AIR QUALITY PERMIT APPLICATION FOR CONSTRUCTION OF THE HIGHWOOD GENERATING STATION NATURAL GAS PLANT

Great Falls, MT

Southern Montana Electric
Generation & Transmission Cooperative, Inc.

Submitted by:

Southern Montana Electric
Generation and Transmission Cooperative
3521 Gabel Road, Suite 5
Billings, MT 59102

Prepared by:

Bison Engineering, Inc.
1400 11th Avenue
Helena, Montana 59601

and

Stanley Consultants
9200 E. Mineral Ave, Suite 400
Englewood, CO 80112

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ACRONYMS AND ABBREVIATIONS

acfm	Actual cubic feet per minute
AERMOD	**A**merican Meteorological Society – **E**PA – **R**egulatory –**MOD**el (current 'approved' EPA dispersion model
AES	Alternative Evaluation Study
AIG	Ammonia Injection Grid – The AIG is the physical grid pattern in the SCR control device that delivers ammonia to the catalyst to promote the removal of NOx emissions.
APW	Anaconda-Pintler Wilderness
AQRV	Air quality-related values
ARD	Air Resource Division
ARM	Administrative Rules of Montana
ARM	Ambient Ratio Method
As	Arsenic
BACT	Best Available Control Technology
BMP	Best management practices
BMW	Bob Marshall Wilderness
Btu/hr	British thermal units per hour
Btu/lb	British thermal units per pound
CAA	Clean Air Act
CAM	Compliance Assurance Monitoring
$CaCO_3$	Calcium carbonate
CaO	Calcium oxide
$CaSO_3$	Calcium sulfite
$CaSO_4$	Calcium sulfate
CD-ROM	Compact disc
CDS	Circulating dry scrubber
CFB	Circulating fluidized bed
cfm	Cubic feet per minute
CFR	Code of Federal Regulations
CEMS	Continuous emissions monitoring system
CO	Carbon monoxide
CO_2	Carbon dioxide
COMS	Continuous opacity monitoring system
DAT	Deposition analysis threshold
DEM	Digital elevation model
dcfm	Dry standard cubic feet per minute
DLN	Dry Low NOx
dscfm	Dry standard cubic feet per minute
EIS	Environmental Impact Statement

EPA	U.S. Environmental Protection Agency
ESP	Electrostatic precipitator
F	Fahrenheit
FCAA	Federal Clean Air Act
FFB	Fabric filter baghouse
FGD	Flue gas desulfurization
FGR	Flue gas recirculation
FLAG	Federal Land Managers' Air Quality Related Values Workgroup
FLM	Federal Land Managers
fps	Feet per second
ft	Feet
GEP	Good engineering practice
g/s	Grams per second
GIS	Geographic Information Systems
GMW	Gates of the Mountains Wilderness
GNP	Glacier National Park
gpm	Gallons per minute
gr	Grains
GWh	Gigawatt-hour
H_2O	Water
H_2S	Hydrogen sulfide
H_2SO_4	Sulfuric acid
HAP	Hazardous air pollutant
HAR	Hydrated ash reinjection
HCL	Hydrochloric acid
HF	Hydrofluoric acid
HGS	Highwood Generating Station
hp	Horsepower
HRSG	Heat recovery steam generator
hr/yr	Hours per year
in Hg	Inches of mercury
IWAQM	Interagency Workgroup on Air Quality Modeling
K	Kelvin
km	Kilometer
kPa	Kilopascals
kW	Kilowatt
lb/MMBtu	Pounds per million British thermal units
lbs	Pounds
lb/hr	Pounds per hour
lb/ton	Pounds per ton

LCC	Lambert Conformal Concentric
LEA	Low excess air
LNB	Low NOx burners
LoTOx	Low temperature oxidation
m	Meter
MACT	Maximum Achievable Control Technology
MDEQ	Montana Department of Environmental Quality
MFMP	Montana First Megawatts Plant
mg/l	Milligrams per liter
MM	Mesoscale Model
mmbtu	Million British thermal units
mmBtu/hr	Million British thermal units per hour
MMGAQP	Montana Modeling Guideline for Air Quality Permits
MMW	Mission Mountain Wilderness
MRC	Montana Refining Company
mW or MW	Megawatt
MWe	Megawatt
MWh	Megawatt-hour
$\mu g/m^3$	Micrograms per cubic meter
MAAQS	Montana Ambient Air Quality Standards
MAC	Montana Administrative Code
MPM	Montana Principle Meridian
N	Nitrogen
NH_3	Ammonia
NAAQS	National Ambient Air Quality Standards
NCDC	National Climatic Data Center
NESHAP	National Emission Standards for Hazardous Air Pollutants
NOx	Nitrogen oxides
NO_2	Nitrogen dioxide
NPS	National Park Service
NSCR	Non-selective catalytic reduction
NSPS	New Source Performance Standards
NWS	National Weather Service
0_3	Ozone
OAQPS	Office of Air Quality Planning and Standards
OFA	Overfire air
OLM	Ozone limiting method

Pb	Lead
PC	Pulverized coal
PM	Particulate matter
PM_{10}	Particulate matter with an aerodynamic diameter of IO micrometers or less
ppb	Parts per billion
pphm	Parts per hundred million
ppm_{vd}	Parts per million volume dry basis
PRB	Powder River Basin
PSD	Prevention of Significant Deterioration
psig	Pounds per square inch gauge
PTE	Potential to emit
RBLC	EPA RACT/BACT/LAER Clearinghouse
RCO	Regenerative catalytic oxidizer
ROM	Run of mine
RCO	Regenerative thermal oxidizer
S	Sulfur
s/cm	Seconds per centimeter
SCR	Selective catalytic reduction
SDA	Spray dry absorber
SGW	Scapegoat Wilderness
SIA	Significant impact area
SNCR	Selective non-catalytic reduction
SO_2	Sulfur dioxide
SO_3	Sulfur trioxide
SO_4	Sulfates
SOA	Secondary organic aerosols
tpy	Tons per year
TDS	Total dissolved solids
ULBW	UL Bend Wilderness
USGS	United States Geological Survey
UTM	Universal Transverse Mercator
VOC	Volatile organic compound
VMT	Vehicle miles traveled

1.0 INTRODUCTION

1.1 Purpose and Summary

Southern Montana Electric Generation and Transmission Cooperative, Inc. (Southern) is submitting this application for a Montana Air Quality Permit, and concurrently a Title V operating permit to the Montana Department of Environmental Quality (MDEQ) in accordance with the requirements of the Montana Clean Air Act (MCAA), the Federal Clean Air Act (FCAA), and the rules adopted pursuant to these Acts: Administrative Rules of Montana (ARM), Sections 17.8.740 *et seq.* 17.8.801 *et seq.* and 17.8.1201 *et seq*.

With this permit application, Southern seeks approval to construct, operate and maintain the Highwood Generating Station gas plant (HGS gas plant), a combination of a simple cycle and combined cycle turbine-based electric generating units located in Cascade County, Montana. The HGS gas plant, when completed, will consist of two natural gas fired generating units whose combined net output (with duct firing and heat recovery steam generators) will be approximately 120 megawatts[1]. It is anticipated that the unit may be operated in either a simple cycle or combined cycle mode. More information about the plant operation is contained in Section 2.0. This application and all analyses contained herein are based on the facility operating in all configurations.

The HGS gas plant will serve supply electricity to Southern's member cooperatives which include:

- Beartooth Electric Cooperative, Inc. with headquarters at Red Lodge, Montana;
- Fergus Electric Cooperative, Inc. with headquarters in Lewistown, Montana;
- Mid-Yellowstone Electric Cooperative, Inc. with headquarters at Hysham, Montana;
- Tongue River Electric Cooperative, Inc. with headquarters at Ashland, Montana;

Southern provides wholesale electric energy and related services to approximately 100,000 Montanans. Southern's member cooperatives have provided electric energy to their customers for over 60 years.

Because Southern plans to add the HGS gas plant at the same location as the currently permitted Highwood Generating Station, this project constitutes a major modification to a major stationary source of regulated pollutant emissions in accordance with Prevention of Significant Deterioration (PSD) regulations at 40 CFR 52.21 and ARM 17.8.801(20) and (22). This application will demonstrate compliance with all applicable air quality rules and provide all relevant information as required at 17.8.743, 17.8.748, 17.8.823 and 17.8.1204 - 1206. Permit application forms have been completed and are included in Appendix A.

[1] 120 MWe at 57.4°F and 1.0 power factor.

This application discusses the effects of the emissions from the proposed project on ambient air quality. The application also discusses, where appropriate, the cumulative impacts from the plant and surrounding industrial sources. This section provides a brief summary of the project and the power generation process. Section 2.0 is a project summary that explains the overall operation of the facility how the facility may be used as both a baseload and peaking resource. Section 3.0 analyzes the "potential" emissions from the proposed facility. Section 4.0 examines the regulations relevant to this application including New Source Performance Standards (NSPS). The Best Available Control Technology (BACT) analysis is presented in Section 5.0. Finally, Section 6.0 describes the air quality impacts from the proposed project.

Southern plans to construct the new facility in two phases. Phase I includes the construction and operation of two natural gas-fired turbines, to operate in simple-cycle mode as a peaking unit. In Phase II, Southern will add duct burners, heat recovery equipment and steam-driven turbines to make HGS a combined cycle system, which may be operated as a either a base-load or peaking facility.

Southern proposes to limit the hours of operation to no more than 3,200 hours per year in simple cycle mode. Southern seeks to operate each generating unit up to the maximum 8,760 hours per year in combined cycle mode. The gas plant will not operate at any time that the coal plant CFB boiler is in operation. Operation of this new combustion turbine facility will result in potential annual emission rates found in Table 1-1 below.

As a matter of administrative convenience and consistent with other industrial facilities, Southern requests a separate air quality permit be issued for the proposed combustion turbine facility. It should be noted that although a separate permit is requested, all applicable PSD compliance demonstrations will be made with all existing and new sources combined. No PSD rules and regulations are circumvented by issuing a separate permit for the combustion turbine facility.

Table 1-1: Estimated Annual Emission Rates (Entire Gas Facility)

Pollutant	Emission Rate (tons/year)[2]
Initial Pre-Steam Plant Simple Cycle Mode	
Oxides of Nitrogen (NOx)	126.34
Carbon Monoxide (CO)	368.52
Volatile Organic Compounds (VOC)	12.72
Particulate ($PM/PM_{10}/PM_{2.5}$)	16.66
Sulfur Dioxide (SO_2)	1.94

[2] Note: Annual emission rates are not additive between the simple cycle and combined cycle modes. Both modes are presented for purposes of completeness.

Simple Cycle/Combined Cycle Mode	
Oxides of Nitrogen (NOx)	171.46
Carbon Monoxide (CO)	379.78
Volatile Organic Compounds (VOC)	20.35
Particulate ($PM/PM_{10}/PM_{2.5}$)	64.41
Sulfur Dioxide (SO_2)	6.16

2.0 PROJECT SUMMARY

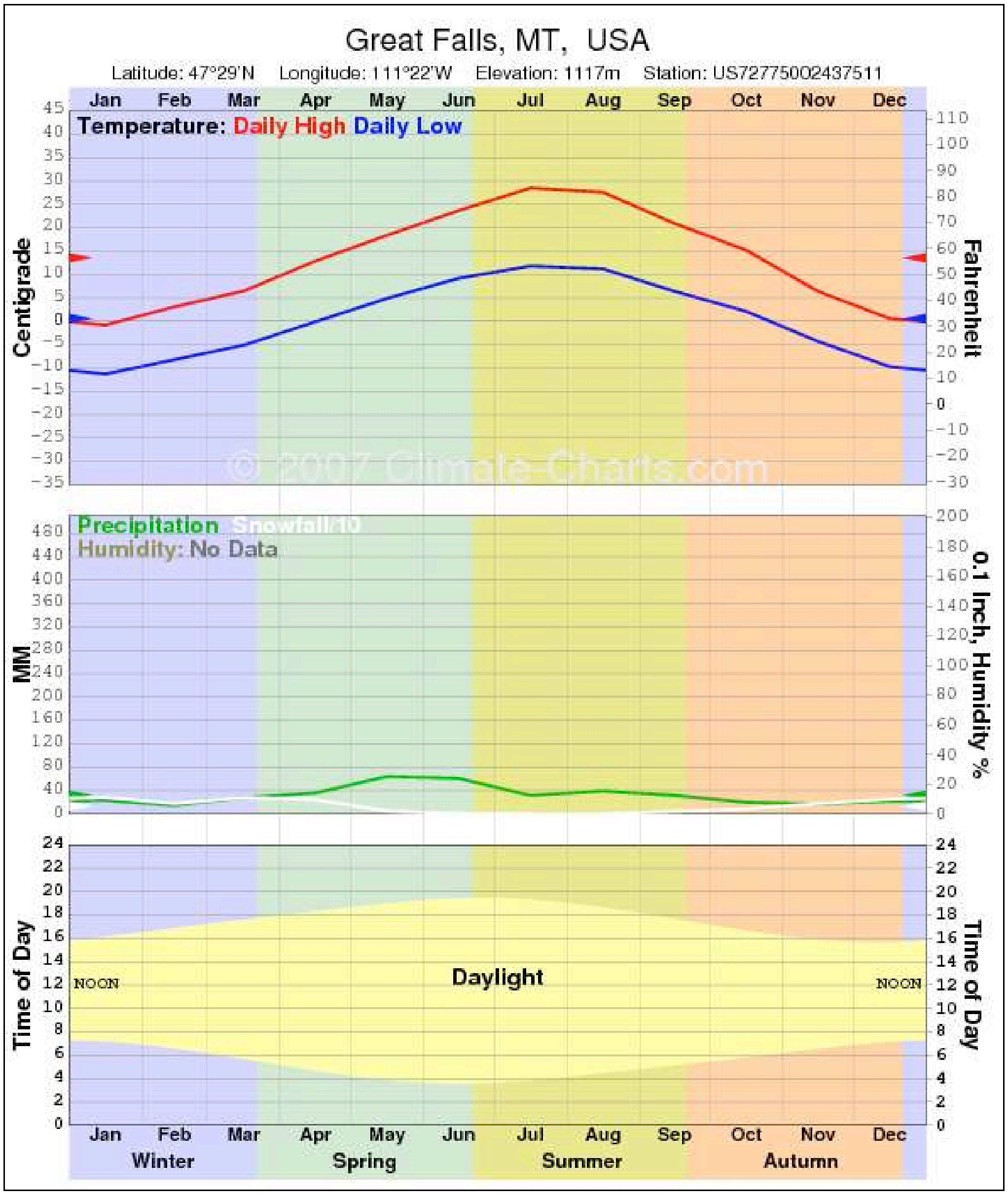
2.1 Site Description

The proposed HGS gas plant will be located approximately 8 miles East of Great Falls, Montana. The legal description of the site is in Sections 24 and 25, Township 21 North, Range 5 East, M.P.M., in Cascade County, Montana. The approximate universal transverse mercator (UTM) coordinates are Zone 12, Easting 497 kilometers (km), and Northing 5,268 km. The site elevation is approximately 3,290 feet. The property lies within the same geographical boundary described in the air quality permit application for the Highwood Generating Station. The HGS encompasses approximately 720 acres of property.

The climatology of the area is considered semi-arid with average rainfall of slightly more than 15 inches per year. Precipitation is most prevalent in May and June, but is especially sparse from October to the following February. Average daily temperatures over the year range from 21℉ in January to 68℉ in July. Figure 2-1 provides a summary of the climatological data for the area.

The air quality classification for the immediate area is "Unclassifiable or Better Than National Standards" (40 CFR 81.327) for all pollutants. A portion of the City of Great Falls near 10th Ave. South was a non-attainment area for CO at one time. The area was re-designated into attainment / unclassifiable in May, 2002. The closest PSD Class I areas are the Scapegoat (and Bob Marshall) Wilderness areas and the Gates of the Mountains Wilderness. Both are about 55 miles from the plant site.

Figure 2-1: Great Falls Climatology Summary[3]

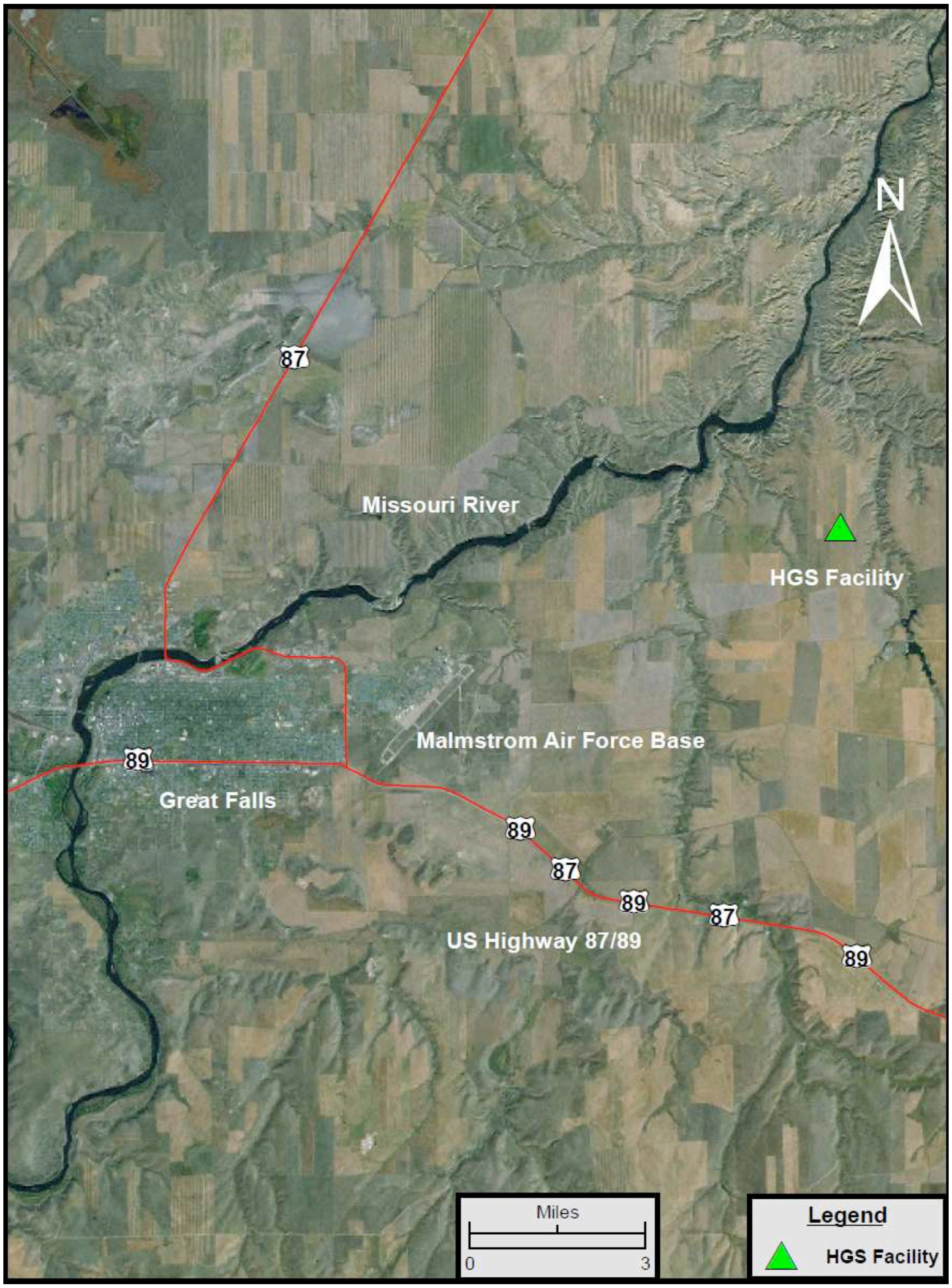


2.2 Site Map

Figure 2-2 shows the site location of the project on a 7.5-minute topographical quadrangle map. More specific information is supplied in Appendix B which contains various drawings regarding the plant layout, etc.

[3] Data taken from: http://www.climate-charts.com/Locations/u/US72775002437511.php.

Figure 2-2: Site Location



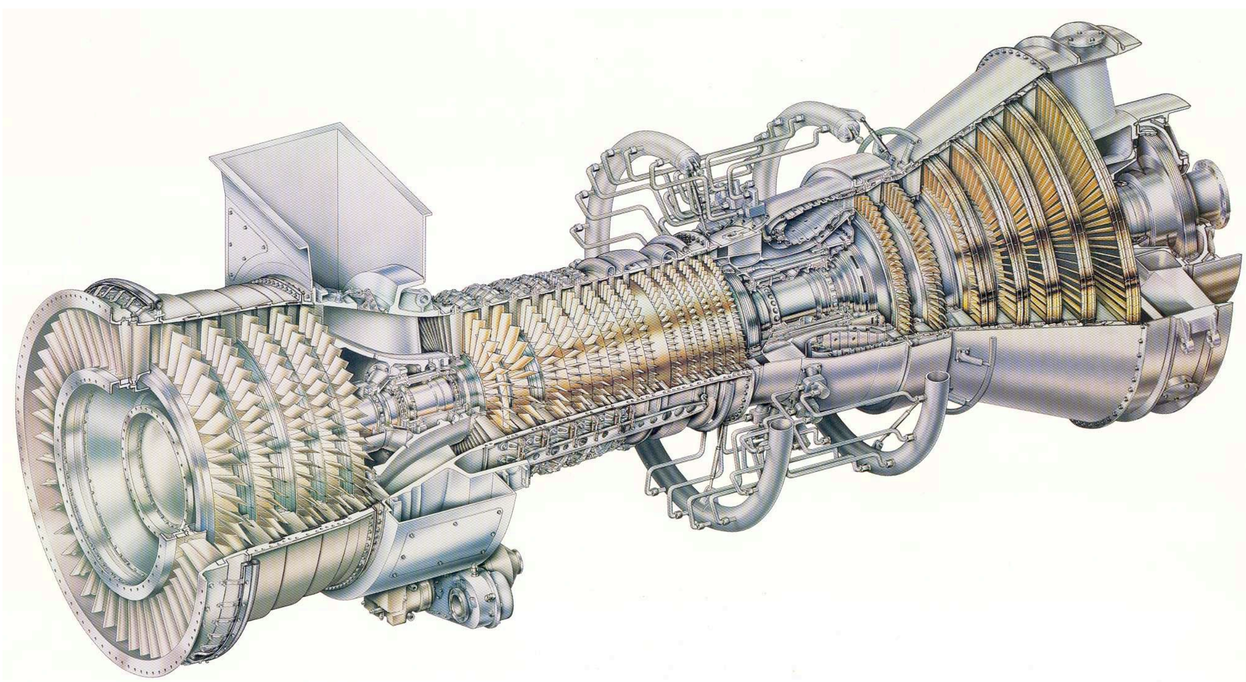
2.3 Public Notice

MDEQ requires the applicant to notify the public of an application for an air quality permit by means of a newspaper of general circulation in the vicinity of the proposed facility. Such public notification will be served by advertisement in the daily *Great Falls Tribute* on April 25, 2009, which was within ten days of filing the permit application. The affidavit will be submitted to MDEQ when made available from the publisher. Additional copies of the affidavits are available upon request.

2.4 Process Description

The selected generating units for the HGS gas plant are two General Electric LM-6000PF Dry Low Emissions (DLE) combustion turbines. The LM6000 is a 2-shaft simple cycle combustion unit containing one aeroderivative[4] combustion turbine and a single shaft-driven electric generator. It is derived from the core of GE's reliable, high performance aircraft engine, the CF6-80C2. This engine has logged more than 76,500,000 operational flight hours with a 99.97% dispatch reliability, resulting in very low system downtime. More than 600 LM6000 generating units have been sold, with more than 10,000,000 operating hours logged at 98% availability[5]. The power generation turbine operates in similar fashion to an aircraft engine, but instead of the driveshaft turning a fan, it turns a generator to produce electricity. Figure 2-3 below shows a simple cut-away of the GE LM6000.

Figure 2-3: GE LM6000 Turbine Engine[6]



[4] An aeroderivative gas turbine is essentially an aircraft engine modified for stationary industrial use.
[5] From GE Power website: GE Energy – LM 6000 Aeroderivative Gas Turbines.
[6] Image from GE Power website.

Figure 2-4: GE LM6000 Turbine Engine – Inside Turbine Enclosure[7]

More details regarding the LM6000 are available at the following website address:

- *http://www.gepower.com/prod_serv/products/aero_turbines/en/lm6000.htm*

Within each combustion turbine, combustion air is compressed and mixed with fuel, then fired in the 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. Each of the two LM6000 generating units are rated at approximately 43 MWe at 100% load at 54.7℉ ambient temperature. Including the electricity generated from the heat recovery steam generators and steam turbines, the plant gross total is approximately 120 MWe[8] while duct burners are firing. Pipeline quality natural gas is the selected operations and startup fuel.

In addition to the power block, other tanks and machinery will be installed at this facility. A black-start emergency generator and fire pump will be installed, both diesel-powered. Aqueous ammonia will be stored in above-ground horizontal tanks for use in the Selective Catalytic Reduction NO_X air pollution control device that has been selected as BACT, as detailed in Section 5.

A wet cooling tower will be used to dissipate the heat from the condenser by using the latent heat of water vaporization to exchange heat between the process and the air passing through the cooling tower. The proposed cooling tower will be an induced,

[7] http://en.wikipedia.org/wiki/General_Electric_LM6000
[8] Total MWe defined with 1.0 power factor

counter flow draft design equipped with drift eliminators. The average make-up water rate for the proposed cooling tower will be approximately 394 gallons per minute (gpm).

The facility plot plan in Appendix B contains conceptual plant layouts showing the major components of the facility and their layout with reference to the property boundary.

2.4.1 Phased Construction

The HGS gas plant will be constructed in two phases. Phase I of construction will consist of two GE LM6000PF simple cycle combustion turbines, with all support equipment and structures, including two simple cycle stacks. Phase II of construction will include the installation of two heat recovery steam generators (HRSG), the two sets of NO_X and CO air pollution controls, one steam turbine electric generator, and two combined cycle stacks.

During initial Phase I service (defined as operations before the HRSG and steam plant are installed), Southern proposes to limit the hours of simple cycle operation to 3200 hours per year. During Phase II, following the installation of the steam plant, the simple cycle hours of operation shall be limited to 3200 hours per year, but combined cycle operation will not. Southern proposes to permit the facility for continuous combined cycle operation of both generating units to service all eventualities including an emergency electrical power demand.

2.4.2 Modes of Operation

Existing Southern power supply contracts with the Bonneville Power Administration will completely expire by 2011. The electricity generated by the HGS gas plant will be used to supplant the expiring contracts. Based on the fabrication and construction schedules of a project of this magnitude, electric power will be necessary before the combined cycle portions of the plant will enter service. Therefore, the HGS gas plant will operate in simple-cycle-only mode during Phase I operations, as mentioned in Section 2.4.1.

In addition, simple cycle operation is beneficial during Phase II operations. Due to the extended startup period for combined cycle operations (in order to evenly heat the boiler tubes of the HRSGs), changes in system demand may require the rapid ten minute startup of simple cycle operation. Therefore, after Phase II is complete, Southern proposes to retain simple cycle operation, with a limit of 3,200 hours per year of operation, the same as Phase I operation.

To enable the turbine to operate in simple cycle mode following the installation of the HRSG and pollutant controls, a diverter system must be used to direct the flow of exhaust through the simple cycle stack. The diverter will prevent damage to the HRSG during the rapid heating that will occur during full load simple cycle operations. Other potential pollutant control and flow-direction equipment was analyzed. See the NO_X BACT in Section 5.4 for the analysis leading to selection of this mode of operation.

3.0 EMISSION INVENTORY

3.1 Emissions Summary

Emissions associated with a proposed facility must be characterized and quantified to perform the various analyses and demonstrations required for an air quality permit application. Specifically, project emissions are used to determine applicability of air quality-related state and federal Clean Air Act regulations (see Section 4.0), identify Best Available Control Technology (BACT) (see Section 5.0), and demonstrate impacts to ground-level concentrations of ambient air (see Section 6.0).

This application seeks an air quality permit for a phased construction electrical generating facility that will initially consist of the following systems and equipment: two GE LM6000PF simple cycle combustion turbines and electrical generators, black-start emergency generator (serving the facility), firepump, and ammonia storage tanks. Phase II of construction will add two HRSGs[9], two duct burners[10], one steam turbine and associated building, and a second set of emission stacks. The calculations and analyses performed in this application account for the emissions during both phases of operation: Phase I – simple cycle only, Phase II - simple cycle and combined cycle operations.

Processes associated with these types of equipment have the potential to emit (PTE)[11] to the atmosphere a variety of regulated pollutants. The LM6000PF generating units represent by far the largest PTE for this facility. The following subsections describe methods used to calculate potential emissions from each emitting source within the facility. Appendix C presents detailed emissions calculations and identifies sources of emission factors and other input data. The PTE calculations for each of the facility's sources were evaluated for several design and operational factors including: operational loads, ambient operating temperatures, best available emissions control technologies, and the heating value of fuels combusted. All calculations are for the facility's total capability of continuous, full-time operations at maximum loads.

Table 3-1 summarizes the facility's estimated annual potential emission rates of oxides of nitrogen (NO_X), carbon monoxide (CO), volatile organic compounds (VOC), particulate matter (PM), particulate matter with an aerodynamic diameter less than 10 microns (PM_{10}), particulate matter with an aerodynamic diameter less than 2.5 microns ($PM_{2.5}$), sulfur dioxide (SO_2), and lead (Pb).

[9] One unit per combustion turbine.
[10] Ibid.
[11] The term "potential to emit" or PTE has a specific regulatory definition which is found in ARM 17.8.740(19) and elsewhere.

Table 3-1: Facility Annual Potential to Emit Summary

Source	NO_X (tpy)	CO (tpy)	VOC (tpy)	PM (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	SO_2 (tpy)	Pb (tpy)
Phase I Operations (Simple Cycle Only)								
Turbines	117.06	367.03	12.48	15.36	15.36	15.36	1.82	---
Cooling Tower	---	---	---	1.14	1.14	1.14	---	---
Building Heaters	1.68	1.01	0.07	0.09	0.09	0.09	0.01	---
Black-start Gen	6.68	0.26	0.14	0.03	0.03	0.03	0.09	---
Fire-pump	0.92	0.21	0.03	0.04	0.04	0.04	0.02	---
Totals	123.34	368.52	12.72	16.66	16.66	16.66	1.94	---
Phase II Operations (Simple Cycle/Combined Cycle)								
Source	**NO_X (tpy)**	**CO (tpy)**	**VOC (tpy)**	**PM (tpy)**	**PM_{10} (tpy)**	**$PM_{2.5}$ (tpy)**	**SO_2 (tpy)**	**Pb (tpy)**
Turbines	162.18	378.30	20.11	63.10	63.10	63.10	6.05	---
Cooling Tower	---	---	---	1.14	1.14	1.14	----	
Building Heaters	1.68	1.01	0.07	0.09	0.09	0.09	0.01	---
Black-start Gen	6.68	0.26	0.14	0.03	0.03	0.03	0.09	---
Fire-pump	0.92	0.21	0.03	0.04	0.04	0.04	0.02	---
Totals	171.46	379.78	20.35	64.41	64.41	64.41	6.16	---

Note: Emissions in this table and elsewhere in this document are frequently expressed to the nearest one hundredth unit (or more) for presentation and calculation purposes. Multiple digit accuracy should not be assumed.

3.2 Powerblock Sources

GE Power Systems (GE) provided turbine exhaust emissions estimates for this project. GE specifically guarantees volumetric concentration values, but also calculated hourly emission rates based on those concentration values. The quarantees are based on steady-state operating conditions for a range of ambient temperatures and load conditions. The combined cycle emissions were calculated based on environmental control vendor guaranteed concentration emissions following the duct burners and controls, based on GE guaranteed turbine exhaust concentrations. The annual PTE emission rates were calculated by assuming hour-limited operation of each generating unit in simple cycle operation, and the remainder of the yearly operations in combined cycle operation. Also, annual emissions resulting from combined cycle operation at 8,760 hours were reviewed.

3.2.1 Annual Potential to Emit

As noted above, instantaneous turbine emission rates vary depending on generator load and ambient temperature. In order to determine an applicable PTE annual emission rate, it was necessary to first define a worst-case annual operating scenario based on those two parameters. The worst case emission rates were reviewed for each of three generator load cases: 100%, 75%, and 60% (minimum sustained guaranteed load). For each of the load cases, emissions were evaluated at three different ambient temperatures: -17.7, 57.4 and 91.5°F.

The highest emissions among the nine cases were used to calculate annual PTE for each pollutant. This approach was used due to the inverse relationship between NO_X and CO emissions. NO_X emissions from the turbines are almost linear: as turbine load increases, NO_X emissions increase as well. The opposite is generally true for CO emissions. Because CO emissions are an indication of incomplete combustion, CO concentrations tend to increase at lower, less fuel-efficient turbine loads, and decrease at higher, more efficient turbine loads. When coupled with flowrate to determine mass emission rates, CO lb/hr emissions may be higher at either high or low turbine loads, depending on the magnitude of the differences between high concentration, low flowrate at low operating loads, and low concentration, high flowrate at high operating loads.

The combined cycle emissions were calculated based on pollution control vendor guaranteed concentration emissions following the duct burners and controls, based on GE guaranteed turbine exhaust concentrations. The annual PTE emission rates were calculated by assuming hours of operation are limited to 3,200 per year for each generating unit in simple cycle operation, and the remainder of the yearly operations in combined cycle operation. Also, annual emissions resulting from combined cycle operation at 8,760 hours were reviewed.

3.2.2 Maximum Hourly Emission Rates

Maximum hourly emission rates were determined for the purpose of conducting dispersion modeling to demonstrate compliance with various ambient air quality standards. The hourly rates were taken directly from vendor-provided emissions data, except as otherwise described in subsequent sections. Maximum uncontrolled emission rates for each pollutant were considered to be equivalent to the maximum rates resulting from the range of operating conditions considered. The values in Table 3-4 below represent the highest potential hourly emissions from each LM6000PF generating unit across all loads and temperatures. Compliance with ambient air quality standards at these maximum hourly rates is demonstrated in Section 6 – Ambient Air Quality Impacts.

3.2.2.1 SO_2 Emissions

The SO_2 emissions of the facility are directly attributed to fuel sulfur content. No additional sulfur originates from the process. Because the turbine vendor cannot control the fuels that are combusted by the turbine customer, only estimates are provided by the vendor for SO_2 emissions. For the purposes of this application, emissions of SO_2 were calculated assuming the combustion of pipeline quality natural gas.[12] The SO_2 values calculated are factored into both the hourly and annual potential emissions analyses. Conservatively, the SO_2 emissions are not reduced due to the calculated formation of ammonium sulfate in the exhaust. Ammonium sulfate formation is covered in Section 3.2.2.2.

[12] Pipeline quality natural gas as defined in 40 CFR 72.2.

3.2.2.2 Particulate Matter Less Than 2.5 Microns ($PM_{2.5}$) Emissions

Modeled impacts of particulate matter with an aerodynamic diameter less than 2.5 microns ($PM_{2.5}$[13]) are directly addressed in this application. EPA issued regulations governing implementation of New Source Review Permitting (NSR) for $PM_{2.5}$ on May 16, 2008 (*Federal Register*, Vol. 73, No. 96, pgs. 28321-28350); this final rule became effective on July 15, 2008. In the preamble to the $PM_{2.5}$ NSR regulations, a transition period to the new NSR regulations of three years from the rulemaking is allowed for "SIP[14]-approved States" like Montana. This time period is allowed for states to develop and implement regulations and prepare an SIP submittal to EPA. During this transition period, EPA will continue to allow states to use PM_{10} as a surrogate for $PM_{2.5}$.

The above EPA rule notwithstanding, the Montana Board of Environmental Review (BER) made a finding on April 21, 2008 on a contested case that the PSD air quality permit for Southern's proposed coal-fired generating facility should be remanded to MDEQ to complete a BACT analysis for $PM_{2.5}$. BER issued their remand order on May 30, 2008, stating that the permit "is remanded for a thorough top-down BACT analysis of $PM_{2.5}$ of the CFB boiler. A surrogate analysis for $PM_{2.5}$ is not acceptable." In light of this decision, and in the interest of fully evaluating all emissions from the proposed HGS gas plant, $PM_{2.5}$ has been added to the analysis of emissions and modeling impacts.

Emission rates of $PM_{2.5}$ were sought directly from the vendor. Direct, speciated $PM_{2.5}$ emission rate projections are not available; however, the vendor-provided emissions are based on EPA Test Methods 5 and 202. Therefore, both filterable and condensable particulate emissions are included in emissions tables. Because the fuel source for the turbines is natural gas, combustion emissions are likely to be only $PM_{2.5}$ filterable and condensables. To speciate these filterable and condensable emissions, the following highly conservative assumptions were used:

- All PM emissions are PM_{10},
- All PM_{10} emissions are $PM_{2.5}$.

PM_{10} emissions are provided by the turbine vendor. These emissions were then scaled by fuel input to the turbine to determine emissions at partial loads, for the purposes of modeling compliance. In addition, all primary sulfate emitted from the turbines, plus sulfate converted from SO_2 via the CO and SCR catalysts is assumed, for the purposes of this analysis only, to fully react with available SCR ammonia to form ammonium sulfate, which was treated as both PM_{10} and $PM_{2.5}$. Finally, as a further effort at conservatism, it was assumed that the ammonium sulfate reaction occurs before stack exit; i.e., it is not a secondary, atmospheric formation. See the BACT analysis in Section 5.6 for further discussion of $PM_{2.5}$ and Appendix C for ammonium sulfate formation calculations.

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[13] $PM_{2.5}$ as defined in 40 CFR §53.1 as "particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers…." $PM_{2.5}$, by definition, is a subset of PM_{10}, defined in 40 CFR §53.1 as "particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers…."
[14] SIP = State Implementation Plan

3.2.2.3 Combined Cycle Emissions

Determining the combined cycle emissions of the generating units is more involved than the emissions from simple cycle operation. Because the vendor of the combustion turbine is not the same vendor as the HRSG/air pollution control system, the mass emissions were not provided for the combined cycle operations. Emissions from the combined cycle portion of the exhaust train are based on the concentration of the turbine exhaust. This turbine exhaust concentration was determined by GE and provided to the HRSG/controls vendors, who in turn guarantee a stack exhaust concentration following the environmental controls. The mass-based emissions were then determined with known exhaust conditions: temperature, flowrate, heat rate, exhaust molecular weights and moisture. These calculations are included in the emission inventory in Appendix C.

3.2.3 BACT Emission Limits

The emission rate limits proposed for the HGS gas plant reflect the application of BACT. To simplify compliance with the limits, mass emission-based BACT limits are proposed to be applied over 24-hour block averages. The application of 24-hour block averages acknowledges the cyclical "peaking-like" daily operations of the facility[15], yet guarantees that the facility maintains the lowest emissions practicable for nominal operations. The annual and maximum hourly emissions calculated within this section are based on the BACT emission limits proposed. See Section 5 – BACT Analysis for complete analysis of these technologies and emission limits.

