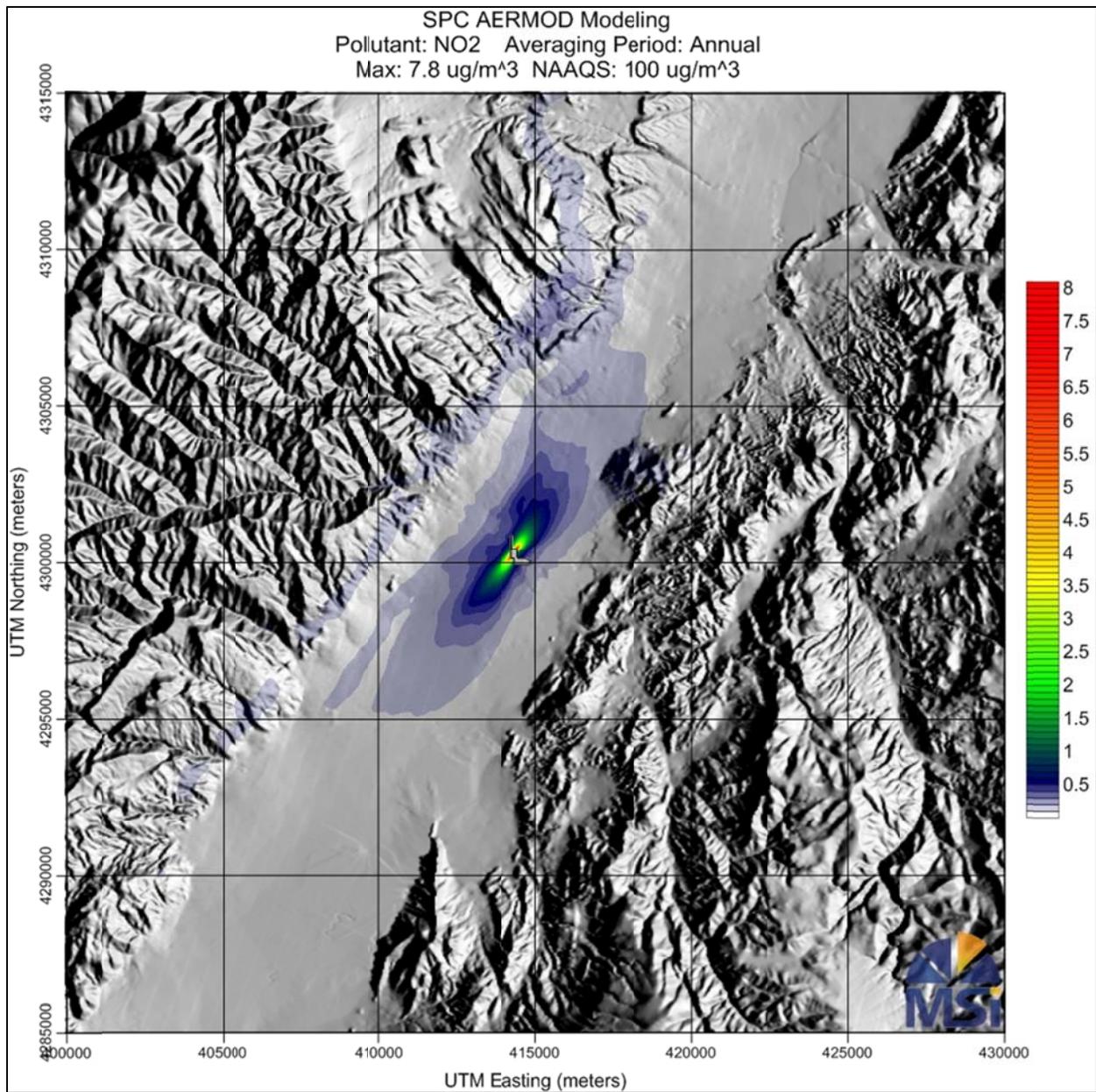


Figure 6.6 Modeled Maximum Annual NO₂ Concentration Isopleth Plot

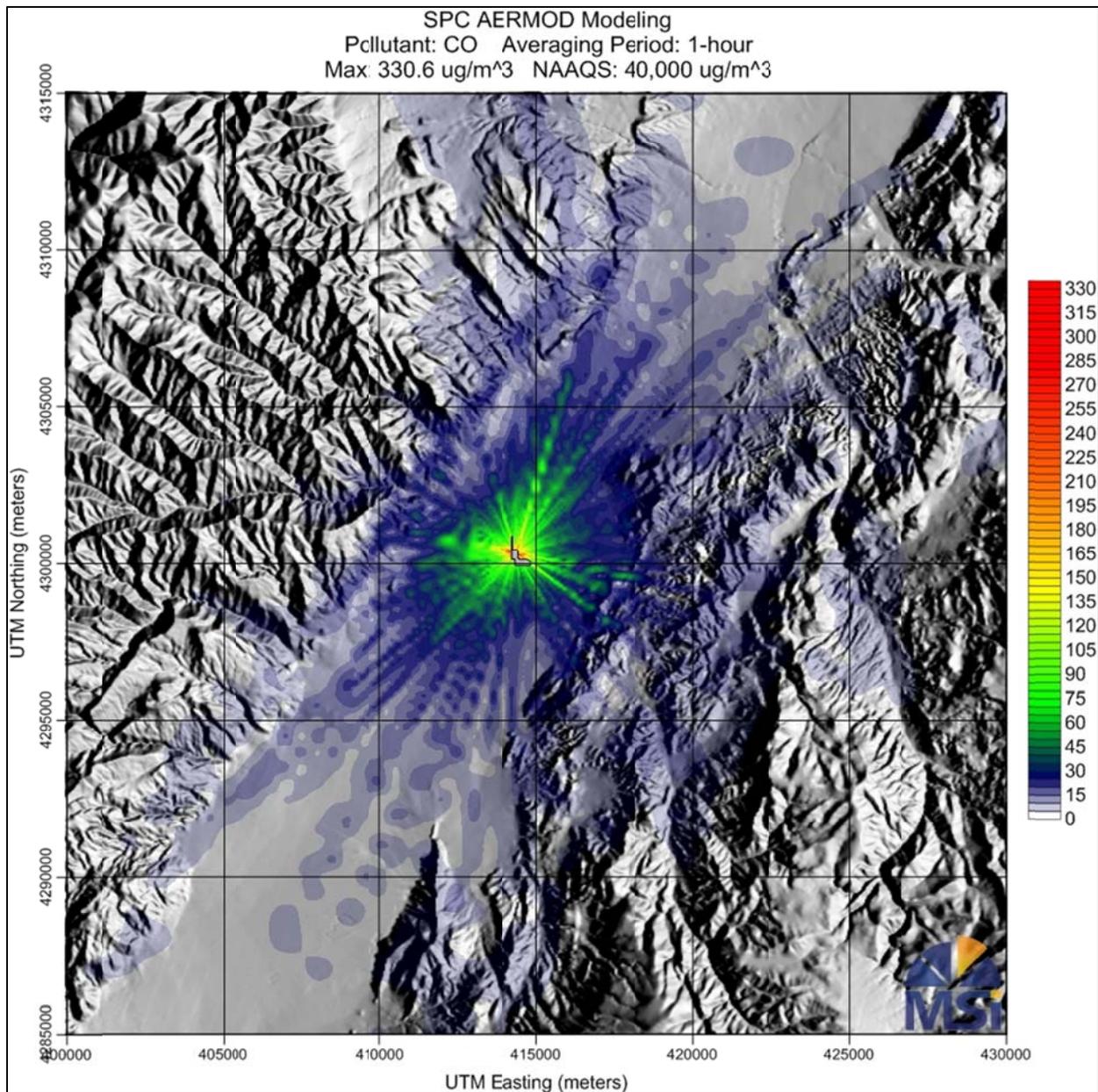


Figure 6.7 Modeled Maximum One-hour CO Concentration Isopleth Plot

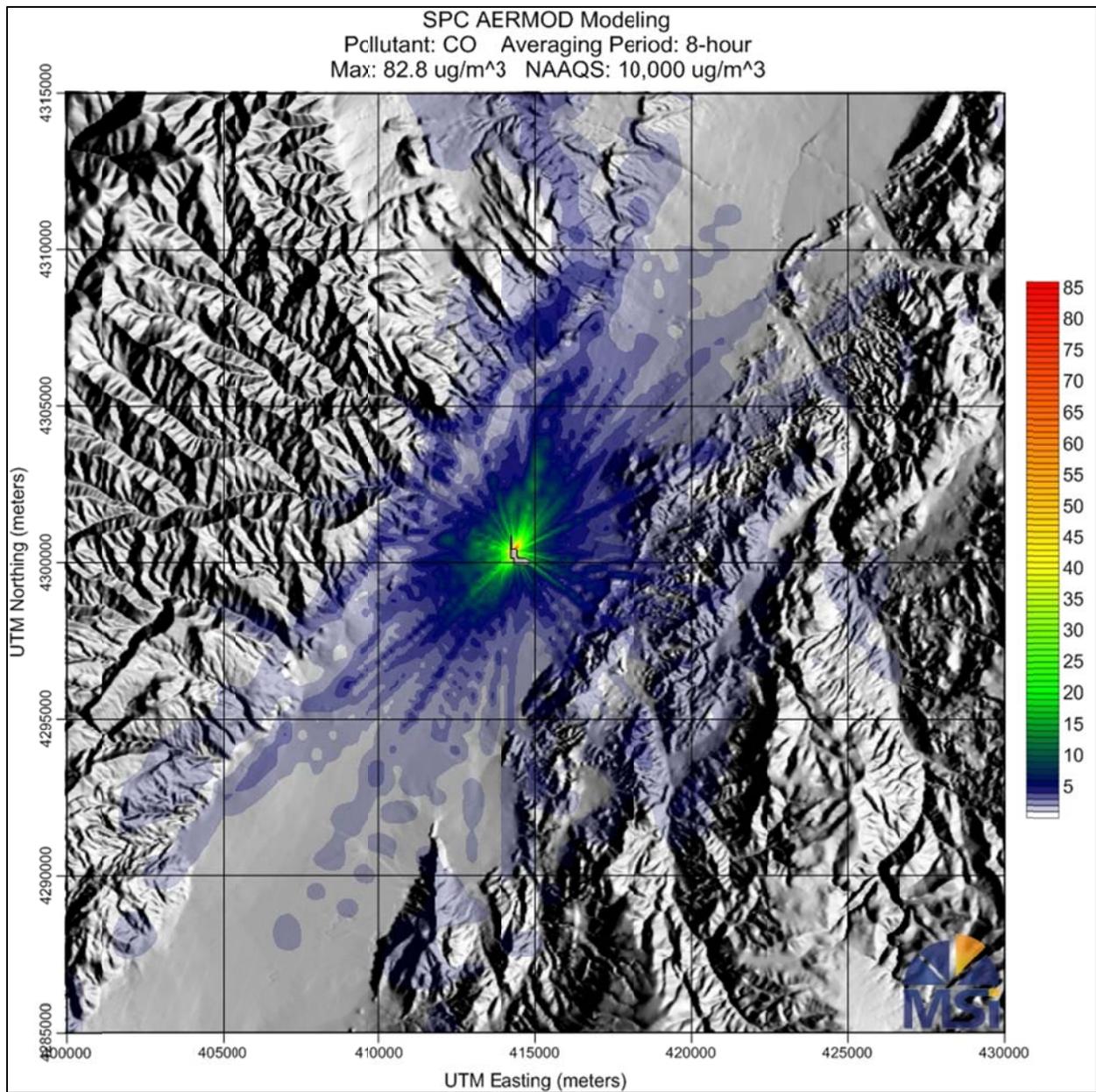


Figure 6.8 Modeled Maximum Eight-hour CO Concentration Isopleth Plot

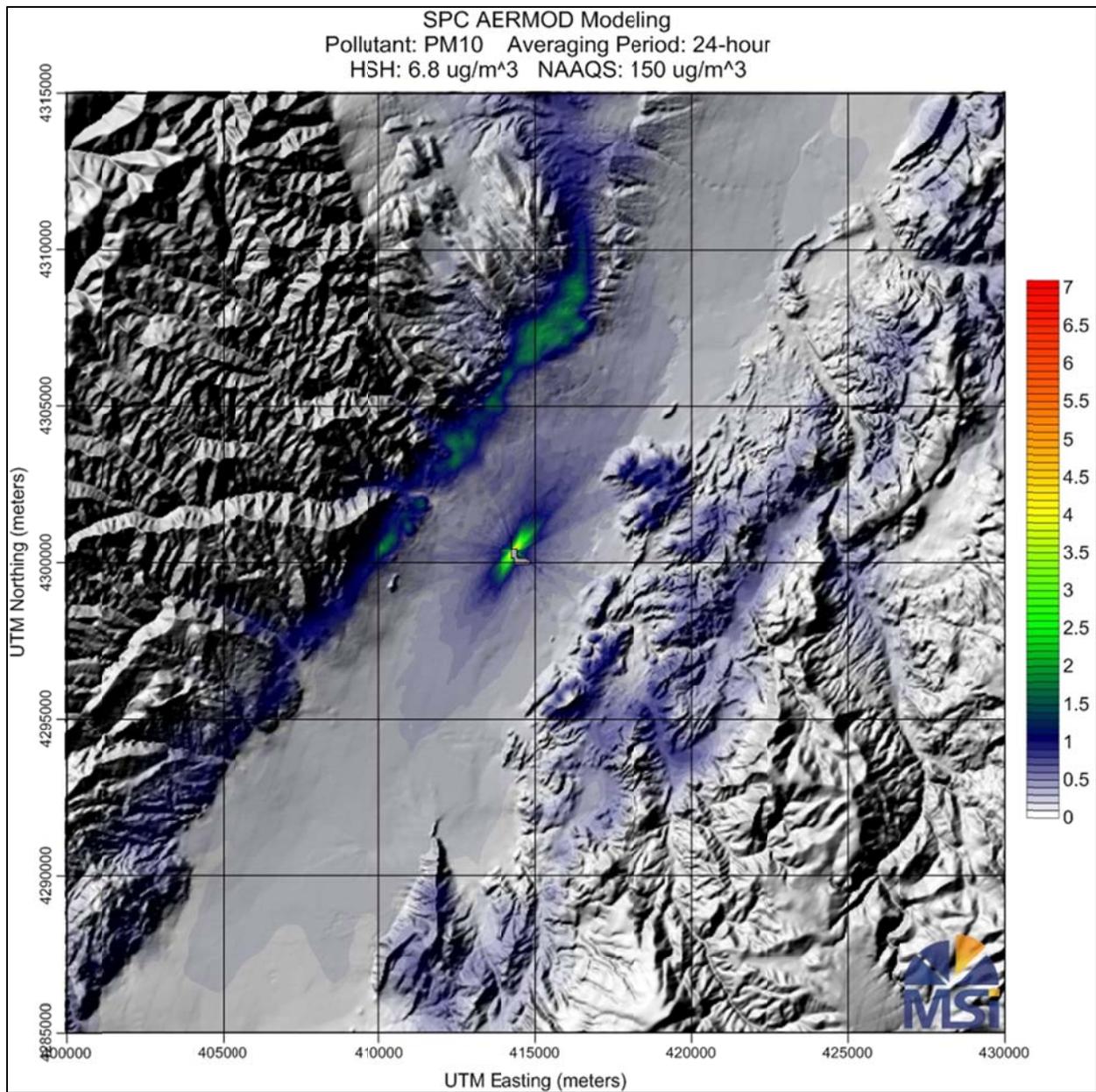


Figure 6.9 Modeled High-Second-High 24-hour PM₁₀ Concentration Isopleth Plot

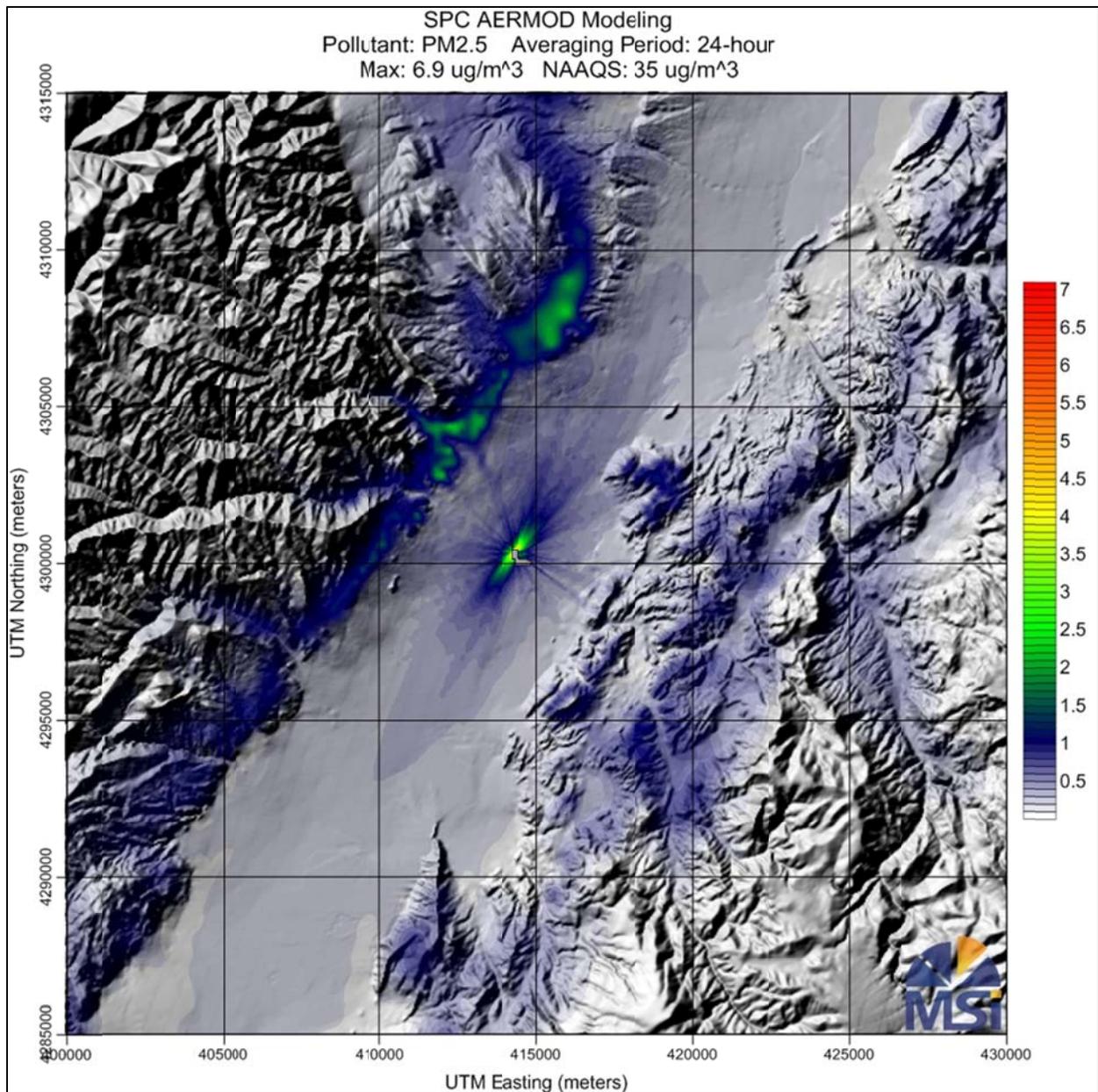


Figure 6.10 Modeled Maximum 24-hour PM_{2.5} Concentration Isopleth Plot

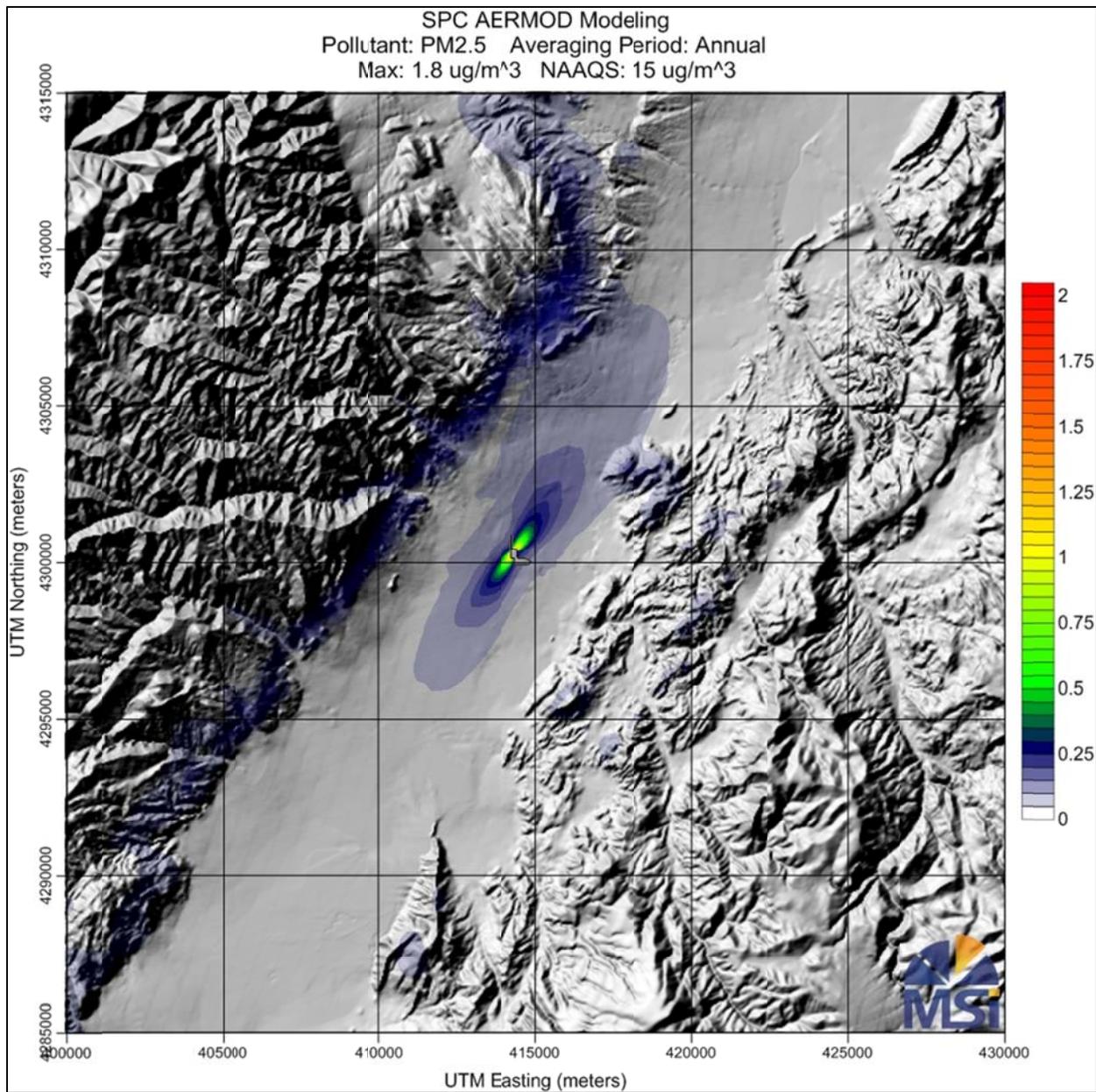


Figure 6.11 Modeled Maximum Annual PM_{2.5} Concentration Isopleth Plot

6.12 Significant Impact Levels

The EPA has adopted significant impact levels (SILs) for criteria pollutants. If the highest modeled concentrations for any pollutant and averaging period evaluated are less than the applicable SIL, a full impact air quality analysis is not required for that pollutant and averaging period; however, these pollutants may still be subject to further review as part of the PSD additional impact analysis requirements. Table 6-10 presents the PSD Class II area SILs.

Table 6-10
PSD Class II Area Significant Air Quality Impact Levels

Pollutant	Averaging Period	Significant Impact Level ($\mu\text{g}/\text{m}^3$)
NO ₂	1-hour	7.5
	annual	1
CO	1-hour	2000
	8-hour	500
PM ₁₀	24-hour	5
PM _{2.5}	24-hour	1.2
	annual	0.3

6.13 Full Impact Analysis

A full impact analysis was performed to determine whether proposed SPC sources could cause a significant off-site impact. In addition to emissions from the proposed project, the full impact analysis considers emissions from existing sources as well as the growth associated with the new project. An impact area was established to determine the geographical area for which the required air quality analyses for the NAAQS and PSD increments are carried out. This area includes all locations where the significant increase in the potential emissions of a pollutant from the SPC facility will cause a significant ambient impact (i.e., equals or exceeds the applicable significant impact levels in Table 6-10). For those pollutants whose impacts were below the modeling significance levels, no further analyses were performed for that pollutant.