3.2.4 Startup/Shutdown and Commissioning Emissions

Emissions from the generating units differ whether the turbines are starting up, operating at steady-state, or shutting down, and whether the duct burners are firing or not. In simple cycle operation, the combustion turbines are capable of a 10 minute cold-startup to full load operations. The DLE system will stabilize and can begin controlling NO_X emissions within several minutes of a cold-start. Startup and shutdown emissions for simple cycle operations provided by the turbine vendor are summarized below in Table 3-3, and are included in Appendix C.

The startup period for combined cycle operations requires more time than a simple cycle startup. In order to maximize energy transfer in the HRSG during nominal steady-state operations, the thickness of the heat exchange tubes is relatively thin. The rapid temperature increase that would be experienced from a 10 minute cold-start simple cycle start would damage the thin heat exchange tubes. Therefore, the duration of the combined cycle startup and shutdown are extended to allow the heat exchange surfaces ample time to evenly heat, preventing damage.

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[15] It is expected that when affordable market power is not available, the average operations of the plant will be to start up in morning, run for several hours, shut down, restart in the afternoon, and shut down at night.

Because the combined cycle SUSD duration is extended, emissions are generally greater than a simple cycle startup. The air pollution environmental controls proposed for this project depend on catalyst temperatures for proper function. Because the heat exchange surfaces must be slowly and evenly heated, the catalysts remain at lower temperatures longer, and begin controlling the emissions of the exhaust stream at a later time than during a simple cycle startup.

Similar to Section 3.2.2.3, Southern calculated mass emissions during the combined cycle startup because the HRSG and air pollution control vendors were not able to provide these emissions by the time this application was prepared. In order to calculate these mass emissions, the instantaneous mass emission rate was calculated for each minute of the SUSD, and then summed-by-parts for the duration of the SUSD period. It was assumed that the HRSG would be heated (and thus, the air pollution controls) at the maximum safe rate to both prevent damage to the heat exchange surfaces, and ensure that the air pollution controls reach operational temperature as soon as practicable. See SUSD BACT discussions in Section 5.0.

As far as the turbine emissions are concerned, the exhaust concentrations from a combined cycle SUSD are no different than a simple cycle SUSD. What is different is the duration of the "ramping" portion of the SUSD cycle. The turbine will still proceed through the hydraulic spin-up, fire-on and flame stabilization periods, at the same rate as a simple cycle startup. The ramp-up to base load will be "extended" up to two hours for the combined cycle startup. Because the HRSG has a known maximum heat input rate[16] which is linear, we can calculate the temperature of the air pollution controls, and hence when they will begin controlling the concentration of the exhaust stream. The controls vendor provided a performance graph indicating the % reduction expected at various temperatures. Coupled with the known turbine exhaust concentration, the mass emissions during combined cycle startup can be calculated with the known parameters listed in Section 3.2.2.3. Table 3-2 below summarizes SUSD emissions for this facility.

Table 3-2: Comparison of Operational Hourly Emission Rates to Startup/Shutdown Emission Rates

Pollutant	Maximum Operational Simple Cycle Hourly Emission Rates (lb/hr)	Maximum Simple Cycle Hourly SUSD Emission Rates (lb/hr)	Maximum Operational Combined Cycle Hourly Emission Rates (lb/hr)	Maximum Combined Cycle Hourly SUSD Emission Rates (lb/hr)
NO_X	36.58	36.58	4.16	26.12
SO_2	0.57	0.57	0.69	0.69
$PM/PM_{10}/PM_{2.5}$	4.80	4.80	7.20	7.20
CO	48.96	114.70	2.03	76.20
VOC	2.03	3.90	1.86	1.86

[16] 22℉ maximum temperature increase per minute, from Vogt International bid proposal

During generating unit installation and any maintenance that requires removal and/or replacement of a combustion turbine, Southern requests a commissioning period to tune the environmental controls.[17] This period and associated limits only applies to the combined cycle mode of operation. The ammonia injection grid controls for the SCR units will arrive with a factory-calculated operation program from the vendor. Actual turbine operations are required to fine-tune the feedforward and feedback loops to attain maximum control efficiencies. This procedure will be performed on each turbine independently. The commissioning period is expected to last 16 weeks per turbine from first firing.

During the commissioning period, it is not practicable to operate the turbines and the controls at maximum efficiency. It is conceivable that the turbines may operate for periods of time without SCR and CO catalyst control during the commissioning period. The BACT-equivalent emission limits need to be relaxed to reflect numerous testing conditions during this traditional start-up period. Table 3-3 summarizes the requested commissioning emission limits. These limits are based on the simple cycle DLE mode of turbine operation.

Table 3-3: Summary of Proposed Commissioning Emission Limits[a, b]

Pollutant	Commissioning Period Emission Limit (lb/hour)	Fuel Type
NO_X	36.58	Natural Gas
CO	114.70	Natural Gas
SO_2	0.69	Natural Gas
Particulate (all sizes)	7.20	Natural Gas
VOC	3.90	Natural Gas

Note a: Emission rates apply only to the turbines. The emission rates are the same as the hourly limit proposed for the turbines in Table 3-4.

Note b: The emission limits in the table would apply only during the first 16 weeks following the first firing of each turbine. The limits would revert to those found in Section 5 (BACT) of this application following the commissioning period.

3.2.5 Powerblock Summary

Potential hourly and annual emission rates for the turbines are summarized in Table 3-4. Detailed emission calculations for the various pieces of equipment installed at the facility can be found in the spreadsheets in Appendix C and on the DVD in Appendix I.

[17] For purposes of this application, the term 'commissioning' refers to any time that a new or refurbished turbine is installed or re-installed at the facility.

Table 3-4: Powerblock Emissions Summary

Pollutant	Annual Emissions * (tpy)	Hourly Emission Rate Natural Gas (lb/hr/generating unit)
NO_X	162.18	36.58
CO	378.30	114.70
SO_2	6.05	0.69
$PM/PM_{10}/PM_{2.5}$	63.10	7.20
VOC	20.11	3.90

* The annual emissions represent the sum of the two turbines and two duct burners.

Note: Emissions are expressed to the nearest one hundredth unit for presentation and calculation purposes. Multiple digit accuracy should not be assumed.

3.2.6 Hazardous Air Pollutants Emissions

Hazardous air pollutants (HAPs) were calculated using emission factors from AP-42, Chapters 3.1 (4/00), 3.3 (10/96) and 3.4 (10/96). Table 3-5 presents the HAPs emissions inventory for the turbines and duct burners.

A spreadsheet with detailed HAPs emissions calculations is contained in Appendix C and on CD-ROM in Appendix I.

Table 3-5: Hazardous Air Pollutants Emission Inventory

Hazardous Air Pollutant	CAS Number	Emissions from Natural Gas Turbines (tpy)	Emissions from Black Start Generator (tpy)	Emissions from Emergency Fire Pump (tpy)	Total Facility Emissions (tpy)
Organic HAPs					
1,3-Butadiene	106-99-0	0.002	0.0E+00	2.45E-05	0.002
Acetaldeyde	75-07-0	0.157	9.2E-05	4.81E-04	0.157
Acrolein	107-02-8	0.025	2.9E-05	5.80E-05	0.025
Benzene	71-43-2	0.047	2.8E-03	5.85E-04	0.050
Ethyl benzene	100-41-4	0.125	0.00	0.00	0.125
Formaldehyde	50-00-0	2.783	2.9E-02	7.40E-04	2.813
Naphthalene	91-20-3	0.005	4.7E-04	5.32E-05	0.006
Polycyclical Aromatic Hydrocarbons (PAH)	PAH	0.009	7.7E-04	1.05E-04	0.010
Propylene Oxide	75-56-9	0.114	1.0E-02	1.62E-03	0.125
Toluene	108-88-3	0.510	1.0E-03	2.57E-04	0.511
Xylenes	1330-20-7	0.251	7.0E-04	1.79E-04	0.252
Total Organic HAPs		**4.03**	**0.045**	**0.004**	**4.08**
Inorganic HAPs					
Lead	7439-92-1	0.00	0.00	0.00	0.00
Total Inorganic HAPs		**0.00**	**0.00**	**0.00**	**0.00**
Total Calculated Maximum Potential HAP Emissions		**4.03**	**0.045**	**0.004**	**4.08**

3.3 Additional Process Emissions

3.3.1 Blackstart Emergency Diesel Generator and Firepump

An emergency generator and an emergency fire pump will each utilize a diesel engine and will be used and tested intermittently at the HGS gas plant. The black-start emergency diesel generator set is estimated to produce 1,500 kW net and will supply power for essential electrical equipment in the event that all other electric power to the facility is interrupted. The diesel fire pump set is estimated to be 230 kW and will provide essential fire protection backup. The emergency generator and emergency fire pump will each operate less than 500 hours a year with potential emissions detailed in Table 3-6 below.

Table 3-6: Potential Emissions From Emergency Diesel Generator and Emergency Diesel Fire Pump

	Blackstart Emergency Generator		Emergency Fire Pump	
	Emission Rate		Emission Rate	
	(lb/hr)	(tpy)	(lb/hr)	(tpy)
NO_x	26.7	6.68	3.68	0.92
CO	1.1	0.26	0.85	0.21
VOC	0.6	0.14	0.14	0.03
SO_2	0.37	0.09	0.06	0.02
$PM/PM_{2.5}/PM_{10}$	0.10	0.03	0.14	0.04

3.4 Additional Non-Process Emissions

3.4.1 Building Heaters

The facility will have several buildings that will require heaters to provide a safe and comfortable working environment. The proposed natural gas-fired heaters are small (i.e., insignificant emitting units as defined in Title V) but have been included for completeness of this emissions inventory. Table 3-7 lists the location and anticipated heat input for the building heaters.

Table 3-7: Building Heater Description

Building Location	Heat Rate (MMBtu/hr)
Turbine Enclosures	0.25
Admin/Maintenance/Electrical/STG Building	1
Water Treatment Building	0.5
Warehouse	0.5
Water Pumphouse	0.25
Fuel Gas Compressor Building	0.25
CEMS Enclosures (2 ea)	0.05
Total	2.8

Potential hourly emissions for the heaters, presented in Table 3-8, were calculated using emission factors from AP-42, Tables 1.4-1 and 1.4-2 for natural gas. The building heaters will operate on an "as-needed" basis and will not run year-round; however, the potential annual emissions in Table 3-9 were calculated using 8,760 hrs per year. Actual annual emissions are expected to be much lower.

Table 3-8: Building Heaters Potential Hourly Emissions

Building Location	NOx (lb/hr)	SO_2 (lb/hr)	CO (lb/hr)	VOC (lb/hr)	$PM/PM_{2.5}/PM_{10}$ (lb/hr)
Turbine Enclosures	0.03	0.0001	0.021	0.001	0.002
Admin/Maintenance/Electrical/STG Building	0.14	0.0006	0.082	0.005	0.007
Water Treatment Building	0.07	0.0003	0.041	0.003	0.004
Warehouse	0.07	0.0003	0.041	0.003	0.004
Water Pumphouse	0.03	0.0001	0.021	0.001	0.002
Fuel Gas Compressor Building	0.03	0.0001	0.021	0.001	0.002
CEMS Enclosure (2 ea)	0.01	0.0000	0.004	0.000	0.000

Table 3-9: Building Heaters Potential Annual Emissions

	NOx (tpy)	SO_2 (tpy)	CO (tpy)	VOC (tpy)	$PM/PM_{2.5}/PM_{10}$ (tpy)
Total All Building Heaters	1.68	0.01	1.01	0.07	0.09

4.0 REGULATORY ANALYSIS

This section evaluates all applicable requirements for this Montana air quality permit application, as required by the Administrative Rules of Montana (ARM). The Montana air quality permit program incorporates various federal and Montana Clean Air Act requirements either explicitly or by reference. A review of the state and federal rules indicates that the requirements listed in Table 4.1 could apply or at least partially apply to the proposed HGS gas plant. Specific applicability or non-applicability determinations are made in following sections of this chapter.

Table 4-1: Applicable Regulations Analysis

Report Section	Description	Rule Citation
4.1	**General Provisions**	**ARM 17.8 Subchapter 1**
4.2	**Ambient Air Quality – Subchapter 2**	**ARM 17.8 Subchapter 2**
4.3	**Emission Standards – Subchapter 3**	**ARM 17.8 Subchapter 3**
4.3.1	Visible Air Contaminants	ARM 17.8.304(2)
4.3.2	Particulate Matter, Airborne	ARM 17.8.308
4.3.3	Particulate Matter – Fuel Burning Equipment	ARM 17.8.309(2)
4.3.4	Sulfur Oxide Emissions – Sulfur-in-Fuel	ARM 17.8.322(5)
4.4	**Standard of Performance For New Stationary Sources**	**ARM 17.8.340**
4.4.1	Subpart KKKK - Standard of Performance For Stationary Gas Turbines	40 CFR 60.4300 - 60.4420
4.4.2	**Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines**	**40 CFR 60.4200 – 60.4219**
4.5	**Emission Standards for Hazardous Air Pollutants for Source Categories**	**ARM 17.8.342(1)**
4.5.1	Subpart B - Requirements for Control Technology Determinations for Major Sources in Accordance With Clean Air Act Sections, Sections 112(g) and 112(j)	40 CFR 63
4.5.2	Subpart YYYY - National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines	40 CFR 63.6080 – 63.6175
4.5.3	Subpart ZZZZ - National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines	40 CFR 63.6580 – 63.6675
4.6	**Stack Heights and Dispersion Techniques**	**ARM 17.8 Subchapter 4**
4.7	**Air Quality Permit Application, Operation and Open Burning Fees**	**ARM 17.8 Subchapter 5**
4.7.1	Air Quality Permit Application Fees	ARM 17.8.504
4.7.2	Air Quality Permit Operation Fees	ARM 17.8.505
4.8	**Open Burning**	**ARM 17.8 Subchapter 6**
4.9	**Permit, Construction, and Operation of Air Contaminant Sources**	**ARM 17.8 Subchapter 7**
4.9.1	Permitting Process	ARM 17.8.704 - 710
4.9.2	Emission Control Requirements	ARM 17.8.715
4.9.3	Public Review of Permit Applications	ARM 17.8.720
Error! Reference source not found.	Duration of Permit	ARM 17.8.760

Report Section	Description	Rule Citation
4.10	**Prevention of Significant Deterioration of Air Quality**	**ARM 17.8 Subchapter 8** **40 CFR 52.21**
4.11	**Permit Requirement for Major Stationary Sources or Major Modifications Locating within Nonattainment Areas**	**ARM 17.8 Subchapter 9**
4.12	**Preconstruction Permit Requirements for Major Stationary Sources Locating within Attainment or Unclassified Areas**	**ARM 17.8 Subchapter 10**
4.13	**Visibility Impact Assessment (Class 1 area analysis)**	**ARM 17.8 Subchapter 11**
4.14	**Operating Permit Program**	**ARM 17.8 Subchapter 12**
4.15	**Chemical Accident Prevention Provisions**	40 CFR Part 68
4.16	**Acid Rain Program**	ARM 17.8.1234 40 CFR Parts 72-78
4.17	**Compliance Assurance Plan**	**ARM 17.8 Subchapter 15**

BACT analyses are presented in Section 5 of this application. Ambient air quality standards and PSD Class II increment analyses are addressed in Section 6 of this application.

4.1 General Provisions

The HGS gas plant will be designed to comply with all of the requirements and general provisions in ARM 17.8 Subchapter 1. The applicable provisions of Subchapter 1 relate to malfunctions, circumvention and variances. The remainder of Subchapter 1 contains provisions applicable to MDEQ procedures and definitions. Regarding malfunctions, Southern will notify reportable malfunctions to MDEQ as specified by §110(2) *et seq*. In regard to circumvention, Southern will not engage in any activity prohibited by §111. Since no variances are being sought for this application, there are no applicable requirements for the HGS gas plant contained in §120 and §121. Finally, emissions testing at the facility, where required, will be conducted in accordance with the provisions of §105 and §106 as required unless otherwise specified by the final air quality permit or other federal or state rule as appropriate.

4.2 Ambient Air Quality Standards

ARM Chapter 17.8, Subchapter 2, establishes the Montana ambient air quality standards (MAAQS). Emissions from the proposed HGS gas plant have been analyzed to ascertain compliance with the ambient air quality standards contained in this sub-chapter. Air dispersion modeling analyses, which are presented in Section 6 of this application, provide a demonstration that the facility will be in compliance with these ambient and federal (40 CFR 50) standards.

4.3 Emission Standards

ARM Chapter 17.8, Subchapter 3 outlines Montana's rules regarding emission standards. Applicable sections of the subchapter are outlined below in Sections 4.3.1 through Section 4.3.4.

4.3.1 Visible Air Contaminants

Montana ARM 17.8.304 limits the opacity of emissions from all facilities. Facilities built or modified after November 23, 1968, must not exhibit opacity greater than 20% (six-minute average) from any source. All equipment associated with the modifications will be subject to the 20% opacity limitation. Southern is required to comply with the provisions of ARM 17.8.304.

4.3.2 Particulate Matter, Airborne

Montana ARM 17.8.308 limits opacity from fugitive emission sources to no greater than 20% (six-minute average). Southern is required to comply with the provisions of ARM 17.8.308.

4.3.3 Particulate Matter – Fuel Burning Equipment

ARM 17.8.309 states that no new fuel burning equipment shall emit PM in excess of the limit provided by the following equation:

$$E = 1.026H^{-0.233}$$

Where: E = Particulate Emission Rate (lbs/MMBtu)
H = Heat Input Capacity (MMBtu/hr)

The maximum heat input capacity of one of the combined cycle GE LM6000PF generating units is approximately 447.5 MMBtu/hr (full load w/ duct burner, natural gas at -17.7°F). The maximum PM emission rate according to the above equation is 0.25 lbs/MMBtu.

$$E = 1.026H^{-0.233}$$
$$E = 1.026(447.5\ \text{MMBtu/hr})^{-0.233}$$
$$E = 0.25\ \text{lbs/MMBtu}$$

The following equation converts a PM emission rate of lbs/hr to lbs/MMBtu. With a PM calculated emission rate of 0.016 lbs/MMBtu (based on PM emissions of 7.20 lb/hr per generating unit firing natural gas) for each combined cycle turbine, the HGS gas plant will be in compliance with ARM 17.8.309. All fuel burning equipment at the HGS gas plant is evaluated in Table 4-2.

$$E = (7.20\ \text{lbs/hr} / 2) / (447.5\ \text{MMBtu/hr})$$
$$E = 0.016\ \text{lbs/MMBtu}$$

Table 4-2 : Fuel Burning Equipment

Fuel Burning Unit	Fuel	Maximum Hourly Heat Input (MMBtu/hr)	Projected PM_{10} Emissions (lb/MMBtu)	Emission Limit $E= 1.026h^{-0.233}$ (lb/MMBtu)	Comply (Yes/No)
Combustion Turbines	Natural Gas	447.5	0.016	0.25	Yes
Emergency Generator	Fuel Oil	10.33	0.007	0.60	Yes
Emergency Fire Pump	Fuel Oil	2.51	0.056	0.83	Yes
Building Heaters	Natural Gas	8.5	0.007	0.62	Yes

4.3.4 Sulfur Oxide Emissions – Sulfur-in-Fuel

ARM 17.8.322(5) states that no facility shall burn any gaseous fuel containing sulfur compounds in excess of 50 grains per 100 cubic feet of gaseous fuel, calculated as hydrogen sulfide at standard conditions. The HGS gas plant will comply with this requirement by combusting pipeline quality natural gas.

4.4 New Source Performance Standards

ARM 17.8.340 incorporates by reference the New Source Performance Standards (NSPS) of 40 CFR 60. Applicable NSPS subparts are detailed below.

4.4.1 Subpart KKKK – Stationary Gas Turbines

Subpart KKKK applies to all stationary gas turbines constructed after February 18, 2005, with a heat input at peak load equal to or greater than 10 MMBtu/hr. Each gas turbine is equal to approximately 447.5 MMBtu/hr; therefore, the turbines are subject to Subpart KKKK. Subpart KKKK specifies standards for NO_X emissions and SO_2 emissions as outlined in Sections 4.4.1.1 and 4.4.1.2. Monitoring requirements are in Section 4.4.1.3.

4.4.1.1 NO_X Emission Limit

Table 1 of Subpart KKKK states that, if a new stationary gas turbine firing natural gas has a heat input at peak load greater than 50 MMBtu/hr and less than or equal to 850 MMBtu/hr, the NO_X emission standard is 25 ppm at 15% O_2. For new stationary gas turbines firing fuels other than natural gas with a heat input at peak load greater than 50 MMBtu/hr and less than or equal to 850 MMBtu/hr, the NO_X emission standard is 74 ppm at 15% O_2.

Per discussion found in Section 5.2 BACT - NO_X and in spreadsheet data provided by the vendor, Southern has established SCR and dry-low emissions (DLE) as BACT for control of combined cycle NOx emissions at the HGS gas plant. Combined cycle emission rates are expected to be approximately 2.5 ppmvd at 15% O_2. In simple cycle mode, the turbines will meet 25 ppmvd at 15% O_2. Since these values are less than or equal to the limitations found in Subpart KKKK, the turbines will operate in full compliance with this subpart.

4.4.1.2 SO_2 Emission Limit

Subpart KKKK states that a stationary gas turbine subject to Subpart KKKK shall comply with one or the other following conditions:

1. An SO_2 emission rate of 0.9 pounds per megawatt-hour.
2. Shall not burn any fuel which contains sulfur in excess of 0.06 lb SO_2/MMBtu heat input.

The HGS gas plant will comply with the SO_2 emission limit by burning pipeline quality natural gas. The natural gas that the HGS gas plant will combust is expected to have approximately 0.0017% sulfur by weight.[18]

4.4.1.3 Monitoring Requirements

Subpart KKKK requires continuous monitoring of fuel consumption and the water to fuel ratio if water injection is used, unless an NO_X CEMS is installed for Part 75 (Acid Rain) requirements. Southern will comply with the requirement to monitor nitrogen as required.

Since Southern is intending to use pipeline quality natural gas as defined in this Subpart, the facility may elect not to monitor total sulfur content of the gaseous fuel.

Records will be maintained that will address all of the MDEQ operating permit requirements applicable to Subpart KKKK.

4.4.2 Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

The requirements of Subpart IIII could apply to the HGS gas plant project if engines associated with the facility meet the manufacture dates (and other requirements) of that Subpart. Specific manufacture dates are not known at this time. Subpart IIII applies to owners and operators of compression ignition internal combustion engines (CI ICE) that commence construction after July 11, 2005, where the CI ICE are manufactured after April 1, 2006, and are not fire pump engines, or are manufactured and certified as a National Fire Protection Association fire pump engine after July 1, 2006. Both cases apply to the HGS gas plant as both a blackstart emergency diesel generator and fire pump engine will be installed, both with manufacture dates potentially after the applicability dates presented above.

Because the new blackstart generator will have a displacement of less than 10 liters per cylinder, the emissions standards of §60.4202 will apply. Based on maximum engine

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[18] [0.5 gr/100 scf (40CFR72.2)] / [7000 gr/lb] / [1 lb NG/23.8 cf (AP-42, Appx A)] = 0.000017 lb S/ 1 lb NG = 0.0017%.

power required in the blackstart generator, §60.4202 refers to emission standards specified in 40 CFR 89.112 and 89.113. Table 1 – Emission standards (g/kW-hr) of §89.112, Oxides of nitrogen, carbon monoxide, hydrocarbon, and particulate matter exhaust emission standards, applies and is reproduced below as Table 4-3. The emission values from the proposed blackstart generator are compared in the table to the emissions standards of §89.112; all emissions will comply.

Table 4-3 : Emission Standards Applicable to the HGS Gas Plant Blackstart Generator

Rated Power	Tier	Model Year	NMHC + NOx	CO	PM
kW > 560	Tier 2	>2006	6.4	3.5	0.20

Because the proposed firepump has a displacement less than 30 liters per cylinder, it must meet the emissions standards of Table 4 of Subpart IIII, which is reproduced below as Table 4-4. The emission values from the proposed fire pump engine are compared in the table to the required emissions standards; all emissions will comply.

Table 4-4 : Emission Standards Applicable to the HGS Gas Plant Fire Pump Engine

Rated Power	Model Year	NMHC + NOx	CO	PM
225 > kW ≥ 450	2008 and earlier	7.8	2.6	0.40
	2009+	3.0	-	0.15

Southern will comply with all fuel specifications, monitoring, and compliance requirements of the subpart.

4.5 National Emission Standards for Hazardous Air Pollutants for Source Categories

ARM 17.8.342 references the rules contained in 40 CFR Part 63 for National Emission Standards for Hazardous Air Pollutants (NESHAPs) for source categories. These requirements affect listed sources and/or facilities that are major for hazardous air pollutants (HAPs). Applicable subparts are detailed below.

A major facility for HAPs is defined as a stationary source that has the potential to emit more than 10 tpy of any individual listed HAP or 25 tpy of the total combination of HAPs. As Table 3-5 summarizes, the highest single HAP (formaldehyde) emission rate is 2.8 tpy, and the combination of HAPs is 4.03 tpy. The HGS gas plant will not operate at the same time as the coal plant, therefore, based on these HAP emissions, the HGS gas plant is not major for HAPs. Therefore, Sections 112(g) and 112(l) of the Federal Clean Air Act are not applicable to this facility.

4.5.1 Subpart B – Requirements for Control Technology Determinations for Major Sources in Accordance With Clean Air Act Sections, Sections 112(g) and 112(j)

Subpart B applies to facilities that are a major source for HAPs. Section 3.2.6 summarizes the HAPs emission inventory, which shows that the facility is not major for HAPs. Therefore, MACT standards for major sources are not applicable and no area source MACT standards apply to any units at HGS.

4.5.2 Subpart YYYY - National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines

Subpart YYYY applies to facilities that are a major source for HAPs. Section 3.2.6 of this application summarizes the HAPs emission inventory, which shows that the facility is not major for HAPs. Therefore, the provisions of Subpart YYYY are not applicable to any units at HGS.

4.5.3 Subpart ZZZZ - National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

Subpart ZZZZ was first signed into rule and published in the *Federal Register* (69FR33473) on June 15, 2004. Subpart ZZZZ contained MACT standards applicable to reciprocating internal combustion engines (RICE) with a manufacturer's nameplate rating above 500 hp located at a major source of HAP emissions.

Modifications to Subpart ZZZZ were published in the *Federal Register* (73FR3568) on January 18, 2008. Subpart ZZZZ was modified to include MACT standards applicable to internal combustion engines with a site rating of less than or equal to 500 hp located at major sources, and new and reconstructed stationary RICE located at area sources.

In 40 CFR 63.2, a major source of HAP emissions is defined as any stationary source that has the potential to emit 10 tons per year of any HAP or 25 tons per year of any combination of HAPs. A source emitting any HAPs below those values is defined as an area source; therefore, HGS is considered an area source of HAP emissions, and not a major source. Per §63.6585, Subpart ZZZZ MACT requirements are applicable to the compression ignition blackstart emergency generator and fire pump.

In §63.6950, an affected source that is a new or reconstructed stationary RICE located at an area source must meet the requirements of this part by meeting the requirements of 40 CFR 60 Subpart IIII, for compression ignition engines. No further requirements apply for such engines under Subpart ZZZZ.

4.6 Stack Heights and Dispersion Techniques

Rules governing stack heights do not physically limit the height of a given stack. Rather, the rules provide no incentive for building "tall" stacks since all analyses of BACT, modeling, etc., are based upon Good Engineering Practice (GEP) stack height or actual height, whichever is less. GEP is defined as the greater of three alternatives as provided in ARM 17.8.401(2)(a) through (c) and 40 CFR 51.100(ii)(1), (2), and (3).

The facility's stacks will be less than 65 meters, which is considered GEP by ARM 17.8.401(2)(a) and 40 CFR 51.100(ii)(1). The applicable part of this regulation prohibits setting an emission limit based upon a stack height in excess of GEP or a "dispersion technique." Since all modeling was conducted at a GEP height, or below, and the HGS gas plant will not employ any "dispersion technique," this analysis complies with this requirement.

4.7 Air Quality Permit Application, Operation and Open Burning Fees

ARM Chapter 17.8 Subchapter 5 sets out applicable fees that will apply to this facility. The following two sections describe these fees.

4.7.1 Air Quality Permit Application Fees

In accordance with ARM 17.8.504, concurrent with the submittal of this application, Southern is submitting $3000 for the associated air quality permit application fee. In addition, Southern is submitting $500 for the associated air quality operating permit fee per ARM 17.8.504(2).

4.7.2 Air Quality Operating Fees

In accordance with ARM 17.8.505, after the facility is operating, Southern will pay the required annual operating fees based on actual or estimated actual emissions.

4.8 Open Burning

No open burning is expected at the HGS gas plant. If Southern plans on any open burning, HGS will comply with all regulations in ARM 17.8 Subchapter 6.

4.9 Permit, Construction, and Operation of Air Contaminant Sources

ARM Chapter 17.8 Subchapter 7 sets out the rules for preconstruction permitting in Montana. Applicable subsections are outlined below.

4.9.1 Permitting Process

Under ARM 17.8.743 and 744, an application for an air quality permit modification is required for the proposed HGS gas plant. Southern proposes to obtain a separate air quality permit for the HGS gas plant from the Highwood Generating Station, which currently is authorized under permit #3423-01. Although Southern requests a separate permit, Southern acknowledges that this permit application constitutes a major modification of a major stationary source, and it has been treated as such in this application. The required permit application forms have been completed for the proposed equipment in accordance with ARM 17.8.748 and are attached to this document in Appendix A.

4.9.2 Emission Control Requirements

ARM 17.8.752 describes Montana's primary emission control standard for new source review (NSR). In order to comply with ARM 17.8.752, BACT has been analyzed for NOx, CO, PM/PM_{10}/$PM_{2.5}$, SO_2, and VOC. The BACT analyses are contained in Section 5.0.

4.9.3 Public Review of Permit Applications

ARM 17.8.748 also requires the applicant to notify the public of its application for an air quality permit by means of a newspaper of general circulation in the area affected by the proposed facility. Such public notification will be served by advertisement in the daily newspaper *Great Falls Tribune* on April 25, which is within ten days of filing the complete permit application. An affidavit of publication will be submitted to MDEQ as soon as it is available.

4.10 Prevention of Significant Deterioration of Air Quality

PSD regulations apply to a new or modified stationary source if it is deemed "major." A stationary source that is "listed" according to ARM 17.8.801(22)(a)(i) is considered major if it has the potential to emit more that 100 tpy of any pollutant subject to regulation under the Federal Clean Air Act. If it is not "listed," it is considered major if it has the potential to emit more than 250 tpy of any regulated pollutant. The HGS gas plant will be a "listed" source, as it will contain a fossil fuel fired steam electric plant of more than 250 million British thermal units per hour heat input. According to Section 3, the facility does have the potential to emit more than 100 tpy of any regulated pollutants. Therefore, the HGS gas plant is a major stationary source per ARM 17.8.801(22)(a)(i).

4.10.1 Air Quality Analysis and Preconstruction Monitoring

Since the HGS gas plant is a major modification to a major source, preconstruction monitoring may be required under ARM 17.8.822. An ambient air quality modeling analysis for preconstruction monitoring was performed and is included in Section 6. Results of that analysis show that the impacts from the proposed gas plant are less than the monitoring thresholds listed in ARM 17.8.818 (7)(a). Thus, the HGS gas plant is exempted from performing any pre-construction monitoring. Table 4-5 shows the preconstruction monitoring thresholds versus the results of the ambient impacts analysis.

Table 4-5: Pre-construction Monitoring Threshold Analysis

	PM_{10} 8 hour	**SO_2** 24 hour	**NO_2** annual	**Ozone** tpy	**CO** 8 hour
Pre-construction Monitoring Thresholds	10 $\mu g/m^3$	13 $\mu g/m^3$	14 $\mu g/m^3$	100 tpy VOC	575 $\mu g/m^3$
Modeled Values	6.5 $\mu g/m^3$	2.75 $\mu g/m^3$	1.8 $\mu g/m^3$	20.06 tpy VOC	107 $\mu g/m^3$
Pre-construction Monitoring Required ?	NO	NO	NO	NO	NO

4.11 Permit Requirements for Major Stationary Sources or Major Modifications Locating Within a Nonattainment Area

HGS is not located within a nonattainment area; therefore, the requirements in ARM 17.8.901 *et seq*. do not apply to this project.

4.12 Preconstruction Permit Requirements for Major Stationary Sources Locating Within Attainment or Unclassified Areas

ARM 17.8.1004 addresses new major stationary sources or major modifications located in an area designated as attainment or unclassifiable, but causing or contributing to a violation of an ambient air quality standard at a location not meeting ambient standards. Modeling has been conducted to show that the HGS gas plant does not cause or contribute to any violation of any ambient air quality standard.

4.13 Visibility Impact Assessment

As a major source, the HGS gas plant is obligated to perform a visibility impact assessment in accordance with ARM 17.8 Subchapter 11. The visibility impact assessment included in Section 6 uses the EPA recognized modeling program CALPUFF for evaluation of potential plume visual impacts. The visibility impact from the HGS gas plant is below significance values at all Class I areas analyzed.

4.14 Operating Permit Program

This permit application also serves as an operating permit (Title V) modification. Southern will comply with all regulations in ARM 17.8 Subchapter 12.

4.15 Chemical Accident Prevention Provisions

40 CFR 68 sets forth requirements of stationary sources to prevent accidental releases of regulated substances. At the HGS gas plant, the aqueous ammonia is injected into

the turbine exhaust for NO_X control in a Selective Catalytic Reduction catalyst. Per Table 1 of §68.130, aqueous ammonia is a regulated substance. However, the size of the proposed ammonia tanks (one each at 10,000 gallons) and the concentration of ammonia used (19%) is below the threshold values of Table 1; therefore, these regulations are not applicable to the HGS gas plant.

4.16 Acid Rain Program

Southern is required to comply with all of the applicable portions of the acid rain program (ARP) set forth in 40 CFR Parts 72-78. Applicability of the acid rain program is found in §72.6(a). At least a portion of the program is applicable to the facility since the generating units will be considered a new utility unit [§72.6(a)(3)(i)]. The term "new unit" (§72.2) is a unit that commences commercial operation on or after November 15, 1990. The project meets this requirement. Because the electric generators driven by the turbines have a nameplate capacity greater than 25 MWe, these units are not exempted by the New Unit Exemption of §72.7.

The acid rain provisions may be summarized as three primary programs. The first is the sulfur dioxide allowance system (§73). Southern will be required to obtain the necessary number of allowances to operate the facility. Allowances are currently available from a number of public and private sources.

The second program is the NO_X emission standards. These standards are found in §76. These standards only apply to coal-fired utility units [§76.1(a)]. Since this unit will not combust coal, it is exempt from these standards.

The final program is emissions monitoring (§75). As the most complex of the programs within the ARP, it is discussed in more detail below in the Acid Rain Permit Application section.

4.16.1 Acid Rain Permit Application

Per §72.31, a complete acid rain permit application shall contain the following:

a) Identification of the affected sources at the facility. Appendix H serves this purpose;
b) Identification of acid rain phase that is applicable to each affected unit. As these units are new, Acid Rain Program Phase II is the sole applicable phase;
c) A complete compliance plan for each unit, in accordance with subpart D of §72;
d) The standard requirements of §72.9;
e) The date that the units will commence operation and the deadline for monitor certification.

4.16.1.1 Compliance Plan

Appendix H serves as the compliance plan for this facility in accordance with §72.31 and §72.40(a)(1). No acid rain compliance options are applicable to this facility. §72.40(2) is not applicable either, as 40 CFR Part 76 - Acid Rain Nitrogen Oxides

Emission Reduction Program has already been demonstrated as not applicable to this facility.

4.16.1.2 Standard Requirements of 40CFR §72.9

Of the Standard Requirements of §72.9, the Permit Requirements, Monitoring Requirements, Sulfur Dioxide Requirements, and Recordkeeping and Reporting Requirements are applicable. A reduced utilization plan is not required per §72.43.

Per §75.10, monitoring is required, as this facility contains affected units. According to §75.11(d), a continuous emissions monitor (CEM) for sulfur dioxide is not specifically required. This regulation provides three options for measuring and reporting sulfur dioxide of which a CEM is one choice. As a gas-fired unit, SO_2 mass emissions for the purpose of the ARP will be calculated per the procedures in Appendix D of 40 CFR Part 75. For NO_X, it appears that a CEM is required, since these generating units do not meet the definition of a peaking unit [§75.12(a)]. Along with the NO_X monitor, a diluent monitor (oxygen or carbon dioxide) is also required.

§75.19 allows for an alternative to CEMs if each turbine can meet the definition of a Low Mass Emitting (LME) unit. In order to be an LME unit, the unit must be a gas- or oil-fired unit with an NO_X emission rate under 100 tpy and an SO_2 emission rate under 25 tpy. The generating units do not meet those requirements when initial emissions are calculated per the elevated emission factors of §75.19(a)(4) for units controlled via SCR. The generating units do meet those requirements when emissions are calculated from vendor performance guarantees. Section 75.19(a)(2)(ii) requires three consecutive years of actual emissions data to prove applicability. Because this is a new facility, actual emissions data is not available. §75.19(a)(2)(ii)(B) allows projected emissions data to be calculated for new units. The NO_X emission rates from Table LM-2 of the section are not representative of emissions from this facility; therefore, a fuel-and-unit-specific NO_X emission rate would be used. Testing would be performed per Appendix E of Part 75. Per §1.1 of the Appendix, the test method applies only to peaking units. Because the HGS gas plant does not meet the definition of a peaking unit per §72.2, the combustion units cannot use a fuel-and-unit-specific NO_X emission rate. The Table LM-2 and §75.19(a)(4) emission rates are almost an order of magnitude higher than the performance guarantees provided by PWPS. As a result, the GE LM6000PF generating units cannot be classified as LME units and must install an NO_X-diluent continuous emission monitoring system per §75.12.

As a new unit, any CEMs installed for acid rain purposes must be installed and certified by the earlier of 90 unit operating days or 180 calendar days after the date the unit commences commercial operation, per §75.4(b)(2).

Finally, per §75.13(b), CO_2 mass emissions will be determined via the numeric procedures of Appendix G of 40 CFR Part 75.

4.17 Compliance Assurance Monitoring

Compliance assurance monitoring (CAM) is applicable to a pollutant-specific emissions unit at a major source (Title V) that is required to obtain an air quality operating permit if it meets the following criteria:

- The emissions unit must be subject to an emission limitation or standard for the regulated air pollutant;
- The unit must use a control device to achieve that emission limit or standard; and
- The unit must have pre-controlled emissions above 100 tpy.

Only the turbines meet the CAM applicability criteria. The criteria are only applicable to NO_X and CO. Southern will supply MDEQ with a formal CAM plan prior to the issuance of a Title V permit. The CAM plan itself will then be incorporated into the final Title V permit.

5.0 BEST AVAILABLE CONTROL TECHNOLOGY (BACT) ANALYSIS

ARM 17.8.752 requires a new facility for which a Montana air quality permit is required to apply "Best Available Control Technology" (BACT) for each pollutant regulated under the Federal Clean Air Act. In addition, as noted in Table 5-1, the HGS gas plant qualifies as a major modification to a PSD facility as defined in ARM 17.8.801(20), and the control technology review of ARM 17.8.819 applies. This major modification results in significant emissions increases of the following pollutants: NOx, CO, and PM. However, in order to apply BACT per ARM 17.8.752, a complete analysis is required to establish BACT. A detailed BACT analysis for NO_X, CO, VOC, $PM/PM_{10}/PM_{2.5}$ and SO_2 is presented in Sections 5.4 through 5.7.

Table 5-1 : Facility Emissions Comparison to PSD Significance Thresholds

Pollutant	Significance Threshold (tpy)	Phase I Annual Emissions (tpy)	Significant?	Phase II Annual Emissions (tpy)	Significant?
NOX	40	126.34	YES	171.46	YES
CO	100	368.52	YES	379.78	YES
O3 (as VOC)	40	12.72	NO	20.35	NO
$PM/PM_{10}/PM_{2.5}$	15	16.66	YES	64.41	YES
SO2	40	1.94	NO	6.16	NO
Lead	0.6	0	NO	0	NO

5.1 BACT Analysis Methodology

BACT is defined as "an emissions limitation, including a visible emissions standard, based on the maximum degree of reduction for each regulated NSR pollutant that would be emitted from any proposed major stationary source or major modification, that the commissioner[19], on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for the 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 the pollutant."

This top-down BACT analysis will follow the general procedures outlined in the *New Source Review Workshop Manual*, Office of Air Quality Planning and Standards, U.S. EPA, Draft - October 1990. The Manual was written for use in (federal) BACT analyses under the PSD or federal NSR program. The methodology described in the manual provides general procedures for a BACT analysis. Although the NSR Manual is a draft document, the methods it describes are widely used and provide consistency in the approach to BACT decision-making. The methodology described in the manual consists of five basic steps:

[19] In this case, "commissioner" would be the Montana Department of Environmental Quality.

Step 1 - Identify all control technologies;
Step 2 - Eliminate technically infeasible options;
Step 3 - Rank remaining technologies by control effectiveness;
Step 4 - Evaluate most effective controls and document results; and
Step 5 - Select BACT.

Each step in the BACT analysis process is outlined below.

5.1.1 Step 1 - Identify All Control Technologies

In a top-down BACT analysis, the first step is to identify all "available" control options for the emissions unit being evaluated. "Available" control options are air pollution control technologies or techniques with a practical potential for application to the emissions unit and regulated pollutant being evaluated.

5.1.2 Step 2 - Eliminate Technically Infeasible Options

In the second step, the technical feasibility of the control options identified in the first step is evaluated with respect to source-specific factors. A demonstration of technical infeasibility must be clearly documented and exhibit, based on physical, chemical, and/or engineering principles that technical difficulties would preclude the successful use of the control option on the emissions unit under review. Technically infeasible control options are eliminated from further consideration. Note that the NSR Manual (at page B-17) states, "a source is not required to experience extended time delays or resource penalties to allow research to be conducted on a new technique or control technology. Neither is it expected that an applicant would be required to experience extended trials to learn how to apply a technology on a totally new and dissimilar source type."

5.1.3 Step 3 - Rank Remaining Technologies by Control Effectiveness

Available control technology options deemed technically feasible are ranked in order of pollutant removal effectiveness. The control option that results in the highest pollutant removal value or lowest pollutant emission limit is considered the "top" control option.

5.1.4 Step 4 - Evaluate Most Effective Controls and Document Results

The fourth step is to consider the directly associated energy, environmental, and economic impacts of the most stringent control option ascertained. Both beneficial and adverse impacts are discussed and quantified where possible.

Energy impact analyses estimate direct energy impacts of the control alternatives in units of energy consumption. Environmental impact analyses consider effects of unregulated air pollutants or non-air impacts such as liquid, solid, or hazardous waste disposal and whether they would justify selection of an alternative control option. Economic impact analyses assess costs associated with installation and operation of the various BACT alternatives.

As a guide in determining excessive control costs, alternative control systems are compared in terms of certain cost-effectiveness ratios. These ratios include the following:

- Ratio of total control costs to total investment costs;
- Cost per unit of pollution removed (for example, dollars per ton);
- Unit production costs (for example, costs per unit of product); and
- Cost per dollar of total sales.

If energy, environmental, or economic impacts show the top candidate to be inappropriate, then the next most stringent alternative becomes the new control candidate and is similarly evaluated. This process continues until the top technology under consideration cannot be eliminated due to any source-specific energy, environmental, or economic impact(s).

5.1.5 Step 5 - Select BACT

The last step in evaluating BACT is to propose the most effective control option that remains after eliminating all non-viable options as part of Step 4.

5.2 Alternative Power Generation Technologies

According to the NSR Manual, the requirement to identify and employ BACT does not generally mean that the applicant must consider alternative processes or equipment that would essentially redefine the project. States are allowed some discretion in this matter. For this project, Southern has evaluated several alternative technologies and methods for satisfying the defined project objectives. A gas turbine generator was selected as the optimum alternative for a variety of reasons. Accordingly, no alternative power generation technologies will be evaluated in this BACT analysis.

Nevertheless, one power generation alternative does merit special consideration. Combined cycle turbines are a commonly used variation of combustion turbine technology. Combined cycle turbines use waste heat from the turbine to create steam. The steam is then fed to an auxiliary turbine to generate additional electrical power. This technology offers inherently improved thermal efficiency and potentially lower emissions per unit of electricity produced. Combined cycle combustion turbines with the ability to operate in simple cycle mode provide the operational flexibility, economic generation, and reduced emissions that are critical to this project. Therefore, combined cycle combustion turbines are the technology of choice for this project.

5.3 Start-Up, Shut-Down and Commissioning

5.3.1 Start-up and Shut-Down

It is not unusual to consider BACT emission limits that may be associated with sporadic or one-time activities such as a start-up, shutdown or commissioning of a new unit. For this facility, the term startup and shutdown do not have the same meaning which would be applied to a more traditional baseload power generation facility. Generally, a startup or shutdown at a baseload facility might be expected to occur a few times a year. The expected nominal operation of the HGS gas plant is more similar to a peaking facility which might start up and shut down once or twice per day. Should demand remain constant (for instance during heating or air-conditioning seasons of the year) then the facility may operate in combined cycle mode for an extended period and not start up and shut down as often as has been included in this analysis.

Because the HGS gas plant is not limited to just baseload operations, it may start up and shut down the turbines on a daily basis, particularly if load conditions change unpredictably. For purposes of emissions calculations found in Appendix C and reflected in Section 3 (and elsewhere), two startups and two shutdowns are accounted for in the emissions inventory for each day of the year. This value is derived from the worst-case operation profile of a peaking plant: startup in morning, shutdown midday, restart in afternoon, shutdown at night.

Given that emissions of some pollutants are higher in SUSD for simple cycle operation, and generally higher in SUSD for combined cycle operation as opposed to steady-state operation, a separate limit is proposed for SUSD conditions. SUSD conditions are evaluated within each separate BACT section below.

5.3.2 Commissioning[20]

As noted in Section 3.2.4, the turbines will not likely be able to meet the steady-state BACT limits proposed in the remainder of this chapter during commissioning of the units. Commissioning by itself is a rarely occurring activity.

The BACT analyses that follow describe a multitude of control technology options. For purposes of commissioning and seeking a BACT-related emission limit associated with this activity, all of those technologies are assumed to be available during the commissioning period.

At issue is the effectiveness of the proposed controls during the commissioning period. For obvious reasons, the controls, while installed prior to commissioning, will not be 100% effective. Rigorous testing is required to fine-tune operations and ensure various monitoring systems are operational, feedback systems perform as required, etc. For purposes of emissions, therefore, it is not possible to identify meaningful emissions during a period of constant change in a progression towards normal operation.

It is clear that these ‘commissioning’ emission rates are not quantifiable for regulatory purposes. The only logical conclusion for satisfying BACT requirements during this period would be a requirement to install and operate the air pollution control equipment prior to commissioning. This meets the requirement that the ‘best available’ control technologies are installed and operational during the period. This includes the requirement to limit hours of simple cycle operation.

[20] For purposes of this application, the term ‘commissioning’ refers to any time that a new or refurbished turbine is installed or re-installed at the facility.

Nonetheless, a short-term limit to meet the spirit of BACT and to protect ambient air quality would be appropriate. During this interim period, we propose that the turbines be subject to the proposed hourly limits found in Table 3-4 (derived from Appendix C and Table 3-5). At the same time, the facility would be required to install and operate the control technology as best as practicable during the period given the testing nature of the commissioning activities.

5.4 BACT - NO_X

NO_X will be formed during the combustion of natural gas in the facility's combustion turbine units. The formation of NO_X is dominated by the process called thermal NO_X formation. Thermal NO_X results from the thermal fixation of atmospheric nitrogen and oxygen in the combustion air. The rate of formation is sensitive to local flame temperature and, to a lesser extent, local oxygen concentrations. Virtually all thermal NO_X is formed in the region of the flame at the highest temperature. Maximum thermal NO_X production occurs at a slightly lean fuel-to-air ratio due to the excess availability of oxygen for reaction with the nitrogen in the air and fuel.

5.4.1 Step 1 - Identify All Control Technologies

NO_X emissions from the proposed process can be reduced by several different methods. Eight of the most applicable methods were evaluated.

- Proper System Design and Operation (base case)
- Water Injection
- Fuel Selection
- Dry Low-NO_X Burners
- Selective Catalytic Reduction (SCR),
- Selective Non-Catalytic Reduction (SNCR),
- Wet Chemistry Scrubber,
- NO_X Scrubber, and
- Low Temperature Oxidation (LoTOx), SCONOx (EMx), XONON.

A discussion of each type of control technology is contained below.

5.4.1.1 Proper System Design and Operation (base case)

Fuel costs are a major portion of the cost of electricity generation. Consequently, every effort is made to conserve energy and thereby reduce costs. Efforts to maximize fuel efficiency also serve to reduce pollutant emissions; increasing the amount of electricity produced per unit of fuel decreases the amount of combustion-related pollutants emitted. This need must be balanced with the operating characteristics of the equipment selected and load behavior of the electrical network served by the proposed facility. Due to the potential for unpredictable load changes, a simple cycle-capable, rapid-ramping aeroderivative combustion turbine is necessary for this facility. Southern will operate these turbines to maximize efficiency and minimize idling when system loads permit.

Idling leads to increased emissions and wasted fuel, hence the combined cycle plant configuration of Phase II.

5.4.1.2 Water Injection

Reducing the peak flame temperatures in the turbine's combustion chamber will reduce thermal NO_X formation. Steam or water injection is a common coolant to be injected into the turbine. NO_X reduction is proportional to the amount of water or steam injected during operation. However, a balance must be reached, effectively limiting the NO_X reduction, due to reducing temperatures to the point of incomplete combustion and resultant increases in CO and VOC formation, flame instability and thermal stress on the engine.

5.4.1.3 Fuel Selection

The fuel of choice to operate the HGS gas plant is natural gas, widely recognized as a cleaner fuel than fuel oil. All emissions calculations and proposed BACT limits are based on natural gas combustion.

5.4.1.4 Dry Low NO_X Burners

Similar to water injection, the purpose of dry low NO_X burners [per turbine vendor, Dry Low Emissions (DLE)] is to lower the combustion temperatures in the turbine, thereby reducing thermal NO_X formation. This is accomplished by lean premixing of fuel and combustion air prior to entry into the compressor, and injecting fuel in stages throughout the flowpath in the combustion turbine. This produces a lower heating value gas/fuel mixture that will then combust at lower temperatures, reducing thermal NO_X. An added benefit to DLE is a lower heat rate, meaning more energy is generated for the same unit of fuel.

5.4.1.5 Selective Catalytic Reduction

SCR is a post-combustion gas treatment technique for reduction of NO and NO_2 in an exhaust stream to molecular nitrogen, water, and oxygen. Ammonia (NH_3) is used as the reducing agent. The basic reactions are:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O$$
$$8NH_3 + 6NO_2 \rightarrow 7N_2 + 12H_2O$$
$$2\ NO_2 + 4\ NH_3 + O_2 \rightarrow 3\ N_2 + 6\ H_2O$$

Ammonia is injected into the flue gas upstream of a catalyst bed, and NO_X and NH_3 combine at the catalyst surface, forming an ammonium salt intermediate, which subsequently decomposes to produce elemental nitrogen and water. The function of the catalyst is to effectively lower the activation energy of the NO_X decomposition reaction. Typical catalyst materials include metal oxides (e.g., titanium oxide and vanadium), noble metals (e.g., platinum and rhodium), zeolite, and ceramics.

The control technology works best for flue gas temperatures between 575°F and 750°F. Excess air is injected at the turbine exhaust to reduce temperatures to the optimum range, or the SCR is located in a section of the HRSG where the exhaust temperature has cooled to this temperature range. The control efficiency for an SCR is typically estimated to be between 80% and 90%[21]. Technical factors that impact the effectiveness of this technology include inlet NO_X concentrations, the catalyst reactor design, operating temperatures and stability, type of fuel fired, sulfur content of the fuel, design of the ammonia injection system, catalyst age and reactivity, and the potential for catalyst poisoning.

SCR has been demonstrated to achieve high levels of NO_x reduction in the range of 80% to 90% control for a wide range of industrial combustion sources, including PC and stoker coal-fired boilers and natural gas-fired boilers and turbines. Typically, installation of the SCR is upstream of the particulate control device (e.g., baghouse). SCRs are classified as a low or high dust SCR. A low dust SCR is usually applied to natural gas combustion units or after a particulate control device. For this application, the turbines will be combusting clean fuels (natural gas), and particulate loading is not anticipated to be a problem.

5.4.1.6 Selective Non-Catalytic Reduction

SNCR involves the noncatalytic decomposition of NO_X in the flue gas to nitrogen and water using a reducing agent (e.g., ammonia or urea). The reactions take place at much higher temperatures than in an SCR, typically between 1,650°F and 1,800°F, because a catalyst is not used to drive the reaction. The efficiency of the conversion process diminishes quickly when operated outside the optimum temperature band and additional ammonia slip or excess NO_X emissions may result.

The process has been used in North America since the early 1980s. Removal efficiencies of NO_X vary considerably for this technology, depending on inlet NO_X concentrations, fluctuating flue gas temperatures, residence time, amount and type of nitrogenous reducing agent, mixing effectiveness, acceptable levels of ammonia slip and the presence of interfering chemical substances in the gas stream. The estimated control efficiency for SNCR on the proposed process is 40%-60% (Cooper/Alley, *Air Pollution Control*, 1986).

5.4.1.7 Wet Chemistry Scrubber

There is no standard model for this system. Generally, a scrubbing system consists of several stages. In one stage, NO is oxidized to NO_2. In another stage, the NO_2 is quenched in order to induce chemical reactions in an aqueous phase. Chemical reactions are carried out in the second or subsequent stages in order to reduce NO_2 (i.e., to N_2, O_2 and/or soluble salts).

Requirements of this system include chemical reagents and water treatment or chemical disposal provisions. The number of reagents and treatment requirements

[21] AP-42, Section 1.4.4.

varies depending on design. Solutions are custom tailored to each source and operating characteristics. The estimated control efficiency of the multistage wet scrubber is around 80% (Cooper/Alley, *Air Pollution Control*, 1986).

5.4.1.8 Low Temperature Oxidation [LoTOx, SCONOx (EMx) , XONON]

<u>LoTOx</u>

With DuPont BELCO's LoTOx NO_X control technology, oxygen is injected into the reaction chamber to transform NO and NO_2 into N_2O_3 or N_2O_5 using an ozone generator and a reactor duct. These higher nitrogen oxides are highly soluble in water, and can be removed from the exhaust stream as nitric and nitrous acids or with caustic solution as nitrite or nitrate salts with a wet scrubber.

Requirements of this system include oxygen and a cooling water supply. Also, the scrubber effluent treatment needs to be provided. LoTOx is specifically designed for high sulfur and particulate processes, as would be experienced in a refinery or coal-fired boiler.[22] The estimated control efficiency of the system is 80-90% (manufacturer's data).

<u>SCONOx/EMx</u>

SCONOx, currently in its second generation, is a multipollutant, postcombustion control technology. Originally developed by Goal Line Environmental Technologies, Emerachem, LLC now markets the technology under the tradename EMx. EMx first oxidizes CO, VOC and NO. The resultant NO_2 is then absorbed into a potassium carbonate coating on a catalyst. The buildup of subsequent potassium nitrites and nitrates must be removed during a catalyst regeneration cycle. The catalyst is separated from the exhaust stream, and a mixture of steam, CO_2 and natural gas (for H_2 generation) are injected into the reaction chamber. The reducing gas reacts with the catalysis products to form elemental nitrogen and water vapor, leaving potassium hydroxide. Additional reaction with CO_2 converts the potassium hydroxide to potassium carbonate. The EMx catalyst is sensitive to sulfur poisoning, and is usually preceded with a SCOSOx catalyst to manage the sulfur compounds.

<u>XONON</u>

XONON, originally developed by Catalytica Energy Systems, and now licensed to Kawasaki Heavy Industries, also reduces NO_X emissions by lowering combustion temperatures inside of the turbine. A lean mix of air and fuel is combusted in a premixing burner to heat the incoming combustion air. More fuel is then mixed into the incoming air and reacted on the catalyst surface without flame, combusting the mixture at very low temperatures and producing little NO_X. This technology has not been

[22] BOC Gases presentation summary, 2000 Conference on Selective Catalytic and Non-Catalytic Reduction for NOx Control.

demonstrated on larger gas turbines, and is currently unavailable in sizes that support the generation needs of this facility.[23]

5.4.2 Step 2 - Eliminate Technically Infeasible Control Options

The NSR Workshop Manual describes two key criteria for determining whether an alternative control technology is technically feasible. According to the NSR Workshop Manual, a technology must be "available" and "applicable" in order to be considered technically feasible. A technology is *available* "if it has reached the licensing and commercial sales stage of development." An identified alternative control technique may be considered *applicable* if "it has been or is soon to be deployed (e.g., is specified in a permit) on the same or similar source type." The following paragraphs evaluate the technical feasibility of the alternative control technologies identified above by applying these criteria of availability and applicability.

Except low temperature oxidation and SNCR, all of the above control alternatives are considered feasible. The following implementations of low temperature oxidation and SNCR are removed from further consideration in this BACT analysis, based on details provided in each respective subsection.

5.4.2.1 LoTOx

LoTOx has only been demonstrated on pilot scale projects, and none that involve combustion turbines.[24] A review of EPA's RACT/BACT/LAER Clearinghouse (RBLC) indicates three facilities nationwide using LoTOx for NO_X control: a steel foundry, an acid regeneration plant, and a refinery. As indicated by the manufacturer, LoTOx was specifically designed for use in high particulate and high sulfur content fuel combustion processes, unlike the combustion environment in a natural gas/liquid fuel-fired gas turbine. Due to these factors, LoTOx was removed from further consideration as a potential control technology for this project.

5.4.2.2 XONON

The XONON low temperature combustion catalyst has not been scaled for installation on turbines the size required by this facility. It has been demonstrated on small scale cogeneration turbines only (Kawasaki Heavy Industries M1A-13 1.4 MWe turbine). As the scale-up potential for this technology is not proven, it is not deemed to be an applicable technology, and was not considered as a control option for this project.

5.4.2.3 SNCR

The high temperatures required for operation of an SNCR system, typically between 1,650°F and 1,800°F, are above that of the exhaust temperatures generated with the GE LM6000PF combustion turbines (typical temperatures range from 630°F to 970°F, depending on turbine load, inlet conditions, and fuels used). In order to achieve the high

[23] CARB, Gas-Fired Power Plant NOx Emission Controls And Related Environmental Impacts, May 2004.
[24] Four Corners Air Quality Task Force, Report of Mitigation Options, Nov 2007.

temperature required for efficient SNCR operation, significant amounts of fuel would need to be combusted to raise the temperature of the gas stream, far more than is possible with the duct burners designed for this facility. This would result in increased emissions without the benefit of utilizing the additional fuel combustion for electricity generation. As this type of operation would be counterproductive, SNCR was eliminated as a possible control option for this project.

5.4.3 Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Of the alternative NO_x control technologies initially identified, the following technologies have been deemed technically infeasible for this application:

- LoTOx^{TM}
- XONON^{TM}
- Selective Non-Catalytic Reduction

The following technologies have been deemed to be technically feasible and will be carried forward in the BACT analysis:

- Proper System Design and Operation
- Water or Steam Injection
- Fuel Selection
- Dry Low Emissions (DLE)
- Selective Catalytic Reduction
- Catalytic Adsorption (EMx^{TM})

Table 5-2 lists control efficiencies for the remaining technically feasible control alternatives.

The control options are expected to have NO_X control efficiencies ranging from 7% to 99% over the base case scenario. Table 5-2 illustrates control effectiveness based on the appropriate control technology for each LM6000PF turbine.

Table 5-2: Ranked NO_X Control Technology Effectiveness

Control Technology	Percent Reduction[25]
No Additional Controls	N/A
DLE, Fuel Selection and SCR	95%
EMx	80% - 90%
SCR	80% - 90%
DLE	51% - 71%
Water Injection	7% - 84%[a]
Wet Chemistry Scrubber	80%
Fuel Selection	40%

Notes:
a. Highly variable control reduction based on turbine load.

The Vice-President for sales at EmeraChem, the EMx™ vendor, stated in a telephone conversation with Bison Engineering (EmeraChem, 2008) that the cost of an EMx™ system would be approximately three times the cost of an SCR system. Because EMx™ technology would provide approximately the same NO_x control efficiency as SCR but cost significantly more, there is no need to perform a detailed analysis of both systems.[26]

5.4.4 Step 4 - Evaluate Most Effective Controls and Document Results

The highest level of control that can be realized is accomplished by utilizing DLE, SCR and clean fuels. Southern proposes to utilize this technology combination on each combined cycle LM6000PF. In addition to SCR, the HGS gas plant will combust natural gas as a primary fuel, and utilize DLE for additional NO_X control and efficiency gains. According to EPA's RBLC, an SCR can be considered BACT for NO_X control on natural gas-fired aeroderivative combustion turbines for electric generating facilities. Furthermore, as demonstrated in Table 5-2 above, an SCR, combined with DLE and fuel selection, provides the maximum level of NO_X reduction.

5.4.4.1 Environmental Impacts

Although there are no prohibitive environmental issues that would preclude the use of an SCR system, there are some areas of concern. SCR presents several potential adverse environmental impacts. Unreacted ammonia in the flue gas (ammonia slip) and

[25] In order to evaluate % reduction of fuel selection, water injection, and DLE, the percent reductions presented in Table 5-2 are based on pollutant concentration reduction, not mass emission reduction as is used within the economic evaluation of each control option, as DLE is the baseline for the economic analysis.

[26] This approach is in accordance with the least-cost envelope (or dominant alternatives) method described in the NSR Manual beginning on page B.41. This method identifies control alternatives for which detailed evaluation would provide no benefit to the analysis. A non-dominant alternative essentially duplicates the potential control effectiveness of one or more other alternatives but is clearly inferior due to cost.

the products of secondary reactions between ammonia and other species present in the flue gas will be emitted to the atmosphere. Ammonia slip is expected to be low, approximately 10 ppm in order to adequately control NO_X during turbine load changes. Higher transient slip may result during large load ramping and other process upsets. Of primary environmental concern is the formation of additional condensable particulate matter such as ammonium sulfate, $(NH_4)_2SO_4$. Ammonium sulfate emissions will be addressed in Section 5.6 in the $PM/PM_{10}/PM_{2.5}$ BACT analysis.

Issues associated with SCR equipment consumables (i.e., ammonia, catalyst) have to be addressed. There are major considerations for the storage and use of large quantities of ammonia on the plant site. Ammonia is one of the regulated substances covered by Section 112(r) of the Clean Air Act, which deals with the prevention and detection of accidental releases of hazardous chemicals. This legislation is implemented through 40 CFR 68 – Chemical Accident Prevention Provisions. The quantity and concentration of aqueous ammonia stored on site is below the threshold quantities of 40 CFR 68 Table 1.

5.4.4.2 Energy Impacts

SCR

An SCR presets a small parasitic load on any combustion turbine upon which it is installed. In this case, 131 kW, or approximately 0.2% of combined cycle gross generation. In simple cycle mode, an SCR would require 318 kW, or 0.7% of gross generation. In addition, due to the increased back pressure from a simple cycle SCR, additional fuel is required to be combusted with no gain in energy production. Costs for these energy expenditures are included in the Economic Analysis section. Alone, these energy impacts would not eliminate SCR as a method to control NO_X from the combustion turbines.

DLE

The LM6000PF combustion turbine is available in two NO_X guaranteed emission levels: 15 ppm NO_X and 25 ppm NO_X (option selected). The capital cost difference between the two options is not significant; however, the 15 ppm turbine reliability is less than the 25 ppm turbine and maintenance costs are higher due to less flame stability and increased system vibrations.[27] What are significant are the heat rate and fuel use differences between the two options. The 25 ppm turbine has higher output capacity, is more efficient and has superior exhaust characteristics in combined cycle mode. Table 5-3 below compares these differences at the same ambient temperature.

[27] Data presented to Stanley Consultants during economic evaluation of various turbines and vendors.

Table 5-3: Comparison of LM6000PF 25 ppm vs. 15 ppm NO_X turbines

Factor	Units	LM6000PF 25 ppm	LM6000PF 15 ppm	% difference
Output	kW	42458	41426	2.5%
Heat Rate	Btu/kWhr	8353	8379	0.3%
Turbine Exhaust Temp	°F	862	849	1.5%
Turbine Exhaust Flow	Mlb/hr	939	935	0.4%
Resulting Fuel Cost Difference[28] ($/year of fuel used)				$939,000

At first glance the differences appear small; however, as the resulting fuel cost difference shows, these small % differences are quite significant. It is obvious from Table 5-2 that DLE alone is an inferior control to the inclusion of the SCR. When the resulting fuel costs of the 15 ppm option are added to the cost-effectiveness of the SCR control, it becomes apparent that the 15 ppm turbine option plus the SCR control is not cost-effective. See the next section for the results of the economic analysis.

5.4.4.3 Economic Impacts

In order to fully evaluate the economic impacts of installing an SCR system, several scenarios were developed for both the simple cycle and combined cycle modes of operation. Because the plant requires simple cycle operation after the Phase II installation of the steam plant, the cost-effectiveness of controlling the simple cycle mode (and the oxidation catalyst) needed to be evaluated independently of the combined cycle mode. The plant orientation and flow path analyzed for each individual simple cycle case begins at the "CT" block of each diagram, and ends at the "SC STACK" for Cases "T1" through "T4," and ends at the "SC/CC STACK" block for Cases "S1" through "S4." The combined cycle flowpath begins identically to the simple cycle cases; however, all combined cycle cases end in either "CC STACK" or "SC/CC STACK."

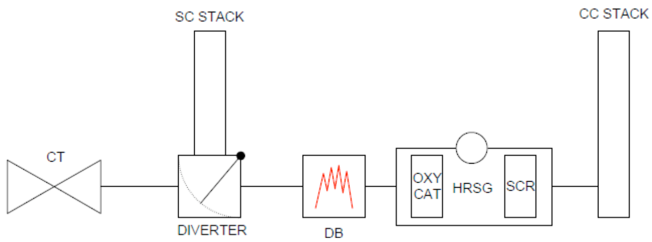
A brief description and block diagram of each of the test cases evaluated are presented below.

Abbreviations used in each block diagram:

CT	Combustion Turbine
SC	Simple Cycle
DB	Duct Burner
OXY CAT	Oxidation Catalyst
HRSG	Heat Recovery Steam Generator
SCR	Selective Catalytic Reduction
CC	Combined Cycle
OTSG	Once Through Steam Generator
COOL	Steam Dump Condenser
ST	Steam Turbine

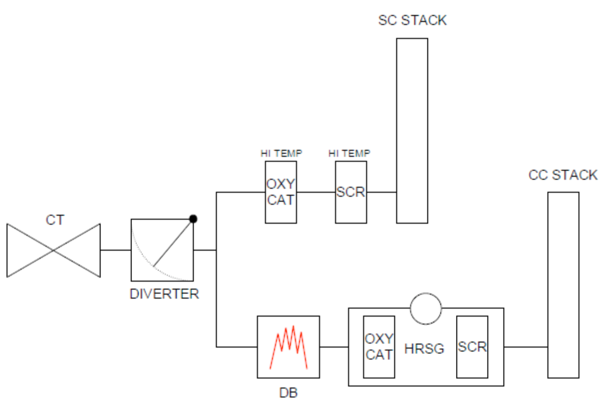
[28] Fuel cost values provided by Stanley Consultants.

Case T1 – Simple cycle diverter, combined cycle controls



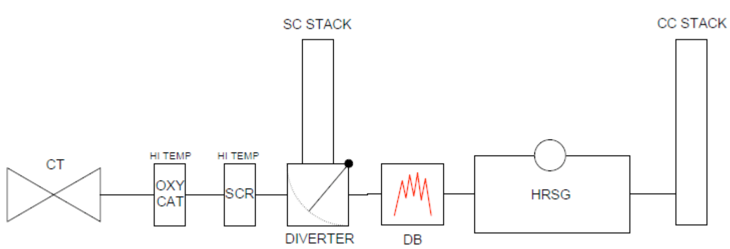
Case T1 is considered the base case for the facility. Two stacks are installed. When operating in simple cycle mode, the exhaust is diverted to the simple cycle stack. When in combined cycle mode, the exhaust is diverted to the duct burners and HRSG where the CO oxidation catalyst and SCR are installed. Less expensive, lower temperature catalysts can be used as the catalysts can be located exactly where they are most efficient in the HRSG, behind the superheater.

Case T2 – Parallel, duplicate controls systems



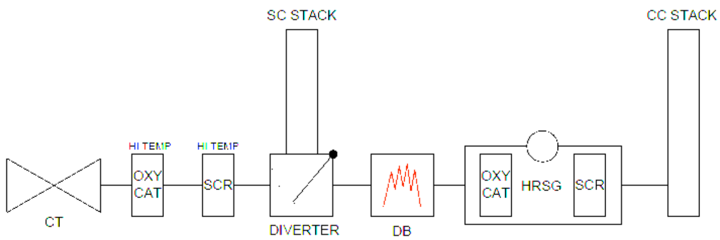
Case T2 represents duplicate SCR and oxidation catalyst systems installed in each flow path. For the simple cycle case, more expensive higher temperature oxidation and SCR catalyst are required as they both experience full exhaust temperature from the turbine; i.e., energy is not removed from the HRSG superheater.

Case T3 – Shared controls



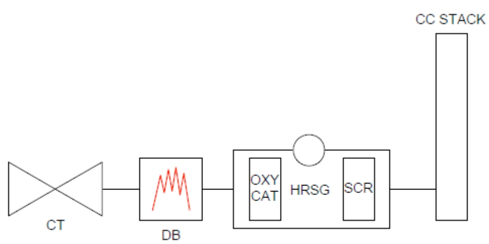
Case T3 represents the installation of the higher temperature catalysts before the simple cycle stack to control both simple cycle and combined cycle emissions of the combustion turbine. At issue with this case is that the emissions from the duct burners are no longer reduced by any control device. The effective control efficiency of such a system is inferior to the other cases analyzed. Higher temperature at the CT exhaust is also not in the ideal catalyst range and may reduce abatement efficiency.

Case T4 – Simple cycle diverter, series controls



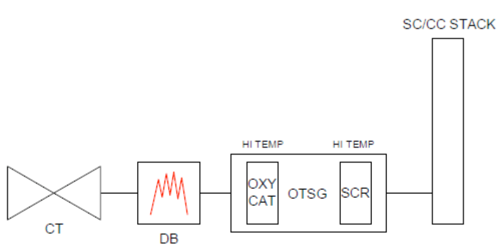
Case T4 represents the addition of controls for simple cycle mode, in addition to controls for combined cycle mode. In this case, all emissions, regardless of operating mode, are controlled. At issue with this case is the significant back pressure added by duplicative controls, for little to no additional control. The additional backpressure reduces the performance of the turbine, significantly increasing the cost of electric power produced by the generating unit. The performance of the catalyst controls are highly dependent on input pollutant concentrations; therefore, the second set of catalysts primarily are for control of the duct burner emissions, as the concentrations of the turbine emissions are already reduced.

Case S1 – Eliminate simple cycle mode



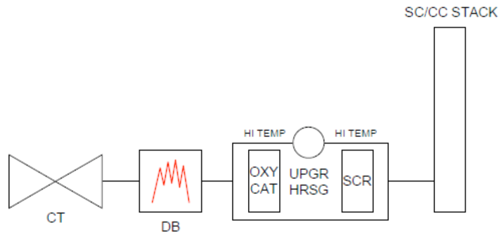
Case S1 represents the removal of the simple cycle mode entirely, but this does not meet the mission of the gas plant and the need for electrical generation, and therefore is not considered for further analysis.

Case S2 – Once Through Steam Generator



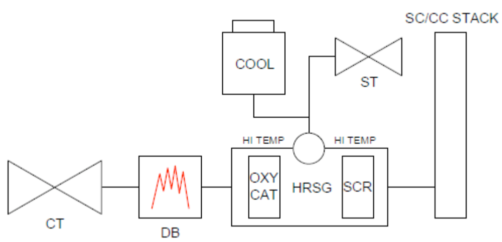
Case S2 represents the installation of a once through steam generator (OTSG) in place of an HRSG. The fundamental design of an OTSG[29] allows it to be run dry, which would be required for operation in simple cycle mode. Capital costs are typically higher for OTSG installations. Of particular concern is the sole-source procurement of such a steam generator. As sole-sourced, the OTSG for this facility could not be competitively bid, significantly driving up the cost of procurement.

Case S3 – Upgraded HRSG



Case S3 represents the procurement of an HRSG with upgraded metallurgy and designed for dry operation. Several HRSG manufacturers were contacted and indicated that such an HRSG was technically infeasible, that an OTSG would be necessary. Therefore, Case S3 is excluded from the analysis for technical infeasibility to control simple cycle emissions.

Case S4 – Steam Dump Condenser



Case S4 represents the installation of a steam dump condenser following the HRSG. In this case the simple cycle mode of operation is possible because the steam generated by the HRSG is then condensed back to feedwater via the dump condenser. This presents only a partial solution as the beneficial startup times of simple cycle operation are negated by the need to slowly heat the tubes of the HRSG. This case is highly undesirable as it is both expensive and energy wasteful, but is not technically infeasible, so it is carried through the BACT economic analysis.

Economic impacts associated with SCR control options were compared using actual vendor and engineering quoted annualized capital, operating, and maintenance costs. Cost derivation equations and methodology were derived from the methods outlined in EPA 453/B-96-001, *Office of Air Quality Planning and Standards Control Cost Manual*,

[29] Expensive high nickel alloy tubes arranged in a continuous run, with steam generated in the tubes, not in a steam drum.

6th Edition (OAQPS). If vendor-specific cost values were not available, assumptions were made from suggested/typical data that were supplied in the manual and if data was not available from the manual, best engineering judgment was used. All cost data are referenced in the economic analysis spreadsheets of Appendix E. The equipment costs calculated were adjusted by the latest Chemical Engineering Plant Cost Index multiplier in Dec 2008 dollars.[30] Table 5-4 and Table 5-5 summarize the economic impacts of the SCR control options. Detailed capital and annual costs can be found in Appendix E.

Table 5-4 : Cost-Effectiveness for NO_X Control, per Turbine, Simple Cycle

Cost-Effectiveness for NO_X Control, per Turbine Simple Cycle Operations limited to 3,200 hours operation per year					
Case	**Estimated Total Annual Cost**	**Uncontrolled Emissions (tpy)**	**Control Efficiency (%)**	**Tons Removed (tpy)**	**Cost-Effectiveness ($/ton)**
T1 (baseline)	---	52.9	---	---	---
T2	$427,432	52.9	89%	46.7	$12,798
T3	$427,432	52.9	89%	46.7	$12,798
T4	$427,432	52.9	89%	46.7	$12,798
S1	No Analysis Required				
S2	$1,640,132	52.9	89%	46.7	$49,138
S3	Not Technically Feasible				
S4	$488,122	52.9	89%	46.7	$14,629

[30] Chemical Engineering Plant Cost Index Dec 2008 (preliminary) had the latest values available at the time the analysis was performed.

Table 5-5 : Cost-Effectiveness for NO_X Control, per Turbine, Combined Cycle

Cost-Effectiveness for NO_X Control, per Turbine Combined Cycle Operations, 8760 hours operation per year[31]					
Case	**Estimated Total Annual Cost**	**Uncontrolled Emissions (tpy)**	**Control Efficiency (%)**	**Tons Removed (tpy)**	**Cost-Effectiveness ($/ton)**
T1 (baseline)	$395,880	201.4	92%	184.9	$3,013
T2	$395,880	201.4	92%	184.9	$3,013
T3	$518,370	201.4	72%	153.2	$4,773
T4	$792,930	201.4	92%	184.9	$6,040
S1	$395,880	201.4	92%	184.9	$3,013
S2	$1,702,660	201.4	92%	184.9	$12,953
S3	$521,260	201.4	92%	184.9	$3,970
S4	638,280	201.4	92%	184.9	$4,857

5.4.5 Step 5 - Identify BACT

Southern has selected the highest control option, the combination of clean fuels, DLE, and SCR, as BACT for combined cycle NO_X emissions from the combustion turbines and duct burners. This control combination will achieve the highest overall reduction in NO_X emissions while minimizing adverse environmental, energy, and economic impacts. Based on hours of operation proposed, the cost of simple cycle NO_X control is cost-prohibitive above the baseline of fuel selection and DLE (Case T1). For the combined cycle case, Cases T1, T2, and S1 are the least-cost dominant alternatives[32] as the control efficiencies are identical and they cost the least of all other alternatives. Case S1 is dropped from the analysis as it does not meet the requirement of simple cycle mode during Phase II operations. When the simple cycle cost-effectiveness figures for Cases T1 and T2 are compared, it is obvious that the cost of NO_X control for Case T2 simple cycle operations is above that which has been determined to be excessive for other combustion turbine projects. Therefore, the basecase of Case T1 (fuel selection and DLE) is proposed as BACT for NO_X emissions from simple cycle operations at the HGS gas plant.

This conclusion is supported by data available from Region 4 of U.S. EPA. They have assembled a database of combustion turbine permit requirements[33]. Table 5-6 lists several combustion turbine permits that eliminated SCR control based on economic impacts and the estimated SCR cost-effectiveness in each case.

[31] Capacity Factor of 0.9 per Stanley Consultants.

[32] This approach is in accordance with the least-cost envelope (or dominant alternatives) method described in the NSR Manual beginning on page B.41. This method identifies control alternatives for which detailed evaluation would provide no benefit to the analysis. A non-dominant alternative essentially duplicates the potential control effectiveness of one or more other alternatives but is clearly inferior due to cost.