For SPC, model predicted impacts of NO₂, PM₁₀, and PM_{2.5} were above the modeling significance levels; thus, a full impact analysis was performed to demonstrate compliance with the applicable standards. The impact area is a circular area with a radius extending from the source to the most distant point where AERMOD predicted a significant impact would occur. The impact area used for the full impact analysis was the largest of the areas determined for each pollutant reviewed. The maximum distance determined for each pollutant above the significance levels was 13.7 kilometers for one-hour NO₂. A distance of 50 kilometers was added to the maximum distance to define the scope of the full impact analysis. Table 6-11 compares modeled maximum concentrations with the significant impact levels.

Table 6-11

Comparison of Modeled Maximum Concentrations to Significant Impact Levels

Pollutant	Averaging Period	Modeled Impact (µg/m³)	SIL (µg/m³)	Percent of SIL	Radius of Impact
NO ₂	1-hour ¹	119.9	7.5	1589%	13.7
	Annual	7.8	1	775%	1.1
CO	1-hour	330.6	2000	17%	N/A
	8-hour	82.8	500	17%	N/A
PM ₁₀ (high)	24-hour	7.1	5	142%	0.2
PM _{2.5}	24-hour	6.9	1.2	571%	10.4
	Annual	1.8	0.3	601%	1.2

¹98th percentile of the daily maximum one-hour average

6.14 Near-by Source Inventory

UDAQ was contacted to obtain source and emissions information for sources of NO_x, PM₁₀, and PM_{2.5} that fell within the radius of impact. The UDAQ identified four NO_x and PM₁₀ sources within the impact area and provided source and emissions information for the identified sources. A summary of the full impact sources modeled and distance from the proposed SPC facility is presented in Table 6-12.

Table 6-12
Full Impact Analysis Sources

Source Name	UTM East (meters)	UTM North (meters)	Distance from SPC (kilometers)
Redmond Minerals	424750	4322470	24.3
Western Clay	420100	4308300	9.6
Georgia Pacific Gypsum	416000	4298500	2.5
United States Gypsum	416370	4299350	2.5

The emissions and source information for Redmond Minerals, Western Clay, Georgia Pacific Gypsum, and United States Gypsum were added to the SPC AERMOD model setup and the model was rerun. Per the UDAQ, the PM₁₀ emissions from Redmond Minerals and Western Clay were modeled as area sources with dimensions of 250 X 250 meters and a release height of 0. Per the UDAQ, the NO₂ emissions from Redmond Minerals and Western Clay were modeled as point sources with 30-meter stack heights, 0.5 meter stack diameters, exit velocities of 15 m/s, and stack exit temperatures of 475°K. The emissions and source parameters for Georgia Pacific Gypsum and United States Gypsum were based on 2009 dispersion modeling information. Full impact source parameters and emission rates are provided in Appendix I. The results of the full impact analysis are presented in Table 6-13 and in Appendix J.

Table 6-13
Full Impact Analysis AERMOD Results

Pollutant	Averaging Period	Modeled Impact (µg/m³)	Location of Model Predicted Concentration	
			UTM East (meters)	UTM North (meters)
NO ₂	1-hour	119.9	414228.6	4300386.1
	Annual	7.8	414404.0	4300428.2
PM ₁₀	24-hour (high)	412.3	420000.0	4308000.0
	24-hour (HSH)	315.4	420000.0	4308000.0

6.15 National Ambient Air Quality Standard Compliance

For NAAQS compliance, the background pollutant concentrations obtained from the UDAQ were added to the modeled maximum concentrations to evaluate the total impact. The modeled maximum and HSH pollutant concentrations, background concentrations, NAAQS, and percent of NAAQS for SPC sources are presented in Table 6-14. The maximum and HSH pollutant concentrations, background concentrations, NAAQS, and percent of NAAQS for all sources modeled (SPC plus full impact sources) are presented in Table 6-15.

Table 6-14
NAAQS Compliance Demonstration for SPC Sources Only

Pollutant	Averaging Period	Modeled Impact ($\mu\text{g}/\text{m}^3$)	Background ($\mu\text{g}/\text{m}^3$)	Total ($\mu\text{g}/\text{m}^3$)	NAAQS ($\mu\text{g}/\text{m}^3$)	Percent of NAAQS
NO ₂	1-hour ¹	119.9	38	157.9	189	83.6%
	Annual	7.8	23	30.8	100	30.8%
CO	1-hour	330.6	4810	5140.6	40000	12.9%
	8-hour	82.8	3208	3290.8	10000	32.9%
PM ₁₀	24-hour (high)	7.1	72	79.1	150	52.7%
	24-hour (HSH)	6.8	73	79.8	150	52.8%
PM _{2.5}	24-hour	6.9	16	22.9	35	65.3%
	Annual	1.8	13	14.8	15	98.7%

¹98th percentile of the daily maximum one-hour average
HSH – High-Second-High

Table 6-15
NAAQS Compliance Demonstration for SPC and Full Impact Analysis Sources

Pollutant	Averaging Period	Modeled Impact ($\mu\text{g}/\text{m}^3$)	Background ($\mu\text{g}/\text{m}^3$)	Total ($\mu\text{g}/\text{m}^3$)	NAAQS ($\mu\text{g}/\text{m}^3$)	Percent of NAAQS
NO ₂	1-hour ¹	119.9	38	157.9	189	83.5
	Annual	7.8	23	30.8	100	30.8
PM ₁₀	24-hour (high)	412.3	72	484.3	150	>100
	24-hour (HSH)	315.4	72	387.4	150	>100

¹98th percentile of the daily maximum one-hour average
HSH – High-Second-High

The results of the full impact analysis which includes SPC and UDAQ identified sources indicate an exceedance of the 24-hour PM₁₀ NAAQS. The source that contributes to the exceedance is Western Clay. The percent contribution from all sources and from SPC sources only at the receptors with modeled 24-hour PM₁₀ concentrations above the NAAQS is presented in Table 6-16.

Table 6-16
Source Contribution at Receptors Over 24-hour PM₁₀ NAAQS

All Source Concentration (µg/m ³)	SPC Source Concentration (µg/m ³)	Location of Model-Predicted Concentration		Percent of SPC Total Contribution
		UTM East (meters)	UTM North (meters)	
78.3	0.190	419,500	4,307,500	0.24%
226.4	0.177	420,000	4,308,500	0.08%
255.8	0.176	420,000	4,308,000	0.07%
109.5	0.196	420,000	4,307,500	0.18%
151.4	0.163	420,500	4,309,000	0.11%
315.4	0.165	420,500	4,308,500	0.05%
164.2	0.177	420,500	4,308,000	0.11%
83.5	0.156	420,500	4,307,500	0.19%
110.4	0.155	421,000	4,309,000	0.14%

Full impact concentration isopleth plots for the entire modeling domain for the one-hour and annual NO₂, as well as 24-hour PM₁₀ are presented in Figures 6.12 through 6.14, respectively. Figures 6.15 through 6.17 present the modeled maximum full impact concentration plots for the area surrounding the SPC facility for the one-hour and annual NO₂, and 24-hour PM₁₀, respectively. In Figures 6.15 through 6.17, the white contour lines represent SPC's contribution to the model predicted concentration and the black dashed contours represent model predicted concentrations for the full impact analysis.

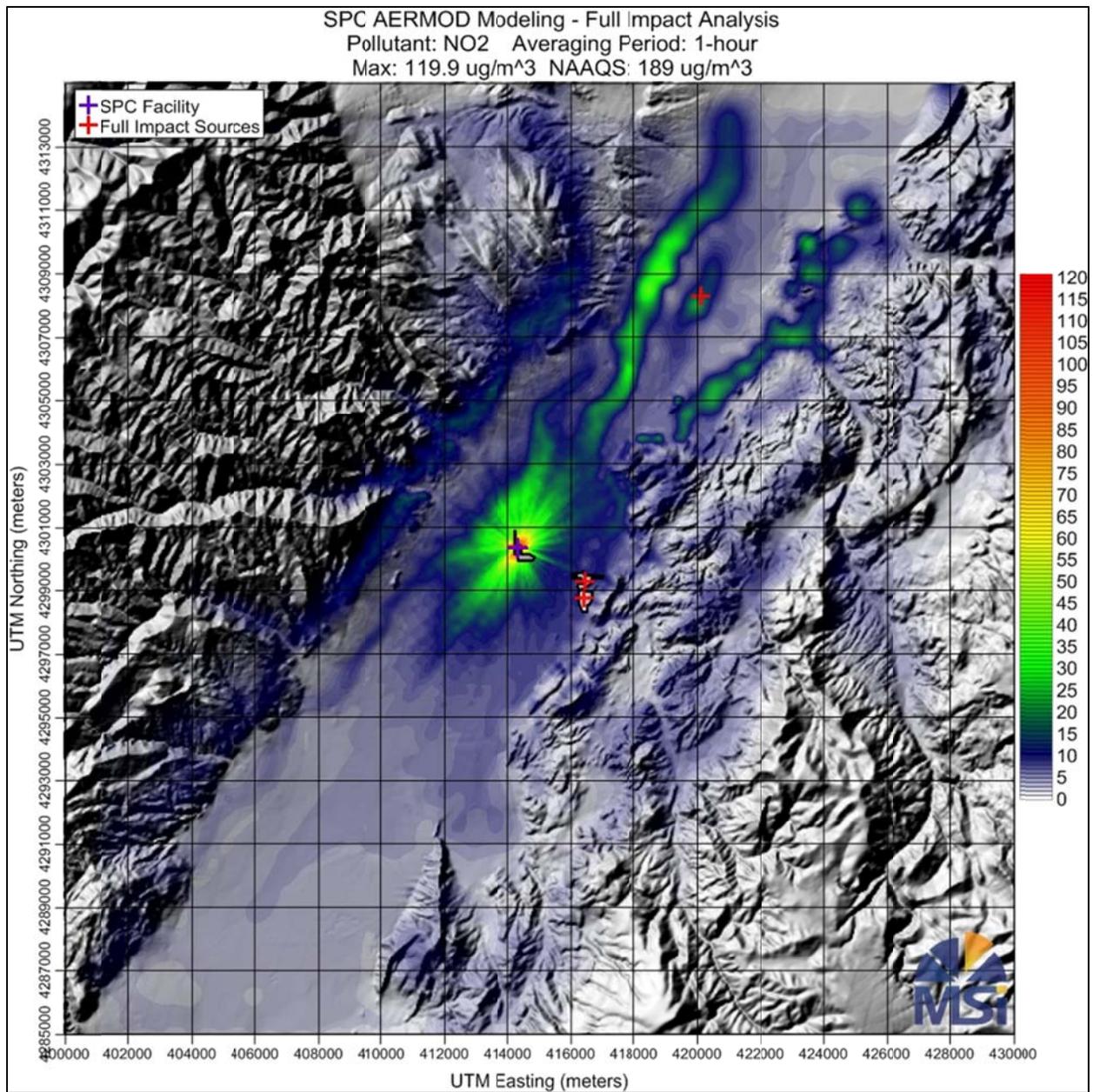
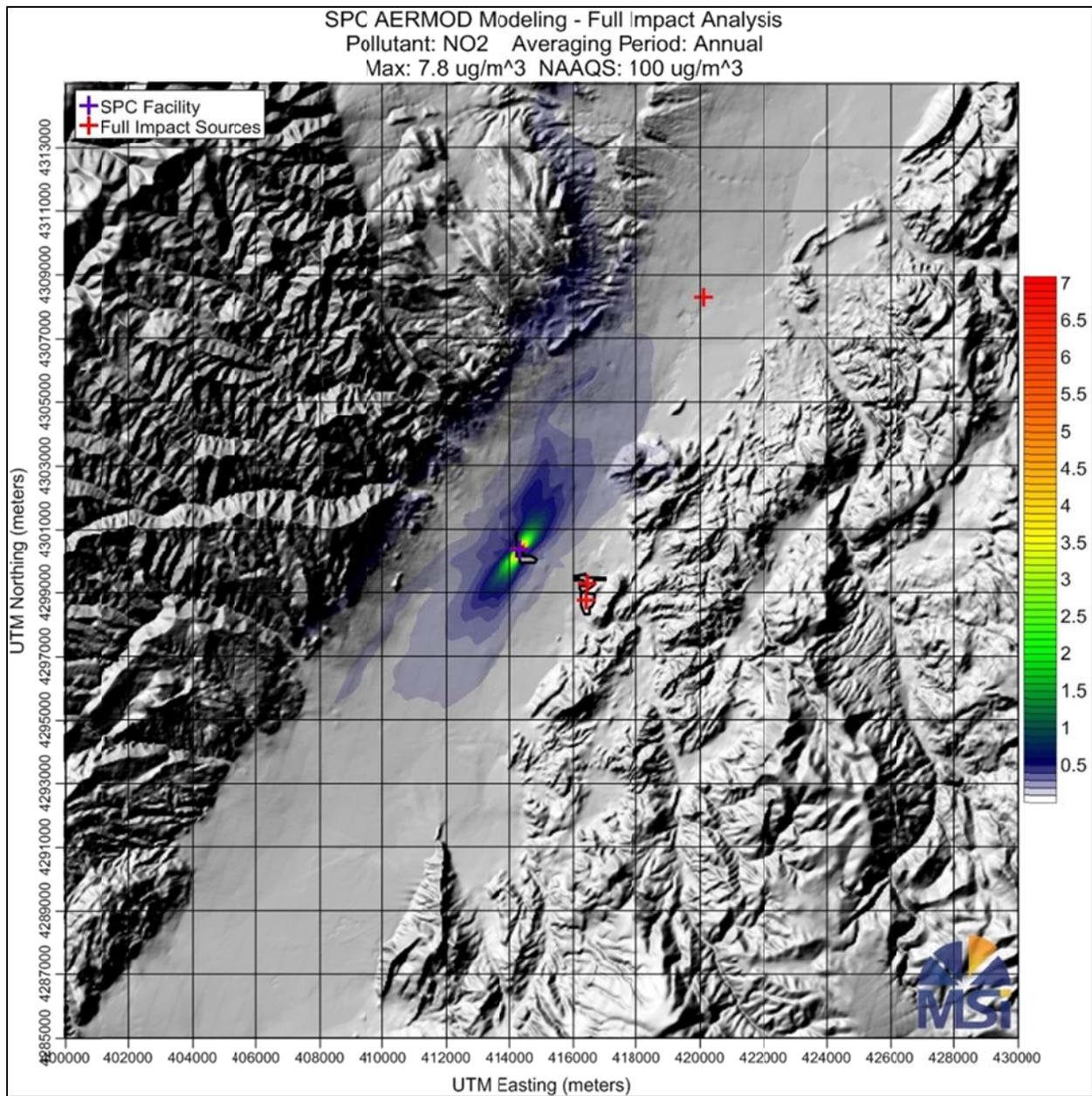


Figure 6.12 Modeled 98th Percentile One-Hour NO₂ Concentration Isoleth Plot – Full Impact Analysis - Entire Modeling Domain



**Figure 6.13 Modeled Maximum Annual NO₂ Concentration Isopleth Plot –
 Full Impact Analysis - Entire Modeling Domain**

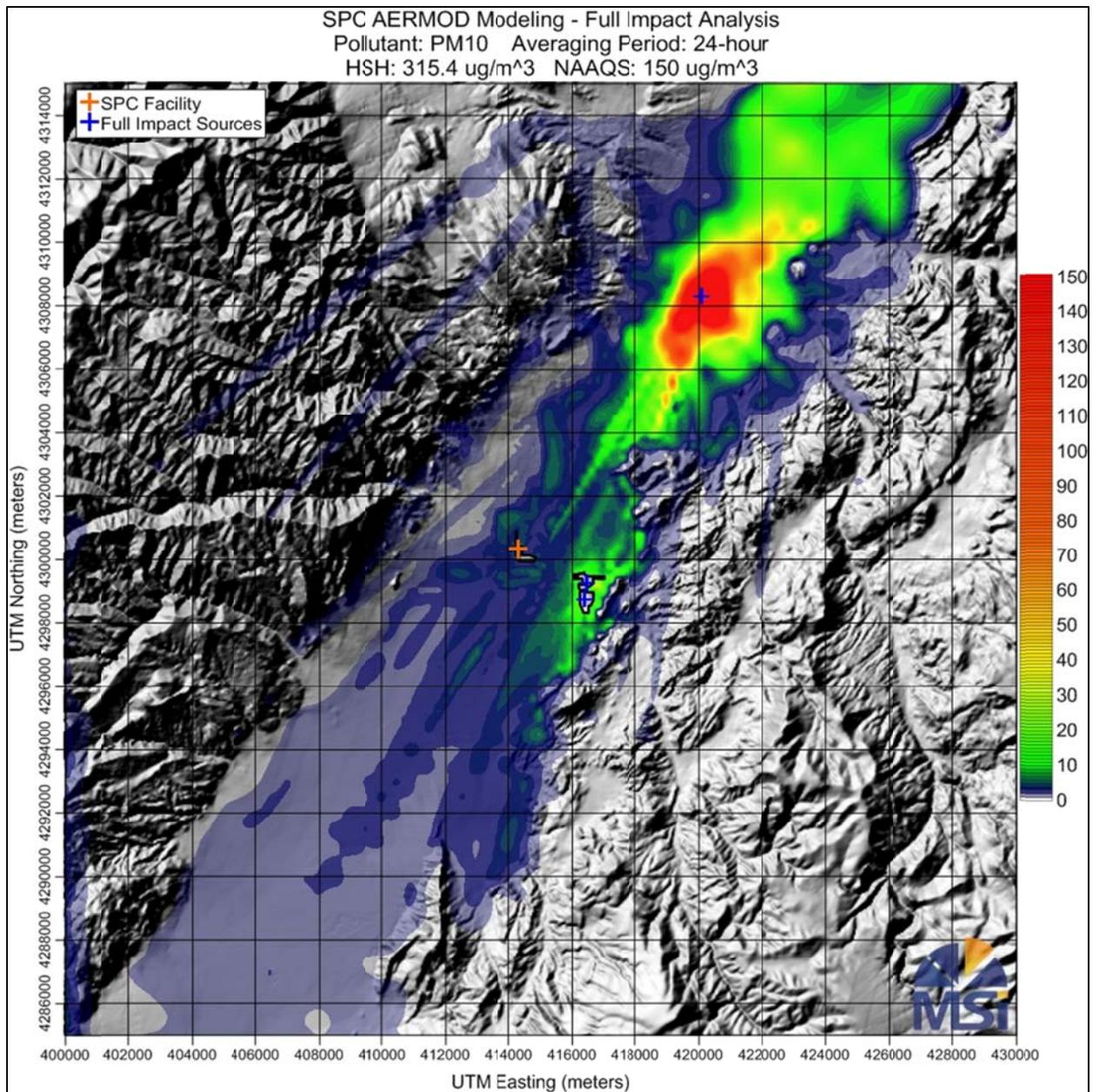


Figure 6.14 Modeled HSH 24-Hour PM₁₀ Concentration Isopleth Plot – Full Impact Analysis – Entire Modeling Domain

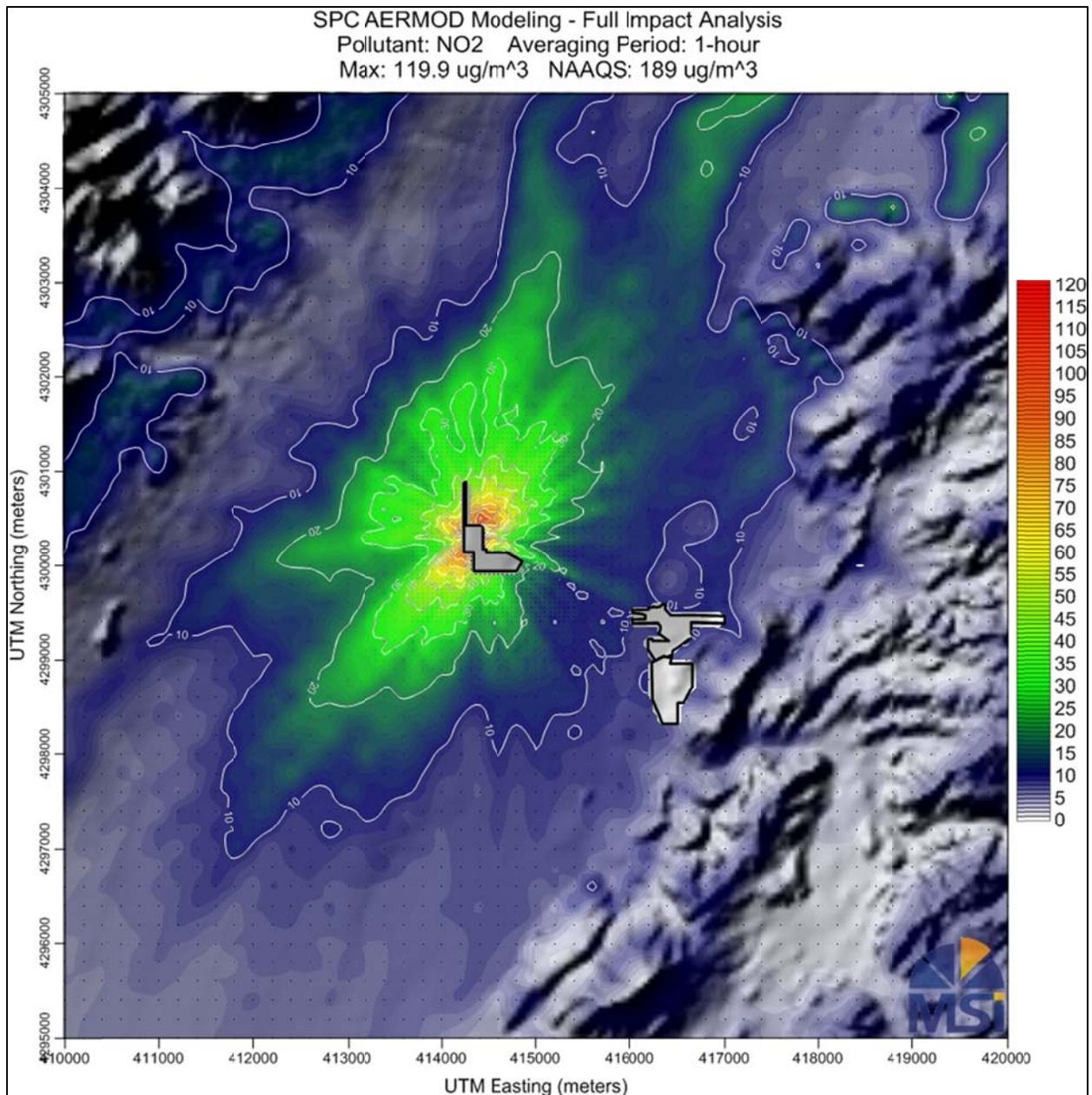


Figure 6.15 Modeled 98th Percentile One-Hour NO₂ Concentration Isopleth Plot – Full Impact Analysis – Around SPC Facility