[33] EPA R4, 2008a. U.S. Environmental Protection Agency, Region 4. National Combustion Turbine Spreadsheet. http://www.epa.gov/region4/air/permits.

Table 5-6: Excessive SCR Costs per EPA Region 4 National Combustion Turbine Spreadsheet

Facility	State	Final Permit Issued	SCR Cost ($/ton NOx)
MEA of Georgia - W. R. Clayton	GA	draft permit	$14,100
TVA - Kemper CT Plant	MS	07/30/2001	$13,700
South Mississippi Electric Power Assn.	MS	draft	$10,000
Entergy Power - Rowan Generating Facility	NC	01/25/2002	$13,000
Greenville Generating	SC	draft permit	$13,100
Santee Cooper Rainey Generating Station	SC	05/08/2003	$15,600
Lakefield Junction	MN	draft permit	$11,500
University of Cincinnati	OH	08/15/2002	$11,800
Wisconsin Public Service	WI	07/01/1999	$13,900
Wisconsin Electric	WI	draft permit	$10,300

The following section addresses the proposed emission limit for the HGS combustion turbines.

5.4.5.1 Discussion of BACT Emission Limit Value

As noted above, Southern is proposing the highest control options available for combined cycle operation for the HGS gas plant. As demonstrated in Table 5-4, the installation of additional control to simple cycle operation is cost-prohibitive. The only issue at hand, therefore, is to determine an emission limit applicable to this facility.

A review of EPA's RBLC indicates that for recently permitted aeroderivative combustion turbine generating units, a normalized emission limit value of 2.5 to 5 ppmvd[34] (corrected to 15% O_2) is BACT for NO_X at full load, <u>steady state operations</u>. The HGS gas plant turbine vendor has estimated an emission limit of 2.5 ppm for controlled, combined cycle operations at full load, steady state conditions. For plants operating in peaking modes, the RBLC emission limits for water injected and/or DLE controlled turbines range from 25 ppm to 73 ppm, depending on fuel type. For this facility, the DLE controlled simple cycle emission rate is guaranteed at 25 ppmvd, steady state.

[34] Note that within this and following paragraphs emissions are sometimes expressed as ppm. This is done for the purpose of comparison among RBLC and vendor data. As noted later in this section, a lb/hour value is proposed for BACT. Since lb/hour values were not available from the RBLC, direct comparisons of those units are not possible. As a result, ppm comparisons are made for consistency purposes here although a mass emission standard represents BACT in this case.

Southern proposes a steady-state, combined cycle NO_X BACT emissions limit of **4.16 lb/hour/generating unit**[35] on a 24-hour block[36] average for all operational combustion turbine loads at the HGS gas plant. This 24-hour block average value excludes any hours when the system is in startup and shutdown conditions. This value is based on a concentration (2.5 ppm) guaranteed by the turbine and HRSG vendors. Two aeroderivative combustion turbine generating units from the RBLC and EPA Region 4 Combustion Turbine Database have NO_X limits that are equivalent to those proposed here. Therefore, 2.5 ppm NO_X emissions represent the lowest BACT emissions values contained within the aforementioned BACT databases. Compliance would be demonstrated via continuous emissions monitoring system (CEMS) required as part of the acid rain program.

Southern proposes a steady-state, simple cycle NO_X BACT emissions limit of **36.58 lb/hour/turbine**[37] on a 24-hour block average for all operational turbine loads at the HGS gas plant.[38] This 24-hour block average value excludes any hours when the system is in startup and shutdown conditions. This value is based on a concentration (25 ppm) guaranteed by the turbine vendor. Many aeroderivative combustion turbine generating units from the RBLC and EPA Region 4 Combustion Turbine Database have NO_X limits that are equivalent to those proposed here. NO_X emissions of 25 ppm represent the lowest steady-state simple cycle BACT emissions values contained within the aforementioned BACT databases. Compliance would be demonstrated via continuous emissions monitoring system (CEMS) required as part of the acid rain program.

Table 5-7 summarizes aeroderivative combustion turbine units and their respective NO_X emission limits (expressed as ppm rather than lb/hour) as reported in RBLC. Full RBLC data are contained in Appendix D.

5.4.5.2 Discussion of Startup and Shutdown Emission Limit Value

Combined Cycle Startup and Shutdown

Control of startup and shutdown (SUSD) emissions from the HGS gas plant are rather straightforward. The BACT controls determined in the analysis above for steady state operating conditions would be the most effective controls available for SUSD conditions.

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[35] The proposed steady-state, combined cycle BACT value of 4.16 lb/hr/turbine was calculated as both the turbine and HRSG vendor only guaranteed pollutant concentrations. See Appendix C for detailed calculations of the mass emission rates. For the purposes of this BACT analysis, a "generating unit" includes emissions from the duct burners.

[36] A block average is proposed because it is consistent with the intended operation. For the most part, the unit is expected to operate as a peaking plant or, on occasion, a base-load plant. As a peaking-related facility, it is expected that the load will follow a diurnal pattern. The unit(s) would typically operate in the morning and then again in the early evening to meet the demand needs of the customers. Therefore, an emission limit that follows this operation seems warranted.

[37] For the purposes of this BACT analysis, a "turbine" includes only the emissions from the combustion turbines as the duct burners do not fire in simple cycle mode.

[38] The proposed steady-state, simple cycle BACT value of 36.58 lb/hr/turbine was provided by the turbine vendor. No calculation was required.

The SCR controls proposed for combined cycle operations are not effective until a particular operating temperature is reached[39]. Once the appropriate catalyst temperature is reached, the ammonia injection grid will then activate, and the SCR reduction reaction can commence. Should the ammonia injection grid be allowed to activate prior to reaching minimum catalyst temperature, the control device would not be effective thereby releasing both NO_X and ammonia directly to the atmosphere. This would defeat the purpose of the control system. Therefore, no NO_X emissions are controlled via SCR during startup until the SCR catalyst reaches minimum operating temperature.

During combined cycle startups, the rate at which the turbine throttle can be increased is limited by the maximum allowable temperature and pressure ramp rates for the HRSG high pressure (HP) steam drum. Throttle increases are managed to prevent HRSG heating in excess of 22°F/min until the drum operating pressure is reached. The average time to accomplish the combined cycle startup is approximately two hours following the introduction of fuel to the turbine[40]. During this heating period of the HRSG steam drum, the minimum SCR operation temperature will be reached, and some NO_X reduction will occur, with maximum steady-state control achieved at the end of the startup period.

External heating of the SCR catalysts is not technically infeasible, but results in more uncontrolled emissions than the turbine alone generated during this heating period of combined cycle startup. In order to externally heat the SCR, it would be required to be removed from the optimum performance location within the HRSG, because the additional heat generated from external heating would overheat the steam drums. Moving the SCR catalysts outside the optimum operating temperature band results in reduced performance for the majority of operation of the system: steady-state operation.

The best method for the control of startup emissions for combined cycle operation is to operate the turbine such that heat is applied to the HRSG from the turbine exhaust in a safe and expedient manner to allow the SCR catalyst to reach operating temperature as fast as practicable, considering the HRSG vendor's maximum allowable temperature and pressure ramp rate for the HP steam drum. For this project, a two-hour time period has been identified as the minimum safe time period to accomplish the HRSG and SCR heating, and allow the system to reach steady-state operating conditions. As noted in Section 3.2.4, Southern proposes an NO_X startup emission limit of **26.12 lb/hr/generating unit**[41]. This limit is to apply during any hour when the generating unit

[39] One potential SCR vendor indicated that the catalyst temperature must reach 500°F before any reduction would occur.
[40] This duration takes into account the HRSG vendor allowable temperature and pressure ramp rate, turbine stabilization and air pollution control equilibrium, and good operating practices.
[41] This proposed combined cycle startup emission limit was calculated because thermal modeling for the project will not proceed in the project development timeline until after the application is submitted. All criteria used in the integration calculation are derived from vendor requirements, where applicable. See Appendix C for detailed CC SUSD calculations.

is in a combined cycle startup condition.[42]. Compliance would be demonstrated via a continuous emissions monitoring system (CEMS) required as part of the acid rain program.

The same basic logic applies during a combined cycle shutdown. The HP steam drum must be cooled at a controlled rate to avoid excessive thermal stresses. The turbine throttle will be managed to avoid cooling the HP steam drum too rapidly. During this time, until the SCR temperature falls below the minimum operating temperature, the ammonia injection grid will be active, and NO_X reduction will occur. Once the temperature falls below the SCR minimum operating temperature, no NO_X reduction will occur. Maximum control of combined cycle shutdown emissions is accomplished by cooling the HP steam drum at the maximum allowable temperature and pressure ramp rate. Emissions during combined cycle shutdown result from the combustion of fuel. Good combustion practice would indicate that fuel cutoff occur as soon as safely practicable, considering the HRSG vendor's maximum allowable temperature and pressure ramp rate. For this project, an average one-hour time period has been identified as the time period to accomplish the HRSG cooling that would require the turbine to remain operational. Once fuel is cut off, the HRSG could cool via convection from the turbine exhaust during spindown, although no emissions occur at this time because no fuel is being combusted. As noted in Section 3.2.4, Southern proposes a combined cycle NO_X shutdown emission limit of **12.33 lb/hr/generating unit**[43]. This limit is to apply during any hour when the generating unit is in a combined cycle shutdown condition.[44] Compliance would be demonstrated via a continuous emissions monitoring system (CEMS) required as part of the acid rain program.

Simple Cycle Startup and Shutdown

Due to the rapid startup and shutdown times for simple cycle operation (minimum of ten minute startup, eight minute shutdown) any additional NO_X controls will not reach operating temperature during that timeframe. Add-on control is effectively zero during such a rapid startup and shutdown. The DLE system will begin "to lean" the fuel combustion during both a simple cycle and combined cycle start after six minutes from hydraulic turbine spin-up. Therefore, the maximum control during rapid simple cycle SUSD conditions is to reach baseload conditions as rapidly as practicable, to enable the DLE system to stabilize.

[42] A combined cycle startup is defined as the time from when the fuel flow is introduced to the turbine following hydraulic startup, to the time when the combustion turbine reaches steady-state operations, up to two hours later.
[43] This proposed combined cycle shutdown emission limit was calculated because thermal modeling for the project will not proceed in the project development timeline until after the application is submitted. All criteria used in the integration calculation are derived from vendor requirements, where applicable. See Appendix C for detailed CC SUSD calculations.
[44] A combined cycle shutdown is defined as the time when the combustion turbine drops below base load conditions to the time that fuel is cut off to the combustion turbine defined as a one-hour time period.

As noted in Section 3.2.4, Southern proposes a simple cycle NO_X startup and shutdown emission limit of **36.58 lb/hr/turbine.**[45] As defined by the turbine vendor, the minimum safe startup period for simple cycle startup is defined as a ten minute startup and an eight minute shutdown. As a practical enforcement matter, with consideration for the maximum number of simple cycle startups and shutdowns physically possible during that hour and that no period less than one hour will be recorded by the CEMS, this SUSD limit is to apply during any hour when the generating unit is in a simple cycle startup or shutdown condition[46]. Compliance would be demonstrated via continuous emissions monitoring system (CEMS) required as part of the acid rain program.

Table 5-7: RBLC NO_X Control Summary for Aeroderivative Combustion Turbines

RBLC ID	PERMIT DATE	CORPORATE/COMPANY NAME FACILITY NAME	DESCRIPTION	POLLUTION CONTROL	EMISSION LIMIT (PPM)	AVG PERIOD
CT-0143	---	PPL WALLINGFORD ENERGY, LLC	---	SCR, DLE	2.5	---
NY*	01/21/2001	NEW YORK POWER AUTHORITY	---	SCR	2.5	1-HR
CA-0954	05/21/2001	CALPEAK CALPEAK POWER – PANOCHE	---	SCR, DLN	3.4	3-HR
CA-1095	12/07/2001	EL COLTON, LLC	---	SCR	3.5	3-HR
CA-1151	06/27/2001	CALPEAK CALPEAK POWER - EL CAJON	PEAKING (NO HRS LIMIT)	SCR, DLN	3.5	1-HR
PA*	02/01/2001	ALLEGHENY ENERGY SUPPLY WESTMORELAND	---	DLE, SCR	3.5	---
FL-0261	10/26/2004	CITY OF TALLAHASSEE ARVAH B. HOPKINS GEN. STATION	PEAKING (5840 HRS/YR) (4000 HRS FO/YR)	SCR, WATER INJ	5	---
KY*	UNDER REVIEW	EAST KENTUCKY POWER COOPERATIVE - J. K.SMITH PLANT	PEAKING (4000 HRS/YR)	WI, SCR	5	1-HR
NE*	04/04/2002	LINCOLN ELECTRIC SYSTEM SALT VALLEY STATION	---	SCR	5	30-DAY
TX*	09/12/2003	BROWNSVILLE PUBLIC UTILITY	---	SCR	5	---
TX*	03/28/2003	CITY OF BRIAN	---	SCR	5	---
TX-0388	02/12/2002	AUSTIN ELECTRIC UTILITY SAND HILL ENERGY CENTER	PEAKING	DLN	5	30-DAY
TX-0457	06/26/2003	CITY PUBLIC SERVICE LEON CREEK PLANT	---	SCR	5	---
UT*	06/15/2001	PACIFICORP WEST VALLEY CITY	---	SCR, WATER INJ	5	30-DAY
UT*	04/03/2002	PACIFICORP GADSBY	---	SCR, WATER INJ	5	30-DAY
WA*	10/26/2001	BENTON COUNTY PUD FINLEY CONBUSTION TURBINE PROJECT	---	SCR, WATER INJ	5	---
WA-0312	07/18/2003	PUGET SOUND ENERGY FREDONIA ENERGY STATION	---	SCR	5	3-HR
FL-0272	09/12/2005	KEYS ENERGY SERVICES STOCK ISLAND POWER PLANT	FO FIRED	SCR, WATER INJ	9	---
TX-0405	12/15/2000	WESTVACO TEXAS LP	TURBINE W/O DUCT BURNERS	DLN, SCR	9	---
WA*	07/03/2001	PIERCE POWER	---	DLN, SCR	9	24-HR

[45] This proposed simple cycle SUSD emission limit was selected because the calculated NO_X SUSD emission value is less than the lb/hr value, for NO_X emissions. Not all pollutants' SUSD emissions are less than the nominal steady-state operating value.

[46] A simple cycle startup is defined as the time when the fuel is introduced into the combustion turbine to the time that base load throttle conditions are reached,. Simple cycle shutdown is defined as the time from when the turbine drops below base load conditions to the time that fuel is cut off to the combustion turbine. The simple cycle SUSD time period lasts for one hour for any hour that an SUSD event occurs.

RBLC ID	PERMIT DATE	CORPORATE/COMPANY NAME FACILITY NAME	DESCRIPTION	POLLUTION CONTROL	EMISSION LIMIT (PPM)	AVG PERIOD
NE*	04/04/2002	LINCOLN ELECTRIC SYSTEM SALT VALLEY STATION	---	SCR	10	3-HR
IL*	02/01/2000	SPECTRUM ENERGY - CENTRAL ILL. POWER - ST. PETER	---	WI	20	---
AR*	02/28/2000	WRIGHTSVILLE ENERGY POWER FACILITY	PEAKING (5250 HRS/YR)	STEAM INJ	25	---
FL*	NOT ISSUED	TECO BAYSIDE POWER STATION	3500 HR LIMIT	WI	25	---
IN-0095	12/07/2001	ALLEGHENY ENERGY SUPPLY CO, LLC	PEAKING (3500 HRS/YR)	WATER INJ	25	24-HR
KS*	04-17-2007	WESTAR ENERGY EMPORIA ENERGY CENTER	PEAKING (4,300 HRS/YR)	WI	25	24-HR
MI-0268	06/26/2000	KM POWER COMPANY	PEAKING	STEAM INJ	25	30-DAY
NE*	04/04/2002	LINCOLN ELECTRIC SYSTEM SALT VALLEY STATION	---	BYPASS	25	3-HR
OR-0030	06/22/2001	PACIFICORP KLAMATH FALLS FACILITY	OPERATES @ 100% LOAD	WATER INJ	25	24-HR
PA-0159	09/29/2000	HANDSOME LAKE ENERGY, L.L.C.	NG FIRED	WATER INJ	25	---
PA-0171	07/10/2001	ALLEGHENY ENERGY SUPPLY COMPANY, LLC HARRISON CITY	NG FIRED	SCR, WATER INJ	25	---
SD-0002	03/20/2001	BLACK HILLS POWER AND LIGHT COMPANY LANGE COMBUSTION TURBINES	PEAKING NG FIRED	DLN	25	---
VA-0244	05/01/2000	WOLF HILLS ENERGY LLC	NG FIRED	WATER INJ	25	---
WV*	07/10/2000	TENASKA BIG SANDY	PEAKING (1314 HRS/YR)	WATER INJ	25	---
WY-0054	03/01/2000	BLACK HILLS POWER & LIGHT NEIL SIMPSON II	NG FIRED	DLN	25	24-HR
WY*	02/27/1998	TWO ELK GENERATION PARTNERS	---	GCP	25	1-HR
VI-0008	01/03/2001	VIRGIN ISLANDS WATER AND POWER AUTHORITY (VIWAPA) KRUM BAY ST. THOMAS GEN. STATION	PEAKING (NO HRS LIMIT) FUEL OIL FIRED	WATER INJ	42	24-HR
PA-0195	7/6/2000	ALLEGHENY ENERGY SUPPLY GANS CT POWER STATION	---	WI	73.9	---
FL-0266	06/29/2005	SEMINOLE ELECTRIC COMPANY RICHARD J. MIDULLA GEN. STATION (FORMERLY PAYNE CREEK GEN. STATION)	PEAKING (2500 HRS/YR) (500 HRS FO/YEAR)	WATER INJ	20 NG 42 FO	24-HR
ID*	09/09/2002	MOUNTAIN VIEW POWER, LLC	---	WATER INJ	25 NG	---
IN*	07/15/1999	PSI CINERGY WABASH PEAKING STATION	PEAKING (3000 HRS/YR)	DLN, WATER INJ	25 NG 28 FO	---
IL*	02/04/1999	DYNEGY, ROCK RD. POWER	PEAKING (1,300 HRS/YR)	---	25 NG 42 FO	---
MO*	07/25/2002	EMPIRE ENERGY DISTRICT EMPIRE ENERGY CENTER	DUAL FUEL, PEAKING (3,300 HRS/YR)	WATER INJ	25 NG 42 FO	3-HR
NE-0012	07/29/1999	OMAHA PUBLIC POWER DISTRICT	PEAKING (2,000 HRS/YR/TURBINE) DUAL FUEL	WATER INJ	25 NG 42 FO	---
SC*	DRAFT PERMIT	DUKE ENERGY - LEE STEAM STATION	PEAKING (4,400 HRS NG, 3,900 FO)	---	25 NG 42 FO	---
VA-0259	01/31/2002	BUCHANAN GENERATION LLC ALLEGHENY ENERGY SUPPLY	NG/FO	WATER INJ	25 NG 42 FO	---
TX-0295	01/17/2002	SOUTH TEXAS ELECTRIC COOP SAM RAYBURN GEN. STATION	720 HRS FO/YR	SCR	5 NG 5 FO	---

Note: Items with an * indicate they are not listed in RBLC, but can be found in EPA Region 4 Combustion Turbine List.

5.5 BACT – CO and VOC

CO and VOCs are formed from incomplete combustion of organic constituents within the natural gas in the facility's combustion turbines. CO and VOC emissions are governed by an inverse relationship of exhaust concentration and turbine flowrate. When the turbine operates at high loads, combustion is more complete and concentrations are lower, but flowrates are at their highest. When the turbine operates at low loads, combustion is incomplete and concentrations tend to increase, but flowrates are reduced. Both cases may result in elevated mass emissions rates of CO and VOCs depending on the magnitude of the individual variables.

Because CO and VOC are generated and controlled by the same mechanisms, they will be addressed in this section together. In an ideal process, complete combustion, or oxidation, of organics results in the emission of water and CO_2. When organic compounds do not oxidize completely, the result is CO and various modified organic compounds (VOCs). Two general and nonexclusive approaches are available for reducing emissions of these compounds:

- Improve combustion conditions to facilitate complete combustion in the turbine burner, and
- Complete oxidation of the exhaust stream after it leaves the turbine burner.

Post-combustion CO/VOC control is accomplished via add-on equipment that creates an environment of high temperature and oxygen concentration to promote complete oxidation of the CO and organic compounds remaining in the exhaust. This can be facilitated at relatively lower temperatures by the use of certain catalyst materials.

5.5.1 Step 1 - Identify All Control Technologies

A review of EPA's RBLC database (see Appendix D) and AP-42[47] indicate three primary control technologies for CO and VOC, some of which are not currently used for control of combustion turbine emissions:

- Proper system design and operation
- Thermal oxidation
- Catalytic oxidation

5.5.1.1 Proper System Design and Operation (base case)

Reduction of CO emissions can be accomplished by controlling the combination of system temperatures through operation at maximum loads, increasing oxygen concentrations, maximizing combustion residence time, and improving mixing of the fuel, exhaust gases, and combustion air (oxygen). Maximizing heating efficiency, and

[47] AP-42 Chapter 3.1 – Stationary Gas Turbines.

subsequently minimizing fuel usage, will also minimize CO formation. Paradoxically, all of these techniques also generally increase NO_X emissions.

5.5.1.2 Thermal Oxidation

Thermal oxidizers are essentially supplementary combustion chambers that complete the conversion of CO/VOC to CO_2 and water by creating a high temperature environment with optimal oxygen concentration, mixing, and residence time. They require temperatures of approximately 1800°F to 2000°F. This high-temperature environment is produced by the combustion of supplemental fuel, generally natural gas. Thermal oxidizers are typically located downstream of a particulate control device, especially when the exhaust stream contains high concentrations of particulate material. Reduced particulate loading improves thermal efficiency since the particulate matter would act as a heat sink, and it reduces equipment maintenance requirements.

Several design variations address different inlet concentrations, air flow rates, fuel efficiency requirements, and other operational variables. All of them function using the basic principles described above. One commonly used design is called a regenerative thermal oxidizer (RTO). This type of thermal oxidizer typically uses a bed of ceramic packing material to capture heat from the incineration process and preheat the incoming exhaust gas. This design improves thermal efficiency and reduces the amount of supplemental fuel that must be combusted. RTOs are capable of reducing CO/VOC emissions by 95 to 99 percent (EPA, 2003).

5.5.1.3 Catalytic Oxidation

Catalytic oxidizers employ the same principles as thermal oxidizers, but they use catalysts to lower the temperature required to effect complete oxidation. The optimum temperature range for catalytic oxidizers is generally 600 to 900°F. Because catalysts are prone to plugging and poisoning, catalytic oxidizers must be located downstream of a particulate control device if the exhaust stream contains appreciable concentrations of particulate matter. Even so, contaminants that are not removed by the particulate control equipment, or those that are not removed in sufficient quantity, can potentially poison the catalyst and reduce or eliminate its effectiveness. For this application, the turbines will be combusting clean fuels (natural gas and ultra low-sulfur diesel fuel), and particulate loading is not anticipated to be a problem.

Like thermal oxidizers, catalytic oxidizer designs include many varieties to address specific operational conditions and requirements. They are generally capable of 90 to 99 percent destruction or removal efficiency at steady-state conditions (EPA, 2003).

5.5.2 Step 2 - Eliminate Technically Infeasible Control Options

The NSR Manual describes two key criteria for determining whether an alternative control technology is technically feasible. According to the NSR Manual, a technology must be "available" and "applicable" in order to be considered technically feasible. A technology is *available* "if it has reached the licensing and commercial sales stage of development." An identified alternative control technique may be considered *applicable* if "it has been or is soon to be deployed (e.g., is specified in a permit) on the same or similar source type." The following paragraphs evaluate the technical feasibility of the alternative control technologies identified above by applying these criteria of availability and applicability.

5.5.2.1 Proper System Design and Operation

Proper system design and operation serve as the baseline for CO and VOC emissions reduction and are clearly technically feasible.

5.5.2.2 Thermal and Catalytic Oxidation

The use of a catalytic oxidizer or an RTO unit was evaluated and several technical difficulties were identified. First, for effective oxidation, gas inlet temperatures are required to be within a narrow "window" of acceptable temperatures. For an RTO unit, additional fuel will need to be combusted to bring the temperatures up to acceptable levels. These technical difficulties do not allow either of the control devices to be eliminated based on technical infeasibility.

5.5.3 Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Catalytic oxidizers and RTO units are expected to have CO and VOC control efficiencies ranging from 70% to 95%. Typically, when an incinerator is designed for either CO or VOC control, the pollutant that the control device was not specifically designed for is controlled less efficiently. For example, for a typical CO catalytic oxidizer, the corresponding VOC control would be approximately half to one-third that of the CO control efficiency value. For this BACT analysis, when each pollutant was analyzed separately, the average catalytic oxidizer control efficiency provided by the turbine vendor for CO was 95%. For VOCs, the turbine vendor has conservatively estimated the value to be 30%.[48]. For this BACT analysis, the minimum reported RTO control efficiency of 95 percent was applied for controlling CO and VOC emissions.[49] Table 5-8 summarizes the control efficiencies for this analysis.

Table 5-8: Ranked CO Control Technology Effectiveness

Control Technology	Percent Reduction	
	CO	VOC
Thermal Oxidizer	95%	95%
Catalytic Oxidizer	95%	30%

[48] The vendor-guaranteed emission rates do not guarantee the potential VOC control gained from the oxidation catalyst.
[49] EPA-452/F-03-021 – Air Pollution Control Technology Fact Sheet, http://www.epa.gov/ttn/catc/dir1/fregen.pdf

5.5.4 Step 4 - Evaluate Most Effective Controls and Document Results

5.5.4.1 Environmental Evaluation

The adverse environmental impact for a catalytic oxidizer results from the handling of the spent catalyst. Many of the catalyst formulations are potentially toxic and subject to hazardous waste disposal regulations under the Resource Conservation and Recovery Act (RCRA).

An RTO will require reheating of the exhaust stream to acceptable levels to facilitate the oxidation reaction. The combustion of the natural gas will cause an increase in additional NO_X, CO, PM_{10}, VOC, and SO_2 emissions. Table 5-9 establishes conservative estimates of uncontrolled emissions caused by the additional fuel combustion for RTO application. These estimates are based on emission factors from AP-42, Tables 1.4-1 and 1.4-2. While there are some adverse environmental impacts, this is not enough to eliminate the technologies from further consideration.

Table 5-9: Uncontrolled Additional Emissions from Fuel Combustion for RTO

Emitting Unit	NO_X (ton/yr)	CO (ton/yr)	PM10 (ton/yr)	VOC (ton/yr)	SO_2 (ton/yr)
RTO - Simple Cycle	13.4	8.0	0.7	0.5	0.1
RTO - Combined Cycle	9.0	5.4	0.5	0.4	0.0

5.5.4.2 Energy Impacts

An RTO would require the exhaust gas to be reheated to achieve the optimal operating temperature for CO oxidation. Energy impacts are created with the combustion of additional natural gas to reheat the exhaust. To reach the required reaction temperature, 34.5% to 62.0% additional heat input over that required to operate each turbine, is required.[50] Even though these large energy impacts exist, the control options cannot be eliminated based on these concerns.

No significant energy impacts result from the installation of a catalytic oxidizer, as it is a passive control system.

5.5.4.3 Economic Evaluation

Economic impacts associated with CO control options were compared using estimated annualized capital, operating, and maintenance costs. Cost estimates for catalytic oxidizers and RTO were derived from the methods outlined in EPA 453/B-96-001, *Office of Air Quality Planning and Standards Control Cost Manual*, 6th Edition (OAQPS). Where appropriate, assumptions were made from suggested/typical data that were supplied in the manual and if data was not available from the manual, best engineering judgment was used. Costs were estimated using the OAQPS cost analysis methods for

[50] Combined Cycle = 154.3 MMBtu/hr RTO / 447.5 MMBtu/hr turbine = 34.5%
Simple Cycle = 229.3 MMBtu/hr RTO / 369.7 MMBtu/hr turbine = 62.0%

an RTO with 90% energy recovery and actual vendor quotes for catalytic oxidizers. The equipment costs estimated via OAQPS were adjusted by the latest Producers Price Index (PPI) multiplier in Jan. 2009 dollars.[51] The eight cases evaluated in this CO BACT analysis for the orientation of the control and HRSG equipment are identical to the eight cases already described in the NO_X BACT analysis of Section 5.4.4.3. The discussion of those cases will not be repeated here. Table 5-10 through Table 5-13 summarizes the economic impacts of the CO control options. Detailed capital and annual costs can be found in Appendix E.

Table 5-10: CO BACT Economic Evaluation Summary – Simple Cycle

Cost-Effectiveness for CO Control, per Simple Cycle Turbine Simple Cycle Operations limited to 3,200 hours operation per year						
Control	**Design Case**	**Estimated Total Annual Cost**	**Uncontrolled Emissions[a] (tpy)**	**Control Efficiency (%)**	**Tons Removed (tpy)**	**Cost-Effectiveness ($/ton)**
RTO	T1	---	78	---	---	---
	T2	$3,174,362	86	95%	82	$38,687
	T3	$3,174,362	86	95%	82	$38,687
	T4	$3,174,362	86	95%	82	$38,687
	S1	No Analysis Required				
	S2	$3,174,362	86	95%	82	$38,687
	S3	Not Technically Feasible				
	S4	$3,174,362	86	95%	82	$38,687
Catalytic Oxidizer	T1	---	78	0	0	---
	T2	$916,620	78	96%	75	$12,205
	T3	$916,620	78	96%	75	$12,205
	T4	$916,620	78	96%	75	$12,205
	S1	No Analysis Required				
	S2	$8,267,080	78	86%	75	$110,099
	S3	Not Technically Feasible				
	S4	$1,632,013	78	96%	75	$21,725

[a] RTO includes additional CO and VOC emissions from reheating exhaust gas.

[51] Bureau of Labor Statistics Data, preliminary Jan 2009 - Other industrial machinery - PCU33329-33329-.

Table 5-11: VOC BACT Economic Evaluation Summary – Simple Cycle

Cost-Effectiveness for VOC Control, per Simple Cycle Turbine Simple Cycle Operations limited to 3,200 hours operation per year						
Unit	Design Case	Estimated Total Annual Cost	Uncontrolled Emissions[a] (tpy)	Control Efficiency (%)	Tons Removed (tpy)	Cost-Effectiveness ($/ton)
RTO	T1	---	3.2	---	---	---
	T2	$3,174,362	3.8	95%	3.6	$885,364
	T3	$3,174,362	3.8	95%	3.6	$885,364
	T4	$3,174,362	3.8	95%	3.6	$885,364
	S1	No Analysis Required				
	S2	$3,174,362	3.8	95%	3.6	$885,364
	S3	Not Technically Feasible				
	S4	$3,174,362	3.8	95%	3.6	$885,364
Catalytic Oxidizer	T1	---	3.2	---	---	---
	T2	$916,620	3.2	30%	1.0	$940,702
	T3	$916,620	3.2	30%	1.0	$940,702
	T4	$916,620	3.2	30%	1.0	$940,702
	S1	No Analysis Required				
	S2	$8,267,080	3.2	30%	1.0	$8,484,278
	S3	Not Technically Feasible				
	S4	$1,632,013	3.2	30%	1.0	$1,674,890

[a] RTO includes additional CO and VOC emissions from reheating exhaust gas.

Table 5-12: CO BACT Economic Evaluation Summary – Combined Cycle

Cost-Effectiveness for CO Control, per Combined Cycle Generating Unit Combined Cycle Operations, 8760 hours operation per year[52]						
Control	Design Case	Estimated Total Annual Cost	Uncontrolled Emissions[a] (tpy)	Control Efficiency (%)	Tons Removed (tpy)	Cost-Effectiveness ($/ton)
RTO	T1	$2,824,164	233	95%	221	$12,772
	T2	$2,824,164	233	95%	221	$12,772
	T3	$2,824,164	233	95%	221	$12,772
	T4	$2,824,164	233	95%	221	$12,772
	S1	$2,824,164	233	95%	221	$12,772
	S2	$2,824,164	233	95%	221	$12,772
	S3	$2,824,164	233	95%	221	$12,772
	S4	$2,824,164	233	95%	221	$12,772
Catalytic Oxidizer	T1	$588,336	227	96%	219	$2,682
	T2	$588,336	227	96%	219	$2,682
	T3	$772,441	227	82%	186	$4,147
	T4	$1,867,700	227	96%	219	$8,515
	S1	$588,336	227	96%	219	$2,682
	S2	$8,267,080	227	96%	219	$37,689
	S3	$916,620	227	96%	219	$4,179
	S4	$1,664,193	227	86%	219	$7,590

[a] RTO includes additional CO and VOC emissions from reheating exhaust gas.

[52] Capacity Factor of 0.9 per Stanley Consultants.

Table 5-13: VOC BACT Economic Evaluation Summary – Combined Cycle

Cost-Effectiveness for VOC Control, per Combined Cycle Generating Unit Combined Cycle Operations, 8760 hours operation per year[53]						
Control	Design Case	Estimated Total Annual Cost	Uncontrolled Emissions[a] (tpy)	Control Efficiency (%)	Tons Removed (tpy)	Cost-Effectiveness ($/ton)
RTO	T1	$2,824,164	10.6	95%	10.1	$280,444
	T2	$2,824,164	10.6	95%	10.1	$280,444
	T3	$2,824,164	10.6	95%	10.1	$280,444
	T4	$2,824,164	10.6	95%	10.1	$280,444
	S1	$2,824,164	10.6	95%	10.1	$280,444
	S2	$2,824,164	10.6	95%	10.1	$280,444
	S3	$2,824,164	10.6	95%	10.1	$280,444
	S4	$2,824,164	10.6	95%	10.1	$280,444
Catalytic Oxidizer	T1	$588,336	10.2	30%	3.1	$245,071
	T2	$588,336	10.2	30%	3.1	$245,071
	T3	$772,441	10.2	23%	2.4	$321,759
	T4	$1,867,700	10.2	30%	3.1	$607,605
	S1	$588,336	10.2	30%	3.1	$245,071
	S2	$8,267,080	10.2	30%	3.1	$2,689,467
	S3	$916,620	10.2	30%	3.1	$298,197
	S4	$1,664,193	10.2	30%	3.1	$541,399

[a] RTO includes additional CO and VOC emissions from reheating exhaust gas.

Annual costs include operating labor and materials, maintenance, utilities, overhead, administrative charges, property taxes, and insurance.

5.5.5 Step 5 - Identify BACT

Installation of a catalytic oxidizer is cost-effective for combined cycle operations, within the meaning of BACT, for these combustion turbines. A control technology is generally considered feasible if the annualized cost is less than $5,000. Based on the low removal cost for CO control for Case T1 by a catalytic oxidizer at approximately $2,682 per ton of CO removed and the relatively small environmental impacts, the proposed BACT for control of CO from combined cycle combustion turbine operation is catalytic oxidation. Based on the high removal cost for CO control for all cases analyzed, with Cases T2, T3, and T4 being the least expensive at $12,205 per ton of CO removed, a catalytic oxidizer is not a cost-effective CO control technology for simple cycle operations at HGS. The proposed BACT for control of CO from simple cycle combustion turbine operation is proper system design and operation.

Based on the data presented in Table 5-11 and Table 5-13, neither RTO nor catalytic oxidation control option is cost-effective for VOC control. However, the benefit of 30% VOC control is realized with the independent analysis and installation of a catalytic

[53] Capacity Factor of 0.9 per Stanley Consultants

oxidizer for CO control.[54] Therefore, the installation of a catalytic oxidizer is considered BACT for the control of both CO and VOC.

5.5.5.1 Discussion of CO and VOC BACT Emission Limit Values

As noted above, Southern is proposing the installation and operation of a high degree of control of CO for combined cycle operation at the HGS gas plant: a catalytic oxidation system. For VOC, the same control device is proposed since the cost of further add-on controls such as RTO are not within BACT norms. As demonstrated in Table 5-11 and Table 5-13, the installation of additional control to simple cycle operation is cost-prohibitive. The final task is to determine an emission limit applicable to this facility.

A review of EPA's RBLC indicates that for recently permitted aeroderivative combustion turbine generating units, a normalized emission limit value of 5 to 10 ppmvd[55] (corrected to 15% O_2) is BACT for CO at full load, steady-state operations. The HGS gas plant oxidation catalyst vendors have guaranteed an emission limit of 2 ppm for controlled, combined cycle operations at full load, steady-state conditions.

Southern proposes a steady-state, combined cycle CO BACT emissions limit of **2.03 lb/hour/generating unit** on a 24-hour block[56] average for all operational turbine loads at the HGS gas plant.[57] This 24-hour block average value excludes any hours when the system is in startup and shutdown conditions. This value is based on a concentration (2 ppm) guaranteed by the oxidation catalyst vendors. These CO emissions represent the lowest BACT emissions values contained within the aforementioned BACT databases for aeroderivative turbines. Compliance would be demonstrated by initial testing followed by testing as required by MDEQ.

Southern proposes a steady-state, simple cycle CO BACT emissions limit of **48.96 lb/hour/turbine** on a 24-hour block average for all operational turbine loads at the HGS gas plant.[58] This 24-hour block average value excludes any hours when the system is in

[54] The vendor has noted that it would be expected for the oxidation catalyst to remove 30% of VOC emissions; the vendor was not willing to make such a guarantee. The calculations in the economic evaluation table reflect this control for purposes of carrying the options to an endpoint, since it is concluded that a catalyst is appropriate for this facility (with or without VOC control).

[55] Note that within this and following paragraphs emissions are sometimes expressed as ppm. This is done for the purpose of comparison among RBLC and vendor data. As noted later in this section, a lb/hour value is proposed for BACT. Since lb/hour values were not available from the RBLC, direct comparisons of those units are not possible. As a result, ppm comparisons are made for consistency purposes here although a mass emission standard represents BACT in this case.

[56] A block average is proposed because it is consistent with the intended operation. For the most part, the unit is expected to operate as a peaking plant or, on occasion, a base-load plant. As a peaking-related facility, it is expected that the load will follow a diurnal pattern. The unit(s) would typically operate in the morning and then again in the early evening to meet the demand needs of the customers. Therefore, an emission limit that follows this operation seems warranted.

[57] The proposed steady-state, combined cycle BACT value of 2.03 lb/hr/turbine was calculated as both the turbine and HRSG vendor only guaranteed pollutant concentrations. See Appendix C for detailed calculations of the mass emission rates.

[58] The proposed steady-state, simple cycle BACT value of 48.96 lb/hr/turbine was provided by the turbine vendor. No calculation was required.

startup and shutdown conditions. This value is based on a concentration (55 ppm) guaranteed by the turbine vendor. Several aeroderivative combustion turbine generating units from the RBLC and EPA Region 4 Combustion Turbine Database have CO limits that are equivalent to or greater than those proposed here when controls are not cost-effective for a particular mode of operation. Compliance would be demonstrated by initial testing followed by testing as required by MDEQ.

Southern proposes a steady-state, combined cycle VOC BACT emissions limit of **1.86 lb/hour/generating unit** on a 24-hour block average for all operational turbine loads at the HGS gas plant.[59] This 24-hour block average value excludes any hours when the system is in startup and shutdown conditions. This value is based on a concentration (4 ppm) guaranteed by the oxidation catalyst vendors. These VOC emissions are within the range of limits that have been deemed BACT for controlling emissions from aeroderivative combustion turbines as presented in the RBLC and EPA Region 4 Combustion Turbine databases. Compliance would be demonstrated by initial testing followed by testing as required by MDEQ.

Southern proposes a steady-state, simple cycle VOC BACT emissions limit of **2.03 lb/hour/turbine** on a 24-hour block average for all operational turbine loads at the HGS gas plant.[60] This 24-hour block average value excludes any hours when the system is in startup and shutdown conditions. This value is based on a concentration (4 ppm) guaranteed by the turbine vendors. These VOC emissions are within the range of limits that have been deemed BACT for controlling emissions from aeroderivative combustion turbines as presented in the RBLC and EPA Region 4 Combustion Turbine databases. Compliance would be demonstrated by initial testing followed by testing as required by MDEQ.

Table 5-14 and Table 5-15 summarize aeroderivative combustion turbine units and their respective CO and VOC emission limits (expressed as ppm rather than lb/hour) as reported in RBLC. Full RBLC data are contained in Appendix D.

5.5.5.2 Discussion of Startup and Shutdown CO and VOC Emission Limit Value

Combined Cycle Startup and Shutdown

Control of startup and shutdown (SUSD) emissions from the HGS gas plant are rather straightforward. The BACT controls determined in the analysis above for steady-state operating conditions would be the most effective controls available for SUSD conditions. However, the oxidation catalyst controls proposed for combined cycle operations are not effective until a particular activation temperature is reached.[61] Once the appropriate

[59] The proposed steady-state, combined cycle BACT value of 1.86 lb/hr/turbine was calculated as both the turbine and HRSG vendor only guaranteed pollutant concentrations. See Appendix C for detailed calculations of the mass emission rates.

[60] The proposed steady-state, simple cycle BACT value of 2.03 lb/hr/turbine was provided by the turbine vendor. No calculation was required.

[61] One potential oxidation catalyst vendor indicated that the catalyst temperature must reach 300℉ befo re CO oxidation will occur.

catalyst temperature is reached, the CO and VOC oxidation reaction can commence at the rate needed to effectively control the large volumes of exhaust passing through the catalyst. Therefore, little CO and VOC emissions are controlled via the oxidation catalyst during startup until the catalyst reaches minimum activation temperature.

During combined cycle startups, the rate at which the turbine throttle can be increased is limited by the maximum allowable temperature and pressure ramp rates for the HRSG high pressure (HP) steam drum. Throttle increases are managed to prevent HRSG heating in excess of 22°F/min until the drum operating pressure is reached. The average time to accomplish the combined cycle startup is approximately two hours following the introduction of fuel to the turbine.[62] During this heating period of the HRSG steam drum, the minimum oxidation catalyst activation temperature will be reached, and CO and VOC oxidation will commence.

External heating of the oxidation catalysts is not technically infeasible, but results in more uncontrolled emissions than the turbine alone will generate during this heating period of combined cycle startup. In order to externally heat the oxidation catalyst, it would be required to be removed from the optimum performance location within the HRSG, because the additional heat generated from external heating would overheat the steam drums. Moving the oxidation catalysts outside the optimum operating temperature band results in reduced performance for the majority of operation of the system: steady-state operation.

The best method for the control of startup emissions for combined cycle operation is to operate the turbine such that heat is applied to the HRSG from the turbine exhaust in a safe and expedient manner to allow the oxidation catalyst to reach activation temperature as fast as practicable, considering the HRSG vendor's maximum allowable temperature and pressure ramp rate for the HP steam drum. For this project, a two-hour time period has been identified as the minimum safe time period to accomplish the HRSG heating and allow the system to stabilize to steady-state operating conditions. As noted in Section 3.2.4, Southern proposes a CO startup emission limit of **76.20 lb/hr/generating unit** and a VOC startup emission limit of **1.86 lb/hr/generating unit.**[63] These limits are to apply during any hour when the generating unit is in a combined cycle startup condition.[64] Compliance would be demonstrated by testing as required by MDEQ.

The same basic logic applies during a combined cycle shutdown. The HP steam drum must be cooled at a controlled rate to avoid excessive thermal stresses. The turbine

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[62] This duration takes into account the HRSG vendor allowable temperature and pressure ramp rate, turbine stabilization and air pollution control equilibrium, and good operating practices.

[63] These proposed combined cycle startup emission limits were calculated because thermal modeling for the project will not proceed in the project development timeline until after the application is submitted. All criteria used in the integration calculations are derived from vendor requirements, where applicable. See Appendix C for detailed CC SUSD calculations.

[64] A combined cycle startup is defined as the time from when the fuel flow is introduced the turbine following hydraulic startup, to the time when the combustion turbine reaches steady-state operations, up to two hours later.

throttle will be managed to avoid cooling the HP steam drum too rapidly. During this time, until the oxidation catalyst temperature falls below the minimum activation temperature, the CO and VOC oxidation reaction will occur. Once the temperature falls below the oxidation catalyst minimum activation temperature, no CO reduction will occur. Maximum control of combined cycle shutdown emissions is accomplished by cooling the HP steam drum at the maximum allowable temperature and pressure ramp rate. Emissions during combined cycle shutdown result from the combustion of fuel. Good combustion practice would indicate that fuel cutoff occur as soon as safely practicable, considering the HRSG vendor's maximum allowable temperature and pressure ramp rate. For this project, an average of a one-hour time period has been identified as the time period to accomplish the HRSG cooling that would require the turbine to remain operational. Once fuel is cut off, the HRSG could cool via convection from the turbine fan exhaust during spindown, although no emissions occur at this time because no fuel is being combusted. As noted in Section 3.2.4, Southern proposes a combined cycle CO shutdown emission limit of **4.15 lb/hr/generating unit** and a VOC shutdown emission limit of **1.86 lb/hr/generating unit**.[65] These limits are to apply during any hour when the generating unit is in a combined cycle shutdown condition.[66] Compliance would be demonstrated by testing as required by MDEQ.

Simple Cycle Startup and Shutdown

Due to the rapid startup and shutdown times for simple cycle operation (ten minute startup, eight minute shutdown) any additional CO and VOC controls will not reach optimal operating temperature during that timeframe. Add-on control is effectively zero during such a rapid startup and shutdown. The DLE system will begin "to lean" the fuel combustion during both a simple cycle and combined cycle start after six minutes from hyrdraulic turbine spin-up. The maximum control available during simple cycle SUSD conditions is to reach baseload conditions as rapidly as practicable, to enable the DLE system to stabilize.

As noted in Section 3.2.4, Southern proposes a simple cycle CO startup and shutdown emission limit of **114.70 lb/hr/turbine** and a VOC startup and shutdown emission limit of **3.90 lb/hr/turbine.** As defined by the turbine vendor, the minimum safe startup period for simple cycle startup is defined as a ten minute startup and an eight minute shutdown. As a practical enforcement matter, with consideration for the maximum number of simple cycle startups and shutdowns physically possible during an hour, this SUSD limit is to apply during any hour when the generating unit is in a simple cycle

[65] These proposed combined cycle shutdown emission limits were calculated because thermal modeling for the project will not proceed in the project development timeline until after the application is submitted. All criteria used in the integration calculation are derived from vendor requirements, where applicable. See Appendix C for detailed CC SUSD calculations.

[66] A combined cycle shutdown is defined as the time when the combustion turbine drops below base load conditions to the time that fuel is cut off to the combustion turbine, which may occur up to an hour after dropping below baseload conditions.

startup or shutdown condition[67]. Compliance would be demonstrated by testing as required by MDEQ.

Table 5-14: RBLC CO Control Summary for Aeroderivative Combustion Turbines

RBLC ID	PERMIT DATE	CORPORATE/COMPANY NAME FACILITY NAME	DESCRIPTION	POLLUTION CONTROL	EMISSION LIMIT (PPM)	AVG PERIOD
NE*	04/04/2002	LINCOLN ELECTRIC SYSTEM SALT VALLEY STATION		SCR	5	30-DAY
NY*	01/21/2001	NEW YORK POWER AUTHORITY	---	OXY CAT	5	1-HR
CA-1095	12/07/2001	EL COLTON, LLC	---	OXY CAT	6	3-HR
FL-0261	10/26/2004	CITY OF TALLAHASSEE ARVAH B. HOPKINS GEN. STATION	PEAKING (5840 HRS/YR) (4000 HRS FO/YR)	OXY CAT	6	---
FL*	NOT ISSUED	TECO BAYSIDE POWER STATION	3500 HR LIMIT	OXY CAT	6	
KY*	UNDER REVIEW	EAST KENTUCKY POWER COOPERATIVE - J. K.SMITH PLANT	PEAKING (4000 HRS/YR)	OXY CAT	6	3-HR
TX-0388	02/12/2002	AUSTIN ELECTRIC UTILITY SAND HILL ENERGY CENTER	PEAKING	OXY CAT	9	30-DAY
UT*	06/15/2001	PACIFICORP WEST VALLEY CITY	---	OXY CAT	10	30-DAY
UT*	04/03/2002	PACIFICORP GADSBY	---	OXY CAT	10	8-HR BLOCK
VI-0008	01/03/2001	VIRGIN ISLANDS WATER AND POWER AUTHORITY (VIWAPA) KRUM BAY ST. THOMAS GEN. STATION	PEAKING (NO HRS LIMIT) FUEL OIL FIRED	---	10	3-HR
WA*	10/26/2001	BENTON COUNTY PUD FINLEY CONBUSTION TURBINE PROJECT	---	OXY CAT	10	---
WA*	07/03/2001	PIERCE POWER		OXY CAT	10	1-HR
NE*	04/04/2002	LINCOLN ELECTRIC SYSTEM SALT VALLEY STATION		OXY CAT	13	3-HR
CT-0143	---	PPL WALLINGFORD ENERGY, LLC	---	OXY CAT	16	---
OR-0030	06/22/2001	PACIFICORP KLAMATH FALLS FACILITY	OPERATES @ 100% LOAD	OXY CAT	16	8-HR
FL-0272	09/12/2005	KEYS ENERGY SERVICES STOCK ISLAND POWER PLANT	FO FIRED	---	20	---
TX-0405	12/15/2000	WESTVACO TEXAS LP	TURBINE W/O DUCT BURNERS	OXY CAT	22	
VA-0259	01/31/2002	BUCHANAN GENERATION LLC ALLEGHENY ENERGY SUPPLY	NG/FO		24	---
OK-0042	11/30/2000	WESTER FARMERS ELEC COOP ANADARKO		WI	25	
PA-0159	09/29/2000	HANDSOME LAKE ENERGY, L.L.C.	NG FIRED	OXY CAT	25	1-HR
PA-0171	07/10/2001	ALLEGHENY ENERGY SUPPLY COMPANY, LLC HARRISON CITY	NG FIRED	OXY CAT	25	---
SD-0002	03/20/2001	BLACK HILLS POWER AND LIGHT COMPANY LANGE COMBUSTION TURBINES	PEAKING NG FIRED		25	---
VA-0244	05/01/2000	WOLF HILLS ENERGY LLC	NG FIRED	OXY CAT	25	---
WY-0054	03/01/2000	BLACK HILLS POWER & LIGHT NEIL SIMPSON II	NG FIRED	---	25	24-HR
WY*	02/27/1998	TWO ELK GENERATION PARTNERS	---	GCP	25	1-HR
TX*	09/12/2003	BROWNSVILLE PUBLIC UTILITY	---	---	32	---
TX*	03/28/2003	CITY OF BRIAN	---	---	32	---
CA-1151	06/27/2001	CALPEAK CALPEAK POWER - EL CAJON	PEAKING (NO HRS LIMIT)	OXY CAT	50	3-HR
MI-0268	06/26/2000	KM POWER COMPANY	PEAKING	---	60	30-DAY

[67] A simple cycle startup is defined as the time when the fuel is introduced into the combustion turbine to the time that base load throttle conditions are reached. Simple cycle shutdown is defined as the time from when the turbine drops below base load conditions to the time that fuel is cut off to the combustion turbine. The simple cycle SUSD time period lasts for one hour for any hour that an SUSD event occurs.

RBLC ID	PERMIT DATE	CORPORATE/COMPANY NAME FACILITY NAME	DESCRIPTION	POLLUTION CONTROL	EMISSION LIMIT (PPM)	AVG PERIOD
NE*	04/04/2002	LINCOLN ELECTRIC SYSTEM SALT VALLEY STATION	---	BYPASS	60 lb/hr	3-HR
IL*	05/01/2000	ROLLS-ROYCE POWER VENTURES - LOCKPORT	---	DLN	60.4 lb/hr	---
KS*	04-17-2007	WESTAR ENERGY EMPORIA ENERGY CENTER	PEAKING (4,300 HRS/YR)	---	63.8 lb/hr	---
AR*	02/28/2000	WRIGHTSVILLE ENERGY POWER FACILITY	PEAKING (5250 HRS/YR)	STEAM INJ	66	---
NE-0012	07/29/1999	OMAHA PUBLIC POWER DISTRICT	PEAKING (2,000 HRS/YR/TURBINE) DUAL FUEL		139	---
DE*	10/20/2000	NRG ENERGY	SYNTHETIC MINOR	GCP	165 lb/hr	1-HR
PA-0195	7/6/2000	ALLEGHENY ENERGY SUPPLY GANS CT POWER STATION		WI	166	
ID*	09/09/2002	MOUNTAIN VIEW POWER, LLC	---	OXY CAT	10 NG 6 FO	---
TX-0295	01/17/2002	SOUTH TEXAS ELECTRIC COOP SAM RAYBURN GEN. STATION	720 HRS FO/YR	OXY CAT	15 NG 15 FO	---
IN-0095	12/07/2001	ALLEGHENY ENERGY SUPPLY CO, LLC	PEAKING (3500 HRS/YR)	---	25-100 (TEMP. DEPEND.)	24-HR
IN*	07/15/1999	PSI CINERGY WABASH PEAKING STATION	PEAKING (3000 HRS/YR)		42 NG 6 FO	---

Note: Items with an * indicate they are not listed in RBLC, but can be found in EPA Region 4 Combustion Turbine List.

Table 5-15: RBLC VOC Control Summary for Aeroderivative Combustion Turbines

RBLC ID	PERMIT DATE	CORPORATE/COMPANY NAME FACILITY NAME	DESCRIPTION	POLLUTION CONTROL	EMISSION LIMIT (PPM)	AVG PERIOD
TX-0405	12/15/2000	WESTVACO TEXAS LP	TURBINE W/O DUCT BURNERS	OXY CAT	1.98	---
CA-0954	05/21/2001	CALPEAK CALPEAK POWER – PANOCHE	---	---	2	3-HR
CA-1095	12/07/2001	EL COLTON, LLC	---	OXY CAT	2	3-HR
CA-1151	06/27/2001	CALPEAK CALPEAK POWER - EL CAJON	PEAKING (NO HRS LIMIT)	OXY CAT	2	---
FL-0261	10/26/2004	CITY OF TALLAHASSEE ARVAH B. HOPKINS GEN. STATION	PEAKING (5840 HRS/YR) (4000 HRS FO/YR)	---	3	---
PA-0195	7/6/2000	ALLEGHENY ENERGY SUPPLY GANS CT POWER STATION	---	WI	5 lb/hr	---
FL-0272	09/12/2005	KEYS ENERGY SERVICES STOCK ISLAND POWER PLANT	FO FIRED	---	8	---
TX-0388	02/12/2002	AUSTIN ELECTRIC UTILITY SAND HILL ENERGY CENTER	PEAKING	---	8	---
VI-0008	01/03/2001	VIRGIN ISLANDS WATER AND POWER AUTHORITY (VIWAPA) KRUM BAY ST. THOMAS GEN. STATION	PEAKING (NO HRS LIMIT) FUEL OIL FIRED	---	8	---

Note: Items with an * indicate they are not listed in RBLC, but can be found in EPA Region 4 Combustion Turbine List.

5.6 BACT - $PM/PM_{10}/PM_{2.5}$

Particulate matter (PM) (including total particulate, PM_{10} and $PM_{2.5}$) emissions from simple cycle combustion turbines originate from ash and sulfur contained within the fuel. Filterable PM emissions are inherently low through combustion of natural gas with its low ash and sulfur content.

There is, as noted previously, a lack of available vendor-provided $PM_{2.5}$ emission rates and appropriate test methods.[68] Nonetheless, to move the analysis forward, it was decided to make the following conservative assumptions:

- All PM emissions are PM_{10},
- All PM_{10} emissions are $PM_{2.5}$.

In addition, all primary sulfate emitted from the turbines and sulfate converted via the CO and SCR catalysts is assumed to react with available ammonia from the SCR to form ammonium sulfate. For purposes of this PSD BACT analysis, this is a highly conservative approach and will likely over-estimate the emissions of $PM_{2.5}$ and the benefits of candidate control devices for consideration. Nonetheless, this approach was taken as a means of a complete BACT analysis of the facility.

Additional constituents of indirect $PM_{2.5}$ emissions are potential *secondary* precursors,[69] three of which happen to be criteria pollutants addressed in other sections of this BACT analysis. In the *Federal Register*, EPA acknowledges that three of the four listed potential precursor pollutants are criteria pollutants that are already regulated and typically subject to limits in an NSR permitting review. Therefore, regulation of these pollutants as precursors for $PM_{2.5}$ "is not expected to add a major burden to regulated sources." Because SO_2, NO_X, and VOCs are fully evaluated in separate BACT analyses and controlled via add-on technologies and fuel selection that are considered BACT, they are not reevaluated as part of this $PM/PM_{10}/PM_{2.5}$ BACT analysis. Ammonia is the remaining potential *secondary* precursor, and is emitted in small quantities as a result of incomplete reaction in the SCR catalyst. According to EPA[70], VOC and ammonia are "presumed out" precursors of $PM_{2.5}$, therefore this ammonia slip is not a direct $PM_{2.5}$

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[68] EPA has not finalized their testing methodologies for filterable and condensable portions of $PM_{2.5}$. In a May 8, 2008, e-mail to stakeholders, EPA's Ron Myers announced the posting of revised methods for measuring filterable PM_{10} and $PM_{2.5}$ (OTM-27), and condensable particulate matter (OTM-28) on EPA's website. Comments are being solicited on both methods through June 27, 2008. A review of currently promulgated EPA test methods shows no listings for $PM_{2.5}$. Clearly, EPA is still in the development phase for standard test methods for $PM_{2.5}$. As a result, reliable emissions information on $PM_{2.5}$ emissions before and after controls is still lacking.

[69] May 16, 2008 *Federal Register.*

[70] This conclusion is consistent per Mr. Raj Rao, manager at EPA's Office of Air Quality Planning and Standards for the New Source Review program for $PM_{2.5}$. According to EPA, such emissions analysis is not the intent of $PM_{2.5}$ NSR, where VOC and ammonia are "presumed out" precursors. See *Federal Register* Vol 73, No. 96, Page 28330 from Friday, May 16, 2008, for a discussion on EPA's conclusions concerning ammonia emissions in NSR

pollutant and is not evaluated as such in this analysis. See Section 5.4.4.1 for a discussion of ammonia slip emissions.

5.6.1 Step 1 - Identify All Control Technologies

PM, PM_{10}, and $PM_{2.5}$ emissions could theoretically be reduced in combustion turbines by using several methods:

- Electrostatic precipitators (ESP), both wet and dry
- Centrifugal collectors
- Fabric filters (baghouses) with specialty bags
- Wet scrubbers
- Fuel selection

A discussion of each type of control technology is contained below.

5.6.1.1 Electrostatic Precipitators

An electrostatic precipitator (ESP) is a particle control device that uses electric forces to move particles out the gas stream and onto collector plates. The particles are given an electric charge by forcing them to pass through a corona, a region in which gaseous ions flow. The electrical field that forces the charged particles to the walls comes from electrodes maintained at high voltage in the center of the flow lane.

ESPs are configured in several ways. The types described here are the plate wire precipitator, the flat plate precipitator, the tubular precipitator, the wet precipitator, and the two-stage precipitator. These descriptions are outlined in the OAQPS Cost Control Manual.

The plate wire precipitator is the most common variety. It is commonly installed in coal-fired boilers, cement kilns, solid waste incinerators, paper mill recovery boilers, petroleum refining catalytic cracking units, sinter plants, and different varieties of furnaces. Plate wire precipitators are designed to handle large volumes of gas.

The flat plate precipitator is designed to use flat plates instead of wires for high-voltage electrodes. Small particle sizes with low-flow velocities are ideal for the flat plate precipitator. The flat plate precipitator usually handles gas flows ranging from 100,000 to 200,000 actual cubic feet per minute (acfm).

Tubular precipitators are typically parallel tubes with electrodes running along the axis of the tubes. Tubular precipitators have typical applications in sulfuric acid plants, coke oven byproduct gas cleaning, and steel sinter plants.

Wet precipitators can be any of the three previously discussed precipitators but with wet walls instead of dry walls. The advantage of a wet precipitator is particles are not re-entrained due to the rapping of the walls common to dry precipitators. The disadvantage is the complexity of the wash, handling and disposal of the slurry.

Finally, two-stage precipitators are parallel in nature (i.e., the discharge and collecting electrodes are side by side). Two-stage precipitators are designed for indoor applications, low gas flows below 50,000 acfm, and submicrometer sources emitting oil mists, smokes, fumes, and other sticky particulates. Two-stage systems are considered separate and distinct types of devices used in very specific applications.

5.6.1.2 Centrifugal Precipitators

Centrifugal, or cyclone, precipitators are used as a "prefilter" before the primary particulate control device. They are also used to capture and recycle high-value process material. While cyclones are generally more effective at removing larger particles than smaller ones, cyclones have been designed to remove filterable $PM_{2.5}$ with up to 70 percent efficiency.[71] At high removal rates, increased power requirements due to increased pressure drop become a significant consideration.

5.6.1.3 Fabric Filters (Baghouses)

Baghouses (FFB) consist of one or more isolated compartments containing rows of fabric filter bags or tubes. Gas flows pass through the fabric where the particulate is retained on the upstream face of the bags, while the cleaned gas stream is vented to the atmosphere or to another pollution control device. Filtering is accomplished through a combination of inertial impaction, impingement, and accumulated dust cake sieving. The captured particulate is typically removed from the filters via pneumatic pulses or by mechanical shakers.

Baghouses will collect particle sizes ranging from submicron to several hundred microns at gas temperatures up to about 500°F. Specialty b ags, including intrinsically coated and membrane bags are required for stack temperatures above 500°F, and can be used to achieve lower particulate emission rates; however, specialty bags may cost significantly more than standard bags.

Fabric filters can be categorized by several means, including types of cleaning devices (shaker, reverse-air, and pulse-jet), direction of gas flow, location of system fan, and gas flow quantity. Typically, the type of cleaning method distinguishes the fabric filter.

Advantages to baghouses are the high collection efficiency in excess of 99% for filterable particulate matter, and the collection of a wide range of particle sizes removed. The disadvantages are limits on gas stream temperatures above 550°F (for typical installations), high-pressure drops, difficulty handling gas or particles that are corrosive or sticky in nature, and minimal capture efficiency[72] for condensable $PM_{2.5}$ fractions of the exhaust gas stream.

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[71] EPA-452/F-03-005, *Control Technology Fact Sheet: Cyclones*

[72] AWMA's Air Pollution Engineering Manual (1992), page 236-237, assumes a build-up of filter cake to capture ammonium sulfate.

5.6.1.4 Wet Scrubbers

Wet scrubbers typically use water to impact, intercept, or diffuse a particulate-laden gas stream. With impaction, particulate matter is accelerated and impacted onto a surface area or into a liquid droplet through devices such as venturis and spray chambers. When using interception, particles flow nearly parallel to the water droplets, which allows the water to capture the particles. Interception works best for submicron particles. Spray-augmented scrubbers and high-energy venturis employ this mechanism. Diffusion is used for particles smaller than 0.5 micron and where there is a high temperature difference between the gas and the scrubbing liquid. The particles migrate through the spray along lines of irregular gas density and turbulence, contacting droplets of approximately equal energy.

Six particle scrubber designs are used in control applications: spray, wet dynamic, cyclonic spray, impactor, venturi, and augmented. In all of these scrubbers, impaction is the main collection mechanism for particles larger than 3 microns. Since smaller sized particles respond to non-inertial capture, a high density of small liquid droplets is needed to trap the particles. This is done at the price of high-energy consumption due to hydraulic or velocity pressure losses.[73]

5.6.1.5 Fuel Selection

As mentioned in Section 5.2.4.1, a majority of $PM_{2.5}$ emissions is ammonium sulfate $(NH_4)_2SO_4$. Because Southern is proposing SCR for NO_X control, the required aqueous ammonia reacts with available fuel sulfur (in the form of converted sulfate) to form ammonium sulfate. The reaction for this formation is detailed below:

$$aSO_2 + \text{Catalyst (CO and SCR)} + bH_2O \rightarrow cH_2SO_4$$
$$dNH_3 + eH_2SO_4 \rightarrow f(NH_4)_2SO_4$$

Normally, the oxidation of SO_2 to sulfate (SO_4) is a photoreactive process that occurs over a period of time downrange in a dispersion plume. The turbine vendor has provided the fractionation of primary SO_2 and SO_3 emissions from the turbine. In addition, the vendor has provided the proportion of SO_2 that is expected to be oxidized to SO_3 by the SCR and CO oxidation catalysts. For this analysis, we have conservatively assumed that all primary and converted SO_3 rapidly oxidizes to SO_4, and is available for ammonium sulfate formation before the stack outlet.

The selection of pipeline quality natural gas fuel significantly reduces the fuel sulfur content, thus removing the majority of the $PM_{2.5}$ precursor.

5.6.2 Step 2 - Eliminate Technically Infeasible Control Options

ESPs, except for the plate wire precipitator, are designed to handle relatively small volumes of gas. Although a plate wire precipitator could potentially handle the large volume of gas from a simple cycle combustion turbine, the plate wire precipitator has

[73] William Vatavuk, *Estimating Costs of Air Pollution Control*, 1990.

not been installed for any natural gas turbine. In addition, both wet and dry ESPs are very sensitive to fluctuations in exhaust stream characteristics.[74] Flow rates, temperatures and subsequently particulate loadings will vary significantly in the operation of these turbines. The RBLC does not list any type of ESP as a particulate control device for combustion turbines. Despite these limitations, ESPs cannot be eliminated as technically infeasible.

Baghouse control could be a potential particulate control device for a combustion turbine. No examples exist in the RBLC database of a baghouse installed on combustion turbines for PM control. The concentration of PM in the exhaust gas from the combustion turbines is inherently low, with relatively high temperatures, leading to low capture efficiencies. In order to use cost-effective filter bags, a significant amount of additional tempering air will be required to reduce the temperature of the exhaust stream to a suitable range that promotes reasonable bag life. Careful analysis and design would be required to prevent temperature reduction of the exhaust stream below the dewpoint of any condensables in the exhaust. In addition, relatively expensive stainless steel construction would be required due to acid gas formation from SCR aqueous ammonia and fuel sulfur reactions. These reasons alone do not eliminate the installation of a baghouse based on technical infeasibility.

Due to the sheer number of wet scrubber design types, a specially designed wet scrubber could potentially act as a particulate control device for the combined cycle turbines. However, wet scrubbers have not been listed by the RBLC as a particulate control device for combustion turbines, and per the OAQPS Cost Control manual, existing wet scrubbers designed for PM control support exhaust flow rates significantly below the flows expected for these turbines.[75] Despite these statements, wet scrubbers cannot be eliminated on technical infeasibility.

Fuel selection of low sulfur pipeline quality natural gas is a simple and widely accepted method for control of both $PM_{2.5}$ and SO_2. Therefore, Southern proposes to include this option as the base case for analysis of PM emissions at the HGS gas plant.

5.6.3 Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The following particulate control efficiency ranges were obtained from the appropriate EPA Air Pollution Control Fact Sheets. Note that where no size-specific efficiencies were provided, it was assumed that the stated efficiency range applied to all three particulate size categories even though there are likely significant differences in some cases, especially between control of filterable and condensable particulate emissions.

[74] EPA Air Pollution Control Technology Fact Sheets for Dry ESP and Wet ESP - Wire-Plate Type, EPA-452/F-03-028 and EPA-452/F-03-030, respectively.
[75] EPA 453/B-96-001, *Office of Air Quality Planning and Standards Control Cost Manual*, 6th Edition (OAQPS), Section 6, Chapter 2 – Wet Scrubbers for PM, Page 2-4.

Table 5-16: EPA Reported Particulate Control Efficiency Ranges

Control Technology	PM	PM_{10}	$PM_{2.5}$
ESP, wet and dry	90-99+%	90-99+%	90-99+%
Cyclones	80-99%	60-95%	20-80%
Fabric filters	99-99.9%	99-99.9%	99-99.9%
Wet scrubbers	70-99+%	70-99+%	70-99+%
Fuel selection	Baseline		

5.6.4 Step 4 - Evaluate Most Effective Controls and Document Results

5.6.4.1 Environmental Evaluation

No environmental impacts severe enough to eliminate any of these control technologies were identified.

5.6.4.2 Economic Evaluation

Because the amount of particulate available for control is quite small, it was assumed that all of the identified control alternatives would result in disproportionate adverse economic impacts. To test this hypothesis, a screening model was developed to identify the lowest potential economic impact. First, representative annual costs for each technology were collected from the appropriate EPA Air Pollution Control Fact Sheets[76]. Table 5-17 lists the provided ranges of annualized costs, in 2002 dollars, for each control alternative.

Table 5-17: EPA Reported Annual Cost Ranges

Control Technology	Cost Range (2002 $/scfm)	Cost Range (Jan 2009 $/scfm)[77]
ESP, wet and dry	$4 – $40	$5.54 – $55.45
Cyclones	$1.3 – $13.5	$1.80 – $18.71
Fabric filters	$5 – $45	$6.93 – $62.38
Wet scrubbers	$5.7 – $193	$7.90 – $267.55

Next, the lowest specific cost value and highest control efficiency were applied to the following formula to produce the lowest possible cost-effectiveness result.

$$\textit{Cost-effectiveness (\$/ton)} = \frac{\textit{Exhaust flow rate (scfm) * Specific cost (\$/scfm)}}{\textit{Uncontrolled annual emission rate (ton) * Control efficiency}}$$

[76] All available at http://www.epa.gov/ttncatc1/products.html.
[77] Cost data converted to 2009 $ via Chemical Engineering Plant Cost Index (CEPCI), Dec 2008 Preliminary.

Entering the following values yields a best-case minimum cost-effectiveness from any of the listed technologies as $14,140 per ton of particulate removed:

- Exhaust flow rate = 200,708 scfm
- Uncontrolled annual emission rate = 32 tons

Table 5-18: PM/PM_{10}/$PM_{2.5}$ BACT Economic Screening Analysis Results

Control	Fact Sheet PM2.5 Efficiency	2009 $ minimum cost/scfm	Best Case, Minimum Cost (Cost/ton)	2009 $ Average cost/scfm	Average Reported Cost (Cost/ton)
ESP	99%	$5.54	$35,159	$30.50	$193,373
Cyclone	80%	$1.80	$14,140	$10.26	$ 80,492
Fabric Filter	99.9%	$6.93	$43,553	$34.66	$217,763
Wet Scrubber	99%	$7.90	$50,101	$137.72	$873,256

This is an unrealistically low value and would likely be much higher, because these technologies are not readily applied to a combustion turbine generating unit, requiring extensive design, engineering, and testing that would significantly increase costs above the screening values presented here. In addition, this analysis assumes that the EPA reported values are able to control condensable particulate $PM_{2.5}$ as well as filterable, which in reality is not the case. However, the analysis demonstrates that all of the identified alternatives would result in disproportionate adverse economic impacts. None, except the baseline use of natural gas as a fuel, are appropriate as BACT for controlling particulate emissions from the HGS gas turbines.

5.6.5 Step 5 - Identify BACT

Due to the inherent low ash and sulfur contents of pipeline quality natural gas little uncontrolled particulate matter is emitted by this facility. Despite the high control efficiencies of some of the evaluated particulate controls, few, if any, add-on control technologies will prove to be cost-effective when only 32 tons per year of total particulate is to be emitted by each of the LM6000PF turbines. Based on the high cost-effectiveness of the best case screening value of $14,140/ton of PM/$PM_{10}$/$PM_{2.5}$, the addition of any add-on control is not cost-effective. The high volumetric flowrate with a relatively low particulate loading of the exhaust gas makes the total annualized cost of the particulate control device an impractical pollution control device for a combustion turbine. Furthermore, RBLC does not list any add-on particulate control device for combustion turbines. The remaining control option is to utilize clean fuels like pipeline quality natural gas. This option has been selected as BACT for PM/PM_{10}/$PM_{2.5}$ for this project.

5.6.5.1 Discussion of PM/PM_{10}/$PM_{2.5}$ BACT Emission Limit Value

Southern proposes a maximum steady-state combined cycle PM/PM_{10}/$PM_{2.5}$ emission limit of **7.20 lb/hr/generating unit**, and a simple cycle steady-state emission limit of

4.80 lb/hr/turbine both on a 24-hour block average for all operational turbine loads at the HGS gas plant. This 24-hour block average value includes any hours when the system is in startup and shutdown conditions, as the emissions of particulate are mostly dependent upon fuel combustion alone. No separate SUSD emission limit is required.

Also of note, the proposed $PM/PM_{10}/PM_{2.5}$ emission limit values include the conservative assumptive formation of ammonium sulfate prior to stack exhaust. No PM is generated within the combustion turbine itself; all PM originates from the fuel, inlet combustion air, and exhaust tempering air.[78] These $PM/PM_{10}/PM_{2.5}$ emissions are within the range of limits that have been deemed BACT for controlling emissions from aeroderivative combustion turbines as presented in the RBLC and EPA Region 4 Combustion Turbine databases. Compliance would be demonstrated by initial testing followed by testing as required by MDEQ.

Table 5-19: RBLC $PM/PM_{10}/PM_{2.5}$ Control Summary for Aeroderivative Combustion Turbines

RBLC ID	PERMIT DATE	CORPORATE/COMPANY NAME FACILITY NAME	DESCRIPTION	POLLUTION CONTROL	EMISSION LIMIT (lb/hr)	AVG PERIOD
OR-0030	06/22/2001	PACIFICORP KLAMATH FALLS FACILITY	OPERATES @ 100% LOAD	---	1.76	---
NE-0012	07/29/1999	OMAHA PUBLIC POWER DISTRICT	PEAKING (2,000 HRS/YR/TURBINE) DUAL FUEL	---	2 NG 7 OIL	---
FL-0261	10/26/2004	CITY OF TALLAHASSEE ARVAH B. HOPKINS GEN. STATION	PEAKING (5840 HRS/YR) (4000 HRS FO/YR)	---	2.45	---
IN-0095	12/07/2001	ALLEGHENY ENERGY SUPPLY CO, LLC	PEAKING (3500 HRS/YR)	---	2.7	---
PA-0195	7/6/2000	ALLEGHENY ENERGY SUPPLY GANS CT POWER STATION	---	---	3	---
VA-0244	05/01/2000	WOLF HILLS ENERGY LLC	NG FIRED	PQNG	3	---
VA-0259	01/31/2002	BUCHANAN GENERATION LLC ALLEGHENY ENERGY SUPPLY	NG/FO	---	3 NG 10.3 OIL	---
TX-0295	01/17/2002	SOUTH TEXAS ELECTRIC COOP SAM RAYBURN GEN. STATION	720 HRS FO/YR	---	3 NG 5 LF	---
NY-0093	03/31/2005	TRIGEN-NASSAU ENERGY CORPORATION	---	---	4.66	---
MI-0268	06/26/2000	KM POWER COMPANY	PEAKING	---	4.9	---
SD-0002	03/20/2001	BLACK HILLS POWER AND LIGHT COMPANY LANGE COMBUSTION TURBINES	PEAKING NG FIRED	---	6	---
TX-0388	02/12/2002	AUSTIN ELECTRIC UTILITY SAND HILL ENERGY CENTER	PEAKING	---	6.21	---
VI-0008	01/03/2001	VIRGIN ISLANDS WATER AND POWER AUTHORITY (VIWAPA) KRUM BAY ST. THOMAS GEN. STATION	PEAKING (NO HRS LIMIT) FUEL OIL FIRED	ASH SULFUR LIMITS	9 PM 22.6 PM10	---

[78] The turbine vendor has provided PM emissions estimates in the turbine performance spreadsheets of Appendix B. The values provided by the vendor are estimates, and not guarantees, because the PM generated is a function of fuel used. The vendor has no control over the fuel used in the turbines, and can only provide an engineered estimated based on fuel characteristics provided by SME. As detailed in §3.2.2.2, presumptive ammonium sulfate formation was added to the vendor-provided emission rates for PM.

RBLC ID	PERMIT DATE	CORPORATE/COMPANY NAME FACILITY NAME	DESCRIPTION	POLLUTION CONTROL	EMISSION LIMIT (lb/hr)	AVG PERIOD
TX-0457	06/26/2003	CITY PUBLIC SERVICE LEON CREEK PLANT	---	---	11.3	---
FL-0272	09/12/2005	KEYS ENERGY SERVICES STOCK ISLAND POWER PLANT	FO FIRED	---	25 FRONT & BACK HALF 13.9 FRONT	---

Note: Items with an * indicate they are not listed in RBLC, but can be found in EPA Region 4 Combustion Turbine List.

5.7 BACT - SO_2

Sulfur is present in natural gas and ultralow sulfur diesel as organic sulfur compounds. In these forms it is readily volatilized under combustion conditions and is then oxidized by the oxygen present in the combustion and exhaust air to SO_2. SO_2 emissions can be reduced by limiting or preventing SO_2 formation and by capturing then converting it once it has formed.

5.7.1 Step 1 - Identify All Control Technologies

EPA's RBLC describes several permitted aeroderivative combustion turbine installations and lists their pollutant emission limits and the control technologies approved to achieve those limits. See Appendix D and Table 5-20 for a summary of RBLC data related to SO_2 emission limits and controls associated with those limits. Another source of information regarding potentially applicable SO_2 control technology for combustion turbines is the U.S. EPA's AP-42 document. AP-42's chapter for stationary gas turbines (Chapter 3, Section 3.1) does not recognize any SO_2 control applicable to combustion turbines. Nevertheless, the following technologies were identified as potentially applicable for controlling SO_2 from industrial combustion processes:

- Proper turbine design and operation;
- Fuel selection;
- Supplemental scrubbing;
- Chemical absorption.