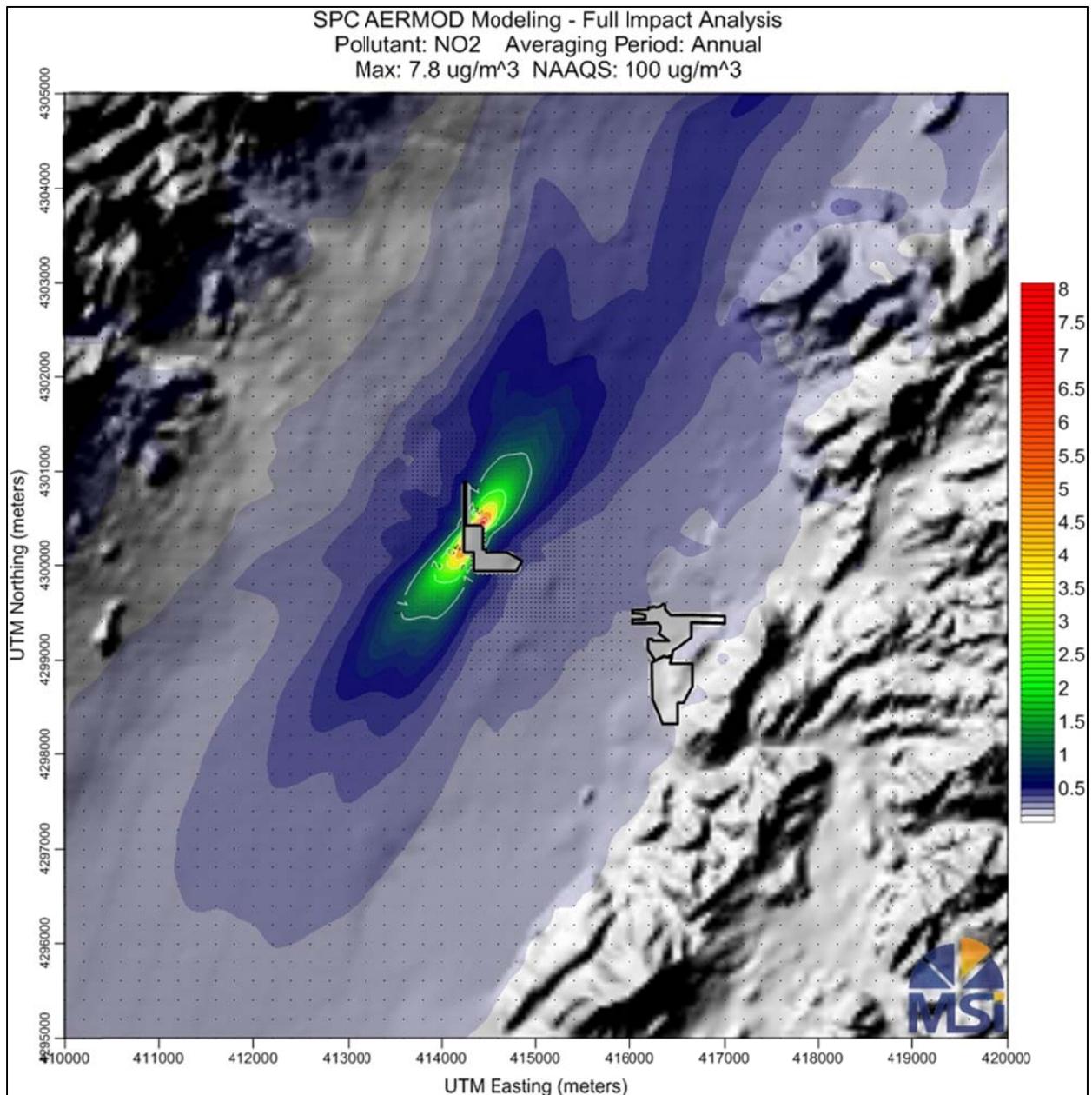


Figure 6.16 Modeled Maximum Annual NO₂ Concentration Isopleth Plot – Full Impact Analysis – Around SPC Facility

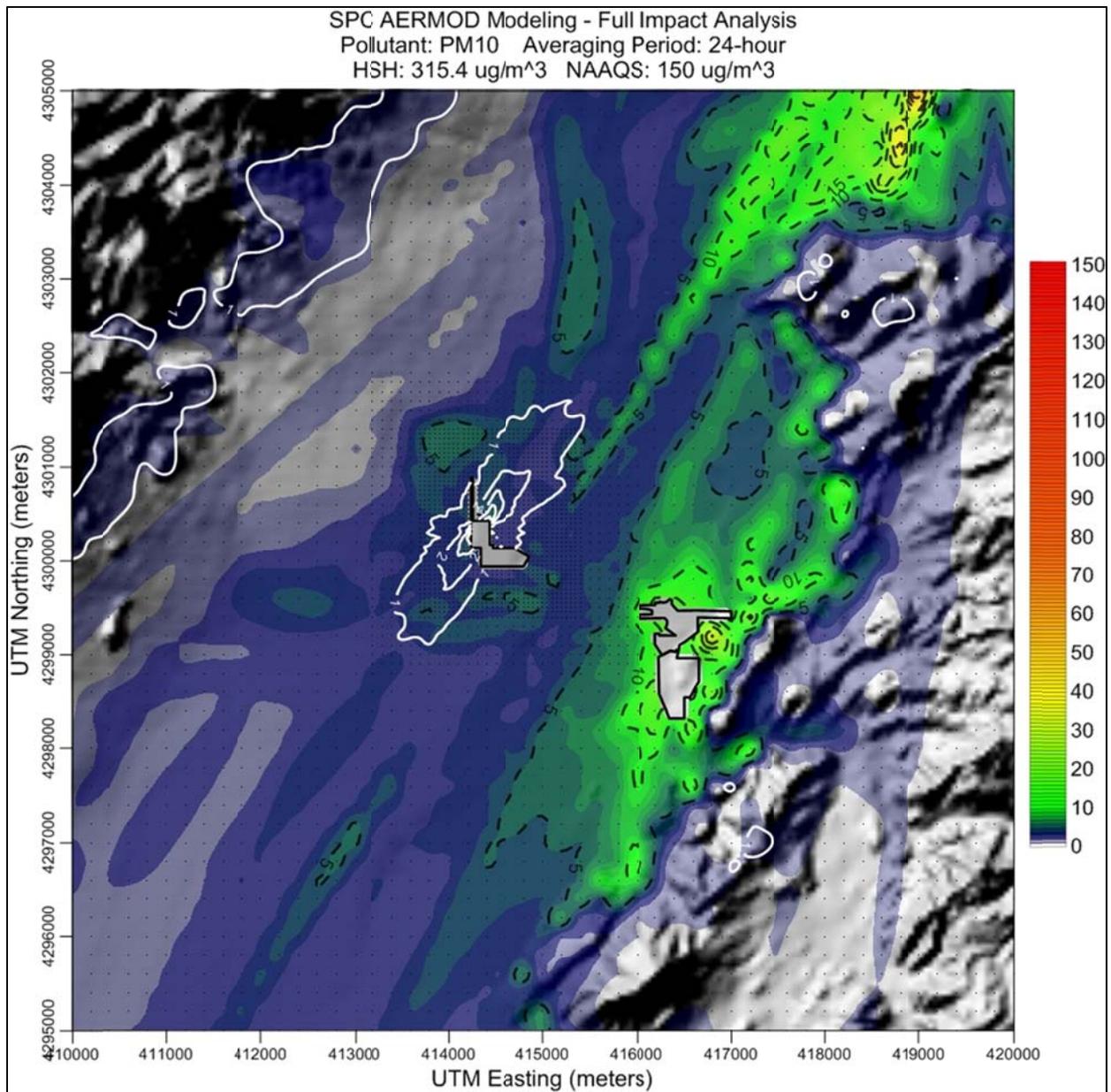


Figure 6.17 Modeled HSH 24-hour PM₁₀ Concentration Isoleth Plot – Full Impact Analysis – Around SPC Facility

6.16 PSD Class II Increment Compliance

The entire NAAQS inventory was conservatively used for both the NAAQS analysis and the PSD increment analysis; thus, all NO₂ and PM₁₀ sources were assumed to consume PSD increment. Since the results of the full impact analyses for 24-hour PM₁₀ showed an exceedance of the NAAQS, the 24-hour PM₁₀ increment would be exceeded also. Thus, the modeled maximum pollutant concentrations from SPC sources only and full impact sources for NO₂ were evaluated against the PSD Class II increments. The modeled pollutant concentrations, the PSD Class II increment, and percent of Class II increment consumed by SPC sources only for PM₁₀ and PM_{2.5} and full impact NO₂ sources (including SPC NO₂ sources) are presented in Table 6-17.

Table 6-17

PSD Class II Increment Compliance for SPC and Full Impact Analysis Sources

Pollutant	Averaging Period	Modeled Impact (µg/m³)	PSD Class II Increment (µg/m³)	Percent of Class II Increment
NO ₂	Annual	7.8 ¹	25	31.2%
PM ₁₀	24-hour (high)	7.1 ²	30	23.6%
	24-hour (HSH)	6.8 ²	30	22.7%
PM _{2.5}	24-hour	6.9 ²	9	76.6%
	Annual	1.8 ²	4	45.0%

¹SPC and full impact analysis sources

²SPC sources only

HSH – High-Second-High

6.17 Hazardous Air Pollutant Air Quality Analyses

Hazardous air pollutant analyses were performed in accordance with Utah Administrative Code R307-410-5. To determine which HAPs required modeling, the UDAQ's 2009 ACGIH Threshold Limit Values (TLVs), Toxic Screening Levels (TSLs) and Emission Threshold Values (ETVs) Microsoft Excel spreadsheet was utilized. The spreadsheet TLVs were updated with data from the ACGIH's 2011 TLV and BEI's Threshold Limit Values for Chemical Substances and Physical Agents & Biological Exposure Indices Handbook.

Based on the spreadsheet results (presented in Appendix K), the emission rates of acrolein, cadmium, and formaldehyde were above the ETV levels. Thus, dispersion modeling for these HAPs was conducted and the HAP model output is presented in Appendix K. All three HAPs were modeled as a vertically unrestricted release with a distance of greater than 20 meters to the property line. Acrolein and formaldehyde were considered to be acute while cadmium was considered carcinogenic. Modeled concentrations were determined based on a 24-hour averaging period. The results of the HAPS modeling are presented in Table 6-18.

Table 6-18
Modeled Maximum HAP Concentrations

HAP	Averaging Period	Model-Predicted Conc. ($\mu\text{g}/\text{m}^3$)	TWA ($\mu\text{g}/\text{m}^3$)	Location of Modeled Predicted Concentration	
				UTM East (m)	UTM North (m)
Acrolein	24-hour	0.01092	229	414400.0	4300450.0
Cadmium	24-hour	0.00073	2	414404.0	4300428.2
Formaldehyde	24-hour	0.17091	368	414228.7	4300312.4

Per R307-410-5, the toxic screenings level for all acute hazardous air pollutants is 1/10 the value of the TLV-TWA; similarly the toxic screenings level for all carcinogenic hazardous air pollutants is 1/90 the value of the TLV-TWA. Based on the ACGIH's 2011 Handbook, the TWA's for acrolein, formaldehyde, and cadmium are $0.229 \text{ mg}/\text{m}^3$, $0.368 \text{ mg}/\text{m}^3$, and $0.002 \text{ mg}/\text{m}^3$ respectively. 1/10 of the TWA for acrolein and formaldehyde are $22.9 \mu\text{g}/\text{m}^3$ and $36.8 \mu\text{g}/\text{m}^3$, respectively. 1/90 of the TWA for cadmium is $0.02 \mu\text{g}/\text{m}^3$.

Thus, the modeled maximum concentrations for acrolein, formaldehyde, and cadmium presented in Table 6-17 are well below the respective 1/10 and 1/90 of the TWA and no adverse health effects are expected from these HAPs.

6.18 Preconstruction Monitoring

The results of the SIL modeling were reviewed to determine if the ambient impacts from the proposed facility were below significant monitoring concentrations. Based on the results of the AERMOD dispersion modeling for SPC sources only, the project's maximum model predicted 24-hour $PM_{2.5}$ concentrations were slightly above the significant monitoring concentration threshold (See Table 4-3). However, based on current plant design, the equipment contributing most to the total 24-hour $PM_{2.5}$ concentration is the convection heaters. The project design engineers are considering replacing the convection heaters with zero emission discharge shell and heat exchange units. Thus, when a CT vendor has been chosen and the final design engineering has been completed, SPC will reevaluate the need and may conduct $PM_{2.5}$ monitoring, if necessary.

7.0 PSD CLASS I AREA IMPACT ANALYSES

Special protection from adverse air quality impacts is afforded to the national parks and certain wilderness areas through the PSD program. Class I areas are areas of special national, scenic, recreational, or historical value. An assessment of potential impacts on visibility and other air quality related values (AQRV's) in Class I and Wilderness Areas is a requirement of the Federal Land Managers (FLMs) for PSD projects. AQRV's include impairment on visibility, injury and reduced growth on vegetation, and acidification and fertilization of soils and surface waters. This section describes results of the Class I area air quality dispersion modeling impact analyses.

7.1 Regional Description

There are six (6) PSD Class I areas that are approximately 300 kilometers or less from the proposed SPC facility. These Class I areas include Arches, Bryce Canyon, Canyonlands, Capitol Reef, Grand Canyon, and Zion National Parks. Grand Canyon National Park, the furthest Class I area examined, is located approximately 220 kilometers (135 miles) south of the proposed facility. Federal Land Managers' Air Quality Related Values Work Group (FLAG) *Phase I Report-Revised (2010)* provides guidance on how to evaluate air pollution on AQRV's, health, and FLM managed resources. The FLAG 2010 guidance was utilized to determine which air quality analyses would be required to be performed by SPC to address Class I area air quality impacts.

7.2 Annual Emissions/Distance (Q/D) Screening Analyses

In the FLAG 2010 Phase 1 report, FLMs developed a consistent and objective approach to evaluate air pollution effects on public AQRVs in Class I areas, including a process to identify those resources and any potential adverse impacts. FLAG also provides State permitting authorities and potential permit applicants consistency on how to assess the impacts of new and existing sources on AQRVs in Class I areas.

FLAG 2010 presents a screening method that would exempt a proposed major source from performing visibility, ozone, and deposition analyses at Class I areas if the screening criteria are met. This AQRV screening criteria is based on EPA's Best Available Retrofit Technology (BART) guidelines. According to FLAG 2010, for sources that are located more than 50 kilometers away from a Class I area, if the ratio of total SO₂, NO_x, PM₁₀, and H₂SO₄ annual emissions (in tons per year) over the distance (in kilometers) from the proposed source to nearest Class I area (Q/D) is less than 10, then it is presumed that there will be no adverse effects on AQRV's at the Class I area being reviewed.

MSI consulted the NPS and in a May 6, 2011 email John Notar of the NPS indicated that "the Agencies will consider a source locating greater than 50 km from a Class I area to have negligible impacts with respect to Class I AQRVs if its total SO₂, NO_x, PM₁₀, and H₂SO₄ annual emissions (in tons per year, based on 24-hour maximum allowable emissions), divided by the distance (in km) from the Class I area (Q/D) is 10 or less. The Agencies would not request any further Class I AQRV impact analyses from such sources".

Table 7-1 presents the estimated annual emissions for the proposed SPC plant in tons per year. The closest Class I area to the proposed SPC plant is Capitol Reef National Park at a distance of 61.6 kilometers (Table 4-1). The Q/D ratios, based on GE and Siemens estimated emissions, were calculated to be 4.36 and 4.16, respectively. Thus, AQRV analyses for visibility and deposition were not required to be performed.

Table 7-1
SPC Annual Emissions

Pollutant	GE Annual Emissions (tn/yr)	Siemens Annual Emissions (tn/yr)
SO ₂	23.41	24.24
NO _x	144.03	148.96
PM ₁₀	100.16	81.91
H ₂ SO ₄	0.99	1.03
Total	268.59	256.14

An analysis of the concentration impact on PSD Class I increments from proposed SPC emission sources was conducted and is discussed below.

7.3 Model Selection

For the far-field PSD Class I concentration impact analysis, the current USEPA version of the CALPUFF modeling system was used. CALPUFF has been formally approved by the U.S. Environmental Protection Agency for inclusion in 40 CFR Part 51 Appendix A, *Guideline on Air Quality Models* as a preferred ("*Guideline*") model for long-range transport.

CALPUFF is a multi-layer, multi-species non steady-state puff dispersion model that simulates the effects of time and space-varying meteorological conditions on pollution transport, transformation and removal. CALPUFF can be applied on scales of tens to hundreds of kilometers. It includes algorithms to calculate long range effects such as pollutant removal due to dry deposition or wet scavenging, chemical transformation, and visibility effects of particulate matter concentrations.

The CALPUFF modeling system has three main components which were utilized for the analyses. These components are CALMET (a diagnostic 3-D meteorological model), CALPUFF (the transport and dispersion model), and CALPOST (a post-processing package).

7.4 CALMET Input

Input requirements for the CALMET model include various meteorological and geophysical data sets. Required meteorological data includes surface, upper air, and mesoscale model output data. Geophysical input data include terrain elevation and land-use data. As required by EPA, three years (2001 through 2003) of meteorological observations and mesoscale model data (MM5) were used in CALMET. The CALMET meteorological grid extended at least 50 kilometers in all directions beyond the project site and beyond any portion of a potentially affected park to allow for the consideration of puff trajectory recirculation.

7.4.1 Mesoscale Model Data (MM5)

Pennsylvania State University in conjunction with the National Center for Atmospheric Research Assessment Laboratory has developed mesoscale meteorological (MM) data sets of prognostic wind fields. The hourly meteorological variables used to create these data sets are extensive. Mesoscale model data in the MM5 format for 2001 through 2003 were used for this project.

Within the modeling domain, a four kilometer computational grid spacing with ten vertical layers was developed. The following data were used by CALMET preprocessor at all three-dimensional points each hour to develop the meteorological fields for CALPUFF:

- Height in millibars and geopotential height in meters
- Temperature (°K)
- Wind direction
- Wind speed
- Vertical Velocity
- Relative Humidity
- Mixing Ratio

These data were read into the model in hourly format for the three-year modeling period.

Concurrent surface and upper air observations for the three-year period (2001 - 2003) were included in CALMET. For this project, NWS upper air and first-order stations within the modeling domain were identified and used in the far-field modeling. The upper air stations include:

- Salt Lake City, Utah
- Elko, Nevada
- Grand Junction, Colorado
- Desert Rock, Nevada

MSI also used surface data from the following sites:

- Salt Lake City, Utah
- Cedar City, Utah
- Grand Junction, Colorado
- Bryce Canyon, Utah
- Milford, Utah
- Canyonlands National Park
- Vernal, Utah
- Page, Arizona
- Cortez, Colorado
- Price, Utah
- Provo, Utah
- Wendover, Utah
- Capitol Reef National Park
- Dugway, Utah
- Blanding, Utah

Figure 7.1 presents a map showing the locations of the upper air surface stations used in the modeling. The surface station parameters included wind speed, wind direction, cloud ceiling height, opaque cloud cover, dry bulb temperature, relative humidity, station pressure, and precipitation. Figure 7.2 presents a quality assurance wind field plot for far-field modeling domain.

Data validity was accomplished by using TRC preprocessors SMERGE and READ62 as well as internal quality assurance software that MSI has written. Standard methods, based on EPA guidance, were applied for missing data substitutions.

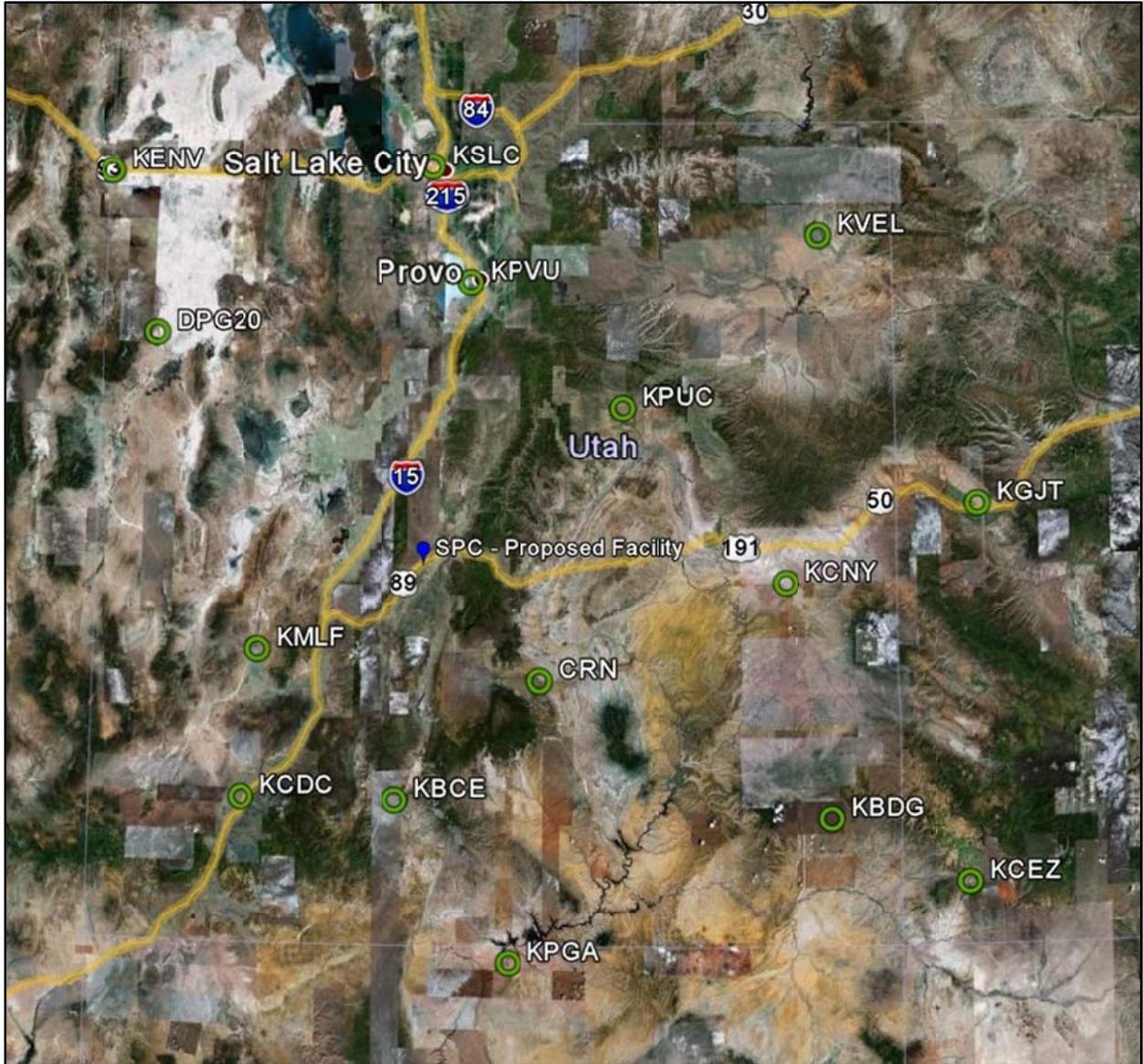


Figure 7.1 Meteorological Surface Stations within CALMET Domain

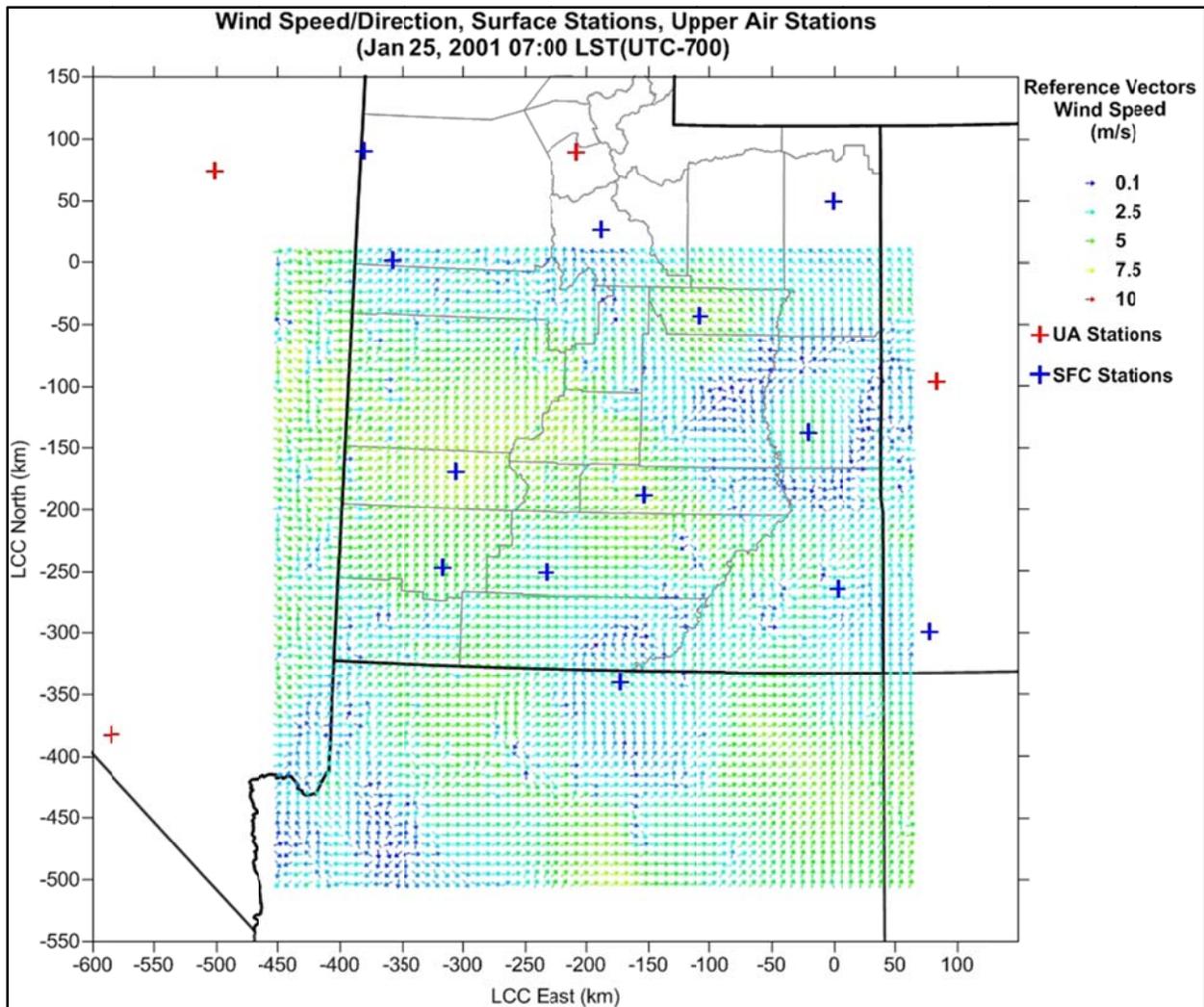


Figure 7.2 Quality Assurance Wind Field Plot for Far-Field Modeling Domain

7.4.2 Geophysical Data

Geophysical data that were input to CALMET included terrain elevations, land use land cover (LULC) categories and optional geophysical parameters including surface roughness, albedo, Bowen ratio, soil heat flux parameter, anthropogenic heat flux, and vegetation leaf area index.