5.7.1.1 Proper Turbine Design and Operation

Fuel costs are a major portion of the cost of electricity generation. Consequently, every effort is made to conserve energy and thereby reduce costs. Efforts to maximize fuel efficiency also serve to reduce pollutant emissions; increasing the amount of electricity produced per unit of fuel decreases the amount of combustion-related pollutants emitted. This need must be balanced with the operating characteristics of the equipment selected and load behavior of the electrical network served by the proposed facility. Southern will operate these turbines to maximize efficiency and minimize idling when system loads permit. Idling leads to increased emissions and wasted fuel.

5.7.1.2 Fuel Selection

The fuel used to fire the combustion turbines is the primary source of sulfur, and ultimately, of SO_2. Pipeline quality natural gas contains very little sulfur. Significantly reduced sulfur emissions result when combusting pipeline quality natural gas in a combustion turbine.

5.7.1.3 Supplemental Scrubbing

It is possible that the exhaust gases could be exposed to additional scrubbing following the SCR to remove additional SO_2. A variety of reagents are available for reaction with SO_2. A large majority of flue gas scrubbers use either lime or limestone. Mixing techniques vary somewhat, but fall into two main categories: wet systems and dry systems. Wet systems use a reagent slurry that is typically brought into contact with the flue gas in a scrubber spray tower or packed bed. Dry systems spray or atomize the reagent into the flue gas stream to achieve the required contact. Many dry systems are actually referred to as semi-dry systems, and inject a high-solids slurry into a spray chamber where it contacts the flue gas stream. The hot flue gas vaporizes the water, leaving a dry particulate which either settles out in the spray chamber or is entrained in the flue gas stream and captured by a downstream particulate control device. No applications of SO_2 scrubbing can be found for combustion turbines.

5.7.1.4 Aqueous Chemical Absorption

Aqueous chemical systems have been successfully employed in various industries to remove SO_2 from concentrated waste streams. These systems are similar to the dry scrubbers described above except they use aqueous solutions or slurries as the contact and reaction media. Two examples of such systems are the double alkali method and the commercial Tri-NO_x Multi-Chem® scrubber (by Tri-Mer Corporation). No applications of chemical SO_2 absorption can be found for combustion turbines.

5.7.2 Step 2 - Eliminate Technically Infeasible Control Options

5.7.2.1 Proper Turbine Design and Operation

Proper design and operation of new combustion turbines is clearly feasible and serves as the baseline case.

5.7.2.2 Fuel Selection

Fuel selection to reduce SO_2 emissions is technically feasible within certain practical bounds. Ample supplies of pipeline quality natural gas are available for this facility at the proposed location. The proposed turbines are well tested combusting the fuel proposed.

5.7.2.3 Supplemental Scrubbing

Supplemental scrubbing requires a method of collecting the particulate generated by reaction of fuel sulfur and the injected lime or limestone. The simplest and most inexpensive means of capture would be a fabric filter baghouse. As demonstrated in §5.6.4.2, a baghouse was not a cost-effective control for a pollutant ($PM/PM_{10}/PM_{2.5}$) with an emission removal rate of about 32 tons/year. The emissions inventory for sulfur dioxide is much less (≈ 3.0 tons/year). It is obvious that if a device is not cost-effective for removing 32 tons per year of a pollutant, it is even less cost-effective for removal of less than 3.0 tons/year before the consideration of the costs associated with an actual SO_2 removal device. As a result, no detailed analysis is offered in this section since the conclusions are obvious given the prior particulate control analysis. Without the particulate capture of baghouse control, supplemental scrubbing is not technically feasible as SO_2 control for the combustion turbines at this facility.

5.7.2.4 Aqueous Chemical Absorption

This type of technology is not considered to be effective for large sources with dilute SO_2 concentrations. For example, the Tri-NOx Multi-Chem® system has not been applied to systems with air flow rates above 60,000 cfm; the combined exhaust flow rate from each of the turbines is approximately fifteen times that amount at full load. Aqueous chemical absorption cannot be considered applicable to the proposed project and is not technically feasible.

5.7.3 Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Removing supplemental scrubbing and aqueous chemical absorption from the SO_2 BACT analysis as technically infeasible leaves fuel selection and proper turbine design as SO_2 BACT control options for this facility. Fuel selection is the remaining control technology option above the base case of proper turbine design and operation.

5.7.4 Step 4 - Evaluate Most Effective Controls and Document Results

Fuel selection is the remaining control technology option above the base case of proper turbine design and operation. Southern proposes to implement both options as BACT for SO_2 for the combustion turbine generating units at HGS. Therefore, no further analysis is required.

5.7.5 Step 5 - Identify BACT

Fuel selection is the remaining control technology option above the base case of proper turbine design and operation. Southern proposes to implement both options as BACT for SO_2 for the combustion turbine generating units at HGS. As SO_2 emissions from the turbines are extremely low, any add-on control technology above proper turbine design and operation with proper fuel selection proves to be cost-prohibitive. Southern proposes the combustion of only pipeline quality natural gas[79] as BACT. Low sulfur fuels are well supported as BACT in EPA's RBLC clearinghouse. The results of the RBLC search can be found in Appendix D and are summarized below in Table 5-20.

[79] Pipeline quality natural gas as defined in 40 CFR §72.2.

5.7.6 Discussion of SO_2 Emission Limit Value

Southern proposes a maximum combined cycle SO_2 emission limit of **0.69 lb/hr/generating unit**, and a maximum simple cycle SO_2 emission limit of **0.57 lb/hr/turbine** both on a 24-hour block average for all operational turbine loads at the HGS gas plant. This 24-hour block average value includes any hours when the system is in startup and shutdown conditions, as the emissions of SO_2 are mostly dependent upon fuel combustion alone. No separate SUSD emission limit is required. Compliance would be demonstrated by initial testing followed by testing as required by MDEQ.

A review of aeroderivative combustion turbine SO_2 emission limits is contained in Table 5-20 below.

Table 5-20: RBLC SO_2 Control Summary for Aeroderivative Combustion Turbines

RBLC ID	PERMIT DATE	CORPORATE/COMPANY NAME FACILITY NAME	DESCRIPTION	POLLUTION CONTROL	EMISSION LIMIT (LB/HR)	AVG PERIOD
CT-0146	10/10/1991	PRATT AND WHITNEY UNITED TECHNOLOGIES CORPORATION	COMBINED CYCLE, DUAL FUEL	---	0.17 NG 54.19 FO	---
TX-0388	02/12/2002	AUSTIN ELECTRIC UTILITY SAND HILL ENERGY CENTER	PEAKING	PQNG	0.3	---
PA-0159	09/29/2000	HANDSOME LAKE ENERGY, L.L.C.	NG FIRED	150 PPM S FUEL	0.7	1-HR
FL-0261	10/26/2004	CITY OF TALLAHASSEE ARVAH B. HOPKINS GEN. STATION	PEAKING (5840 HRS/YR) (4000 HRS FO/YR)	PQNG	1.13	---
CT-0143	---	PPL WALLINGFORD ENERGY, LLC	---	---	1.26	---
TX-0457	06/26/2003	CITY PUBLIC SERVICE LEON CREEK PLANT	---	---	1.3	---
WA-0312	07/18/2003	PUGET SOUND ENERGY FREDONIA ENERGY STATION	---	PQNG 100 PPM S OIL	1.5	3-HR
TX-0295	01/17/2002	SOUTH TEXAS ELECTRIC COOP SAM RAYBURN GEN. STATION	720 HRS FO/YR	---	2.2 NG 21 FO	---
OR-0030	06/22/2001	PACIFICORP KLAMATH FALLS FACILITY	OPERATES @ 100% LOAD	PQNG	2.24	24-HR
PA-0195	7/6/2000	ALLEGHENY ENERGY SUPPLY GANS CT POWER STATION	---	---	2.5	---
VA-0259	01/31/2002	BUCHANAN GENERATION LLC ALLEGHENY ENERGY SUPPLY	NG/FO	---	2.5 NG 23.9 FO	---
PA-0171	07/10/2001	ALLEGHENY ENERGY SUPPLY COMPANY, LLC HARRISON CITY	NG FIRED	LOW SULFUR FUELS	4.8	---
NE-0012	07/29/1999	OMAHA PUBLIC POWER DISTRICT	PEAKING (2,000 HRS/YR/TURBINE) DUAL FUEL	PQNG CLEAN FUELS	14	---
FL-0272	09/12/2005	KEYS ENERGY SERVICES STOCK ISLAND POWER PLANT	FO FIRED	LOW SULFUR FUELS	23.6	---
VI-0008	01/03/2001	VIRGIN ISLANDS WATER AND POWER AUTHORITY (VIWAPA) KRUM BAY ST. THOMAS GEN. STATION	PEAKING (NO HRS LIMIT) FUEL OIL FIRED	2000 PPM S FUEL	52.1	---

Note: Items with an * indicate they are not listed in RBLC, but can be found in the EPA Region 4 Combustion Turbine List.

5.8 Emergency Generator and Emergency Fire Water Pump BACT Analysis

Southern is proposing the ability to operate the black-start emergency generator and emergency fire pump on diesel fuel. The emergency generator and emergency fire pump will only run during emergencies and during required maintenance. The maximum anticipated number of hours of operation per year is expected to be less than 500 hours per unit.

The BACT analysis and discussion below is similar to the BACT analysis for the combustion turbines. Nonetheless, a majority of the information is repeated here for completeness. Where appropriate, the reader is referred to the BACT analysis for the combustion turbines for reference.

5.8.1 NO_X BACT

NO_X will be formed during the combustion of diesel fuel in the black-start emergency generator and emergency firewater pump. Three fundamentally different mechanisms produce NO_X during the combustion of hydrocarbon fuels. The formation of NO_X is dominated by the thermal mechanism, which involves the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules in the combustion air. Most of the "thermal NO_X" is formed in the high temperature flame zone near the burners or in the combustion chambers. The amount of thermal NO_X formed is directly proportional to 1) oxygen concentration, 2) peak temperature, and 3) time of exposure to peak temperature. Virtually all thermal NO_X is formed in the region of the flame at the highest temperature. Maximum thermal NO_X production occurs at a slightly lean fuel-to-air ratio due to the excess availability of oxygen for reaction with the nitrogen in the air and fuel.

A second mechanism for the formation of NO_X, termed "prompt NO_X," occurs through early reactions of nitrogen molecules in the combustion air and hydrocarbon radicals present in the fuel. The prompt NO_X reactions occur within the flame (or combustion chamber for a reciprocating engine) and are usually negligible when compared to the amount of thermal NO_X. However, prompt NO_X levels may become significant when technologies are applied that control thermal NO_X to ultra-low levels.

A third mechanism, "fuel NO_X," stems from the evolution and reaction of fuel-bound nitrogen compounds with oxygen. The contribution of this mechanism to the total NO_X depends entirely on the nitrogen content in the fuel. For low-sulfur fuel oil, which is proposed for this facility, the contribution of fuel NO_X is usually negligible.

5.8.1.1 Step 1 - Identify All NO_X Control Technologies

NO_X emissions from the black-start emergency generator and emergency fire water pump can be reduced by several different methods. The following list presents methods listed in the RACT/BACT/LAER database and other technologies that are applicable to natural gas combustion processes:

- Proper System Design and Operation (base case)
- Water Injection
- Fuel Selection
- Dry Low-NO_X Burners
- Selective Catalytic Reduction (SCR),
- Selective Non-Catalytic Reduction (SNCR),
- Wet Chemistry Scrubber,
- NO_X Scrubber,
- Low Temperature Oxidation (LoTOx), SCONOx (EMx), XONON, and
- Process Limitations.

These control technologies may be applied individually or in combination. Section 5.4, with one exception, provided an explanation of these controls and it will not be repeated here.

Process Limitations

The amount of NO_X and other pollutants formed by fossil fuel combustion can be reduced proportionately by limiting operating hours or reducing fuel consumption.

5.8.1.2 Step 2 - Eliminate Technically Infeasible NO_X Control Options

Innovative catalytic systems typically installed on combustion turbines are technically infeasible to install on an emergency generator and emergency fire water pump. DLN technology is technically infeasible on spark or compression ignition reciprocating internal combustion engines. Therefore, DLN is eliminated from use on the emergency generator and emergency firewater pump. All other control options are assumed technically feasible.

5.8.1.3 Step 3 - Rank Remaining NO_X Control Technologies by Control Effectiveness

Table 5-21 ranks the control options according to control effectiveness, which includes no additional add-on control and process limitations

Table 5-21: Ranked NO_X Control Effectiveness

Control Technology	Percent Reduction
SCR	80-90%
LoTOx	80-90%
NSCR	60-80%
Wet Controls	40-60%
Process Limitations	Varies with limitation
Proper Design (No Additional Control)	N/A

5.8.1.4 Step 4 - Evaluate Most Effective NO_X Controls and Document Results

Economic, Environment, and Energy Evaluation

No significant environmental or energy impacts exist for the NO_X control options that would eliminate any of the control options. However, due to intermittent and infrequent use of the black-start generator and fire pump, the catalyst controls (i.e., SCR and NSCR), wet control (including LoTOx), and SNCR will not operate properly and efficiently. These controls require steady-state operating conditions. For example, before any one of these control options can operate at maximum efficiency, the source and exhaust stream have to come up to the optimal steady-state temperature. When these controls are not operated at optimal efficiency and the annual hours of operation are limited to less than 500 hours per year, these control options become cost-prohibitive. An economic evaluation is not provided for these control options because the reduction in emissions due to intermittent and infrequent use is difficult to quantify.

5.8.1.5 Step 5 - Identify NO_X BACT

Southern proposes NO_X BACT for the black-start emergency generator and fire pump as process limits. Southern does not propose any NO_X BACT emission limits on the emergency generator and fire pump because these units will only operate during limited situations. The NO_X emission factors for each unit were obtained from latest edition of EPA AP-42.

Southern proposes the process limits in the table below for the emergency generator, and emergency firewater pump. Industry norms and previous BACT determinations do not require catalyst or other add-on NO_x controls on standby and emergency equipment because of the limited hours of operation and infrequent use.

Table 5-22: Process Limits

Combustion Unit	Process Limitations	Annual Hours of Operation
Black-start Emergency Generator	Operate only in emergencies and for required maintenance	500 hrs/yr
Emergency Fire Pump	Operate only in emergencies and for required maintenance	500 hrs/yr

5.8.2 CO BACT

5.8.2.1 Step 1 - Identify All CO Control Technologies

Control of CO and VOC can be achieved through oxidation of post-combustion gases with or without a catalyst. The following is a list of available CO control technologies.

- Oxidation Catalyst;
- Thermal Oxidation;
- Process Limitations; and
- Proper Design (no additional control).

The oxidation catalyst and thermal oxidation control options have been described in the Turbine CO BACT analysis. NSCR has been described in the NO_x BACT analysis in the previous section. NSCR has the ability to control NO_X and CO from rich-burn internal combustion engines.

5.8.2.2 Step 2 - Eliminate Technically Infeasible CO Control Options

Depending on the type of fuel that will be combusted, the type of combustion device, and the hours of operation per year, the control options listed in Step 1 are assumed technically feasible.

5.8.2.3 Step 3 - Rank Remaining CO Control Technologies by Control Effectiveness

Table 5-23 ranks the control options according to control effectiveness.

Table 5-23: Ranked CO Control Effectiveness

Control Technology	Percent Reduction
Catalytic Oxidation	80-90%
Thermal Oxidation	80-90%
Process Limitations	Varies with limitation
Proper Design (No Add-on Controls)	N/A

5.8.2.4 Step 4 - Evaluate Most Effective CO Controls and Document Results

Economic, Environment, and Energy Evaluation

No environmental or energy impacts exist for the remaining CO control options that would eliminate any of the control options. However, due to intermittent and infrequent use of the generator and fire pump, the catalyst controls (i.e., catalytic oxidizer and NSCR) and thermal oxidation will not operate properly and efficiently. These controls require steady-state operating conditions. For example, before any one of these control options can operate at maximum efficiency, the source and exhaust stream have to come up to the optimal steady-state temperature. When these controls are not operated at optimal efficiency and the annual hours of operation are limited to less than 500 hours per year, these control options become cost-prohibitive. An economic evaluation is not provided for these control options because the reduction in emissions due to intermittent and infrequent use is difficult to quantify.

5.8.2.5 Step 5 - Identify CO BACT

Because all other control options are eliminated, Southern proposes CO BACT for the emergency generator and fire pump as proper combustion design with limited hours of operation as described in Table 5-24. Southern does not propose any CO BACT emission limits for the emergency generator and fire pump because these units will operate intermittently and infrequently. Industry norms and previous BACT determinations do not require catalyst or thermal CO controls on standby and emergency equipment because of the limited hours of operation and infrequent use.

Table 5-24: Process Limits

Combustion Unit	Process Limitations	Annual Hours of Operation
Emergency Generator	Operate only in emergencies and for required maintenance	500 hrs/yr
Emergency Fire Pump	Operate only in emergencies and for required maintenance	500 hrs/yr

5.8.3 SO_2 BACT

5.8.3.1 Step 1 - Identify All SO_2 Control Technologies

The following is a list of available SO_2 control technologies.

- Wet or Dry FGD;
- Low Sulfur Fuels;
- Process Limitations; and
- No Additional Control.

Wet and dry flue gas desulfurization control options are described in the SO_2 Turbine BACT. Using low sulfur fuels such as propane, pipeline quality natural gas, and low sulfur diesel can control SO_2 emissions.

5.8.3.2 Step 2 - Eliminate Technically Infeasible SO_2 Control Options

Depending on the type of fuel that will be combusted, the type of combustion device, and the hours of operation per year, the control options listed in Step 1 are assumed to be technically feasible.

5.8.3.3 Step 3 - Rank Remaining SO2 Control Technologies by Control Effectiveness

Table 5-16 ranks the control options according to control effectiveness.

Table 5-25: Ranked SO_2 Control Effectiveness

Control Technology	Percent Reduction
Wet or Dry FGD	70-90%
Low Sulfur Fuels	Varies
Process Limitations	Varies with limitation
No Additional Controls	N/A

5.8.3.4 Step 4 - Evaluate Most Effective SO_2 Controls and Document Results

Economic, Environment, and Energy Evaluation

No economic, environmental or energy impacts exist for the SO_2 control options that would eliminate any of the control options. However, due to intermittent and infrequent use of the generator and fire pump, the wet and dry FGD systems will not operate properly and efficiently. These controls require steady-state operating conditions. For example, before any one of these control options can operate at maximum efficiency, the source and exhaust stream have to come up to the optimal steady-state temperature. When these controls are not operated at optimal efficiency and the annual hours of operation are limited to less than 500 hours per year, these control options become cost-prohibitive. An economic evaluation is not provided for these control options because the reduction in emissions due to intermittent and infrequent use is difficult to quantify.

5.8.3.5 Step 5 - Identify SO_2 BACT

Since wet and dry FGD were eliminated, Southern proposes SO_2 BACT for the emergency generator and emergency fire water pump as low sulfur fuels and limited hours of operation as described in Table 5-17. Southern does not propose any SO_2 BACT emission limits on the emergency generator and fire pump because these units will operate intermittently and infrequently. Emission rates were calculated based on the amount of sulfur in fuel. Industry norms and previous BACT determinations do not require wet or dry FGD controls on standby and emergency equipment because of the limited hours of operation and infrequent use.

Table 5-26: Process Limits

Combustion Unit	Process Limitations	Annual Hours of Operation
Emergency Generator	Operate only in emergencies and for required maintenance	500 hrs/yr
Emergency Fire Pump	Operate only in emergencies and for required maintenance	500 hrs/yr

5.8.4 PM/PM_{10} /$PM_{2.5}$ BACT

5.8.4.1 Step 1 - Identify All $PM/PM_{10}/PM_{2.5}$ Control Technologies

The following is a list of available $PM/PM_{10}/PM_{2.5}$ control technologies.

- Fabric Filter Baghouse;
- Electrostatic Precipitator;
- Process Limitations; and
- No Additional Control.

Fabric filter baghouses and ESPs are described in the $PM/PM_{10}/PM_{2.5}$ Turbine BACT.

5.8.4.2 Step 2 - Eliminate Technically Infeasible $PM/PM_{10}/PM_{2.5}$ Control Options

Fabric filter baghouses are technically infeasible control options for the emergency generator and emergency firewater pump because the exhaust temperature is too hot for high temperature bags. The remaining control options listed in Step 1 are assumed technically feasible.

5.8.4.3 Step 3 - Rank Remaining $PM/PM_{10}/PM_{2.5}$ Control Technologies by Control Effectiveness

Table 5-18 ranks the control options according to control effectiveness.

Table 5-27: Ranked $PM/PM_{10}/PM_{2.5}$ Control Effectiveness

Control Technology	Percent Reduction
ESP	+99%
Process Limitations	Varies with limitation
No Additional Controls	N/A

5.8.4.4 Step 4 - Evaluate Most Effective $PM/PM_{10}/PM_{2.5}$ Controls and Document Results

Economic, Environment, and Energy Evaluation

No economic, environmental, or energy impacts exist for the $PM/PM_{10}/PM_{2.5}$ control options that would eliminate any of the control options. However, due to intermittent and infrequent use, the FFB and ESP systems will not operate properly and efficiently. These controls require steady-state operating conditions. For example, before any one of these control options can operate at maximum efficiency, the source and exhaust streams have to come up to the optimal steady-state temperature. When these controls are not operated at optimal efficiency and the annual hours of operation are limited to less than 500 hours per year, these control options become cost-prohibitive. An economic evaluation is not provided for these control options because the reduction in emissions due to intermittent and infrequent use is difficult to quantify.

5.8.4.5 Step 5 - Identify $PM/PM_{10}/PM_{2.5}$ BACT

Since FFB and ESPs were eliminated, Southern proposes the $PM/PM_{10}/PM_{2.5}$ BACT for the emergency generator and emergency firewater pump as process limitations as described in Table 5-28. Southern does not propose any $PM/PM_{10}/PM_{2.5}$ BACT emission limits on the emergency generator and fire pump because these units will only operate during limited situations. Industry norms and previous BACT determinations do not require FFB or ESPs on standby and emergency equipment because of the limited hours of operation and infrequent use.

Table 5-28: Process Limits

Combustion Unit	Process Limitations	Annual Hours of Operation
Emergency Generator	Operate only in emergencies and for required maintenance	500 hrs/yr
Emergency Fire Pump	Operate only in emergencies and for required maintenance	500 hrs/yr

5.9 BACT Emission Limit Summary

The following table summarizes the previously stated proposed BACT process and emissions limits:

Table 5-29: BACT Emission and Process Limit Summary

Unit	Cycle type	Operational Period	Pollutant	Limit	Units
Gas Turbine	Simple	Steady State and Startup/Shutdown	---	3200	hours/yr/turbine
Gas Turbine	Combined	Steady State	NOx	4.16	lb/hr/generating unit
Gas Turbine	Simple	Steady State	NOx	36.58	lb/hr/turbine
Gas Turbine	Combined	Startup	NOx	26.12	lb/hr/generating unit
Gas Turbine	Combined	Shutdown	NOx	12.33	lb/hr/generating unit
Gas Turbine	Simple	Startup and Shutdown	NOx	36.58	lb/hr/turbine
Gas Turbine	Combined	Steady State	CO	2.03	lb/hr/generating unit
Gas Turbine	Simple	Steady State	CO	48.96	lb/hr/turbine
Gas Turbine	Combined	Startup	CO	76.20	lb/hr/generating unit
Gas Turbine	Combined	Shutdown	CO	4.15	lb/hr/generating unit
Gas Turbine	Simple	Startup and Shutdown	CO	114.70	lb/hr/turbine
Gas Turbine	Combined	Steady State	VOC	1.86	lb/hr/generating unit
Gas Turbine	Simple	Steady State	VOC	2.03	lb/hr/turbine
Gas Turbine	Combined	Startup	VOC	1.86	lb/hr/generating unit
Gas Turbine	Combined	Shutdown	VOC	1.86	lb/hr/generating unit
Gas Turbine	Simple	Startup and Shutdown	VOC	3.90	lb/hr/turbine
Gas Turbine	Combined	Steady State	$PM/PM_{10}/PM/_{2.5}$	7.20	lb/hr/generating unit
Gas Turbine	Simple	Steady State	$PM/PM_{10}/PM_{2.5}$	4.80	lb/hr/turbine
Gas Turbine	Combined	Steady State	SO_2	0.69	lb/hr/generating unit
Gas Turbine	Simple	Steady State	SO_2	0.57	lb/hr/turbine
Black Start Emergency Generator	N/A	All Operations	---	500	hours of operation/yr
Emergency Fire Pump	N/A	All Operations	---	500	hours of operation/yr

6.0 AIR QUALITY IMPACT DEMONSTRATIONS

Montana's Air Quality Rules require an industrial facility subject to an air quality permit, such as the HGS gas plant, to demonstrate compliance with standards and regulations designed to limit environmental impacts from air pollution emissions. These demonstrations were generally performed using approved air dispersion modeling techniques.

Air quality impact analyses around the proposed HGS gas plant site were conducted for areas that were both nearby and at extended distances. In general, nearby impacts (less than 50 km) are analyzed for compliance with ambient air quality standards. Impacts farther away were typically used to analyze air quality impacts on all the Class I areas that are within 250 km of the facility.

The air dispersion modeling analyses in this section compare model results with the following standards and/or requirements:

- National Ambient Air Quality Standards (NAAQS – 40 CFR 50),
- Montana Ambient Air Quality Standards (MAAQS – ARM 17.8.201 *et seq.*)

As noted in Section 1.1, the HGS gas plant facility constitutes a major modification to a major stationary source, and is therefore defined as a PSD source, which requires a PSD air quality impact analysis

In March 2009, Southern submitted a modeling protocol to MDEQ summarizing model selection and processing details for the evaluation of ambient air quality impacts resulting from Southern's proposed Highwood Generating Station. MDEQ responded to the modeling protocol requiring meteorological data substitution. These changes have been fully implemented and are included in the air quality impact demonstrations presented below.

6.1 Modeling Methodology

As discussed in Section 3 of this application, emissions from the HGS gas plant facility have been estimated for the following pollutants: CO, lead (Pb), NO_X, SO_2, $PM/PM_{10}/PM_{2.5}$, and VOC (as ozone). The projected potential emissions of these pollutants, except VOC and Pb, were modeled to predict the resulting ground-level concentrations. The VOC and Pb emissions were deemed sufficiently small (below modeling thresholds) that dispersion modeling was not necessary (see discussion in Section 6.2.1). The modeling methodology (e.g., description of the model selection, meteorological data, receptor network, emission sources, etc.) is presented in the following sections.

All dispersion modeling analyses performed for this application were conducted in general accordance with the methodology outlined in the *New Source Review Workshop Manual*, EPA, October 1990, Draft. The guidance found in Appendix W of 40 CFR 51, *Guideline on Air Quality Models*, November 9, 2005 (the Guideline Document) and the Montana Modeling Guideline for Air Quality Permits (MMGAQP) (November 2007 Draft) were also used as references. These documents outline a general phased approach to performing dispersion modeling demonstrations, moving from screening level to refined analyses. Outlined below is the four-phased approach used to conduct the dispersion modeling demonstrations for this project:

Phase 1: Determine Threshold Emission Rates and Significant Impact Areas

The first step in the modeling process is to determine if the predicted emissions are above modeling thresholds as defined in the MMGAQP (and the Guideline Document). The MMGAQP defines two periods for comparison, lbs/day and tons/year. If the emissions from the facility are less than the thresholds in Table 1 of MMGAQP, impacts are expected to be insignificant and further modeling is generally not required.

A comparison may be made between the emission rates found in Sections 3 and 5 of this application and the threshold values found in Table 7 of MMGAQP. The comparison indicates that the predicted emission rates for VOC and Pb are below the Table 7 (MMGAQP) values. As a result, no dispersion modeling demonstrations are necessary for these pollutants.[80]

The next step is to determine the ambient concentration impact “significance levels" and, for instances where impacts are significant, to define the significant impact area (SIA) of the proposed project. Through dispersion modeling analyses, the SIA is determined for each pollutant proposed to be emitted in “significant” quantities and for the appropriate averaging periods. According to the New Source Review Workshop Manual (see reference to this manual in Section 5.1), NAAQS and PSD increment analyses should be conducted within an area defined for each averaging period and pollutant by the greatest distance at which predicted ground level concentrations exceed defined “significance levels.” Significance levels are listed in Table 7 in MMGAQP and are summarized below in Table 6-1.

[80] A detailed analysis of these results is contained in Table 6-9 below.

Table 6-1: MMGAQP (Table 7) Modeling Significance Levels

Pollutant and Averaging Period	Class II Modeling Significant Impact Level ($\mu g/m^3$)
CO 1-hr Average	2,000
CO 8-hr Average	500
NO_2 Annual Average	1
SO_2 3 hr Average	1
SO_2 24 hr Average	5
SO_2 Annual Average	25
PM_{10} 24-hr Average	5
PM_{10} Annual Average	1
$PM_{2.5}$ 24-hr Average[81]	0.3
$PM_{2.5}$ Annual Average[82]	1.2

The receptor networks used in the modeling analyses must extend outward as far as necessary to include all locations with modeled concentrations equal to or exceeding the Class II area significance levels. Once the farthest significant receptor is established for each pollutant, ambient analyses may proceed for all receptors within the radius of significant impact. The SIA is defined by a circle centered on the center of the project sources and having a radius equal to the distance to the most distant significant receptor.

All emissions, as applicable, from the HGS gas plant are included in determining the SIA. If the predicted impacts for a given pollutant and averaging period are below the relevant significance level, no further modeling analyses are required since the modeled source, by definition, could not significantly contribute to any modeling exceedances.

The MMGAQP states that Class I PSD increment impacts analyses are required for major sources that exceed the "Modeling Significance Levels for Class I Areas" found in Table 8 of the MMGAQP document. A long-range modeling analysis was completed for five Class I areas that are within 250 km of the HGS gas plant. The following table lists the number of receptors and the minimum distance from each Class I area to Southern.

[81] There are no published "insignificant" concentrations (typically found in 40 CFR 51, Appendix S) for $PM_{2.5}$. The insignificant demonstration was conducted using the concentrations found in MMGAQP Table 7 for this pollutant.

[82] Ibid

Table 6-2: Class I Areas

Class I Area	Number of Receptors	Distance (km)
Bob Marshall Wilderness	788	134
Scapegoat Wilderness	423	122
Gates of the Mountains Wilderness	194	88
Glacier National Park	790	192
UL Bend National Wildlife Refuge	134	222

Phase 2: Determine Preliminary Impacts Resulting From All Applicable Sources

The next phase of the analysis is the modeling of all appropriate emissions sources within the project area. The MMGAQP guidance (Section 5.1.2) indicates that all major permitted stationary sources within 50 km of the SIA and all minor permitted stationary sources within the SIA should be included in the analysis.

Phase 3: Predict Comprehensive Impacts Using a Refined Receptor Grid

Peak receptor locations identified in Phase 2 that were located in a low-resolution area of the receptor grid are surrounded with a 100 meter receptor refined grid and re-run. This ensures that peak ambient concentration impacts are identified. Peak impacts predicted within these "hot spot" receptor grids are compared to the NAAQS and MAAQS for compliance determination. If the modeled concentrations are below the standards or increment, no other analysis is required.

Phase 4: Identify Source Contributions As Needed

This phase of the analysis calls for an analysis of the applicant's potential contributions to possible model-predicted exceedances of the Class II PSD increments or ambient standards if any are indicated. If it is determined that the applicant's contributions are insignificant at each location and time of exceedance, the applicant will have successfully demonstrated that their emissions will not cause or contribute to a violation of any standard or increment. If the applicant's contributions are significant, adjustments must be made and the modeling demonstrations repeated. Before a permit may be issued, it must be demonstrated that the project will not cause or significantly contribute to a model-predicted exceedance of a PDS Class II increment or ambient standard.

6.1.1 Model Selection

6.1.1.1 Overview

Dispersion modeling uses mathematical formulations to characterize the atmospheric processes that disperse a pollutant emitted by a source. Based on emissions and meteorological inputs, a dispersion model can be used to predict concentrations at selected downwind receptor locations. These air quality models are used to predict compliance with the National Ambient Air Quality Standards (NAAQS) and other regulatory requirements such as New Source Review (NSR) and Prevention of Significant Deterioration (PSD) regulations. These models are described in Appendix A of EPA's Guideline on Air Quality Models (published as Appendix W of 40 CFR Part 51), which was originally published in April 1978 to provide consistency and equity in the use of modeling within the U.S. air quality management system. The Guideline on Air Quality Models (the Guideline Document) is periodically revised to ensure that new model developments or expanded regulatory requirements are incorporated. Appendix W was last updated with a final rule published in the *Federal Register* on Wednesday, November 9, 2005.

The recommended models include:

AERMOD Modeling System - A steady-state plume model that incorporates air dispersion based on planetary boundary layer turbulence structure and scaling concepts, including treatment of both surface and elevated sources, and both simple and complex terrain.

CALPUFF Modeling System - A 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 for long-range transport (LRT) and for complex terrain.

CTDMPLUS - Complex Terrain Dispersion Model Plus Algorithms for Unstable Situations is a refined point source Gaussian air quality model for use in all stability conditions for complex terrain. The model contains, in its entirety, the technology of CTDM for stable and neutral conditions. CTSCREEN is the screening version of CTDMPLUS.

Other recommended models are suited for specific circumstances as described below:

- BLP is designed to handle unique modeling problems associated with buoyant line sources.
- CALINE3 is used for predicting air pollution levels near highways and arterial streets. CALINE3 is incorporated into the more refined CAL3QHC and CAL3QHCR models.
- CDM 2.0 and UAM are best suited for urban areas.
- OCD is used to assess impacts near shorelines from offshore sources.

A review of the Guideline Document indicates only a few models that may be acceptable in this situation. The area is characterized as rural with complex terrain near the facility. Section 5.2.1 of the Guideline Document recommends CTSCREEN for a screening analysis in complex terrain. However, CTSCREEN is most applicable to a single source situation and calculates 1-hour average concentrations only. Factors internal to the model are used to determine 3-hour, 24-hour, and annual average concentrations. The numerous point sources at this facility preclude the use of this model.

The refined version of CTDMPLUS requires meteorological data collected at multiple levels. Such data are not readily available for this facility.

For refined modeling applications in simple and complex terrain situations within 50 km, AERMOD is recommended in Section 4.2.2 of the Guideline Document. This model also is listed as a preferred model in Appendix A of the Guideline Document. AERMOD has features capable of handling multiple point, area, line, and volume sources, hourly meteorological data, building downwash effects, and simple and complex terrain. AERMOD applies to complex terrain and incorporates the downwash algorithm - PRIME.

The CALPUFF model is appropriate for modeling LRT impacts at the listed mandatory Federal Class I areas. For the HGS gas plant, CALPUFF will be required since as a PSD modification modeled insignificance must demonstrated for all Class I areas within 250 km of the facility.

6.1.2 Selected Models

The model selected for the analysis of impacts within 50 km of the facility is AERMOD as recommended by the preamble to the revised Guideline Document (November 2005).

AERMOD is a steady-state plume dispersion model for the assessment of pollutant concentrations from a variety of sources. AERMOD simulates transport and dispersion from multiple sources based on an updated characterization of the atmospheric boundary layer. Sources may be located in rural or urban areas and receptors may be located in simple or complex terrain. AERMOD accounts for building wake effects and plume downwash. Sequential meteorological data is processed to estimate concentrations for averaging times from one hour to one year. AERMOD is appropriate for point, volume, and/or area sources; for surface, near-surface, and elevated releases; for rural or urban areas; for simple and complex terrain; for transport distances over which steady-state assumptions are appropriate (up to 50 km); and for continuous toxic air emissions. AERMOD's regulatory default option includes the use of terrain elevation data, stack-tip downwash, and sequential date checking. The regulatory option does not employ pollutant half-life or decay options except in the case of an urban source of sulfur dioxide where a four-hour half-life is applied.

AERMOD is designed to accept input data prepared by two specific pre-processor programs, AERMET and AERMAP. AERMET processes meteorological data available from the National Climatic Data Center (NCDC). AERMAP processes digital elevation data available from several different sources.

AERMET is designed to accept National Weather Service (NWS) 1-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.

AERMAP processes terrain elevation data available from the U.S. Geological Survey (USGS). The data are available in three distinct formats. There is the Digital Elevation Model (DEM) format which follows the old USGS “Blue Book” standard. There is the newer Spatial Data Transfer Standard (SDTS) which formats the DEM and other associated data in metadata form. Finally, there is the National Elevation Dataset (NED) which is constantly updated and is available in several formats for importing into widely used commercial software packages. Of these data formats and standards, AERMAP is programmed to read the USGS Blue Book format, which can be in either 7.5 minute Digital Elevation Model (DEM) files prepared by the USGS or a 1 degree (3 arc-second) format produced by the Defense Mapping Agency (DMA). Each 7.5 minute DEM file corresponds to a single 1:24,000-scale quadrangle map. The 1-degree files correspond to the east or west half of a USGS 1:250,000-scale topographic map. SDTS and XYZ data must be converted to the Blue Book format. EPA has developed SDTS and XYZ conversion programs. The latest version of AERMAP does accept NED data which will replace the DEM format.

AERMAP first 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. In response to 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.

AERMOD, Version 07026 with the standard regulatory default options, has been selected for the HGS gas plant air quality analysis. AERMET was used to prepare the meteorological data set for the AERMOD analyses. For this application, the source code for the AERMOD modeling system is provided by BEE-Line Software Version 9.78a.

6.1.3 General Settings

General options are available to influence model calculations. Regulatory default options were selected for the analyses described here. Neither plume depletion nor the Urban Dispersion Option was selected.

6.1.4 Meteorological Input Data

AERMOD requires hourly meteorological data (met data). On-site data was not available; however, MDEQ previously determined that surface data from the Great Falls airport would be representative. The National Weather Service operates this station. Five years of this data was used, from 1999 through 2003. All met data was processed with upper air soundings from the Great Falls Airport. Table 6-3 summarizes the met data used for this analysis. Quality assurance charts evaluating proper heat fluxes are available in Appendix F. Meteorological ASCII data files are included on the enclosed DVD-ROM in Appendix I.

Table 6-3: Meteorological Data Set Summary

Met Data Set		Years of Data
Surface Data	**Upper Air Data**	
Great Falls NWS	Great Falls NWS	1999-2003

6.1.5 Receptor Networks

The following receptor grid was generated using the “special fenceline grid” function in BEEST to identify the facility’s SIA. The resulting SIA receptor set contained almost 13,000 individual receptors. A plot of the SIA, and ambient analysis receptor grids is included in Appendix F.

- 100 m spacing along the facility’s property boundary,
- 100 m spacing from 0 to 1,000 m from the facility,
- 250 m spacing from 1,000 m to 3,000 m from the facility,
- 500 m spacing from 3,000 m to 10,000 m from the facility,
- 975 m spacing from 10,000 m to approx 50,000 m from the facility’s boundary.

For the NAAQS/MAAQS and Class II Increment demonstrations, a receptor grid was based on the SIA grid developed for each modeled pollutant. The resulting receptor sets contained up to 1,312 individual receptors (for 24 hr $PM_{2.5,}$ the largest ROI) case. A plot of these receptor grids is also included in Appendix F. Receptors outside the largest Radius of Impact are excluded from the analysis.