7.4.3 Terrain Data

The terrain elevation data that were used for this study were obtained from the United States Geological Survey's (USGS) Digital Elevation Model (DEM) which is available on the USGS web site. These data are in World Geodetic System 1984 (WGS 84) format and consisted of one-degree quadrangles with a scale of 1:250,000 and a horizontal resolution of 90 meters. The CALMET processor Terrel.exe was used to create gridded elevation data. The grids extended over each study area and four kilometer grid spacing was used to adequately resolve the important terrain features. Figure 7.3 presents a graphic of the terrain data within the modeling domain.

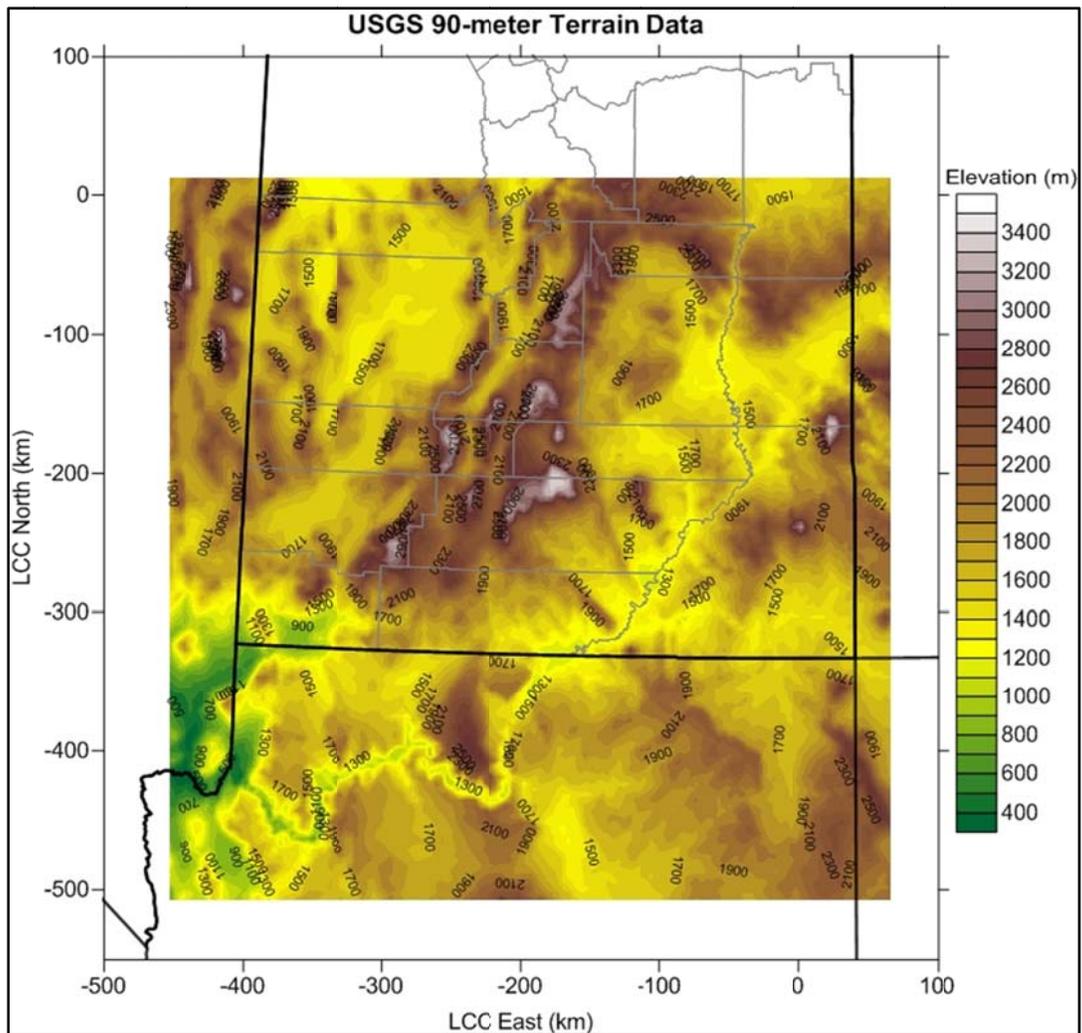


Figure 7.3 Terrain Data Within Modeling Domain

7.4.4 Land Use Data

The land use data used in this modeling analysis was also obtained from the USGS. These land use land cover (LULC) data consisted of 1:250,000 scale or 1:100,000 scale quadrangles with a horizontal resolution of 200 meters. The grid spacing used was four kilometers. The CALMET preprocessor, Makegeo.exe, was used to combine the terrain and the LULC data to generate the geophysical file needed by CALPUFF. Makegeo.exe maps the original 37 USGS land uses to the 14 CALMET-default land uses which were used by CALPUFF. CALMET-default land uses are presented in Table 7-2. The default values presented in Table 7-1 were used by CALPUFF. Figure 7.4 presents a graphic of the land use data within the modeling domain.

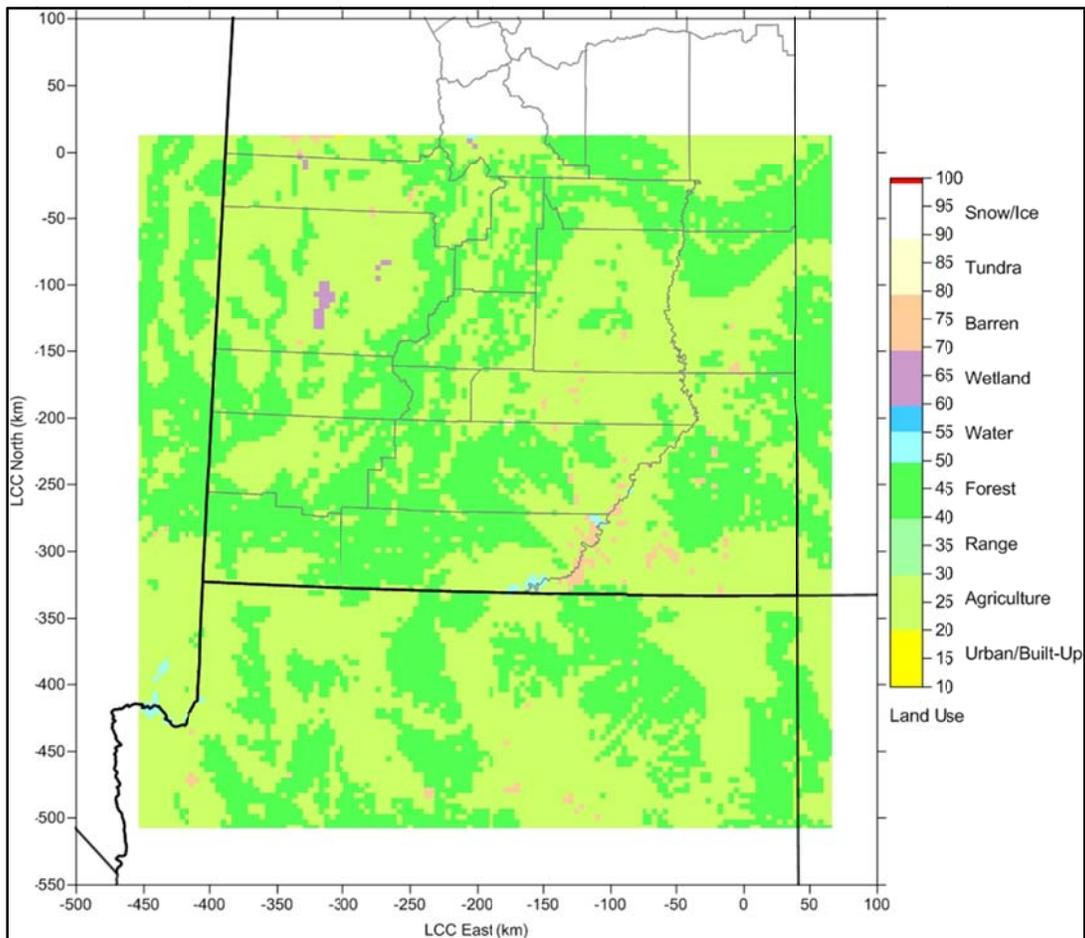


Figure 7.4 Land Use Data Within Modeling Domain

Table 7-2

Default CALMET Land Use Categories and Associated Geophysical Parameters Based on USGS Classification System

Land Use Type	Description	Surface Roughness (m)	Albedo	Bowen Ratio	Soil Heat Flux Parameter	Anthropogenic Heat Flux (W/m²)	Leaf Area Index
10	Urban	1.0	0.18	1.5	0.25	0.0	0.2
20	Agricultural Land - Unirrigated	0.25	0.15	1.0	0.15	0.0	3.0
-20	Agricultural Land - Irrigated	0.25	0.15	0.5	0.15	0.0	3.0
30	Rangeland	0.05	0.25	1.0	0.15	0.0	0.5
40	Forest Land	1.0	0.10	1.0	0.15	0.0	7.0
51	Small Water Body	0.001	0.10	0.0	1.0	0.0	0.0
54	Bays and Estuaries	0.001	0.10	0.0	1.0	0.0	0.0
55	Large Water Body	0.001	0.10	0.0	1.0	0.0	0.0
60	Wetland	1.0	0.10	0.5	0.25	0.0	2.0
61	Forested Wetland	1.0	0.1	0.5	0.25	0.0	2.0
62	Non-forested Wetland	0.2	0.1	0.1	0.25	0.0	1.0
70	Barren Land	0.05	0.30	1.0	0.15	0.0	0.05
80	Tundra	0.20	0.30	0.5	0.15	0.0	0.0
90	Perenneiel Snow or Ice	0.20	0.70	0.5	0.15	0.0	0.0

7.4.5 CALMET Control File Settings

The CALMET control file settings were chosen in accordance with the August 31, 2009 EPA clarification memo “Clarification on EPA-FLM Recommended Settings for CALMET. Control file settings that were used in CALMET are presented in Appendix L.

7.5 CALPUFF Input

Along with the CALMET meteorological data, CALPUFF requires the user to provide emissions and source data, receptor locations, input control file settings, and a background ammonia value before the model can be executed. These inputs are discussed below.

7.5.1 Emissions and Source Parameter Data

Emissions and source parameter data from SPC's proposed HRSG stacks data were incorporated into the CALPUFF model (See Tables 6-4 through 6-6). For the Class I modeling, maximum projected hourly emissions for NO₂ and PM₁₀ were modeled for the short-term and annual averaging periods.

7.5.2 Receptor Grids

MSI used the NPS receptor placement location files as provided on NPS website at <http://www.nature.nps.gov/air/Maps/Receptors/index.cfm>. In addition, the NPS conversion program was utilized to convert receptor locations in longitude and latitude into Lambert Conformal coordinates. Table 7-3 presents the range of receptor numbers for the national parks that were modeled for proposed Oldcastle project.

Table 7-3
Class I Area Receptors

Class I Area	Receptor Number Range
Arches National Park	1 - 115
Bryce Canyon National Park	116 - 328
Canyonlands National Park	329 - 834
Capitol Reef National Park	835 - 1197
Grand Canyon National Park	1198 - 1988
Zion National Park	1989 - 2212

7.5.3 Chemical Species

The CALPUFF chemistry algorithms require hourly estimates of background ozone (O_3) and ammonia (NH_3) for the conversion of SO_2 and NO/NO_2 to sulfates (SO_4) and nitrates (NO_3), respectively.

7.5.3.1 Ozone and Ammonia Data

Background hourly ozone values from EPA's Clean Air Status and Trends Network (CASTNET) database for 2001 through 2003 from Canyonlands and Mesa Verde were used in the modeling. Background ammonia concentrations of 10 ppb NH_4 were used in CALPUFF for the far-field modeling. Default background ozone and ammonia values were used where no representative data were available.

7.5.4 Study Area

The study area for the PSD Class I analyses is a square shaped, 525 km by 525 km region. The domain includes a 50 km buffer zone around the Class I areas to capture recirculation effects. Puffs are tracked within this grid until they cross outside the boundary. At this point, they are dropped from the simulation. Because the domain is relatively large, the Lambert Conformal map projection was used to better accommodate the earth's curvature. Figure 7.5 presents the CALPUFF modeling domain and the locations of the national parks within the domain.

CALPUFF was run using the IWAQM-recommended control file switch settings for all parameters. Chemical transformation was based on the MESOPUFF-II chemistry mechanism for conversion of SO_2 to SO_4 and NO_x to nitric acid (HNO_3) and NO_3 . These pollutant species are included in the CALPUFF model runs. The CALPUFF control parameters and technical options which were used in the far-field analyses are presented in Appendix M.

7.6 CALPOST Processing

The CALPOST processor was used to process CALPUFF output files to obtain modeled ground-level concentrations. The CALPOST post-processor was used to summarize concentration impacts of NO₂ and PM₁₀ at the Class I areas modeled. Predicted concentrations were compared to PSD Class I increments and PSD Class I significance levels at each Class I area.

7.7 PSD Class I Concentration Modeling Results

A significant impact analysis was conducted to determine if emissions from the proposed SPC project could cause a significant impact at any of the five national parks reviewed. Per 61 Federal Register 38250 dated July 23, 1996, a significant impact is defined as an impact that exceeds four percent of the PSD Class I increments. The proposed Class I SILs and PSD Class I increments are presented in Table 7-4.

Table 7-4
PSD Class I SILs and Increments

Pollutant	Averaging Period	PSD Class I Significant Impact Level (µg/m³)	PSD Class I Increment (µg/m³)
NO ₂	Annual	0.1	2.5
PM ₁₀	24-hour	0.3	8.0
PM _{2.5}	24-hour	0.07	2.0
	Annual	0.06	1.0

The results of the significant impact analysis are provided in Table 7-5. Since the maximum predicted impact for all modeled pollutants and averaging periods was found to be below each applicable SIL at each national park modeled, it is assumed that impacts from proposed SPC sources will not cause or contribute to any Class I area increment exceedances.

Thus, a cumulative increment impact analysis was not required. Figures 7.5 through 7.28 present the modeled maximum concentration isopleths plots, for the three years modeled for NO₂ and PM₁₀ at the Class I areas that showed the highest modeled concentration. Appendix N presents the far-field modeling concentration results for 2001 through 2003.

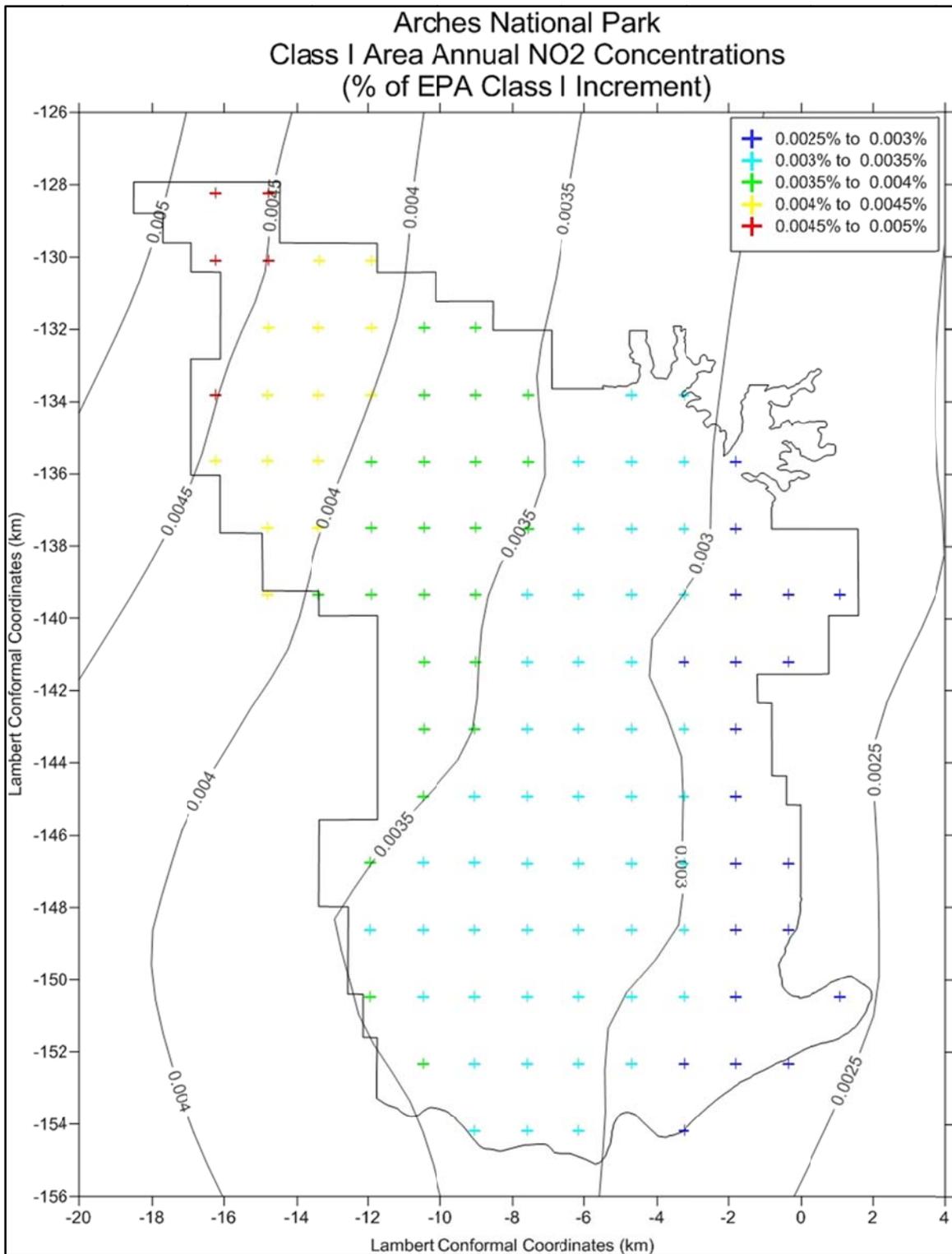
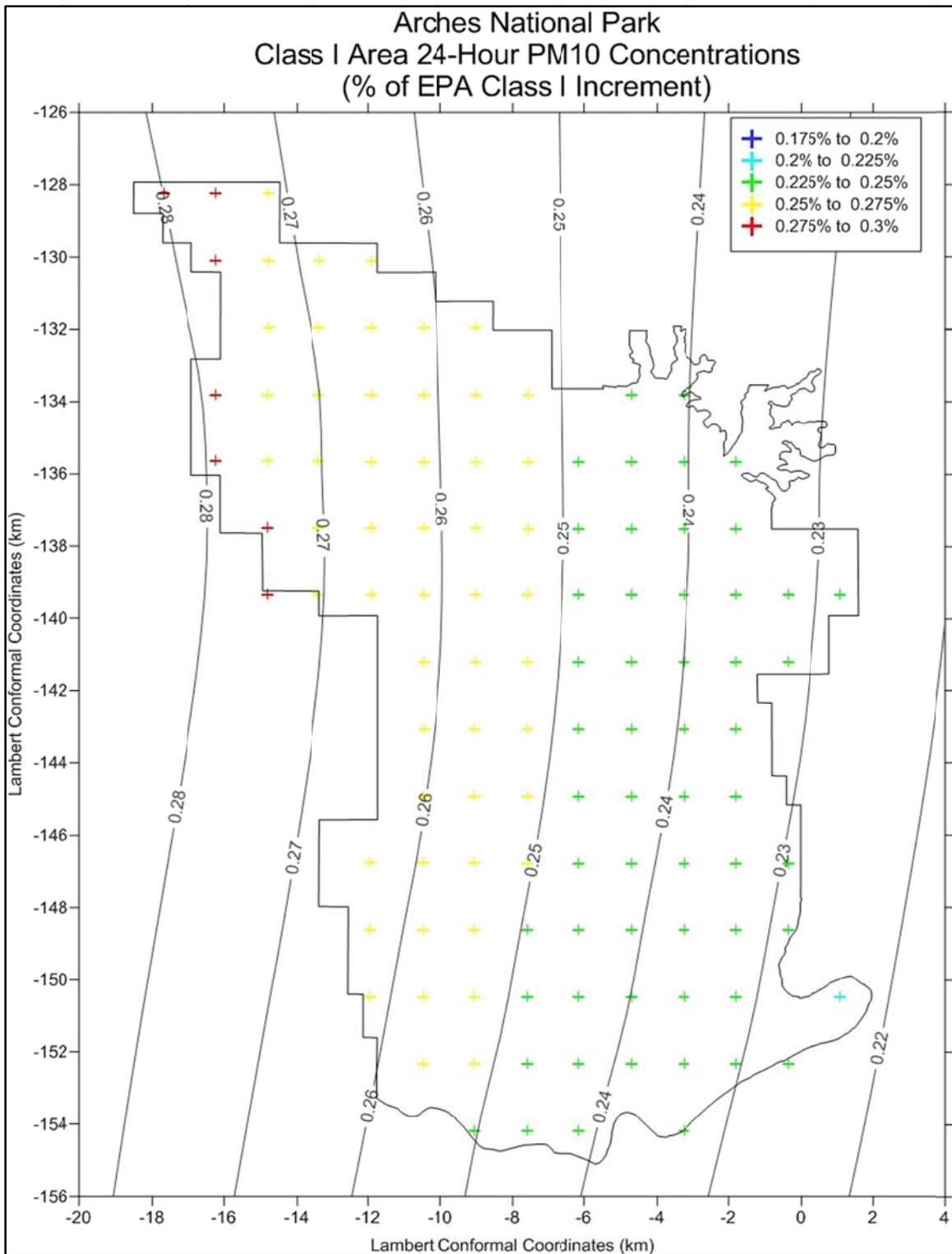


Figure 7.5 Modeled Highest Annual NO₂ Concentration as Percent of PSD Class I Increment at Arches National Park



**Figure 7.6 Modeled Highest 24-Hour PM₁₀ Concentration as Percent of
PSD Class I Increment at Arches National Park**

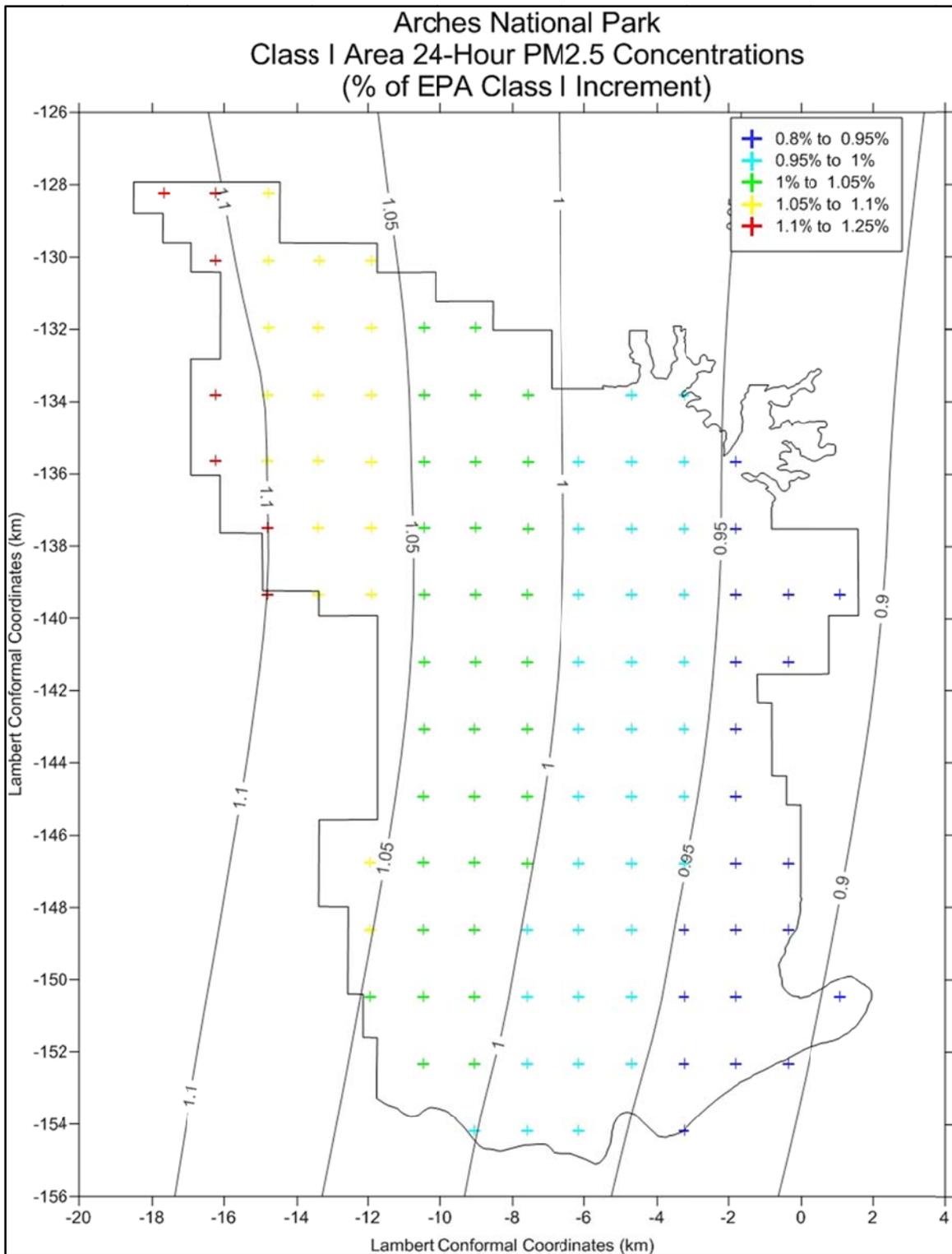


Figure 7.7 Modeled Highest 24-Hour PM_{2.5} Concentration as Percent of PSD Class I Increment at Arches National Park