- 100 m spacing along the facility’s property boundary,
- 100 m spacing from 0 to 1,000 m from the facility, and
- 250 m spacing from 1,000 m to 3,000 m from the facility.

See Table 6-10 for details of the largest radii of impact.

6.1.6 Terrain Data

Elevations of emissions sources and buildings in the modeling analyses were determined from plant layout drawings. The BEEST modeling software's "Calc Domain" function was used to determine the modeling domain extent and to identify the USGS digital elevation model (DEMs) files required by the AERMAP terrain preprocessor to properly calculate receptor elevations and maximum hill height values. The DEM files derive from USGS 7.5-minute topographic maps based on the 1927 North American Datum (NAD27).

6.1.7 Modeled Sources

6.1.7.1 Turbine Generating Station Sources

Facility emissions sources were characterized for modeling purposes as point sources. The physical characteristics of the facility's emissions sources included in the modeling analyses, and the emission rates of each criteria pollutant, are presented in Appendix F. The generating unit stacks, blackstart emergency diesel generator, firepump, cooling towers, and building heaters were all modeled as point sources. The exhaust stacks for these sources will be vertical, unobstructed stacks. Generating unit emissions are based upon the turbine load and ambient temperature that has the highest potential to emit. In order to demonstrate that the HGS gas plant does not adversely impact Class II air quality standards several model cases were developed to fully characterize the facility for dispersion modeling. Model cases were created for both the annual emission rates and for the maximum lb/hr values for steady state operations of either the simple cycle or combined cycle turbines. Additional model cases were also included to analyze startup/shutdown emissions for the generators. These model analyses are needed to address the steady state BACT emissions limits, the startup/shutdown BACT emission limits, and the hours of operation limits for the simple cycle turbine operation proposed in Section 5.

The modeling analysis for this project was designed to capture the potential worst case modeled generator impacts and to that end eight model groups of sources were analyzed. Further conservatism was built into the analysis by modeling potential annual impacts using the short-term emission rates for the generators. This presents a modeling analysis of potential impacts that exceed the facility's potential to emit values presented in Section 3. All eight source groups modeled include emissions from the following sources: cooling tower, fire pump, black-start generator, nine building heaters, and the appropriate combination of turbine stacks. The eight model groups and combination of turbine stacks are presented inTable 6-4.

Table 6-4: Summary of HGS Gas Plant Source Emission Rates

Model Group Name	Turbine	Turbine	Additional Sources
SCSTEADY	Simple Cycle West Turbine Steady State	Simple Cycle East Turbine Steady State	All Auxiliary Units
CCSTEADY	Combined Cycle West Turbine Steady State	Combined Cycle East Turbine Steady State	All Auxiliary Units
SC_SS	Simple Cycle West Turbine Startup/Shutdown	Simple Cycle East Turbine Startup/Shutdown	All Auxiliary Units
CC_SS	Combined Cycle West Turbine Startup/Shutdown	Combined Cycle East Turbine Startup/Shutdown	All Auxiliary Units
1SCW_CCE	Simple Cycle West Turbine Steady State	Combined Cycle East Turbine Steady State	All Auxiliary Units
2SCE_CCW	Simple Cycle East Turbine Steady State	Combined Cycle West Turbine Steady State	All Auxiliary Units
3SCW_CCE	Simple Cycle West Turbine Startup/Shutdown	Combined Cycle East Turbine Startup/Shutdown	All Auxiliary Units
4SCE_CCW	Simple Cycle East Turbine Startup/Shutdown	Combined Cycle West Turbine Startup/Shutdown	All Auxiliary Units

Locations for the generating unit stacks, blackstart emergency diesel generator, firepump, and building heaters were based on general arrangement drawings from the design engineering firm for the facility. See Table 6-5 and Table 6-6 below for a summary of HGS gas plant source characteristics. The general arrangement drawings are included in Appendix B.

Table 6-5: Summary of HGS Gas Plant Source Emission Rates

Source Description	PMANN	PMHR	NOXANN	NOXHR	SO2ANN	SO2HR	COHR
	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(lb/hr)
Simple Cycle Steady State West	21.0	4.80	160.2	36.6	2.5	0.6	49.0
Simple Cycle Steady State East	21.0	4.80	160.2	36.6	2.5	0.6	49.0
Simple Cycle Startup Shutdown West	31.5	7.20	18.2	4.2	3.0	0.7	2.0
Simple Cycle Startup Shutdown East	31.5	7.20	18.2	4.2	3.0	0.7	2.0
Combined Cycle Steady State West	21.0	4.80	160.2	36.6	2.5	0.6	114.7
Combined Cycle Steady State East	21.0	4.80	160.2	36.6	2.5	0.6	114.7
Combined Cycle Startup Shutdown West	31.5	7.20	114.4	26.1	3.0	0.7	76.2
Combined Cycle Startup Shutdown East	31.5	7.20	114.4	26.1	3.0	0.7	76.2
Cooling Tower	1.029	0.235					
Cooling Tower	1.029	0.235					
Cooling Tower	1.029	0.235					

Fire Pump	0.036	0.140	0.920	3.680	0.031	0.060	0.850
Black Start Generator	0.032	0.100	6.680	26.700	0.180	0.370	1.100
Turbine Enclosures West	8.8E-03	2.0E-03	1.5E-01	3.4E-02	6.6E-04	1.5E-04	2.1E-02
Turbine Enclosures East	8.8E-03	2.0E-03	1.5E-01	3.4E-02	6.6E-04	1.5E-04	2.1E-02
Admin/Maintenance/Electrical/STG Building	3.1E-02	7.0E-03	6.0E-01	1.4E-01	2.6E-03	5.9E-04	8.2E-02
Water Treatment Building	1.8E-02	4.0E-03	3.0E-01	6.9E-02	1.3E-03	2.9E-04	4.1E-02
Warehouse	1.8E-02	4.0E-03	3.0E-01	6.9E-02	1.3E-03	2.9E-04	4.1E-02
Water Pump house	8.8E-03	2.0E-03	1.5E-01	3.4E-02	6.6E-04	1.5E-04	2.1E-02
Fuel Gas Compressor Building	8.8E-03	2.0E-03	1.5E-01	3.4E-02	6.6E-04	1.5E-04	2.1E-02
CEMS Enclosures West Turbine	1.8E-03	4.0E-04	3.1E-02	7.0E-03	1.3E-04	3.0E-05	4.0E-03
CEMS Enclosures East Turbine	1.8E-03	4.0E-04	3.1E-02	7.0E-03	1.3E-04	3.0E-05	4.0E-03

Table 6-6: Summary of HGS Gas Plant Point Source Physical Parameters

Source	Source Description	X-UTM (m)	Y-UTM (m)	Stack Elevation (ft)	Stack Height (ft)	Stack Temp. (℉)	Stack Velocity (ft/sec)	Stack Diameter (ft)
HI_SCW	Simple Cycle Steady State	497423	5266224	3310	80	865	181	10
HI_SCE	Simple Cycle Steady State	497460	5266224	3310	80	865	181	10
SS_SCW	Simple Cycle Startup/Shutdown	497422	5266262	3310	105	223	66	10
SS_SCE	Simple Cycle Startup/Shutdown	497460	5266262	3310	105	223	66	10
HI_CCW	Combined Cycle Steady State	497423	5266224	3310	80	871	105	10
HI_CCE	Combined Cycle Steady State	497460	5266224	3310	80	871	105	10
SS_CCW	Combined Cycle Startup/Shutdown	497422	5266262	3310	105	216	55	10
SS_CCE	Combined Cycle Startup Shutdown	497460	5266262	3310	105	216	55	10
COOLING1	Cooling Tower	497495	5266449	3310	45	70	27	15
COOLING2	Cooling Tower	497507	5266460	3310	45	70	27	15
COOLING3	Cooling Tower	497518	5266472	3310	45	70	27	15
FIREP	Fire Pump	497374	5266297	3310	25	1032	170	0.5
GENSET	Black Start Generator	497401	5266235	3310	35	764	170	0.67
HEATTW	Turbine Enclosures West	497422	5266213	3310	45	550	85	0.5
HEATTE	Turbine Enclosures East	497459	5266213	3310	45	550	85	0.5
HEATAD	Admin/Maintenance /Electrical/STG Building	497380	5266237	3310	60	550	85	1
HEATWT	Water Treatment Building	497373	5266323	3310	30	550	42	1
HEATWH	Warehouse	497307	5266184	3310	30	550	42	1
HEATWP	Water Pump house	497495	5266426	3310	21	550	85	0.5
HEATCB	Fuel Gas Compressor Building	497407	5266386	3310	20	550	170	0.5
HEATCW	CEMS Enclosures West Turbine	497430	5266259	3310	15	550	17	0.5
HEATCE	CEMS Enclosures East Turbine	497468	5266259	3310	15	550	17	0.5

6.1.7.2 NAAQS Inventory Sources

All major permitted sources within 50-km of the largest significant impact area of the facility were selected for inclusion in the ambient air quality compliance modeling analyses. The sources to be included were provided by MDEQ. The emissions from and source characteristics for several of these sources were made available from MDEQ. The Montana Waste Systems, Inc. and the Land O'Lakes/Harvest States Feeds data was compiled from a permit analysis of the MDEQ-provided facilities and conversations with plant personnel. Sources included in the model are summarized in Table 6-7 below. Because the size of the spreadsheets does not readily support printing, refer to Appendix F files in the DVD contained in Appendix I for further descriptions of surrounding sources and the source groupings included in the modeling analyses.

Table 6-7: Summary of Modeled Inventory Sources

Name	Easting (m)	Northing (m)
Montana Ethanol Project, LLC	484378	5263012
Montana Refining Company	478155	5263199
Montana Waste Systems Inc.	485955	5274852
U.S. Air Force - Malmstrom AFB	485700	5263000
Land O'Lakes/Harvest States Feed	483540	5262503
MaltEurop US	480100	5265541
Montgomery Great Falls Energy Partners LP	479707	5265902

6.1.8 Building Effects

Building downwash effects from the facility buildings were considered in the modeling analyses. The EPA-developed program Building Profile Input Program, Plume Rise Model Enhancement (BPIP-PRIME), version 04274, was used to estimate building profile data from structures at the site. BEE-Line software provided the source code for BPIP-PRIME in the BEEST modeling package. AERMOD uses the output from BPIP-PRIME to calculate ambient impacts as a result of the emissions, receptors and building profile data.

6.1.9 Background Concentrations

Background concentrations for the NAAQS/MAAQS modeling demonstrations were provided in MMGAQP. Table 6-8 below summarizes the stations and values selected.

Table 6-8: MMGAQP Established Background Concentrations

Pollutant	Averaging Period	Background Concentration ($\mu g/m^3$)
PM_{10} [(a)]	Annual	7
PM_{10} [(a)]	24-hour	23
$PM_{2.5}$ [(b)]	Annual	5.88
$PM_{2.5}$ [(b)]	24-hour	18.4
SO_2 [(c)]	Annual	3
SO_2 [(c)]	24-hour	11
SO_2 [(c)]	3-hour	26
SO_2 [(c)]	1-hour (19th)	35
CO [(c)]	8-hour	1,150
CO [(c)]	1-hour	1,725
NO_2 [(c)]	Annual	6
NO_2 [(c)]	1-hour	75

(a) The PM_{10} background data in this table is taken from the Southern onsite monitoring data collected from 11/2004-12/2005 .

(b) The MDEQ guideline suggests that the $PM_{2.5}$ values should be assumed to be the same as the PM_{10} values unless more representative data is available. Exact $PM_{2.5}$ monitored background values have been assessed in Great Falls, MT. The values to be used in the application demonstration were obtained from the document "Potential Montana $PM_{2.5}$ Non-Attainment Areas Draft March 2008." http://www.deq.mt.gov/AirQuality/WhatsNew/PM25_NAAQS_MT_Review_Mar_2008.pdf .

(c) The data in this table is taken from Table 5 of the MDEQ Modeling Guideline dated 3/29/07.

6.2 Ambient Air Quality Standard Analyses Results

6.2.1 Modeling Threshold Results

Emissions from the facility were compared to the published modeling thresholds in MMGAQP. The maximum lb/hr values were assumed to be emitted for a full day and were compared to the threshold lb/day values. The annual emission values were compared to the tons/year thresholds. Per MMGAQP, pollutants below the thresholds were no longer included in the modeling analysis. In this analysis, SO_2 and lead (Pb) are removed from further analysis. See the table below for the results of the thresholds analysis.

Table 6-9: Modeling Thresholds Results

Pollutant	Emissions (per turbine)				Turbine Emission (facility)		Thresholds		Modeling Triggered	
	Steady State		Startup Shutdown							
	Short Term		Short Term							
	Simple Cycle Steady State (lb/hr)	Combined Cycle Steady State (lb/hr)	Simple Cycle Startup/Shutdown (lb/hr)	Combined Cycle Startup/ Shut-down (lb/hr)	Max Daily (lb/day)	Annual (tpy)	Max Daily (lb/day)	Annual (tpy)	Max Daily	Annual
NOX	36.58	4.16	36.58	26.12	1756	320	548	100	TRUE	TRUE
CO	48.96	2.03	114.7	76.2	5506	1005	548	100	TRUE	TRUE
VOC	2.03	1.86	3.09	1.86	148	27	548	100	FALSE	FALSE
SO2	0.57	0.69	0.57	0.69	33	6	274	50	FALSE	FALSE
PM_{10}	4.8	7.2	4.8	7.2	346	63	274	50	TRUE	TRUE
$PM_{2.5}$	4.8	7.2	4.8	7.2	346	63	63.9	12	TRUE	TRUE
Pb	---	---	---	---	0	0	27.3	5	FALSE	FALSE

The table indicates that VOC, SO_2 and Pb are below the modeling thresholds. In discussions with MDEQ it was determined that the Class II PSD increment date had been established and for completeness MDEQ requested that potential SO_2 emissions from the HGS gas plant be included in the SIA analysis. VOC and Pb are below the modeling significance levels and no further analysis for these pollutants is warranted.

6.2.2 SIA Results

For the remaining air pollutants, SIAs were identified for each combination of pollutant and averaging periods for which an ambient air quality standard is defined. Table 6-10 lists the results of these analyses. As shown, peak impacts related to the facility did not exceed the significance levels for one-hour and eight-hour average CO nor were the annual, 24-hour, three-hour, or one-hour SO_2 significance levels exceeded. To simplify the SIA modeling analyses, one model run was done for the particulate emissions since $PM_{2.5}$ is assumed to equal PM_{10} as discussed in Section 3. The SIA model runs were completed using individual yearly meteorological data to establish the high-first-high (H1H) model impacts. Subsequent modeling analyses associated with $PM_{2.5}$ 24-hr concentrations use concatenated yearly meteorological data to determine the three-year 8^{th} high average model impacts. A summary of peak impacts predicted for all meteorological years modeled is contained in Appendix F. Due to its size, the full results analysis, model input and output data files are included on the CD-ROM in Appendix I.

Table 6-10: Air Quality Significance Levels and SIA Results

Pollutant	Average	High	Met Data	Model Group	Modeling Significance Level (ug/m3)	Radius of Impact (km)
NOX	Annual	H1H	1999	CC_SS	1	1.1
CO	01-HR	H1H	1999	CC_SS	2000	0.0
CO	08-HR	H1H	1999	CC_SS	500	0.0
PM10	24-HR	H1H	2002	CC_SS	5	0.5
PM10	Annual	H1H	1999	CC_SS	1	0.0
PM2.5	24-HR	H1H	1999	CC_SS	1.2	2.7
PM2.5	Annual	H1H	1999	CC_SS	0.3	1.0

Note: Predicted and threshold values are high-first-high concentrations.

6.2.3 NAAQS Analysis Results

NAAQS analyses for NO_x, $PM_{10,}$ and $PM_{2.5}$ were conducted using potential emissions from the facility and from surrounding sources as described in Section 6.1 above. The maximum impacts from these analyses are shown in Table 6-11. Peak impacts for all meteorological years modeled are listed in Appendix F and included in electronic files on the CD-ROM in Appendix I. No exceedances of any ambient standards were predicted.

Table 6-11: Ambient Air Quality Standards Impact Analysis Results

Pollutant	Source Group	Avg. Period	Met Data Year	Predicted Ambient Conc. ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	Compli-ance Status (In/Out)	MAAQS ($\mu g/m^3$)	Compli-ance Status (In/Out)
NO_X	SCSTEADY	1-hr	2000	318.8	NA	In	564	In
	CC_SS	Annual	1999	9.83	100	In	94	In
PM_{10}	All Groups	24-hr	2001	33.95	150	In	150	In
$PM_{2.5}$	CC_SS	24-hr	5-yr Met	22.26	35	In	35	In
	CCSTEADY	Annual	5-yr Met	6.74	15	In	15	In

NOTE: Predicted concentrations for all pollutants and short-term averages are high-second-high values, except $PM_{2.5}$. Per the MDEQ modeler, the $PM_{2.5}$ ambient standard is to be interpreted literally; i.e., three-year average of 98% values was applied to every receptor. Values for all annual averaging periods are high-first-high.

6.2.3.1 Nitrogen Oxides (NO_X)

The NO_X ambient air quality modeling analysis was performed using the same pollutant groupings as presented for the Significant Impact Analysis. Separate NO_X model analyses were generated to predict maximum lb/hr and annual emission rate impacts. Groups were generated by stack operation case and based on simple cycle, combined cycle, or startup/shutdown of each turbine generator. This form of pollutant grouping was feasible in AERMOD due to the relatively small number of additional inventory sources that emit NO_X that were required to be modeled. No additional "hot-spot" refined receptor grids were required for NO_X modeling because the NO_X SIA for the facility was wholly contained within the 100-meter spacing portions of the receptor grid.

The Ozone Limiting Method, as described in Appendix B of MMGAQP, was applied to the 1-hr predicted concentration for this facility, resulting in the 1-hr NO_X values indicated in Table 6-11. Neither the Ambient Ratio Method nor the Ozone Limiting Method was required to demonstrate compliance with the annual NAAQS and MAAQS standards.

6.2.3.2 Particulate Matter (PM_{10} and $PM_{2.5}$)

In the SIA analysis it was appropriate to model PM_{10} and $PM_{2.5}$ as one pollutant since they are represented by the same emission rates. The NAAQS/MAAQs analysis required modeling PM_{10} and $PM_{2.5}$ emissions separately for this facility. The separate runs are required to take advantage of the AERMOD derived three-year averaging capability for $PM_{2.5}$ emissions. This functionality requires that the five years of meteorological data used be concatenated into one file for the $PM_{2.5}$ analysis. Therefore, the PM_{10} and $PM_{2.5}$ analyses are made in separate model runs. Groups that were created for the SIA analysis carried into the particulate models with the stack sources for each emission rate case, plus all respective inventory sources. All 140 inventory PM_{10} and $PM_{2.5}$ sources were modeled one time for each pollutant using this method. See the Source Group Summary in Table 6.4 for a detailed view of which HGS gas plant sources were included in each of the modeled groupings. The additional sources were obtained from MDEQ or permit research.

Annual modeling of PM_{10} impacts was not necessary as the facility was insignificant at all receptors, as demonstrated in Table 6-10.

Based on the significantly different sizes of the significant impact area from the HGS gas plant for $PM_{2.5}$ and PM_{10} emissions, two SIA receptor grids were modeled: The $PM_{2.5}$ 24-hour SIA of 2.7 km was used for all the $PM_{2.5}$ modeled impacts. The largest PM_{10} SIA was 0.6 km and this was less than the NO_x SIA of 1.1 km that was conservatively used in the PM_{10} modeling analysis.

6.2.4 PSD Analysis Results

The HGS gas plant has been determined to be a PSD source and is required to demonstrate that PSD increments are not exceeded. The PSD modeling analyis was completed using the same sources and PTE emission rates as are presented in the NAAQS/MAAQS analysis and the impacts are the same modeled values without background values added in. This PSD analysis is conservative since two-year average actual emissions from existing sources can be substituted for the utilized PTE emission rates. As listed in Table 6.10 the only pollutants above modeling significance levels are annual NO_x, 24-hour PM_{10}, and both annual and 24-hour $PM_{2.5.}$ There are no established PSD increments for $PM_{2.5}$; therefore an analysis is not required. The results for the remaining two pollutants are presented in Table 6-12.

Table 6-12: PSD Air Quality Standards Impact Analysis Results

Pollutant	Source Group	Avg. Period	Met Data Year	Predicted Ambient Conc. ($\mu g/m^3$)	PSD Increment ($\mu g/m^3$)	Compli-ance Status (In/Out)
NO_X	CC_SS	Annual	1999	3.83	25	In
PM_{10}	All Groups	24-hr	2001	10.95	30	In

6.3 Modeling Files

Model input and output files are included on the DVD-ROM attached to this submittal in Appendix I. Table 6-13 lists and describes the modeling file names. Files are included for the SIA and Ambient Standards Analysis. A summary of all of the AERMOD modeling results can be found in Appendix F.

Table 6-13: Model File Names

File Description	Filename
Significant Impact Analysis	**In "\MODELING\AERMOD\SIA\SIA FINAL" directory** Note: Local Partitioning (to enable multiprocessor computing) was used in these model runs. Some combinations of met years and pollutants have additional files ending in "_0n", where "n" is the partition number. The results are recombined in BEEST into a single resultant .GRF, .LST, and .USF, but all files are included for completeness. Domain.txt STGS_SIA_remodel_results.xls SIA (remodel) AERMAP OUT.rar SIA.MAP SIA.Mot SIA.rcf SIA.Rmp SIA_BPIP.PIP SIA_BPIP.PRW SIA_BPIP.SO SIA_BPIP.SUM SIA_BPIP.TAB SIA_FINAL_****_***.BST SIA_FINAL_****_***.BND SIA_FINAL_****_***.DTA SIA_FINAL_****_***.GRF SIA_FINAL_****_***.LST SIA_FINAL_****_***.RUN SIA_FINAL_****_***.USF **** YYYY (1999-2003) *** Pollutant
Ambient Air Quality Analyses	**In "\MODELING \M-NAAQS" directory** Note: Local Partitioning (to enable multiprocessor computing) was used in these model runs. Some combinations of met years and pollutants have additional files ending in "_0n", where "n" is the partition number. The results are recombined in BEEST into a single result .GRF, .LST, and .USF, but all files are included for completeness.

<table>
<tr><td></td><td colspan="2">In “\MODELING \M-NAAQS\M-NAAQS NOx_PM10” directory
M-NAAQS GasNOX_PM10_****_***.BST
M-NAAQS GasNOX_PM10_****_***.BND
M-NAAQS GasNOX_PM10_****_***.DTA
M-NAAQS GasNOX_PM10_****_***.GRF
M-NAAQS GasNOX_PM10_****_***.LST
M-NAAQS GasNOX_PM10_****_***.RUN
M-NAAQS GasNOX_PM10_****_***.USF</td></tr>
<tr><td>Meteorological Data Files</td><td colspan="2">In “\MODELING\AERMET\” directory

Also included in this folder are all processing files used to develop the meteorological data, as well as heat flux evaluation spreadsheets for the BTM airport data

AERMET README.txt
GTFSFC_GTFUA_1999.PFL
GTFSFC_GTFUA_1999.SFC
GTFSFC_GTFUA_2000.PFL
GTFSFC_GTFUA_2000.SFC
GTFSFC_GTFUA_2001.PFL
GTFSFC_GTFUA_2001.SFC
GTFSFC_GTFUA_2002.PFL
GTFSFC_GTFUA_2002.SFC
GTFSFC_GTFUA_2003.PFL
GTFSFC_GTFUA_2003.SFC
Concatenated
GTFSFC_GTFUA_1999-2003.PFL
GTFSFC_GTFUA_1999-2003.SFC</td></tr>
<tr><td>Digital Terrain Files
(/M-NAAQS GasNOX_PM10 directory)</td><td>46110H2.DEM
46110H3.DEM
46110H4.DEM
46110H5.DEM
46110H6.DEM
46110H7.DEM
46110H8.DEM
46111H1.DEM
46111H2.DEM
46111H3.DEM
46111H4.DEM
46111H5.DEM
46111H6.DEM
46111H7.DEM
47110A2.DEM
47110A3.DEM
47110A4.DEM
47110A5.DEM
47110A6.DEM
47110A7.DEM
47110A8.DEM
47110B2.DEM
47110B3.DEM
47110B4.DEM
47110B5.DEM
47110B6.DEM
47110B7.DEM
47110B8.DEM
47110C2.DEM
47110C3.DEM</td><td>47111A1.DEM
47111A2.DEM
47111A3.DEM
47111A4.DEM
47111A5.DEM
47111A6.DEM
47111A7.DEM
47111B1.DEM
47111B2.DEM
47111B3.DEM
47111B4.DEM
47111B5.DEM
47111B6.DEM
47111B7.DEM
47111C1.DEM
47111C2.DEM
47111C3.DEM
47111C4.DEM
47111C5.DEM
47111C6.DEM
47111C7.DEM
47111D1.DEM
47111D2.DEM
47111D3.DEM
47111D4.DEM
47111D5.DEM
47111D6.DEM
47111D7.DEM
47111E1.DEM
47111E2.DEM</td></tr>
</table>

	47110C4.DEM 47110C5.DEM 47110C6.DEM 47110C7.DEM 47110C8.DEM 47110D2.DEM 47110D3.DEM 47110D4.DEM 47110D5.DEM 47110D6.DEM 47110D7.DEM 47110D8.DEM 47110E2.DEM 47110E3.DEM 47110E4.DEM 47110E5.DEM 47110E6.DEM 47110E7.DEM 47110E8.DEM 47110F2.DEM 47110F3.DEM 47110F4.DEM 47110F5.DEM 47110F6.DEM 47110F7.DEM 47110F8.DEM 47110G2.DEM 47110G3.DEM 47110G4.DEM 47110G5.DEM 47110G6.DEM 47110G7.DEM 47110G8.DEM 47110H2.DEM 47110H3.DEM 47110H4.DEM 47110H5.DEM 47110H6.DEM 47110H7.DEM 47110H8.DEM	47111E3.DEM 47111E4.DEM 47111E5.DEM 47111E6.DEM 47111E7.DEM 47111F1.DEM 47111F2.DEM 47111F3.DEM 47111F4.DEM 47111F5.DEM 47111F6.DEM 47111F7.DEM 47111G1.DEM 47111G2.DEM 47111G3.DEM 47111G4.DEM 47111G5.DEM 47111G6.DEM 47111G7.DEM 47111H1.DEM 47111H2.DEM 47111H3.DEM 47111H4.DEM 47111H5.DEM 47111H6.DEM 47111H7.DEM 48110A2.DEM 48110A3.DEM 48110A4.DEM 48110A5.DEM 48110A6.DEM 48110A7.DEM 48110A8.DEM 48111A1.DEM 48111A2.DEM 48111A3.DEM 48111A4.DEM 48111A5.DEM 48111A6.DEM 48111A7.DEM

Extensions have the following meanings:

*.DTA - Input file
*.LST - Standard data output
* GRF - Standard graphics output
*.SO - Building dimensions used by ISC3
*.PIP - BPIP input file
*.TAB - BPIP tab file
*.SUM - BPIP summary file
*.USF - Modeling results summary
*.DEM - USGS Digital Terrain File
*.BAT - DOS Batch Run File
*.BST - Beeline Software BEEST Modeling Suite File

6.4 Class II and Ambient Summary

Results of impact analyses reported in this section can be summarized as follows:

- The facility will meet all national and Montana ambient air quality standards, including $PM_{2.5}$.

6.5 Class I Analysis

As required by ARM 17.8.800 *et seq*. and ARM 17.8.1100 *et seq*., Southern must assess potential impacts to PSD Class I increments and air quality-related values (AQRV) in Class I areas as a part of the air quality permit application for a new major stationary source.

This portion of Section 6 discusses predicted ambient air quality impacts to the nearest Class I areas. A Class I area is generally defined as an area that is afforded more restrictive air quality protection than other areas of the state and nation. They are typically national parks, wilderness areas, etc. The Class I areas that are specific to Montana are found in ARM 17.8.806(1) and (6).

With this permit application, Southern is providing a modeling analysis for Class I increments, impacts of a visual plume and impacts to AQRVs. The AQRV impact analysis for the HGS gas plant followed the technical approach and methodologies published in the Federal Land Managers' Air Quality Related Values Workgroup (FLAG) Phase I Report, December 2000 (FLAG document) for regional haze (visibility) and acid deposition impacts. In addition, Southern is providing a visibility impact analysis as required in ARM Subchapter 11 regulations.

6.5.1 Model Selection

Selection of the appropriate dispersion model for assessing compliance with PSD increments in Class I areas is typically based on the distance from the emitting source to the Class I area. Appendix W in 40 CFR Part 51 recommends different models for different applications and identifies appropriate models for short- and long-range impacts.

Impacts to Class I areas beyond 50 km from the source are considered "long-range" impacts. The HGS gas plant facility is farther than 50 km from any Class I area. Accordingly, the CALPUFF model was used in the present analyses of Class I area ambient air and air quality related impacts.

CALPUFF is a non-steady-state Lagrangian dispersion model that simulates pollutant releases as a continuous series of "puffs." It includes algorithms for building downwash, pollutant removal due to wet scavenging and dry deposition, chemical transformation, and plume fumigation. It is supported by two primary sub-programs, CALMET and CALPOST. CALMET is used in refined analyses to create three-dimensional wind fields based on multiple sources of geophysical and meteorological data. The output of the CALPUFF model consists of binary data files with information on pollutant concentrations, wet and dry flux rates, and visibility parameters. CALPOST processes these data based on specified input parameters, and reports calculated impact values.

The present CALPUFF analysis utilized the most current "EPA-approved" version of the following primary programs and pre- and post-processors obtained from the CALPUFF developer, Atmospheric Studies Group (ASG) at:

http://www.src.com/calpuff/calpuff1.htm.

Geophysical Data Processors
- TERREL (Version 3.684, Level 070327)
- CTGCOMP (Version 2.25, Level 070327)
- CTGPROC (Version 2.681, Level 070327)
- MAKEGEO (Version 2.29, Level 070327)

Meteorological Preprocessors
- STGSRGE (Version 5.57, Level 070627)
- PXTRACT (Version 4.25, Level 070327)
- PMERGE (Version 5.32, Level 070627)
- READ62 (Version 5.54, Level 070627)

Main Models
- CALMET (Version 5.8, Level 070623)
- CALPUFF (Version 5.8, Level 070623)

Postprocessors
- CALPOST (Version 5.6394, Level 070622)
- PRTMET (Version 4.34, Level 070627)
- CALSUM (Version 1.33, Level 051122)
- POSTUTIL (Version 1.56, Level 070627)

These preprocessors, processors, main models, and postprocessors are collectively part of what EPA terms its "'EPA-approved' version of the CALPUFF modeling system." This system was approved by EPA on June 29, 2007. Electronic executable files for the primary modules used are included on the CD-ROM attached with this report. The CD-ROM also contains the primary electronic input and output files associated with this analysis. A description of file names is included in the attachment.

Regional Modeling Domain

The modeling domain is defined in a Lambert Conformal Conic (LCC) system. The LCC coordinate system for this project has a projection origin at 44.25° N and 109.5° W and matching parallels of latitude of 45.0° and 49.0° N , with a false easting of 600.0 kilometers and a false northing of 0.0 kilometers. The coordinates of the southwest corner of the domain are 0.000 km easting and 0.000 km northing.

CALMET

CALMET, the meteorological preprocessor for CALPUFF, was used to compile and process land use data, terrain data, and meteorological data for use in the CALPUFF model program. The CALMET output files defined gridded fields of wind speed, wind direction, mixing heights, stabilities, micrometeorological parameters, and precipitation – all parameters required for input to the CALPUFF dispersion model. The following sections provide a brief description of each of these data sets. The CALMET input files are included electronically on the attached CD-ROM.

Land Use Data

CALMET uses specific land use data developed by the USGS.[83] The data files used for this project were 1:250,000-scale files. Each land use cell, typically 200 meters square, is assigned a land use code. The terrain data used for this analysis were provided by MDEQ.

Terrain Data

CALMET uses USGS 1:250k Digital Elevation Models (DEMs) to determine the terrain elevation in the model domain. The terrain data is preprocessed into a data set recognized by CALMET and used to help create the CALMET output file. The terrain data used for this analysis were provided by MDEQ.

Meteorological Data

CALMET output files representing meteorological data for the 2001, 2002, and 2003 calendar years were prepared for the analysis in accordance with the Montana BART protocol. Input meteorological data consisted of Mesoscale Model (MM) meteorological data, observed hourly surface data, upper air rawinsonde data, and hourly precipitation data.

6.5.2 Mesoscale Model Data

The MM meteorological data for the 2001, 2002, and 2003 calendar years obtained from the Western Regional Air Partnership (WRAP) are available at the following website: http://pah.cert.ucr.edu/aqm/308/bart.shtml. Similar data for these years were also obtained from MDEQ. These data are generated by Pennsylvania State University/National Center for Atmospheric Research mesoscale models. The mesoscale models are limited-area, nonhydrostatic or hydrostatic, terrain-following sigma-coordinate models designed to simulate or predict mesoscale and regional-scale atmospheric circulation. The data are used as a basis for generating an "initial guess field" of multilayer wind vectors in CALMET. The meteorological data for all three years are in the MM5 format. They reflect a spatial resolution of 36 km. The MM5 data obtained from MDEQ were used for the 2001 and 2003 calendar years, and the MM5 data obtained from WRAP were used for the 2002 calendar year. This was done because there are periods of missing data between the monthly data files in the MDEQ MM5 data set for 2002. The WRAP 2002 MM5 data was in separate daily files which had to be combined into monthly files for the annual CALPUFF model runs.

[83] Available for download from the USGS Earth Resources Observation and Science (EROS) web site.

6.5.3 Surface Data

Hourly observed surface data for 2001, 2002, and 2003 were also obtained from the WRAP internet site. In accordance with the Montana BART protocol, National Weather Service (NWS) hourly surface data for 39 stations for 2001 and 36 stations for 2002 and 2003 were processed in CALMET. The data files were provided in the STGSRGE format and were ready for input into CALMET Version 6. The data were manually converted for use with CALMET version 5.8 (this involved only minor changes to the header rows in the data files).

Surface data from the following locations were used for the CALMET analysis:

- Badger Peak, MT (2001 only)
- Billings, MT
- Bismarck, ND
- Boise, ID
- Bozeman, MT
- Butte, MT
- Casper, WY
- Coeur d'Alene, ID
- Cut Bank, MT
- Dickinson, ND
- Dillon, MT
- Estevan, SK
- Havre, MT
- Kalispell, MT
- Garfield Peak, MT (2001 only)
- Glacier National Park, MT
- Glasgow, MT
- Great Falls, MT
- Helena, MT
- Havre, MT
- Lander, WY
- Lewistown, MT
- Livingston, MT
- Medicine Hat, AB
- Miles City, MT
- Minot, ND
- Missoula, MT
- Morningstar, MT (2001 only)
- Peabody Coal, MT
- Pocatello, ID
- Rapid City, SD
- Rexburg, ID
- Riverton, WY

- Salmon, ID
- Sheridan, WY
- Spokane, WA
- Spring Creek Coal, MT
- Theodore Roosevelt National Park, ND
- Williston, ND
- Yellowstone National Park, WY

6.5.4 Upper Air Data

Upper air rawinsonde data collected by seven NWS stations were obtained from the rawinsonde data repository maintained by NOAA at http://raob.fsl.noaa.gov/. The data were obtained in the standard FSL data format for use in the CALMET system. The seven NWS upper air rawinsonde locations used for this project are:

- Bismarck, ND
- Boise, ID
- Glasgow, MT
- Great Falls, MT
- Rapid City, SD
- Riverton, WY
- Spokane, WA

Upper air data substitution and extrapolation were accomplished as needed according to ASG's FAQ 2.3.4, which recommends temporal substitution (for example, substituting an afternoon sounding with the previous or succeeding afternoon sounding) or spatial substitution from a nearby location if soundings are missing. For in-sounding values flagged by READ62, the data values were corrected using an in-house computer program (Fix6201.exe) developed for this purpose. Nearly all of these flagged values were due to either (1) the pressure remaining constant or rising with height, or (2) the elevation remaining constant or decreasing with height. These were corrected by the in-house program by changing the flagged values by a small amount so that the pressure decreased with height or the elevation increased with height as appropriate. For spatial substitutions, another in-house program (AdjUa.exe) was used to adjust for the difference in elevation between the two locations. Temporal substitutions were accomplished manually using a text editor. All raw and processed data and data processing algorithms are available upon request.

6.5.5 Precipitation Data

Hourly precipitation data in NCDC's TD-3240 format were obtained from the data set developed by MDEQ for their BART modeling analysis effort. All precipitation stations located within the CALMET modeling domain were extracted from the data set and were used in the CALMET analysis. A total of 286 stations were selected for each of the three modeled years. No precipitation data interpolation or substitution was required for this project.

6.5.6 CALPUFF

CALPUFF applies mathematical algorithms to calculate pollutant concentrations at Class I receptors. CALPUFF requires CALMET output files, source emissions, and receptor grids to model Class I impacts.

6.5.6.1 CALPUFF Parameters

CALPUFF was run in the refined mode using the MESOPUFF III chemical transformation scheme and dry and wet deposition calculations. Model settings were based on recommendations found in the Montana BART protocol. The table below summarizes the model control file settings used for this analysis. Complete CALPUFF input files are included on the attached CD-ROM.

Table 6-14: CALPUFF Model Control File Settings

Model Parameter/Option	Value
Number of chemical species	9
Number of chemical species emitted	3
Vertical distribution near field	Gaussian
Terrain adjustment method	Partial plume path adjustment
Subgrid-scale complex terrain	Not modeled
Slug model	Not used
Transitional plume rise	Yes
Stack tip downwash	Yes
Vertical wind shear	Yes
Puff splitting	Yes
Chemical mechanism	MESOPUFF II scheme
Wet removal	Yes
Dry deposition	Yes
Dispersion coefficient method	PG dispersion coefficients for rural areas
Partial plume penetration – elevated inversion	Yes
PDF used under convective conditions	No
CSPEC	SO_2, SO_4, NO_X, HNO_3, NO_3, SOA, EC, PMC, PMF
Chemical parameters – dry gas deposition	Default
Size parameters – dry particle deposition	Default
Reference cuticle resistance (RCUTR)	30 s/cm
Reference ground resistance (RGR)	10 s/cm
Reference pollutant reactivity (REACTR)	8
Number of particle-size intervals (NINT)	9
Vegetation state in un-irrigated areas (IVEG)	1
Wet deposition parameters	Default
Ozone data input option	0
Background ozone concentration	Ozone data: Yellowstone NP, Glacier NP, Theodore Roosevelt NP
Background ammonia concentration	1.22, 1.23, 1.6, 1.94, 2.29, 1.63, 1.65, 1.69, 0.98, 1.04, 1.37, 1.06 ppb
SYTDEP	550 m
MHFTSZ	0
JSUP	5
XSAMLEN	1.0 grid units
MXNEW	99
MXSAM	99
Maximum mixing height	3,000 m
Minimum mixing height	50 m
NSPLIT	2
IRESPLIT	Hour 17-22 = 1
ZISPLIT	100 m
ROLDMAX	0.25

Notes:
ppb = parts per billion
s/cm = seconds per centimeter

6.5.6.2 CALPUFF Receptors

The Air Resources Division (ARD) of the National Park Service (NPS) has developed a database of modeling receptors for all federal Class I areas in the United States. ARD has also developed a file conversion program to convert the data from latitude/longitude to either Lambert Conformal or UTM coordinates. Receptor grids for each federally mandated Class I area of concern were developed using the ARD data files converted to the appropriate LCC coordinate system.