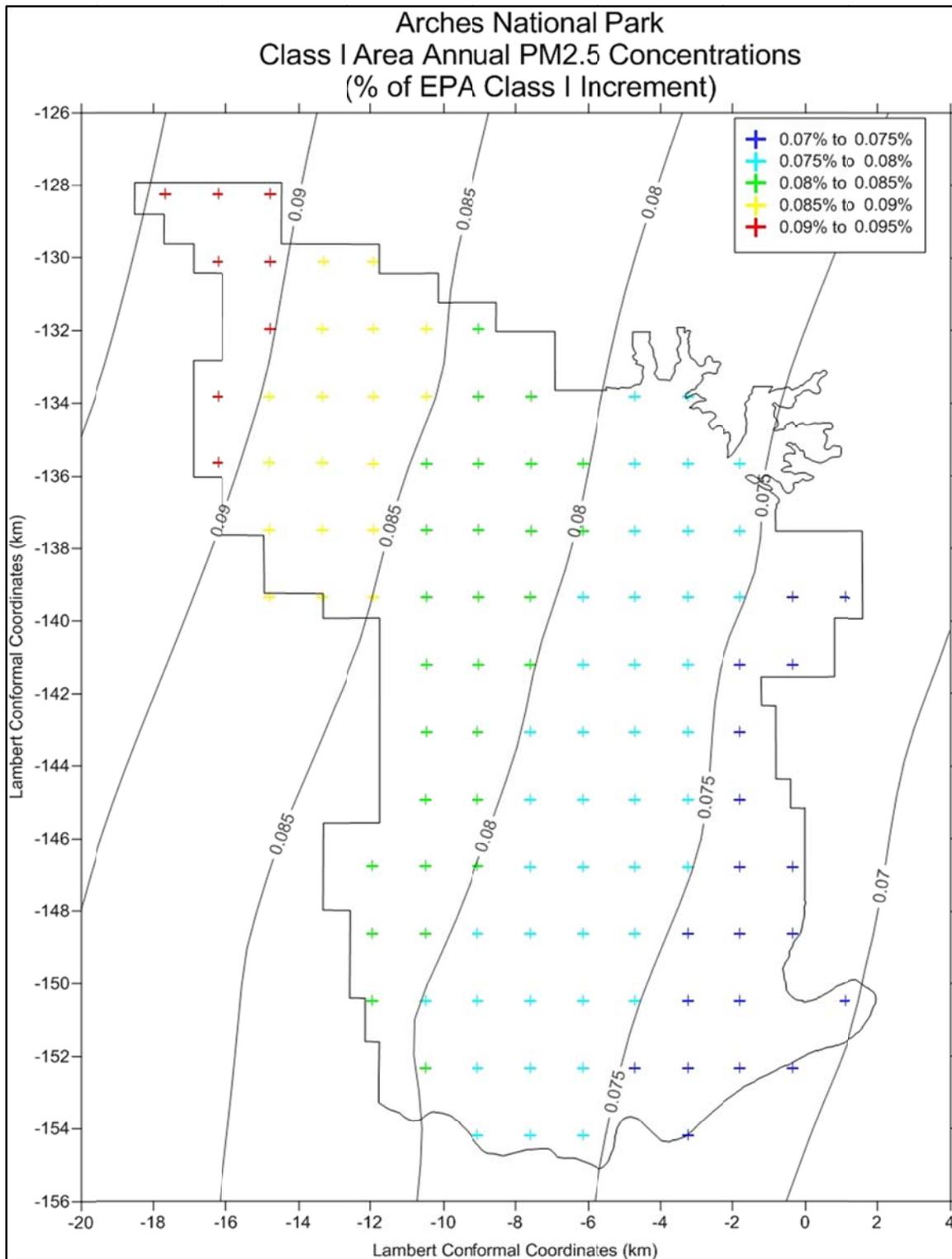


Figure 7.8 Modeled Highest Annual PM_{2.5} Concentration as Percent of PSD Class I Increment at Arches National Park

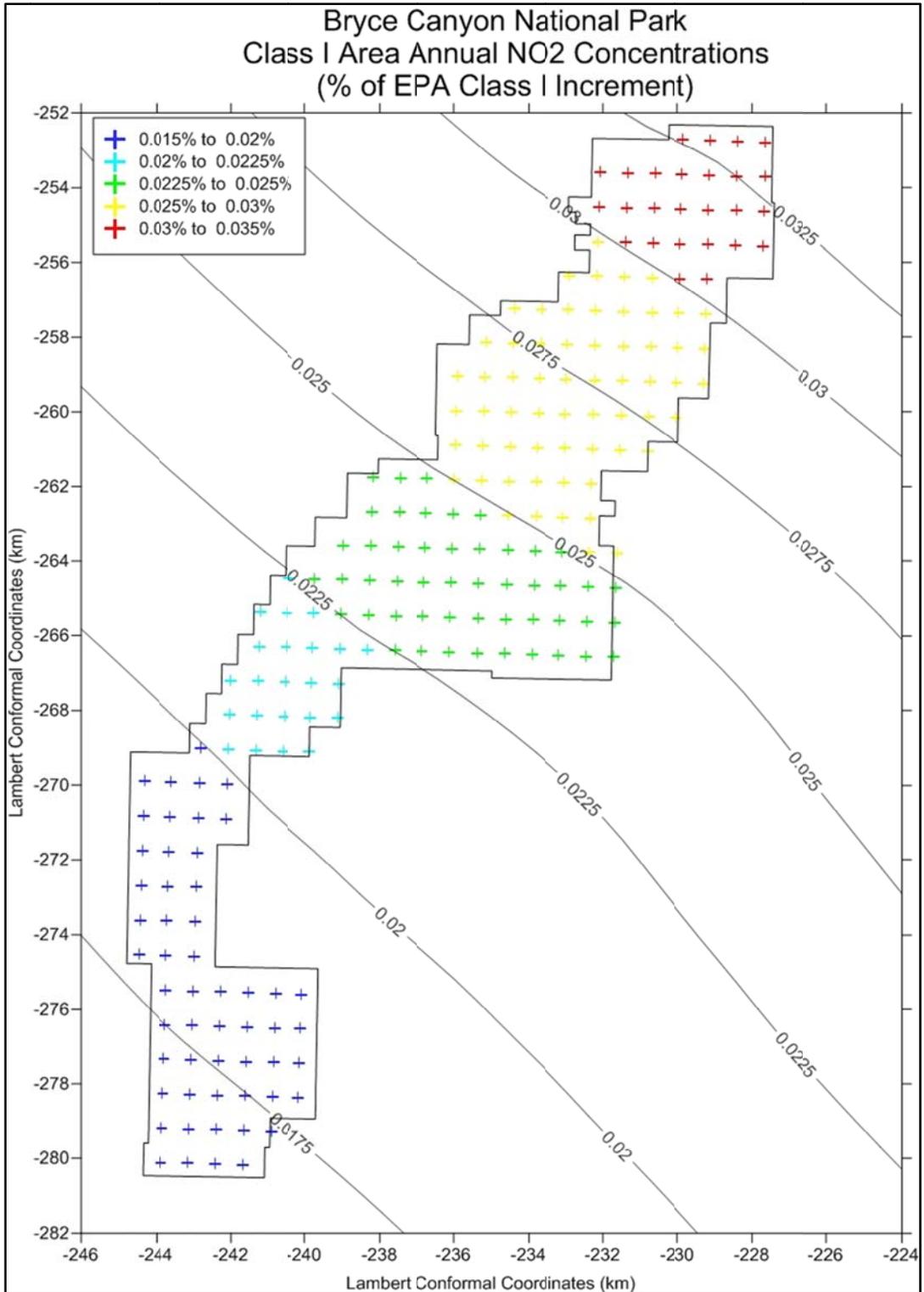


Figure 7.9 Modeled Highest Annual NO₂ Concentration as Percent of PSD Class I Increment at Bryce Canyon National Park

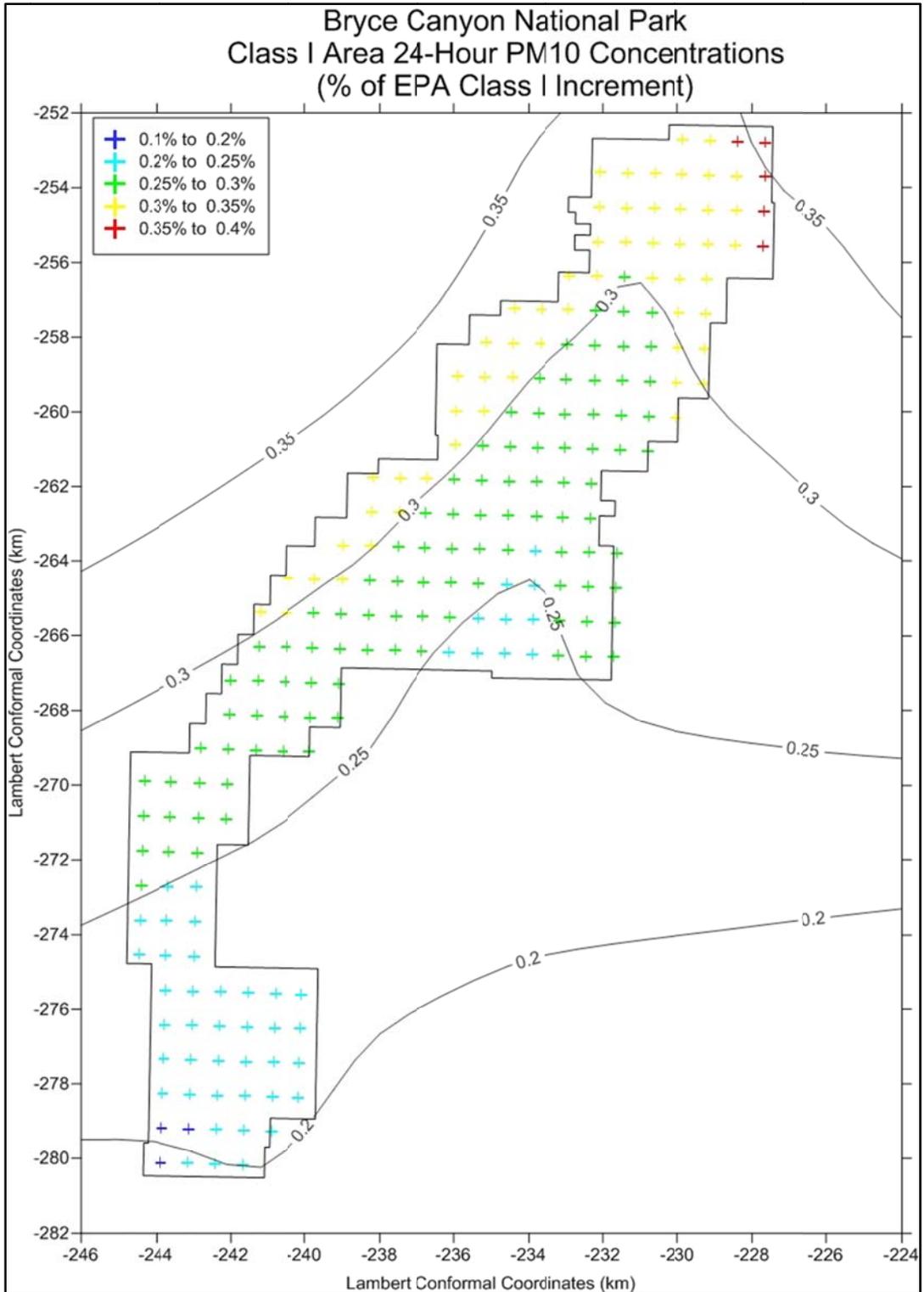


Figure 7.10 Modeled Highest 24-Hour PM₁₀ Concentration as Percent of PSD Class I Increment at Bryce Canyon National Park

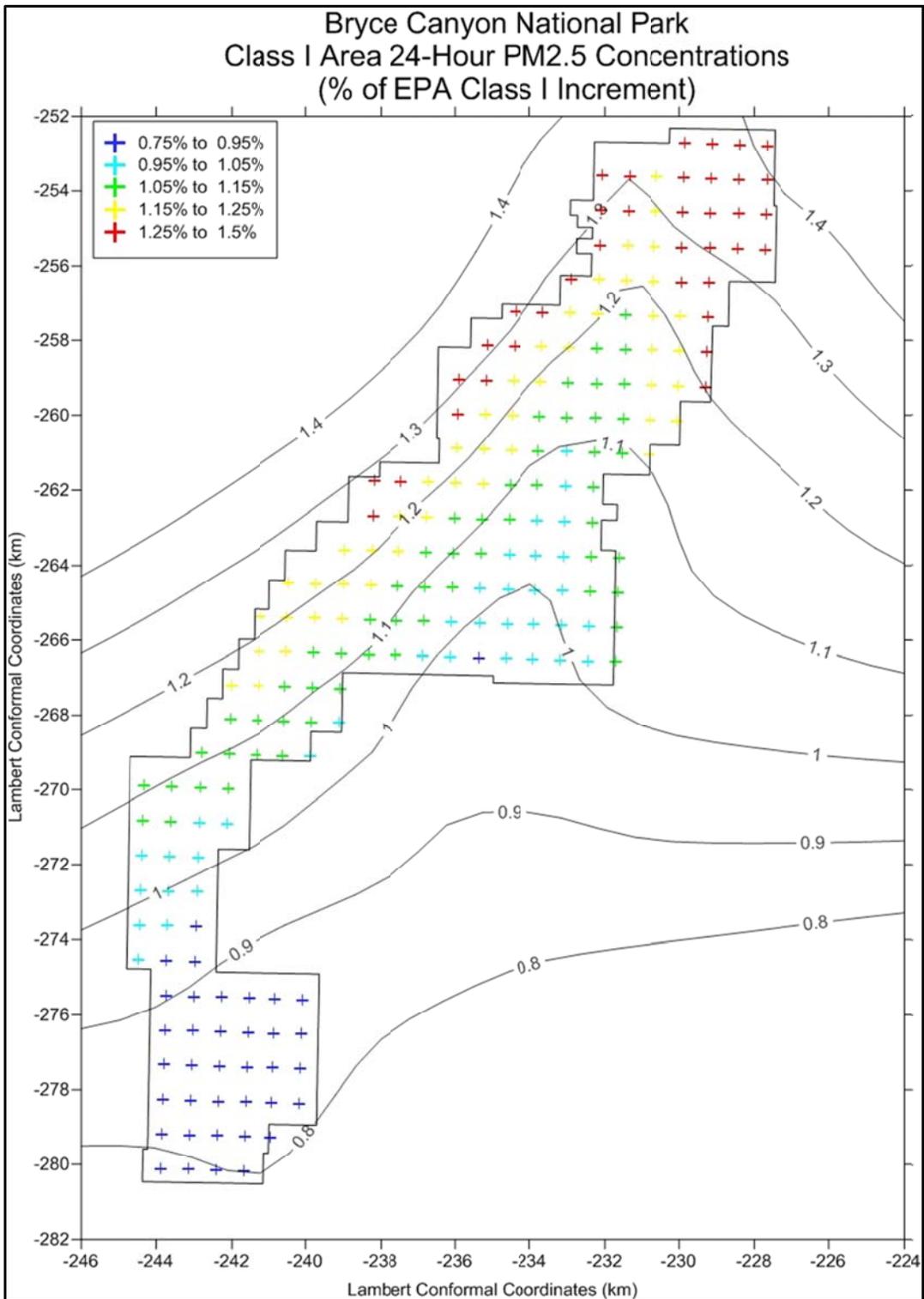


Figure 7.11 Modeled Highest 24-Hour PM_{2.5} Concentration as Percent of PSD Class I Increment at Bryce Canyon National Park

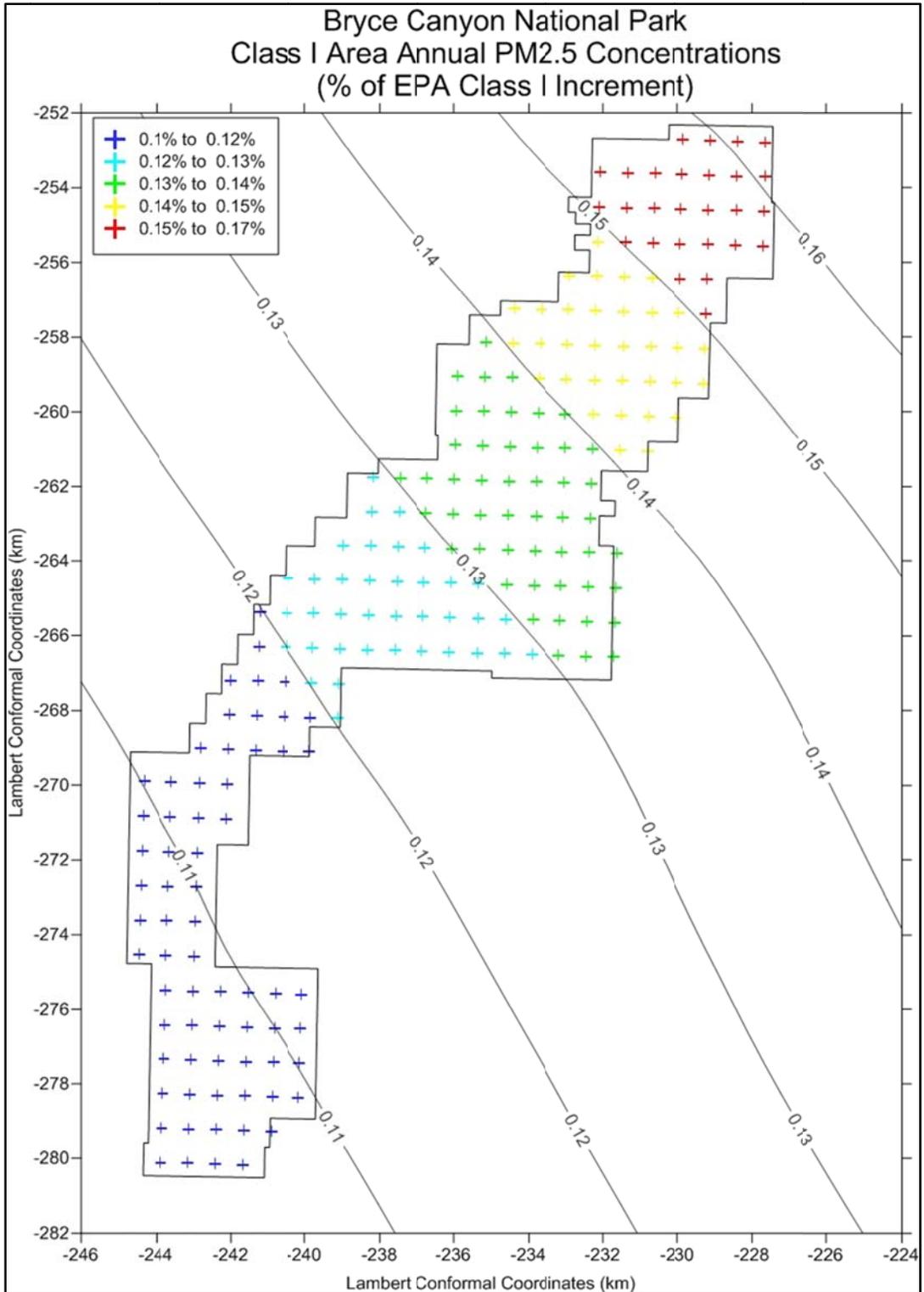


Figure 7.12 Modeled Highest Annual PM_{2.5} Concentration as Percent of PSD Class I Increment at Bryce Canyon National Park

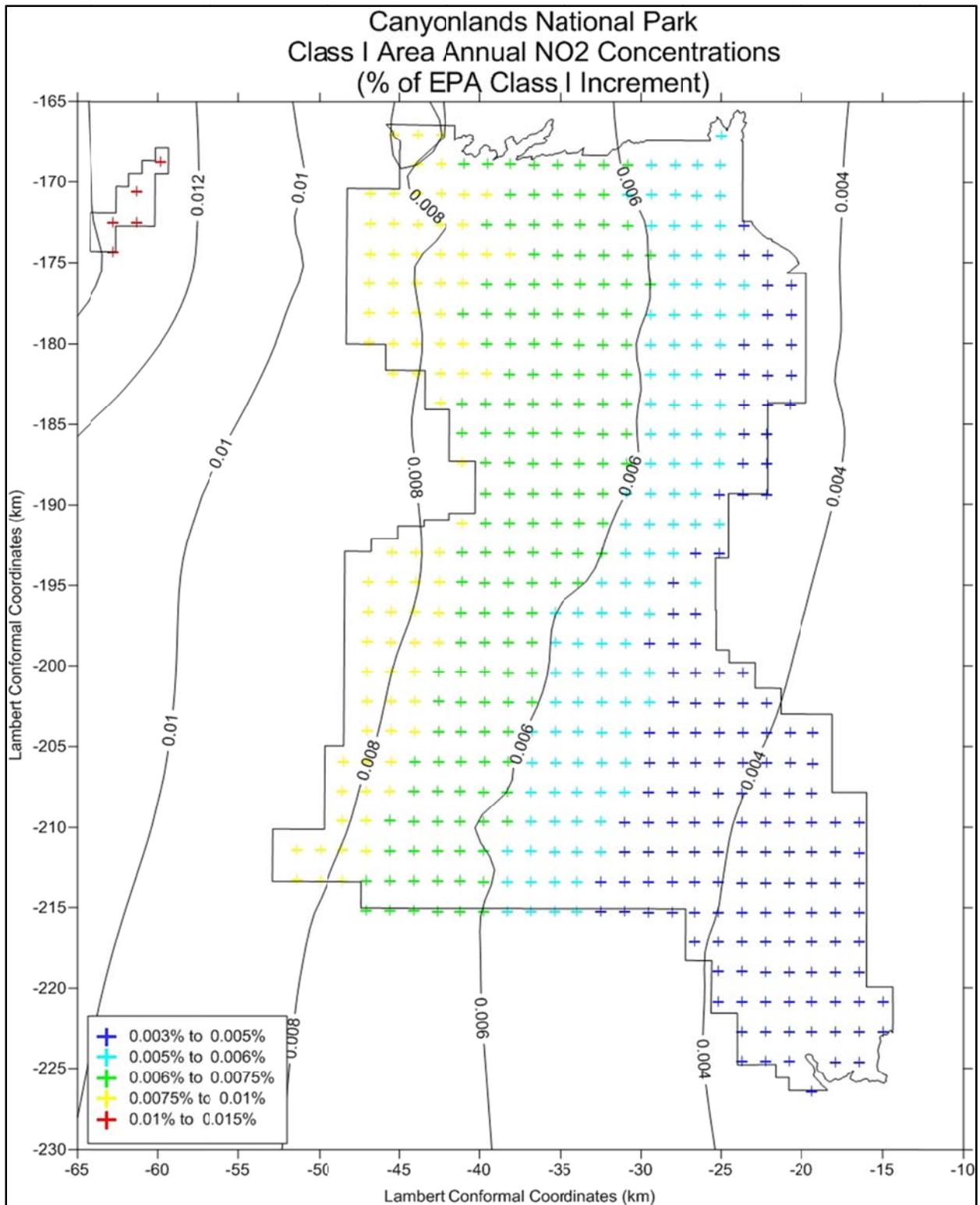


Figure 7.13 Modeled Highest Annual NO₂ Concentration as Percent of PSD Class I Increment at Canyonlands National Park

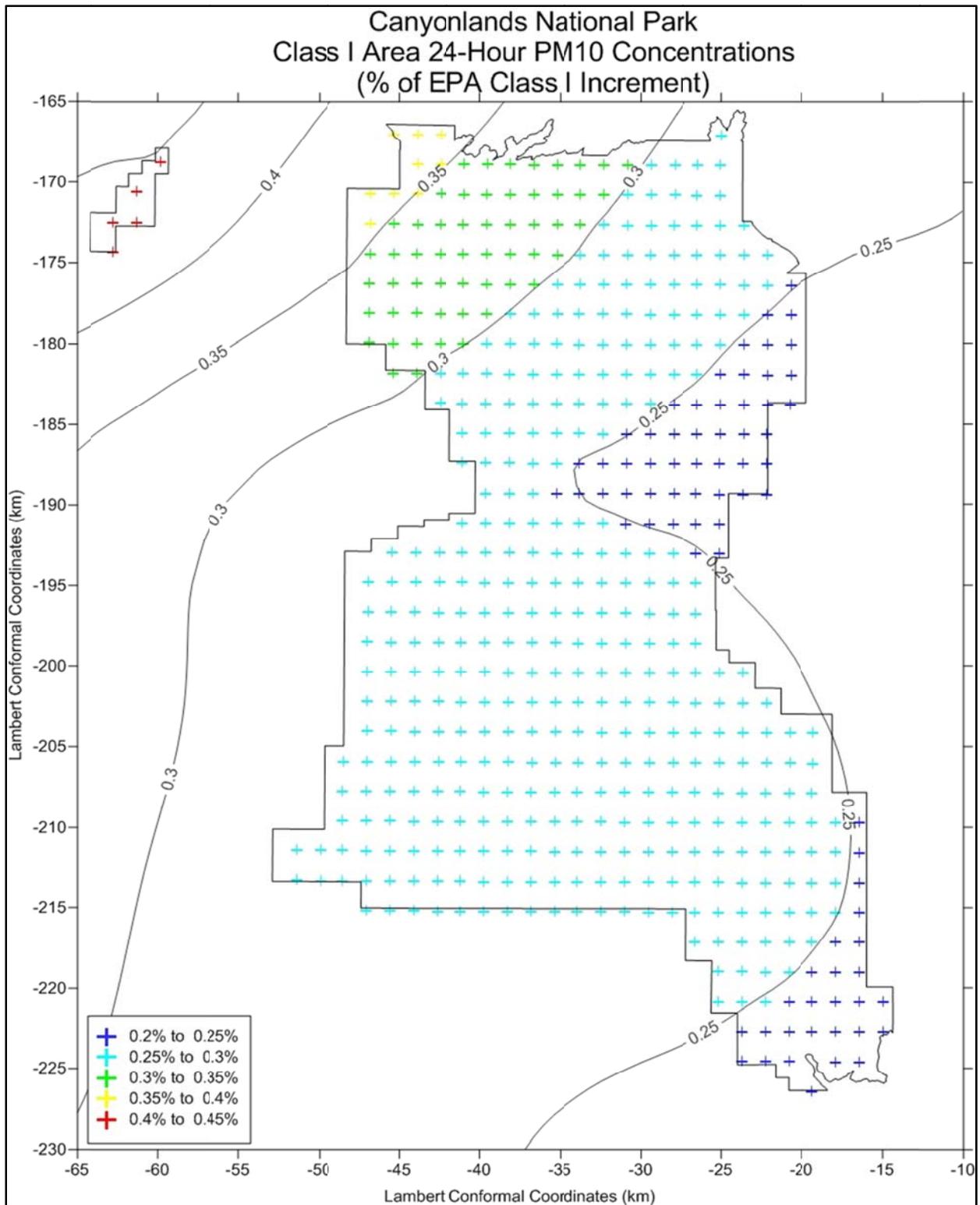


Figure 7.14 Modeled Highest 24-Hour PM₁₀ Concentration as Percent of PSD Class I Increment at Canyonlands National Park

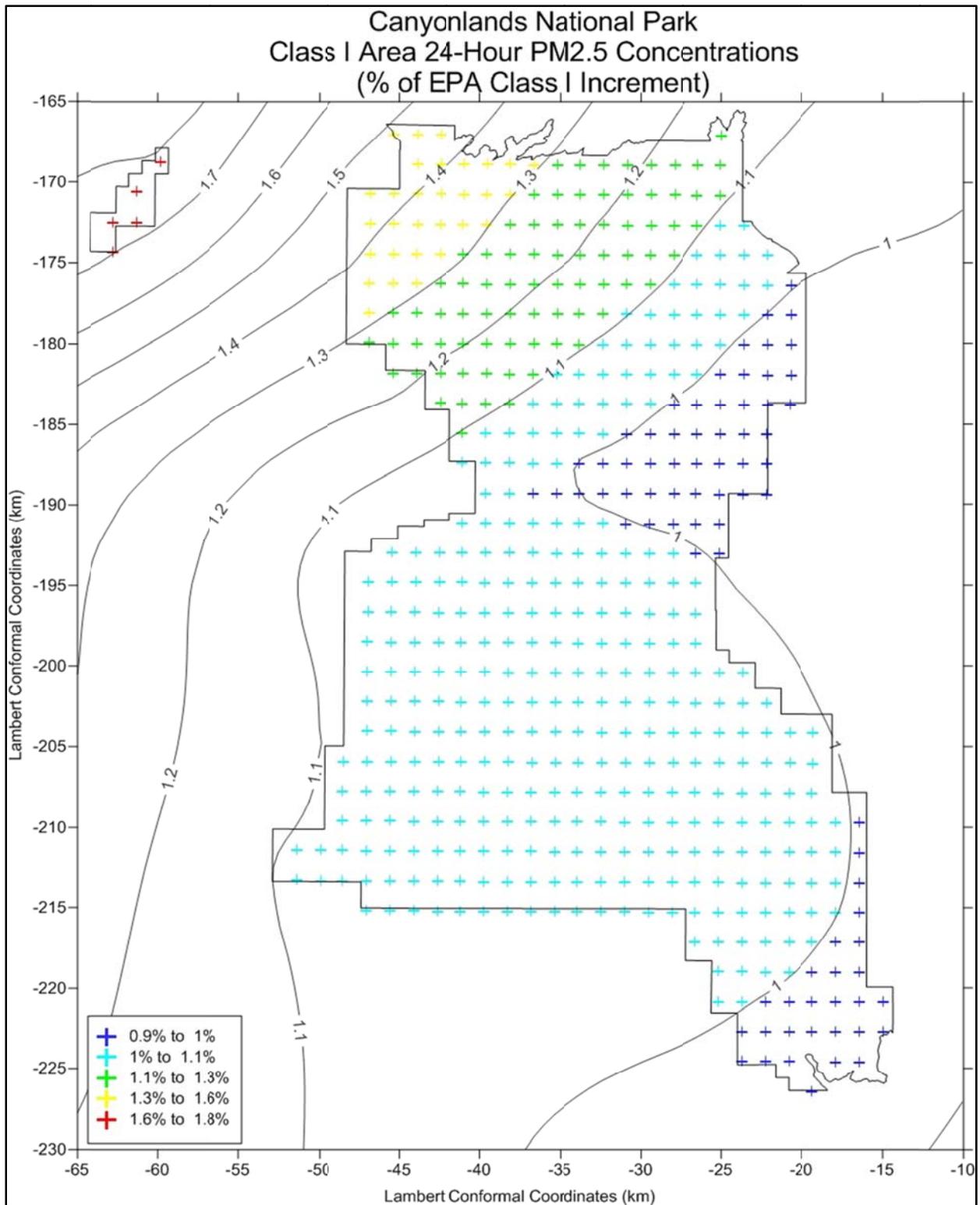


Figure 7.15 Modeled Highest 24-Hour PM_{2.5} Concentration as Percent of PSD Class I Increment at Canyonlands National Park

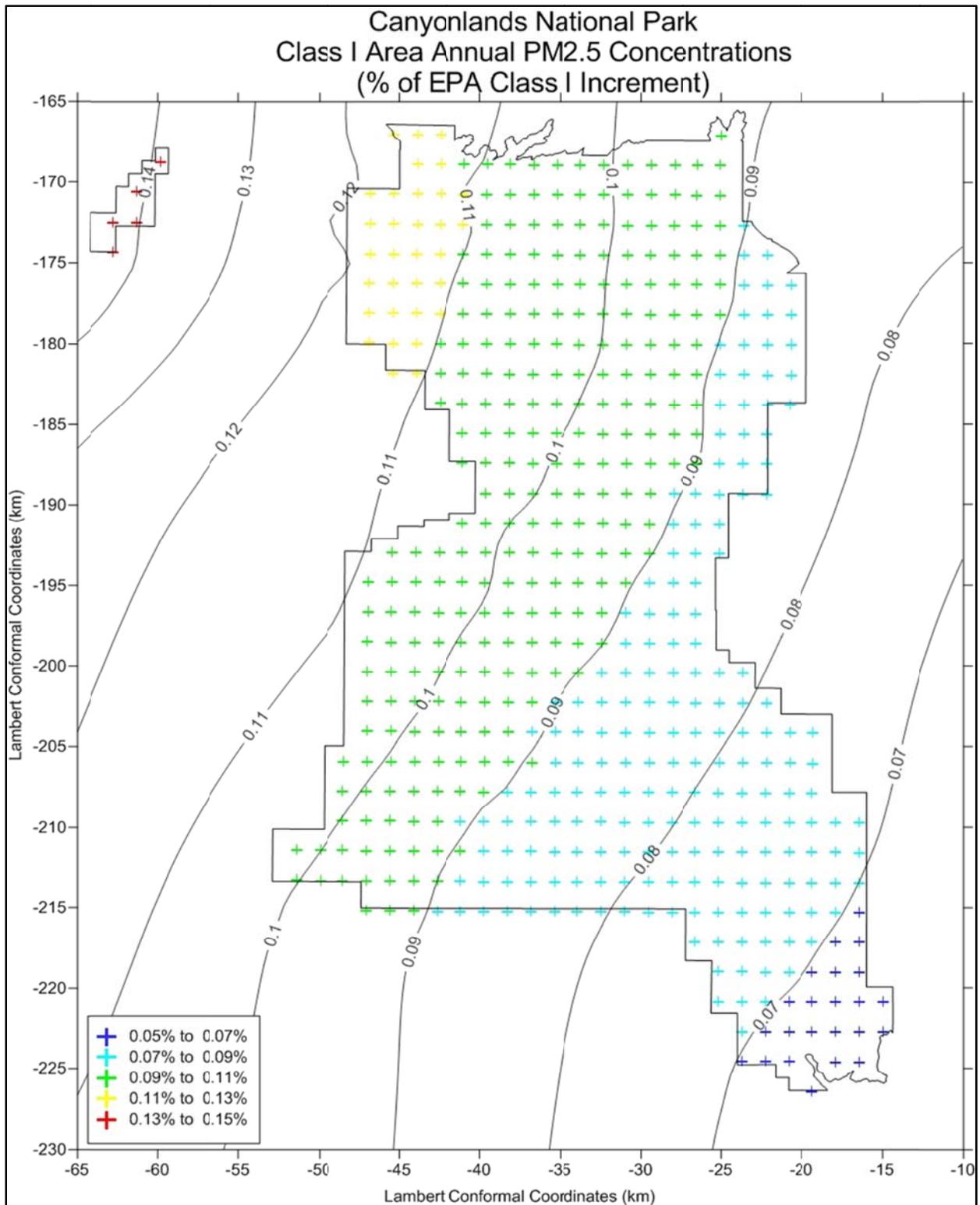


Figure 7.16 Modeled Highest Annual PM_{2.5} Concentration as Percent of PSD Class I Increment at Canyonlands National Park

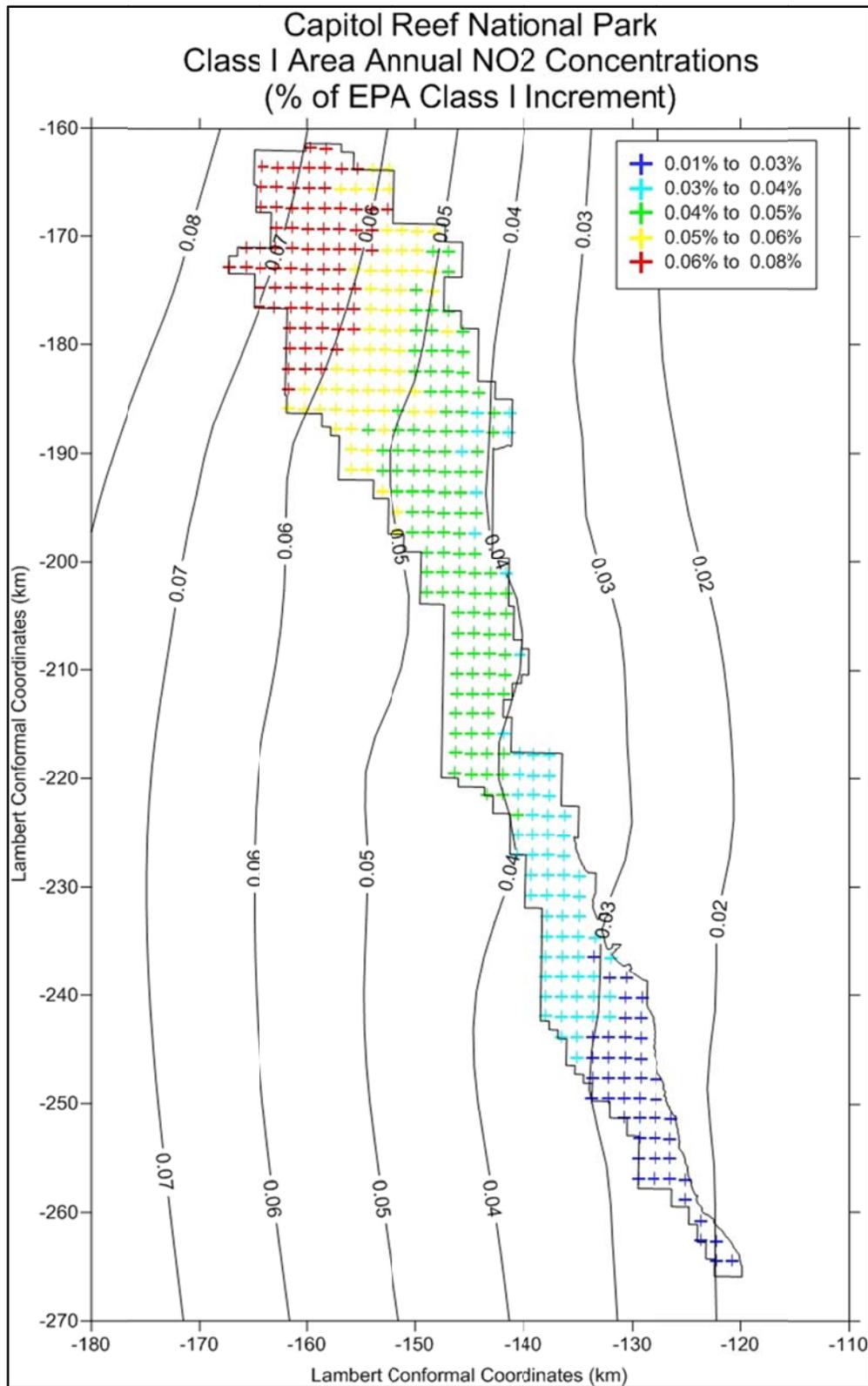


Figure 7.17 Modeled Highest Annual NO₂ Concentration as Percent of PSD Class I Increment at Capitol Reef National Park

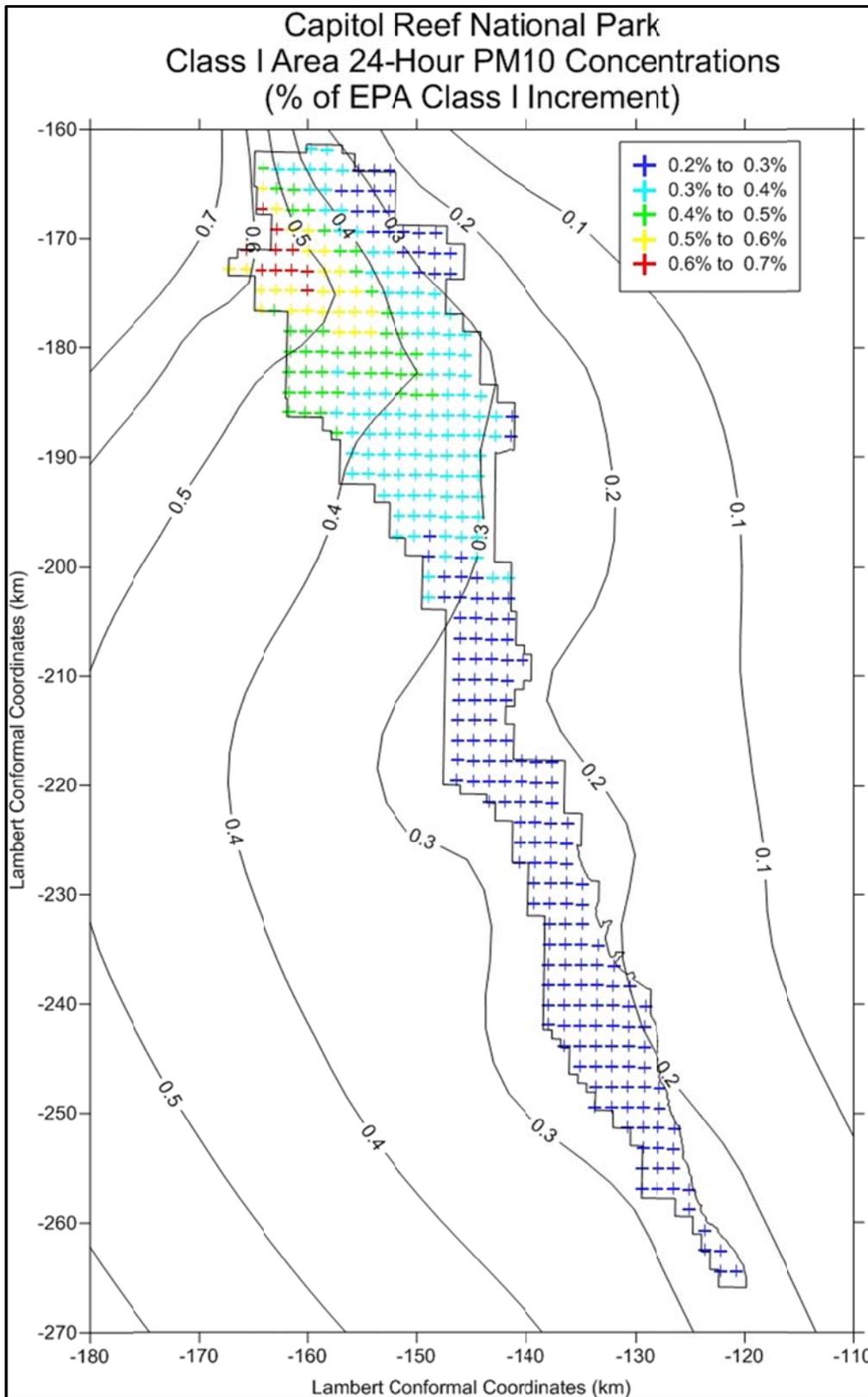


Figure 7.18 Modeled Highest 24-Hour PM₁₀ Concentration as Percent of PSD Class I Increment at Capitol Reef National Park

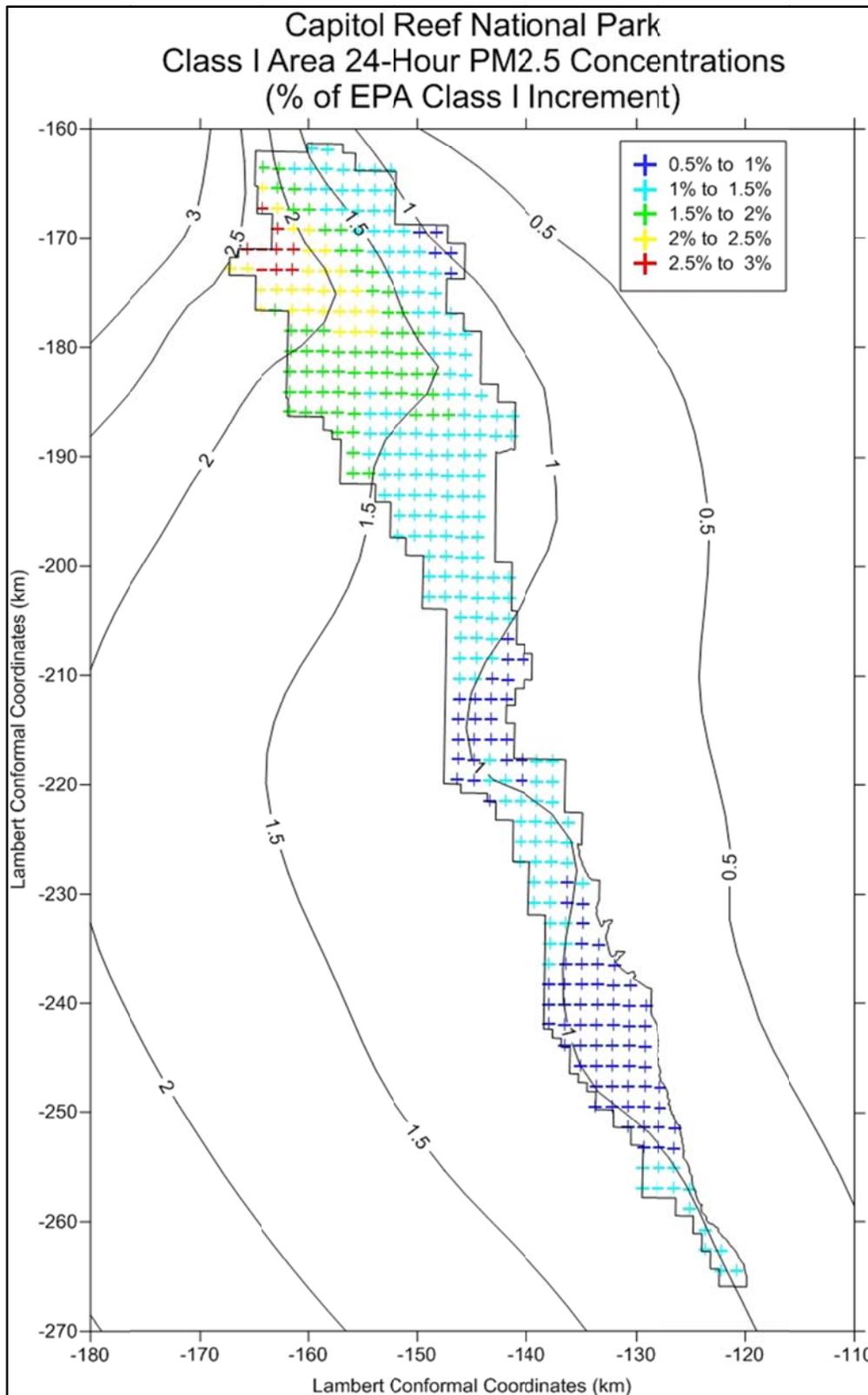


Figure 7.19 Modeled Highest 24-Hour PM_{2.5} Concentration as Percent of PSD Class I Increment at Capitol Reef National Park

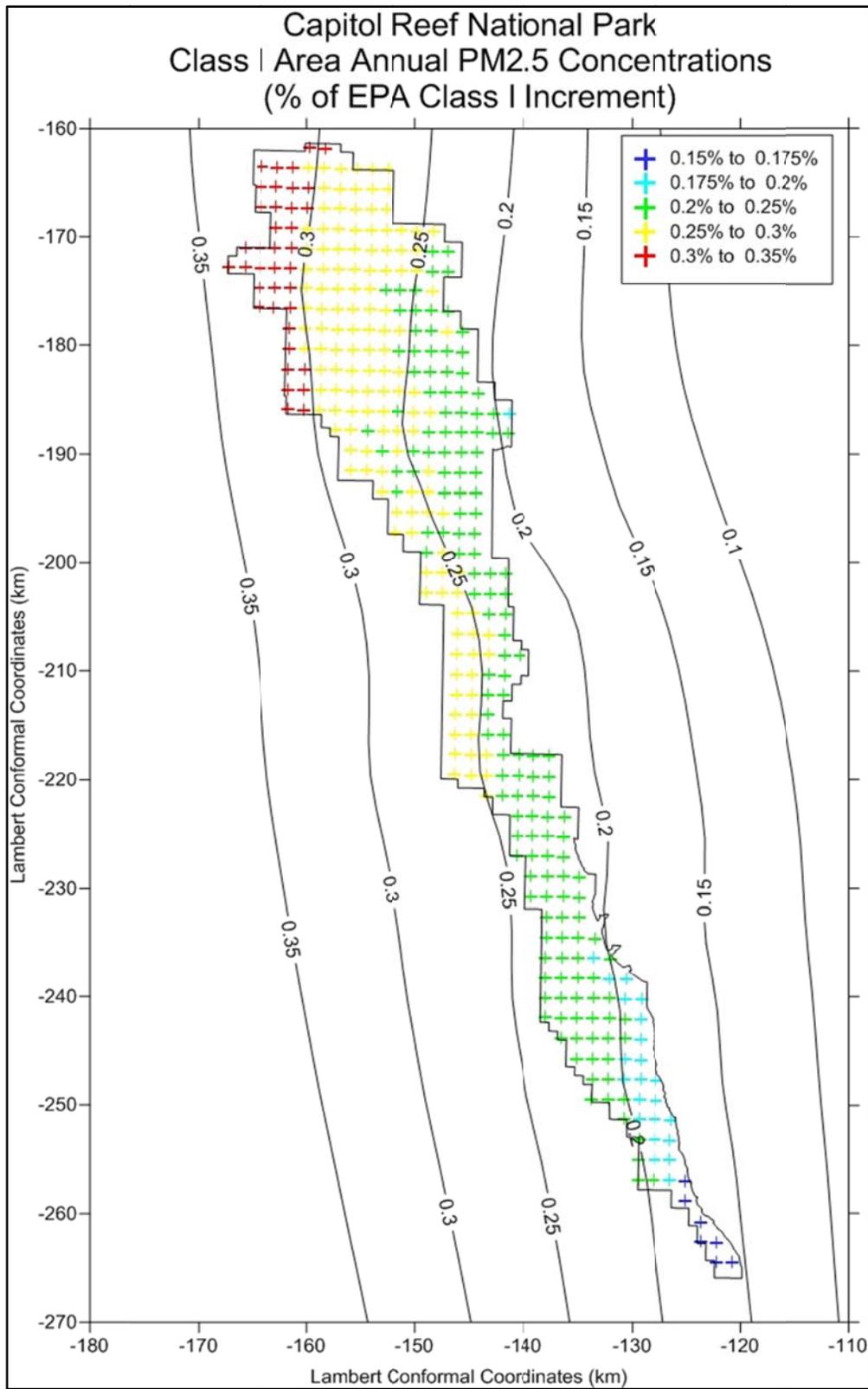


Figure 7.20 Modeled Highest Annual PM_{2.5} Concentration as Percent of PSD Class I Increment at Capitol Reef National Park

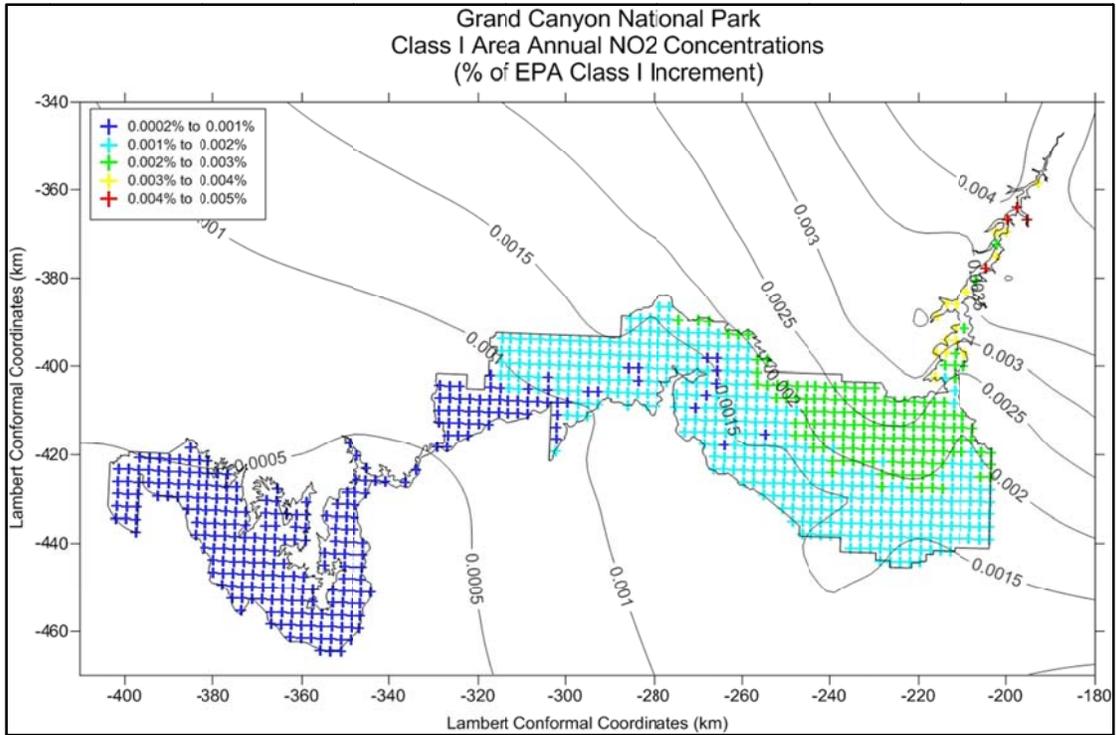


Figure 7.21 Modeled Highest Annual NO₂ Concentration as Percent of PSD Class I Increment at Grand Canyon National Park

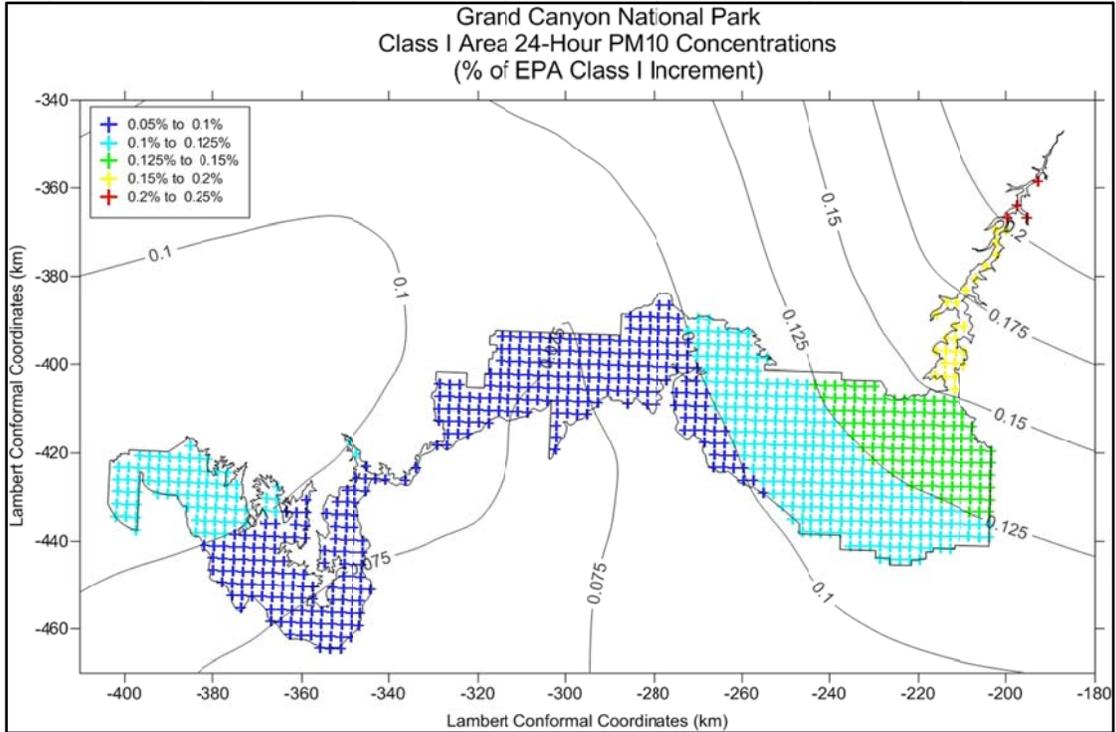


Figure 7.22 Modeled Highest 24-Hour PM₁₀ Concentration as Percent of PSD Class I Increment at Grand Canyon National Park

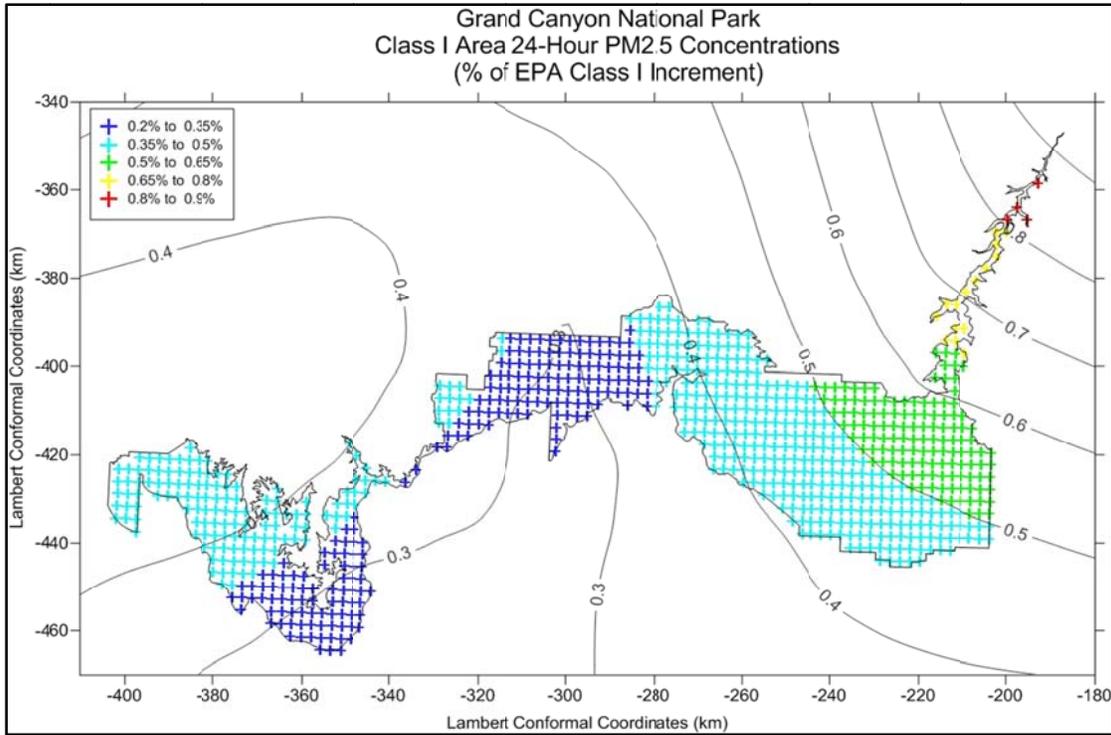


Figure 7.23 Modeled Highest 24-Hour PM_{2.5} Concentration as Percent of PSD Class I Increment at Grand Canyon National Park

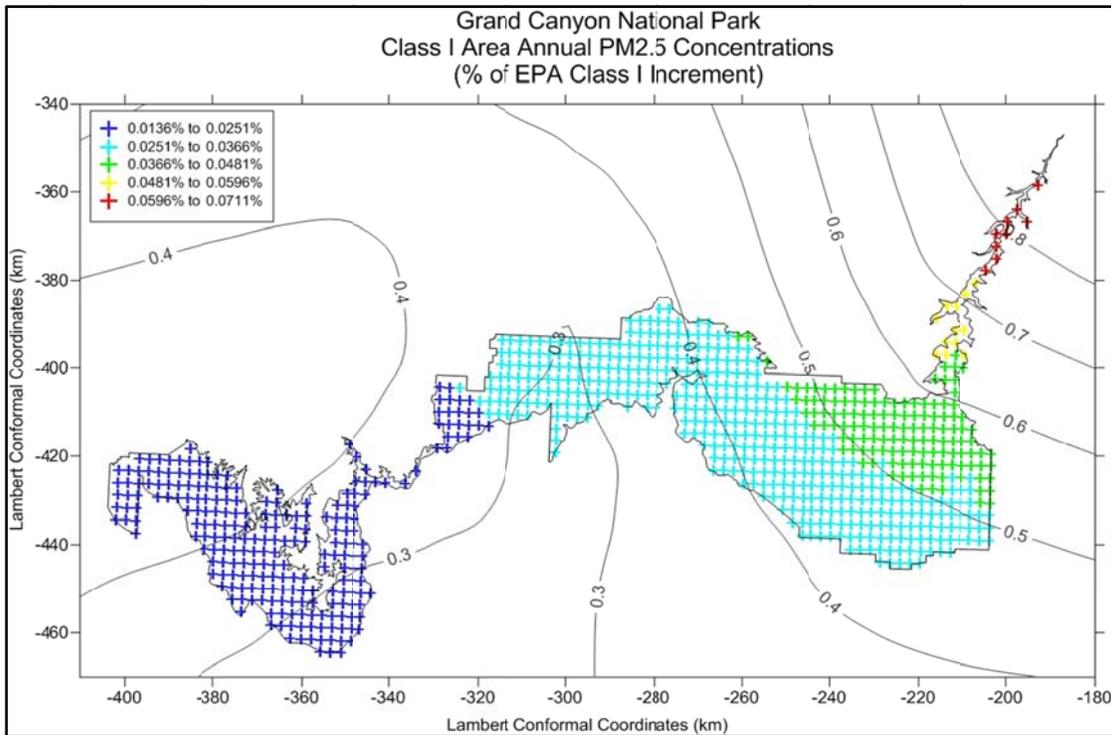


Figure 7.24 Modeled Highest Annual PM_{2.5} Concentration as Percent of PSD Class I Increment at Grand Canyon National Park

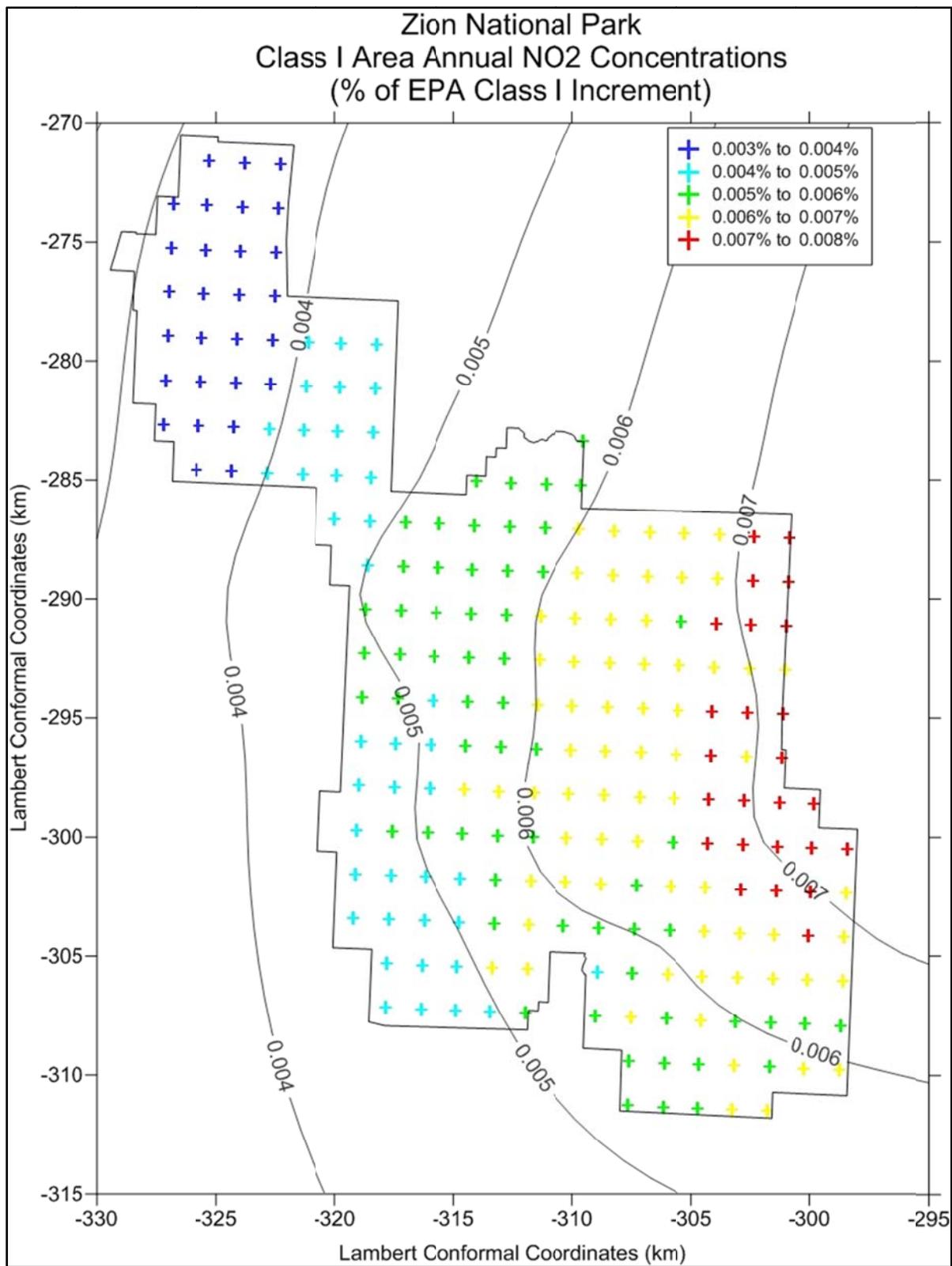


Figure 7.25 Modeled Highest Annual NO₂ Concentration as Percent of PSD Class I Increment at Zion National Park

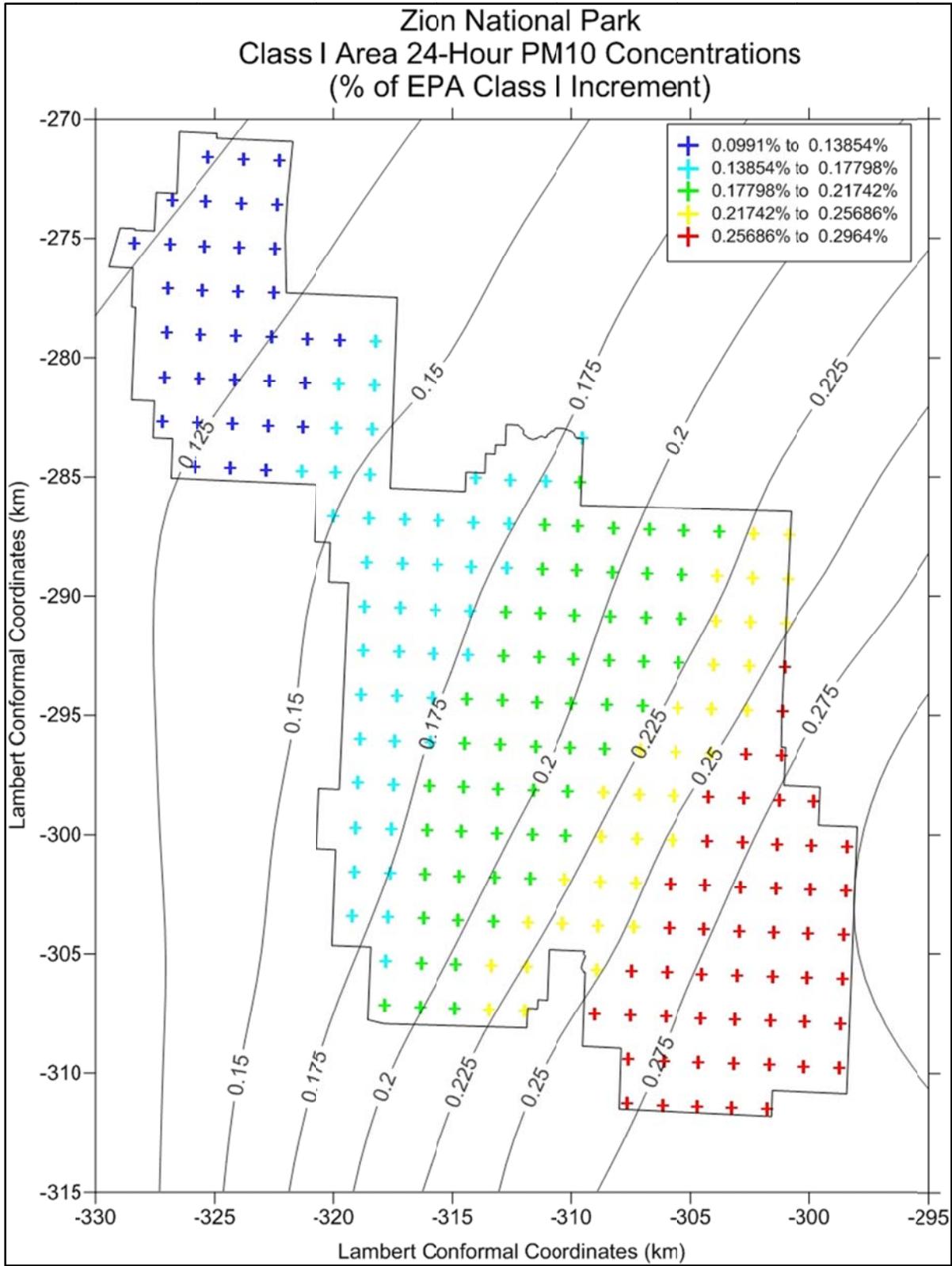


Figure 7.26 Modeled Highest 24-Hour PM₁₀ Concentration as Percent of PSD Class I Increment at Zion National Park

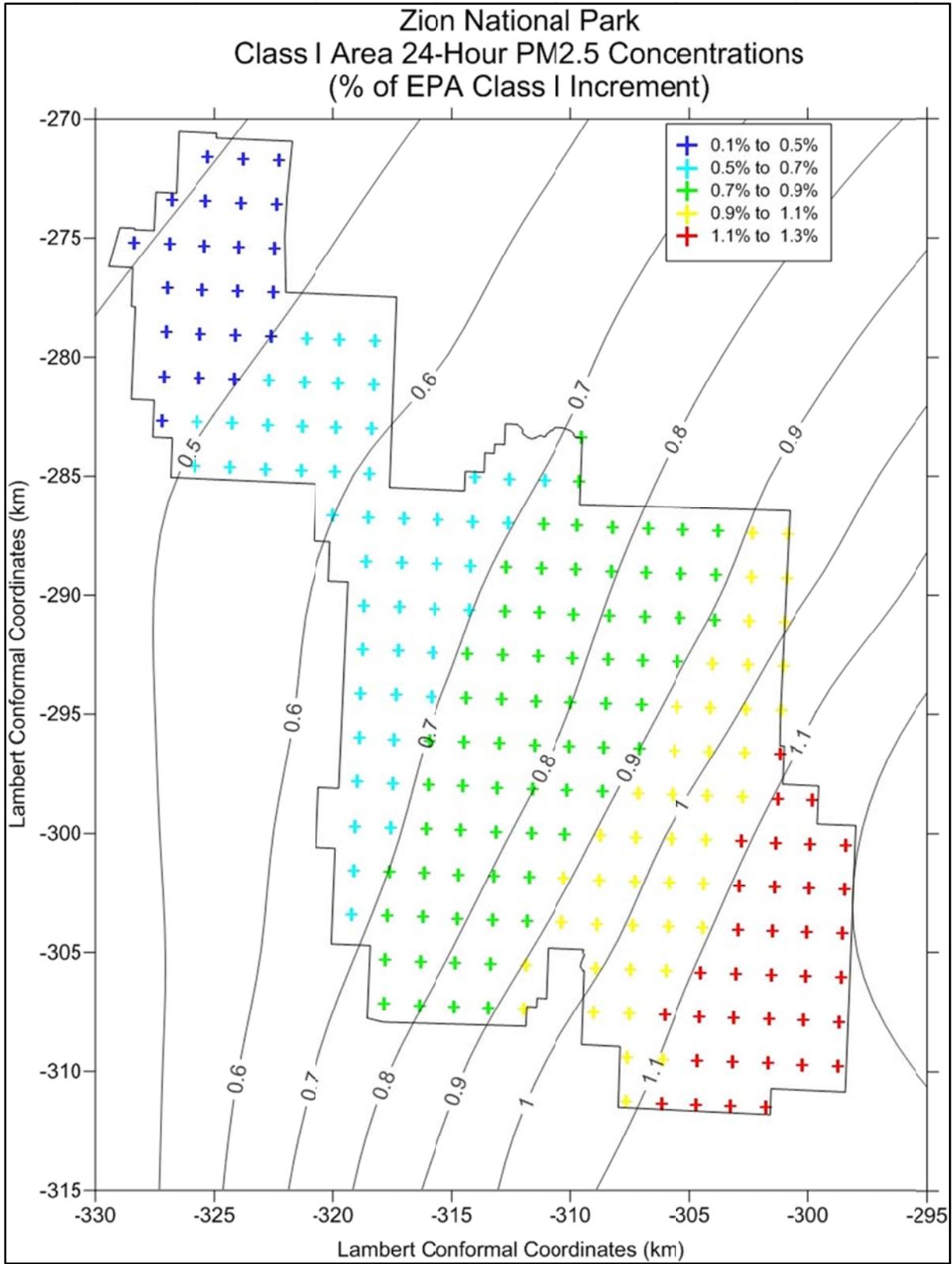


Figure 7.27 Modeled Highest 24-Hour PM_{2.5} Concentration as Percent of PSD Class I Increment at Zion National Park

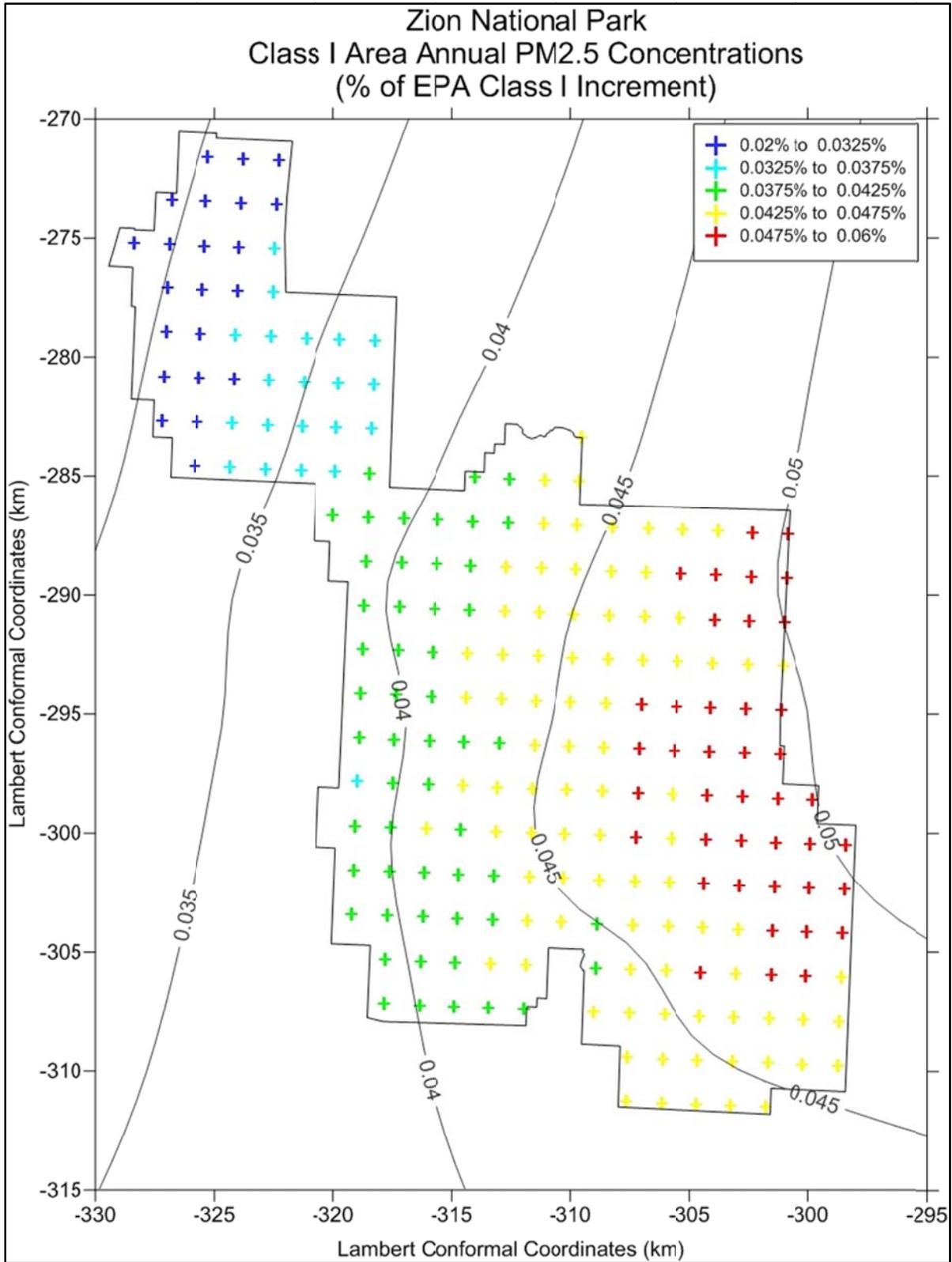


Figure 7.28 Modeled Highest Annual PM_{2.5} Concentration as Percent of PSD Class I Increment at Zion National Park

Table 7-5

Modeled Maximum Class I Area Concentrations Compared to Significant Impact Levels and PSD Class I Increments

Pollutant	Averaging Period	Model-Predicted Concentration ($\mu\text{g}/\text{m}^3$)	Location of Model-Predicted Concentration		EPA Class I Significance Levels ($\mu\text{g}/\text{m}^3$)	Percent of EPA Class I Significance Levels	EPA Class Increment ($\mu\text{g}/\text{m}^3$)	Percent of EPA Class I Increment
			Lambert Conformal E-W (km)	Lambert Conformal N-S (km)				
Arches National Park - 2001								
NO ₂	Annual	1.24E-04	-17.671	-128.228	0.10	0.1%	2.5	<0.1%
PM ₁₀	24-hour	2.24E-02	-17.671	-128.228	0.30	7.5%	8.0	0.3%
	24-hour HSH	1.40E-02	-11.936	-150.466	0.30	4.7%	8.0	0.2%
PM _{2.5}	Annual	9.43E-04	-17.671	-128.228	0.06	1.6%	1.0	0.1%
	24-hour	2.24E-02	-17.671	-128.228	0.07	32.0%	2.0	1.1%
Arches National Park - 2002								
NO ₂	Annual	6.28E-05	-10.491	-152.321	0.10	0.1%	2.5	<0.1%
PM ₁₀	24-hour	1.03E-02	-17.671	-128.228	0.30	3.4%	8.0	0.1%
	24-hour HSH	9.07E-03	-16.245	-135.640	0.30	3.0%	8.0	0.1%
PM _{2.5}	Annual	7.37E-04	-17.671	-128.228	0.06	1.2%	1.0	0.1%
	24-hour	1.03E-02	-17.671	-128.228	0.07	14.8%	2.0	0.5%
Arches National Park - 2003								
NO ₂	Annual	1.13E-04	-17.671	-128.228	0.10	0.1%	2.5	<0.1%
PM ₁₀	24-hour	1.66E-02	-17.671	-128.228	0.30	5.5%	8.0	0.2%
	24-hour HSH	9.02E-03	-17.671	-128.228	0.30	3.0%	8.0	0.1%
PM _{2.5}	Annual	9.05E-04	-17.671	-128.228	0.06	1.5%	1.0	0.1%
	24-hour	1.66E-02	-17.671	-128.228	0.07	23.8%	2.0	0.8%

Table 7-5 Continued

Modeled Maximum Class I Area Concentrations Compared to Significant Impact Levels and PSD Class I Increments

Pollutant	Averaging Period	Model-Predicted Concentration ($\mu\text{g}/\text{m}^3$)	Location of Model-Predicted Concentration		EPA Class I Significance Levels ($\mu\text{g}/\text{m}^3$)	Percent of EPA Class I Significance Levels	EPA Class Increment ($\mu\text{g}/\text{m}^3$)	Percent of EPA Class I Increment
			Lambert Conformal E-W (km)	Lambert Conformal N-S (km)				
Bryce Canyon National Park - 2001								
NO ₂	Annual	4.14E-04	-227.638	-252.780	0.10	0.4%	2.5	<0.1%
PM ₁₀	24-hour	2.32E-02	-227.638	-252.780	0.30	7.7%	8.0	0.3%
	24-hour HSH	1.76E-02	-227.638	-252.780	0.30	5.9%	8.0	0.2%
PM _{2.5}	Annual	8.40E-04	-227.638	-252.780	0.06	1.4%	1.0	0.1%
	24-hour	2.32E-02	-227.638	-252.780	0.07	33.1%	2.0	1.2%
Bryce Canyon National Park - 2002								
NO ₂	Annual	8.40E-04	-227.638	-252.780	0.10	0.8%	2.5	<0.1%
PM ₁₀	24-hour	2.94E-02	-227.638	-252.780	0.30	9.8%	8.0	0.4%
	24-hour HSH	2.53E-02	-227.638	-252.780	0.30	8.4%	8.0	0.3%
PM _{2.5}	Annual	1.63E-03	-227.638	-252.780	0.06	2.7%	1.0	0.2%
	24-hour	2.94E-02	-227.638	-252.780	0.07	41.9%	2.0	1.5%
Bryce Canyon National Park - 2003								
NO ₂	Annual	5.60E-04	-227.638	-252.780	0.10	0.6%	2.5	<0.1%
PM ₁₀	24-hour	2.61E-02	-230.625	-254.547	0.30	8.7%	8.0	0.3%
	24-hour HSH	1.66E-02	-228.371	-252.759	0.30	5.5%	8.0	0.2%
PM _{2.5}	Annual	1.11E-03	-227.638	-252.780	0.06	1.8%	1.0	0.1%
	24-hour	2.61E-02	-230.625	-254.547	0.07	37.4%	2.0	1.3%

Table 7-5 Continued

Modeled Maximum Class I Area Concentrations Compared to Significant Impact Levels and PSD Class I Increments

Pollutant	Averaging Period	Model-Predicted Concentration (µg/m ³)	Location of Model-Predicted Concentration		EPA Class I Significance Levels (µg/m ³)	Percent of EPA Class I Significance Levels	EPA Class Increment (µg/m ³)	Percent of EPA Class I Increment
			Lambert Conformal E-W (km)	Lambert Conformal N-S (km)				
Canyonlands National Park - 2001								
NO ₂	Annual	3.45E-04	-62.765	-174.303	0.10	0.3%	2.5	<0.1%
PM ₁₀	24-hour	3.55E-02	-59.820	-168.769	0.30	11.8%	8.0	0.4%
	24-hour HSH	3.12E-02	-62.750	-172.451	0.30	10.4%	8.0	0.4%
PM _{2.5}	Annual	1.43E-03	-62.765	-174.303	0.06	2.4%	1.0	0.1%
	24-hour	3.55E-02	-59.820	-168.769	0.07	50.7%	2.0	1.8%
Canyonlands National Park - 2002								
NO ₂	Annual	2.40E-04	-62.765	-174.303	0.10	0.2%	2.5	<0.1%
PM ₁₀	24-hour	1.66E-02	-62.765	-174.303	0.30	5.5%	8.0	0.2%
	24-hour HSH	1.28E-02	-45.329	-170.720	0.30	4.3%	8.0	0.2%
PM _{2.5}	Annual	1.15E-03	-62.765	-174.303	0.06	1.9%	1.0	0.1%
	24-hour	1.66E-02	-62.765	-174.303	0.07	23.7%	2.0	0.8%
Canyonlands National Park - 2003								
NO ₂	Annual	2.99E-04	-62.765	-174.303	0.10	0.3%	2.5	<0.1%
PM ₁₀	24-hour	1.57E-02	-61.285	-170.610	0.30	5.2%	8.0	0.2%
	24-hour HSH	1.19E-02	-61.299	-172.462	0.30	4.0%	8.0	0.1%
PM _{2.5}	Annual	1.20E-03	-62.765	-174.303	0.06	2.0%	1.0	0.1%
	24-hour	1.57E-02	-61.285	-170.610	0.07	22.4%	2.0	0.8%

Table 7-5 Continued

Modeled Maximum Class I Area Concentrations Compared to Significant Impact Levels and PSD Class I Increments

Pollutant	Averaging Period	Model-Predicted Concentration (µg/m ³)	Location of Model-Predicted Concentration		EPA Class I Significance Levels (µg/m ³)	Percent of EPA Class I Significance Levels	EPA Class Increment (µg/m ³)	Percent of EPA Class I Increment
			Lambert Conformal E-W (km)	Lambert Conformal N-S (km)				
Capitol Reef National Park - 2001								
NO ₂	Annual	1.95E-03	-164.143	-163.556	0.10	1.9%	2.5	<0.1%
PM ₁₀	24-hour	4.13E-02	-165.751	-170.934	0.30	13.8%	8.0	0.5%
	24-hour HSH	3.55E-02	-164.222	-167.260	0.30	11.8%	8.0	0.4%
PM _{2.5}	Annual	2.97E-03	-164.143	-163.556	0.06	5.0%	1.0	0.3%
	24-hour	4.13E-02	-165.751	-170.934	0.07	59.0%	2.0	2.1%
Capitol Reef National Park - 2002								
NO ₂	Annual	1.91E-03	-167.241	-172.755	0.10	1.9%	2.5	0.1%
PM ₁₀	24-hour	3.12E-02	-164.418	-176.521	0.30	10.4%	8.0	0.4%
	24-hour HSH	3.01E-02	-161.707	-185.843	0.30	10.0%	8.0	0.4%
PM _{2.5}	Annual	3.38E-03	-167.241	-172.755	0.06	5.6%	1.0	0.3%
	24-hour	3.12E-02	-164.418	-176.521	0.07	44.6%	2.0	1.6%
Capitol Reef National Park - 2003								
NO ₂	Annual	1.87E-03	-167.241	-172.755	0.10	1.9%	2.5	0.1%
PM ₁₀	24-hour	5.65E-02	-164.300	-170.965	0.30	18.8%	8.0	0.7%
	24-hour HSH	4.33E-02	-167.241	-172.755	0.30	14.4%	8.0	0.5%
PM _{2.5}	Annual	3.02E-03	-167.241	-172.755	0.06	5.0%	1.0	0.3%
	24-hour	5.65E-02	-164.300	-170.965	0.07	80.8%	2.0	2.8%

Table 7-5 Continued

Modeled Maximum Class I Area Concentrations Compared to Significant Impact Levels and PSD Class I Increments

Pollutant	Averaging Period	Model-Predicted Concentration (µg/m ³)	Location of Model-Predicted Concentration		EPA Class I Significance Levels (µg/m ³)	Percent of EPA Class I Significance Levels	EPA Class Increment (µg/m ³)	Percent of EPA Class I Increment
			Lambert Conformal E-W (km)	Lambert Conformal N-S (km)				
Grand Canyon National Park - 2001								
NO ₂	Annual	7.64E-05	-195.231	-366.787	0.10	0.1%	2.5	<0.1%
PM ₁₀	24-hour	1.65E-02	-192.798	-358.497	0.30	5.5%	8.0	0.2%
	24-hour HSH	1.18E-02	-204.440	-377.689	0.30	3.9%	8.0	0.1%
PM _{2.5}	Annual	4.52E-04	-192.798	-358.497	0.06	0.8%	1.0	<0.1%
	24-hour	1.65E-02	-192.798	-358.497	0.07	23.5%	2.0	0.8%
Grand Canyon National Park - 2002								
NO ₂	Annual	1.07E-04	-195.231	-366.787	0.10	0.1%	2.5	<0.1%
PM ₁₀	24-hour	1.71E-02	-192.798	-358.497	0.30	5.7%	8.0	0.2%
	24-hour HSH	1.53E-02	-199.693	-366.676	0.30	5.1%	8.0	0.2%
PM _{2.5}	Annual	7.11E-04	-192.798	-358.497	0.06	1.2%	1.0	0.1%
	24-hour	1.71E-02	-192.798	-358.497	0.07	24.5%	2.0	0.9%
Grand Canyon National Park - 2003								
NO ₂	Annual	6.78E-05	-195.231	-366.787	0.10	0.1%	2.5	<0.1%
PM ₁₀	24-hour	6.35E-03	-195.231	-366.787	0.30	2.1%	8.0	0.1%
	24-hour HSH	5.20E-03	-195.231	-366.787	0.30	1.7%	8.0	0.1%
PM _{2.5}	Annual	4.06E-04	-195.231	-366.787	0.06	0.7%	1.0	<0.1%
	24-hour	6.30E-03	-195.231	-366.787	0.07	9.0%	2.0	0.3%

Table 7-5 Continued

Modeled Maximum Class I Area Concentrations Compared to Significant Impact Levels and PSD Class I Increments

Pollutant	Averaging Period	Model-Predicted Concentration ($\mu\text{g}/\text{m}^3$)	Location of Model-Predicted Concentration		EPA Class I Significance Levels ($\mu\text{g}/\text{m}^3$)	Percent of EPA Class I Significance Levels	EPA Class Increment ($\mu\text{g}/\text{m}^3$)	Percent of EPA Class I Increment
			Lambert Conformal E-W (km)	Lambert Conformal N-S (km)				
Zion National Park - 2001								
NO ₂	Annual	1.87E-04	-301.012	-291.114	0.10	0.2%	2.5	<0.1%
PM ₁₀	24-hour	2.37E-02	-298.417	-300.488	0.30	7.9%	8.0	0.3%
	24-hour HSH	1.86E-02	-300.941	-289.261	0.30	6.2%	8.0	0.2%
PM _{2.5}	Annual	5.04E-04	-299.821	-298.580	0.06	0.8%	1.0	<0.1%
	24-hour	2.37E-02	-298.417	-300.488	0.07	33.9%	2.0	1.2%
Zion National Park - 2002								
NO ₂	Annual	9.84E-05	-299.821	-298.580	0.10	0.1%	2.5	<0.1%
PM ₁₀	24-hour	1.46E-02	-301.154	-294.819	0.30	4.9%	8.0	0.2%
	24-hour HSH	9.64E-03	-322.346	-271.717	0.30	3.2%	8.0	0.1%
PM _{2.5}	Annual	4.34E-04	-298.417	-300.488	0.06	0.7%	1.0	<0.1%
	24-hour	1.46E-02	-301.154	-294.819	0.07	20.9%	2.0	0.7%
Zion National Park - 2003								
NO ₂	Annual	1.02E-04	-298.557	-304.194	0.10	0.1%	2.5	<0.1%
PM ₁₀	24-hour	8.95E-03	-298.417	-300.488	0.30	3.0%	8.0	0.1%
	24-hour HSH	7.13E-03	-302.343	-287.352	0.30	2.4%	8.0	0.1%
PM _{2.5}	Annual	3.36E-04	-298.557	-304.194	0.06	0.6%	1.0	<0.1%
	24-hour	8.95E-03	-298.417	-300.488	0.07	12.8%	2.0	0.4%

7.8 Visibility

Visibility impairment is defined as any humanly perceptible change in visibility (visual range, contrast, coloration) from that which would have existed under natural conditions. The pollutant loading of a section of the atmosphere can become visible, by the contrast or color difference between a layer or plume and a viewed background, such as a landscape feature or the sky. The second way that visibility can be impaired is a general alteration in the appearance of landscape features or the sky, changing the color or the contrast between landscape features or causing features of a view to disappear. The first phenomenon is referred to as plume blight; the second is referred to as regional haze impairment. Per the FLAG 2010 Q/D test, as discussed in Section 7.1, a regional haze impairment analysis was not required.

7.8.1 Plume Blight

Plume blight analyses were conducted using the most current EPA plume visibility model, VISCREEN, and following the guidance provided in EPA's Workbook for Plume Visual Impact Screening and Analysis (Revised). VISCREEN was used to estimate the following visual impact parameters: plume perceptibility (ΔE) and plume contrast (C_p). In VISCREEN, contrasts at three wavelengths (0.45, 0.55, and 0.65 μm) were used to characterize blue, green, and red regions of the visible spectrum. VISCREEN can be applied in two successive levels of screening (Levels 1 and 2), where necessary. Level 1 screening is designed to provide a conservative estimate of plume visual impacts using worst-case meteorological conditions. Level 2 screening is identical to that of Level 1 (estimation of worst-day plume visual impacts) with the exception that more realistic data may be input to the model. The joint frequency distribution based on wind speed and stability for given wind direction was calculated for six-hour periods utilizing the on-site meteorological data. Table 7-6 presents the VISCREEN Level I model input parameters used.

Table 7-6
VISCREEN Level 1 Model Input Parameters

Model Input Parameters	Parameter Values
Particulate Emission Rate	3.53 g/sec
NO _x Emission Rate	3.78 g/sec
Sulfate Emission Rate	0.0 g/sec
Primary NO ₂ , soot, and sulfate emission rate	0.0 g/sec
Meteorological Conditions	Pasquill stability F wind speed of 1 m/s
Fine Particulate Mass Median Diameter	0.3 μm
Coarse Particulate Mass Median Diameter	6 μm
Plume particulate	2 μm
Plume soot	0.1 μm
Plume primary sulfate	0.5 μm
Background Visual Range	
Capitol Reef National Park	250 km
Bryce Canyon National Park	250 km
Zion National Park	252 km
Canyonlands National Park	250 km
Arches National Park	250 km
Background Ozone	0.04 ppm
Minimum Distance between Emission Source and Observer	
Arches National Park	196.7 km
Bryce Canyon National Park	127.3 km
Canyonlands National Park	158.0 km
Capital Reef National Park	61.6 km
Grand Canyon National Park	222.8 km
Zion National Park	179.9 km
Plume offset angle	11.25°

Capitol Reef National Park was the only protected area that did not pass the Level 1 screening analysis requiring Level 2 screening to be performed. For the Level 2 analysis, using on-site data, a joint frequency distribution based on wind speed and stability for given wind direction sectors were calculated for four time periods (0000-0600, 0600-1200, 1200-1800, 1800-2400) to better assess diurnal effects. These data are presented in Appendix O and were used in the Level 2 analyses. The results of the VISCREEN analyses conducted for all the national parks are also presented in Appendix O.

VISCREEN was used to determine potential plume visual impacts inside each area of interest as well as at integral vistas. Integral vistas are views within an area of interest to landscape features located outside the area of interest. There are no integral vistas at the national parks reviews; thus, only plume visual impacts for views within each national park are presented. Based on the VISCREEN Level-1 results and Level 2 results for Capitol Reef, the plume from the proposed SPC facility will not be perceptible at Arches, Bryce Canyon, Canyonlands, Capitol Reef, Grand Canyon, and Zion National Parks. VISCREEN results are presented in Table 7-7.

Table 7-7
Maximum Predicted Visual Impact - VISCREEN

National Park	Maximum Plume Perceptibility (ΔE)		Maximum Plume Contrast (C_p)		Plume Perceptible?
	Plume	Threshold	Plume	Threshold	
Arches	0.319	2.0	0.006	± 0.05	No
Bryce Canyon	0.807	2.0	0.012	± 0.05	No
Canyonlands	0.479	2.0	0.008	± 0.05	No
Capitol Reef ¹	0.283	2.0	0.004	± 0.05	No
Grand Canyon	0.265	2.0	0.005	± 0.05	No
Zion	0.370	2.0	0.007	± 0.05	No

¹Capitol Reef Results based on Level 2 Screening Analysis

8.0 ADDITIONAL AIR QUALITY ANALYSES

This section contains supplemental information regarding the potential impacts of the project; specifically, the potential for impacts to soils, vegetation, and growth.

8.1 Soils and Vegetation Analysis

The soils and vegetation analysis was conducted by MWH Americas and is included in Appendix P.

8.2 Growth Analysis

The work force for the proposed facility is expected to range from 200 to 300 jobs during various phases of the construction. It is expected that a regional construction force is already available to build the proposed facility. Therefore, it is anticipated that no new housing, commercial or industrial construction is necessary to support the SPC Power Plant during the two-year construction schedule.

The proposed facility will also require approximately 20 to 25 permanent positions. It is assumed that individuals that already live in the region will perform a number of these jobs. No new housing requirements are expected for any new personnel moving to the area. In addition, due to the small number of new individuals expected to move into the area to support the SPC Power Plant and the existence of some commercial activity in the area, new commercial construction would not be necessary to support the permanent work force. Additionally, no significant level of industrial related support will be necessary for the SPC Power Plant. Therefore, industrial growth is not expected. Based on the growth expectations discussed above, no new significant emissions from secondary growth during the construction and operation phases of the SPC Power Plant are anticipated.

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