The following table lists the number of receptors and the minimum distance from each modeled Class I area to the HGS gas plant.

Table 6-15: Class I Receptors

Class I Area	Number of Receptors	Distance (km)
Bob Marshall Wilderness	788	134
Scapegoat Wilderness	423	122
Gates of the Mountains Wilderness	194	88
Glacier National Park	790	192
UL Bend National Wildlife Refuge	134	222

6.5.6.3 CALPUFF Modeled Sources

The following table lists physical parameters for each of the sources included in the models.

Table 6-16: CALPUFF Modeled Source Physical Parameters

Source ID	Source Description	UTM Zone	Base Elevation (m)	Stack Height (m)	Temp. (K)	Exit Velocity (m/s)	Stack Diameter (m)
HI_CCW	Combined Cycle West	12	1008.9	27.43	379.26	20.238	3.048
HI_CCE	Combined Cycle East	12	1008.9	27.43	379.26	20.238	3.048
HI_SCW	Single Cycle West	12	1008.9	18.29	735.93	55.105	3.048
HI_SCE	Single Cycle East	12	1008.9	18.29	735.93	55.105	3.048

Table 6-17: CALPUFF Modeled Emission Rates

Source ID	Source Description	NO_x (lb/hr)	PM (lb/hr)
HI_CCW	Combined Cycle West	4.16	7.20
HI_CCE	Combined Cycle East	4.16	7.20
HI_SCW	Single Cycle West	36.58	4.80
HI_SCE	Single Cycle East	36.58	4.80

6.5.7 CALPOST

Data generated by CALPUFF was entered into the CALPOST program to summarize peak Class I increment and visibility impacts. For the visibility analysis, CALPOST used modeled sulfate, nitrate, and PM_{10} concentration data to determine the light-absorbing and light-scattering effects resulting from the project's emissions. The method recommended and used for calculating light extinction was "Method 6: Compute extinction from speciated particulate matter measurements." The background extinction coefficients were calculated based on the annual relative humidity factors and data presented in Section 6.1 and Appendices C and D of the Montana BART Protocol. Inputs to CALPOST for visibility processing are summarized in the following table.

Table 6-18: CALPUFF Visibility Control File Settings

CALPOST Parameter/Option	Value
Maximum relative humidity (RHMAX)	95%
Included species	Sulfate, nitrate, coarse particulate (as PM_{10}), and fine particulate (as $PM_{2.5}$)
Coarse particulate extinction efficiency	0.6 (l/Mm per $\mu g/m^3$)
Fine particulate extinction efficiency	1.0 (l/Mm per $\mu g/m^3$)
Ammonium sulfate extinction efficiency	3.0 (l/Mm per $\mu g/m^3$)
Ammonium nitrate extinction efficiency	3.0 (l/Mm per $\mu g/m^3$)
Organic carbon extinction efficiency	4.0 (l/Mm per $\mu g/m^3$)
Soil extinction efficiency	1.0 (l/Mm per $\mu g/m^3$)
Elemental carbon extinction efficiency	10.0 (l/Mm per $\mu g/m^3$)
Method used for background light extinction	MVISBK = 6
Relative humidity	From *.VIS Files
Background extinction coefficients, SO_4	*
Background extinction coefficients, NO_3	*
Background extinction coefficients, PMC	*
Background extinction coefficients, OC	*
Background extinction coefficients, soil	*
Background extinction coefficients, EC	*
Extinction due to Rayleigh scattering	10.0

Notes:
NO_3 = Nitrate
* These values are specific to individual Class I areas; they are calculated according to the method given in Section 6.1 of the Montana BART Protocol document. The calculated values are given in the table below.

Table 6-19: Background Extinction Coefficients

Parameter	Bob Marshall WA	Scapegoat WA	Gates of the Mountains WA	Glacier NP	UL Bend WA
SO_4	0.121	0.119	0.120	0.120	0.120
NO_3	0.101	0.099	0.100	0.100	0.100
PMC	3.021	2.966	3.000	3.005	3.004
OC	0.473	0.465	0.470	0.471	0.471
Soil	0.503	0.494	0.500	0.501	0.501
EC	0.020	0.020	0.020	0.020	0.020

6.5.8 Class I Increment – Mandatory Class I Areas

Peak Class I increment impacts resulting from requested SO_2 emissions from the HGS gas plant are summarized for SO_2, NO_2, and PM_{10} for each relevant averaging period at each of the Class I areas analyzed.

6.5.9 Regional Haze (Visibility)

Impacts to natural background visibility, expressed in terms of percentage change in 24-hour average background extinction (ΔBex) are calculated by CALPOST. The FLAG report suggests that a predicted change in extinction, resulting from a single source, of less than 0.5 deciview should generally be acceptable. A predicted change in extinction between 0.5 and 1.0 may warrant a cumulative analysis that includes impacts from other nearby PSD sources. The guidelines also reference 40 CFR §51.301(a) in asserting that determinations must be made on a "…case-by-case basis taking into account the geographic extent, intensity, duration, frequency and time of visibility impairments…."

6.5.10 Acid Deposition Impacts

CALPUFF produces two binary files containing wet and dry flux rates for several nitrogen and sulfur-based compounds [compounds that would be created over time from atmospheric reactions of nitrogen oxides (NOx) and sulfur dioxide (SO_2) emissions]. The individual wet and dry deposition rates are summed by the POSTUTIL utility program to produce total dry and wet deposition rates. These files are processed through CALPOST to predict deposition rates for NOx, nitric acid (HNO_3), nitrate ion (NO_3^-), SO_2, and sulfate (SO_4). The predicted total annual sulfur and nitrogen deposition rates are then compared to the Western US Deposition Analysis Threshold (DAT) value of 0.0050 kilogram per hectare per year (kb/ha/y).

6.5.11 Class I Increment Results

Peak Class I increment impacts resulting from requested SO_2 emissions from the HGS gas plant are summarized in the table below.

Table 6-20: Peak Predicted Class I Increments

Class I Area	Pollutant	Avg. Period	Predicted Impact [(a)] ($\mu g/m^3$)	Year	Class I Increment ($\mu g/m^3$)	Class I Sig. Level ($\mu g/m^3$)
Bob Marshall WA	PM_{10} (SC)	24-hr	0.0122	2003	8	0.3
		Annual	0.000141	2003	4	0.2
	PM_{10} (CC)	24-hr	0.0174	2003	8	0.3
		Annual	0.000286	2003	4	0.2
	NO_2 (SC)	Annual	0.00037	2003	2.5	0.1
	NO_2 (CC)	Annual	0.000465	2003	2.5	0.1
	SO_2 (SC)	3-hr	0.000406	2002	25	1.0
		24-hr	0.000126	2003	5	0.2
		Annual	0.0000013	2003	2	0.1
	SO_2 (CC)	3-hr	0.00577	2002	25	1.0
		24-hr	0.00136	2002	5	0.2
		Annual	0.0000189	2003	2	0.1
Gates of the Mountains WA	PM_{10} (SC)	24-hr	0.02	2002	8	0.3
		Annual	0.000698	2002	4	0.2
	PM_{10} (CC)	24-hr	0.0347	2003	8	0.3
		Annual	0.00113	2002	4	0.2
	NO_2 (SC)	Annual	0.00254	2002	2.5	0.1
	NO_2 (CC)	Annual	0.000935	2001	2.5	0.1
	SO_2 (SC)	3-hr	0.000642	2003	25	1.0
		24-hr	0.00022	2002	5	0.2
		Annual	0.00000719	2002	2	0.1
	SO_2 (CC)	3-hr	0.0104	2001	25	1.0
		24-hr	0.00238	2003	5	0.2
		Annual	0.0000834	2002	2	0.1
Glacier NP	PM_{10} (SC)	24-hr	0.0051	2001	8	0.3
		Annual	0.00069	2001	4	0.2
	PM_{10} (CC)	24-hr	0.00636	2001	8	0.3
		Annual	0.000108	2001	4	0.2
	NO_2 (SC)	Annual	0.000107	2001	2.5	0.1
	NO_2 (CC)	Annual	0.00000757	2001	2.5	0.1
	SO_2 (SC)	3-hr	0.000267	2001	25	1.0
		24-hr	0.0000489	2001	5	0.2
		Annual	0.000000579	2001	2	0.1
	SO_2 (CC)	3-hr	0.00164	2002	25	1.0

Class I Area	Pollutant	Avg. Period	Predicted Impact [a] ($\mu g/m^3$)	Year	Class I Increment ($\mu g/m^3$)	Class I Sig. Level ($\mu g/m^3$)
		24-hr	0.000486	2002	5	0.2
		Annual	0.00000594	2001	2	0.1
Scapegoat WA	PM_{10} (SC)	24-hr	0.0133	2003	8	0.3
		Annual	0.00018	2003	4	0.2
	PM_{10} (CC)	24-hr	0.0108	2002	8	0.3
		Annual	0.000397	2003	4	0.2
	NO_2 (SC)	Annual	0.000472	2003	2.5	0.1
	NO_2 (CC)	Annual	0.0000691	2003	2.5	0.1
	SO_2 (SC)	3-hr	0.00051	2003	25	1.0
		24-hr	0.000138	2003	5	0.2
		Annual	0.00000171	2003	2	0.1
	SO_2 (CC)	3-hr	0.00515	2003	25	1.0
		24-hr	0.00148	2003	5	0.2
		Annual	0.0000273	2003	2	0.1
UL Bend WA	PM_{10} (SC)	24-hr	0.0068	2002	8	0.3
		Annual	0.000758	2002	4	0.2
	PM_{10} (CC)	24-hr	0.0152	2001	8	0.3
		Annual	0.00142	2002	4	0.2
	NO_2 (SC)	Annual	0.00233	2002	2.5	0.1
	NO_2 (CC)	Annual	0.000324	2002	2.5	0.1
	SO_2 (SC)	3-hr	0.000189	2003	25	1.0
		24-hr	0.0000621	2003	5	0.2
		Annual	0.00000734	2002	2	0.1
	SO_2 (CC)	3-hr	0.00267	2002	25	1.0
		24-hr	0.00099	2003	5	0.2
		Annual	0.0000987	2002	2	0.1

(a) Predicted concentration impacts are high-first-high values.

The 3-hour, 24-hour and annual average impacts are below the guideline Class I modeling significance thresholds. These significant impact thresholds were proposed by the EPA and are recognized in MDEQ's draft modeling protocol as guideline values. By convention, this means that the HGS gas plant's emissions will not cause or contribute to an exceedance of any Class I increment. No cumulative analysis is required in this case.

6.5.12 Regional Haze (Visibility) Results

Impacts to natural background visibility, expressed in terms of percentage change in 24-hour average background extinction (ΔBex) were calculated by CALPOST. The FLAG report suggests that a predicted change in extinction, resulting from a single source, of less than 0.5 deciview should generally be acceptable. A predicted change in extinction between 0.5 and 1.0 may warrant a cumulative analysis that includes impacts from other nearby PSD sources. The guidelines also reference 40 CFR §51.301(a) in asserting that determinations must be made on a "…case-by-case basis taking into account the geographic extent, intensity, duration, frequency and time of visibility impairments…." Peak impact results resulting from the HGS gas plant emissions are summarized in the following table.

Table 6-21: Peak Predicted Class I Visibility Impacts

	SC			CC		
Modeled Year	**ΔB_{ex} (dv)**	**No. of Days $\Delta B_{ext} \geq 0.5$ dv**	**No. of Days $\Delta B_{ext} \geq 1.0$ dv**	**ΔB_{ex} (dv)**	**No. of Days $\Delta B_{ext} \geq 0.5$ dv**	**No. of Days $\Delta B_{ext} \geq 1.0$ dv**
Bob Marshall WA						
2001	0.098	0	0	0.024	0	0
2002	0.081	0	0	0.032	0	0
2003	0.074	0	0	0.032	0	0
Max/Total	0.098	0	0	0.032	0	0
Gates of the Mountains WA						
2001	0.109	0	0	0.055	0	0
2002	0.350	0	0	0.086	0	0
2003	0.252	0	0	0.081	0	0
Max/Total	0.350	0	0	0.086	0	0
Glacier NP						
2001	0.091	0	0	0.019	0	0
2002	0.097	0	0	0.017	0	0
2003	0.026	0	0	0.010	0	0
Max/Total	0.097	0	0	0.019	0	0
Scapegoat WA						
2001	0.103	0	0	0.021	0	0
2002	0.213	0	0	0.033	0	0
2003	0.078	0	0	0.032	0	0
Max/Total	0.213	0	0	0.033	0	0
UL Bend WA						
2001	0.088	0	0	0.036	0	0
2002	0.111	0	0	0.034	0	0
2003	0.140	0	0	0.027	0	0
Max/Total	0.140	0	0	0.036	0	0

6.5.13 Acid Deposition Results

CALPUFF produces two binary files containing wet and dry flux rates for several nitrogen and sulfur-based compounds (compounds that would be created over time from atmospheric reactions of nitrogen oxides (NOx) and sulfur dioxide (SO_2) emissions). The individual wet and dry deposition rates are summed by the POSTUTIL utility program to produce total dry and wet deposition rates. These files are processed through CALPOST to predict deposition rates for NOx, nitric acid (HNO_3), nitrate ion (NO_3^-), SO_2, and sulfate (SO_4). The predicted total annual sulfur and nitrogen deposition rates are then compared to the Western US Deposition Analysis Threshold (DAT) value of 0.0050 kilogram per hectare per year (kg/ha/y). All of the predicted sulfur and nitrogen deposition values are well below the DAT value.

Table 6-22: Peak Predicted Sulfur Deposition – Class I Area

Modeled Year	S Deposition (SC)	S Deposition (CC)
Bob Marshall WA		
2001	0.000000869	0.00000702
2001	0.00000142	0.0000144
2003	0.0000011	0.0000143
Max	0.00000142	0.0000144
Gates of the Mountains WA		
2001	0.00000401	0.00000498
2001	0.00000597	0.00000622
2003	0.00000498	0.00000592
Max	0.00000597	0.00000622
Glacier NP		
2001	0.000000486	0.00000551
2001	0.00000062	0.00000779
2003	0.000000423	0.00000447
Max	0.00000062	0.00000779
Scapegoat WA		
2001	0.00000157	0.000013
2001	0.0000021	0.000022
2003	0.00000195	0.0000233
Max	0.0000021	0.0000233
UL Bend WA		
2001	0.0000031	0.0000389
2001	0.00000334	0.0000391
2003	0.00000339	0.0000415
Max	0.00000339	0.0000415

Units: kg/ha/yr

Table 6-23: Peak Predicted Nitrogen Deposition – Class I Area

Modeled Year	N Deposition (SC)	N Deposition (CC)
Bob Marshall WA0.0000137		
2001	0.000138	0.0000137
2001	0.000207	0.0000276
2003	0.000176	0.0000274
Max	0.000207	0.0000276
Gates of the Mountains WA		
2001	0.000658	0.0000989
2001	0.00101	0.000124
2003	0.000789	0.00012
Max	0.00101	0.000124
Glacier NP		

Modeled Year	N Deposition (SC)	N Deposition (CC)
2001	0.0000703	0.0000096
2001	0.0000788	0.000014
2003	0.0000579	0.000008
Max	0.0000788	0.000014
Scapegoat WA		
2001	0.000238	0.000024
2001	0.000269	0.0000402
2003	0.000311	0.0000451
Max	0.000311	0.0000451
UL Bend WA		
2001	0.000487	0.000078
2001	0.000555	0.0000822
2003	0.000518	0.0000871
Max	0.000555	0.0000871

Units: kg/ha/yr

6.5.14 Class I Summary Results

The preceding long-range-transport modeling analysis demonstrates that the modeled emissions from the HGS gas plant will not cause or contribute to PSD Class I increments at surrounding Class I areas. The modeled emissions will not adversely impact visibility at surrounding federally mandated Class I areas, nor will the emissions cause any sulfur or nitrogen deposition greater than the threshold DAT value.

APPENDIX A: MDEQ AIR QUALITY PERMIT APPLICATION FORMS

AIR QUALITY PERMIT APPLICATION FOR STATIONARY SOURCES

Montana Department of Environmental Quality
Air Resources Management Bureau
Permitting Section Supervisor
1520 E. Sixth Avenue
P.O. Box 200901
Helena, MT 59620-0901
Phone: (406) 444-3490 FAX (406) 444-1499
Email: DEQ-ARMB-Admin@mt.gov

For State of Montana Use Only
Permit Application #: _________ AFS #: _________
Application Fee Paid with Application? ☐ Yes ☐ No
Amount Paid: ___________ Check #: ___________

Three complete copies of this application, any associated fees, and the affidavit of publication of the attached public notice must be delivered to the address above. The application may be submitted electronically to the email address provided above; however, the application will not be considered complete until the appropriate permit application fee, affidavit of publication, and certification of truth, accuracy, and completeness are submitted to the Department. Any checks, affidavits, and certifications submitted separately from the application should be clearly identified. The applicant is encouraged to contact the Department with any questions related to this application form.

*Note: This application form should **not** be used for portable sources, crematoriums, oil and gas registrations, or Acid Rain permits required under Title IV of the Clean Air Act. Permit application forms for portable sources, crematoriums, and oil and gas registrations are available on the Department's website. Applications for Acid Rain permits must be made on nationally standardized forms available from the U.S. Environmental Protection Agency.*

§1.0 GENERAL FACILITY INFORMATION AND SITE DESCRIPTION

§1.1 FACILITY NAME AND ADDRESS (As registered with the Montana Secretary of State)

Company Name **Southern Montana Electric Generation and Transmission Cooperative, Inc.**

Facility Name **Highwood Generating Station**

Mailing Address	Physical Address (if different from mailing address)
3521 Gabel Road, Suite 5 Address	**8 Miles East of Great Falls, MT** Address
Billings (City) **MT** (State) **59102** (Zip)	**Great Falls** (City) **MT** (State) **59401** (Zip)

§1.2 CONTACT INFORMATION

	Name	Title	Telephone	Email
Owner	**Southern Montana Electric Generation & Transmission Cooperative**			
Facility Manager	**TBD**			
Responsible Official	**Tim Gregori**	**Manager**	**406-294-9527**	
Contact Person	**Tim Gregori**	**Manager**	**406-294-9527**	
Alternate Contact Person	**NA**	**NA**	**NA**	

[Note: If email address is provided, the Department will send all permit notices (i.e. Preliminary Determination, Department Decision, and Final Permit) electronically.

§1.3 PERMIT TYPE (Check all that apply)

☒ **Montana Air Quality Permit (MAQP)**

MAQP Permit Action: ☐ New Facility ☒ Modification to Existing Permit # **3423** - **01**

☒ Synthetic Minor (major source using federally enforceable permit conditions to avoid MACT, NSR, or Title V Operating Permit requirements) **(MACT ONLY)**

☒ New Source Review

☒ Prevention of Significant Deterioration

☐ Nonattainment Area

☒ **Air Quality Operating Permit (Title V)**

Title V Permit Action: ☒ Initial Air Quality Operating Permit

☐ Renewal of Air Quality Operating Permit #OP______ - ____

☐ Modification of Air Quality Operating Permit #OP

☐ Minor Modification

☐ Significant Modification

Note: The applicant must also send one copy of the Title V Operating Permit application to the EPA at the following address:

Office of Partnerships and Regulatory Assistance
Air and Radiation Program
US EPA Region VIII 8P-AR
1595 Wynkoop St.
Denver, Colorado 80202-1129

A statement certifying that a copy of the Title V Operating Permit application has been mailed to EPA must accompany the Title V Operating Permit application.

§1.4 PHYSICAL LOCATION AND FACILITY INFORMATION

Qtr/Qtr Section _____ Section **24 and 25** Township **21N** Range **5E**

Latitude (in decimal degrees) _**47.55**_ Longitude (in decimal degrees) _**111.03** County **Cascade**____

Will the facility be operating in (or impacting) a nonattainment area? ☐ Yes ☒ No

(*Note: Maps of the state's nonattainment areas can be found at the following website:* http://deq.mt.gov/AirQuality/Planning/AirNonattainment.asp.)

If yes, which pollutant(s) is the area nonattainment for?

____

Total Property Area (acres): **~680** Year Facility Began Operation at Site: **N/A**

General Nature of Business: **Electric Regulation**

Standard Industrial Classification (SIC) Codes(s): **4911**

SIC Description(s): **Electric Services**

(*Note: SIC Codes can be found at the following website:* http://www.osha.gov/pls/imis/sicsearch.html.)

For MAQP only, **a drawing, sketch, or topographic map of appropriate scale must be submitted** (maximum scale 1"=500', measurement to the nearest 20'), showing at least the following:

a. The property boundaries on which the source is located;

b. The outlines and dimensions of all existing and proposed buildings and stacks;

c. The locations of existing and proposed emitting units, including lat/long coordinates (in NAD83) and elevation (in feet above mean sea level) for each emitting unit. The emissions units and points should be identified as existing or proposed;

d. Any nearby streets, highways, and waterbodies;

e. Any nearby sensitive areas, such as schools, hospitals, parks, residential areas, etc.;

f. A true north arrow; and

g. A graphically displayed scale.

§1.5 PROJECT SUMMARY (*Not Required for Title V Operating Permit applications*)

Overview of project, including any new or modified equipment (*attach additional information as necessary*):

Please refer to Application Section 2 for a comprehensive project summary and description.

Include a process flow diagram showing material balances (below or attached).

Please refer to Appendix B for all layout drawings of the facility.

Construction/Installation Schedule:

Expected Construction Start Date: **Autumn 2009** Expected Operation Start Date: **Spring 2010**

Duration (if a temporary source): ____

Optional Information:

Estimate of Capital Expenditure for Proposed Project: $ **NA**

Estimate of Cost of Air Pollution Control Equipment: $ **NA**

§2.0 EMITTING UNIT LISTING

List all existing and proposed emitting units. For Title V Operating Permits only, note all insignificant emission units.

> Note: An **insignificant emissions unit** includes any activity or emissions unit that has the potential to emit less than 5 tons per year of any regulated pollutant, less than 500 pounds per year of lead, less than 500 pounds per year of a hazardous air pollutant, and is not regulated by an applicable requirement, such as a New Source Performance Standard (NSPS) or Maximum Achievable Control Technology (MACT) standard.

EMITTING UNIT		Pollution Control Device	New Source	Existing Source	Insignificant	
ID	Name				Yes	No
EU1	LM6000PF Combustion Turbine	DLE/SCR/Oxy Cat	☒	☐	☐	☒
EU2	LM6000PF Combustion Turbine	DLE/SCR/Oxy Cat	☒	☐	☐	☒
EU3	Cooling Tower	None	☒	☐	☒	☐
EU4	Misc. Building Heaters	None	☒	☐	☒	☐
EU5	Black-Start Emergency Generator	None	☒	☐	☐	☒
EU6	Emergency Firepump	None	☒	☐	☐	☒
			☐	☐	☐	☐
			☐	☐	☐	☐
			☐	☐	☐	☐
			☐	☐	☐	☐
			☐	☐	☐	☐
			☐	☐	☐	☐
			☐	☐	☐	☐
			☐	☐	☐	☐
			☐	☐	☐	☐
			☐	☐	☐	☐
			☐	☐	☐	☐
			☐	☐	☐	☐
			☐	☐	☐	☐
			☐	☐	☐	☐

§3.0 EMISSIONS INVENTORY

A separate Section 3.0 must be completed for each emitting unit listed in Section 2.0.

Emitting Unit ID: **EU1 and EU2 (each)**
Emitting Unit Name: **LM6000PF Combustion Cycle Turbines**

Attach calculations. The source(s) of all emissions estimates must be indicated (e.g. manufacturer's data, AP-42, source tests, etc.) If possible, calculations should be submitted electronically using an Excel spreadsheet.

Regulated Air Pollutant	**Allowable Emission Rate(s)[1] (each)**		**Actual Emission Rate(s) *(if applicable)*[2]**	
	(Lb/Hour)[3]	(Tons/Year)	(Lb/Hour)	(Tons/Year)
PM	**7.20**	**63.10**		
PM_{10}	**7.20**	**63.10**		
$PM_{2.5}$	**7.20**	**63.10**		
SO_2	**0.69**	**6.05**		
NO_x	**36.58**	**81.09**		
CO	**114.7**	**189.15**		
VOC	**3.90**	**10.56**		
Pb	**Negligible**	**Negligible**		
Other *(specify):*				
Other *(specify):*				
Other *(specify):*				
Other *(specify):*				
Other *(specify):*				
Other *(specify):*				

[1] Allowable emission rate(s) should equal the potential to emit, unless a federally enforceable permit limit is proposed. Potential emissions are to be calculated based on production at the maximum capacity for 8,760 hours per year. Only control practices or equipment which is proposed to be made federally enforceable may be used to limit the potential to emit of the unit.

[2] Actual emission rate(s) should equal the average rate at which the unit actually emitted the pollutant during a two-year period which precedes the particular date and which is representative of normal source operation. Actual emissions shall be calculated using the unit's actual operating hours, production rates, and types of materials processed, stored, or combusted during the selected time period.

[3] Pound per hour allowable emission rates are based on the maximum rate emitted on an hourly basis regardless of whether the facility is operating in steady state conditions or in startup and shutdown conditions.

§3.0 EMISSIONS INVENTORY

A separate Section 3.0 must be completed for each emitting unit listed in Section 2.0.

Emitting Unit ID: **EU3**
Emitting Unit Name: **Cooling Tower**

Attach calculations. The source(s) of all emissions estimates must be indicated (e.g. manufacturer's data, AP-42, source tests, etc.) If possible, calculations should be submitted electronically using an Excel spreadsheet.

Regulated Air Pollutant	**Allowable Emission Rate(s)[4]**		**Actual Emission Rate(s) *(if applicable)*[5]**	
	(Lb/Hour)	(Tons/Year)	(Lb/Hour)	(Tons/Year)
PM	**0.26**	**1.14**		
PM_{10}	**0.26**	**1.14**		
$PM_{2.5}$	**0.26**	**1.14**		
SO_2	**NA**	**NA**		
NO_x	**NA**	**NA**		
CO	**NA**	**NA**		
VOC	**NA**	**NA**		
Pb	**NA**	**NA**		
Other *(specify):*				
Other *(specify):*				
Other *(specify):*				
Other *(specify):*				
Other *(specify):*				
Other *(specify):*				

[4] Allowable emission rate(s) should equal the potential to emit, unless a federally enforceable permit limit is proposed. Potential emissions are to be calculated based on production at the maximum capacity for 8,760 hours per year. Only control practices or equipment which is proposed to be made federally enforceable may be used to limit the potential to emit of the unit.

[5] Actual emission rate(s) should equal the average rate at which the unit actually emitted the pollutant during a two-year period which precedes the particular date and which is representative of normal source operation. Actual emissions shall be calculated using the unit's actual operating hours, production rates, and types of materials processed, stored, or combusted during the selected time period.

§3.0 EMISSIONS INVENTORY

A separate Section 3.0 must be completed for each emitting unit listed in Section 2.0.

Emitting Unit ID: **EU4**
Emitting Unit Name: **Miscellaneous Building Heaters**

Attach calculations. The source(s) of all emissions estimates must be indicated (e.g. manufacturer's data, AP-42, source tests, etc.) If possible, calculations should be submitted electronically using an Excel spreadsheet.

Regulated Air Pollutant	**Allowable Emission Rate(s)**[6]		**Actual Emission Rate(s)** ***(if applicable)***[7]	
	(Lb/Hour)	(Tons/Year)	(Lb/Hour)	(Tons/Year)
PM	**0.021**	**0.09**		
PM_{10}	**0.021**	**0.09**		
$PM_{2.5}$	**0.021**	**0.09**		
SO_2	**0.0016**	**0.01**		
NO_x	**0.38**	**1.68**		
CO	**0.23**	**1.01**		
VOC	**0.015**	**0.07**		
Pb	**Negligible**	**Negligible**		
Other *(specify)*:				
Other *(specify)*:				
Other *(specify)*:				
Other *(specify)*:				
Other *(specify)*:				
Other *(specify)*:				

[6] Allowable emission rate(s) should equal the potential to emit, unless a federally enforceable permit limit is proposed. Potential emissions are to be calculated based on production at the maximum capacity for 8,760 hours per year. Only control practices or equipment which is proposed to be made federally enforceable may be used to limit the potential to emit of the unit.

[7] Actual emission rate(s) should equal the average rate at which the unit actually emitted the pollutant during a two-year period which precedes the particular date and which is representative of normal source operation. Actual emissions shall be calculated using the unit's actual operating hours, production rates, and types of materials processed, stored, or combusted during the selected time period.

§3.0 EMISSIONS INVENTORY

A separate Section 3.0 must be completed for each emitting unit listed in Section 2.0.

Emitting Unit ID: **EU5**
Emitting Unit Name: **Black-Start Emergency Generator**

Attach calculations. The source(s) of all emissions estimates must be indicated (e.g. manufacturer's data, AP-42, source tests, etc.) If possible, calculations should be submitted electronically using an Excel spreadsheet.

Regulated Air Pollutant	**Allowable Emission Rate(s)**[8]		**Actual Emission Rate(s) *(if applicable)***[9]	
	(Lb/Hour)	(Tons/Year)	(Lb/Hour)	(Tons/Year)
PM	**0.10**	**0.03**		
PM_{10}	**0.10**	**0.03**		
$PM_{2.5}$	**0.10**	**0.03**		
SO_2	**0.73**	**0.09**		
NO_x	**26.7**	**6.68**		
CO	**1.1**	**0.26**		
VOC	**0.60**	**0.14**		
Pb	**Negligible**	**Negligible**		
Other *(specify):*				
Other *(specify):*				
Other *(specify):*				
Other *(specify):*				
Other *(specify):*				
Other *(specify):*				

[8] Allowable emission rate(s) should equal the potential to emit, unless a federally enforceable permit limit is proposed. Potential emissions are to be calculated based on production at the maximum capacity for 8,760 hours per year. Only control practices or equipment which is proposed to be made federally enforceable may be used to limit the potential to emit of the unit.

[9] Actual emission rate(s) should equal the average rate at which the unit actually emitted the pollutant during a two-year period which precedes the particular date and which is representative of normal source operation. Actual emissions shall be calculated using the unit's actual operating hours, production rates, and types of materials processed, stored, or combusted during the selected time period.

§3.0 EMISSIONS INVENTORY

A separate Section 3.0 must be completed for each emitting unit listed in Section 2.0.

Emitting Unit ID: **EU6**
Emitting Unit Name: **Emergency Firepump**

Attach calculations. The source(s) of all emissions estimates must be indicated (e.g. manufacturer's data, AP-42, source tests, etc.) If possible, calculations should be submitted electronically using an Excel spreadsheet.

Regulated Air Pollutant	**Allowable Emission Rate(s)**[10]		**Actual Emission Rate(s)** ***(if applicable)***[11]	
	(Lb/Hour)	(Tons/Year)	(Lb/Hour)	(Tons/Year)
PM	**0.14**	**0.04**		
PM_{10}	**0.14**	**0.04**		
$PM_{2.5}$	**0.14**	**0.04**		
SO_2	**0.13**	**0.02**		
NO_x	**3.68**	**0.92**		
CO	**0.85**	**0.21**		
VOC	**0.14**	**0.03**		
Pb	**Negligible**	**Negligible**		
Other *(specify):*				
Other *(specify):*				
Other *(specify):*				
Other *(specify):*				
Other *(specify):*				
Other *(specify):*				

[10] Allowable emission rate(s) should equal the potential to emit, unless a federally enforceable permit limit is proposed. Potential emissions are to be calculated based on production at the maximum capacity for 8,760 hours per year. Only control practices or equipment which is proposed to be made federally enforceable may be used to limit the potential to emit of the unit.

[11] Actual emission rate(s) should equal the average rate at which the unit actually emitted the pollutant during a two-year period which precedes the particular date and which is representative of normal source operation. Actual emissions shall be calculated using the unit's actual operating hours, production rates, and types of materials processed, stored, or combusted during the selected time period.

§4.0 Emitting Unit and Control Equipment Information

A separate Section 4.0 must be completed for each emitting unit listed in Section 2.0. Applications for Title V Operating Permits must address significant emission units individually. Insignificant emission units may be addressed as a group. For information that has been previously submitted, the applicant may instead reference the previously submitted information, including the date the material was submitted and the source (i.e. permit application number, etc.)

Emitting Unit ID: **EU1 and EU2 (each)**
Emitting Unit Name: **LM6000PF Combustion Turbines**

§4.1 Emitting Unit Overview:

Narrative Process Equipment/Process Description (*attach additional sheets as necessary*) **See Application Section 2.**

Proposed Operational Limitations (*if any*) **While operating in simple cycle the limit of hours of operation is 3,200 hours per year.**

Source Classification Code (SCC)/ Description: **20100201 - Internal Combustion Engine/Electric Generation/ Natural Gas Turbines**

(*Note: SCC Codes can be found at the following website*: http://cfpub.epa.gov/oarweb/download/WebFIRESCCs.csv)

Regulatory Programs: Indicate all air pollution control programs applicable to this emitting unit:

- ☒ NSPS: 40 CFR 60, Subpart(s): (**See application Section 4)**
- ☐ NESHAPS: 40 CFR 61, Subpart(s): (**See application Section 4)**
- ☒ MACT: 40 CFR 63, Subpart(s): (**See application Section 4)**
- ☒ Title V Operating Permit – Significant Emitting Unit
- ☒ Acid Rain (Title IV)
- ☐ Risk Management Plan
- ☒ CAM Plan
- ☐ Other: ______________________________

§4.2 Process Information (*include units*):

Type of Material Processed **Electricity**

Average Process Rate (tons/hr, gal/hr, etc.)**NA**

Maximum Rated Design Process Rate (tons/hr, gal/hr, etc.) **60 MWe (each) @ 100% load, 57.4 °F**

§4.3 Process Identification

Make **General Electric** Model **LM6000PF**

Type **Combustion Turbine** Size **447.5 MMBtu/hr**

Year of Manufacture/Reconstruction **TBD** Year of Installation **TBD**

Power Source **Natural Gas**

If applicable, provide the following generator information:

Rated Output of the generator (kW) _**44,600 kW Combustion Turbine Generator (each), 30,800 kW Steam Turbine Generator (total), 100% load, -17.7°F, power factor 1.0**______

Rated Size of Engine powering the generator (hp) _**60,977 Max Shaft HP, 100% load, -17.7°F** _______

§4.4 Fuel/Combustion Information:

(For variable parameters, indicate the maximum value or a range)

Fuel Type(s) **Natural Gas**____

Average Fuel Combustion Rate: ______________________

Maximum Rated Combustion Rate: **447.5 MMBtu/hr @ 100% load 91.5°F amb** _____________________

Heat Content (Btu rating) **1000 Btu/scf HHV** Sulfur Content (%) **0.5 gr/dscf** Ash Content (%) **Negligible**

§4.5 Emitting Unit Location

Combined Cycle West Stack

Latitude (in decimal degrees): **47.5517N** Longitude (in decimal degrees): **111.0343 W**

Datum (NAD27, NAD83, etc.): **NAD27**

Combined Cycle East Stack

Latitude (in decimal degrees): **47.5517N** Longitude (in decimal degrees): **111.0337 W**

Datum (NAD27, NAD83, etc.): **NAD27**

Simple Cycle West Stack

Latitude (in decimal degrees): **47.5514N** Longitude (in decimal degrees): **111.0342 W**

Datum (NAD27, NAD83, etc.): **NAD27**

Simple Cycle East Stack

Latitude (in decimal degrees): **47.5514N** Longitude (in decimal degrees): **111.0337 W**

Datum (NAD27, NAD83, etc.): **NAD27**

§4.6 Stack Information (*if applicable*):

Height (feet) **105** Inside Diameter (feet) **10**

Exit Gas Temperature (˚F) **223 (MAX)** Exit Gas Flow Rate (ACFM) **312,899 (MAX)**

Exit Gas Velocity (ft/sec) **66.4** Exit Gas Moisture Content (%) **5.49**

Stack Type (check one):
- ☐ Downward Exit
- ☐ Multiple Actual Stacks
- ☐ Fugitive Source
- ☐ Horizontal Exit
- ☐ Building Roof Vent
- ☐ Process Vent
- ☒ Vertical Exit
- ☐ Vertical Exit with Cap

Simple Cycle Stacks

Height (feet) **80** Inside Diameter (feet) **10**

Exit Gas Temperature (˚F) **865 (MAX)** Exit Gas Flow Rate (ACFM) **851,959 (MAX)**

Exit Gas Velocity (ft/sec) **180.8** Exit Gas Moisture Content (%) **5.49**

Stack Type (check one):
- ☐ Downward Exit
- ☐ Multiple Actual Stacks
- ☐ Fugitive Source
- ☐ Horizontal Exit
- ☐ Building Roof Vent
- ☐ Process Vent
- ☒ Vertical Exit
- ☐ Vertical Exit with Cap

§4.7 Approximate Operating Schedule:

Combined Cycle

Hours/Day **24 hr/day** Days/Week **7 days/wk**

Hours/Year **8760 hrs/yrs** Weeks/Year **52 wks/hr**

Simple Cycle

Hours/Day **24 hr/day** Days/Week **7 days/wk**

Hours/Year **3200 hrs/yrs** Weeks/Year

§4.8 Air Pollution Control Equipment and Practices

Primary and Secondary Air Pollution Control Equipment and/or Procedure Description:

Dry Low Emissions (integral to turbine), Selective Catalytic Reduction (SCR), and Oxidation Catalyst.

Primary Air Pollution Control Equipment Description:

Make **TBD** Model **TBD**

Type **SCR** Size **TBD**

Year of Manufacture **TBD** Year of Installation **TBD**

Fuel Type(s) **NA** Estimated Control Efficiency **89% for NOx**

Estimated Capital Equipment Cost (*not required for Title V Operating Permit applications*) _ See Section 5.0 of application ________

Secondary Air Pollution Control Equipment Description:

Make**TBD** Model **TBD**

Type **Oxidation Catalyst** Size **TBD**

Year of Manufacture **TBD** Year of Installation **TBD**

Fuel Type(s) **NA** Estimated Control Efficiency **95% of CO**

Estimated Capital Equipment Cost (*not required for Title V Operating Permit applications*) _**See Section 5.0 of application** ________

§4.9 Shakedown Procedures (*not required for Title V Operating Permit applications*)

Describe any shakedown procedures that are expected to affect emissions, including the duration of the shakedown period: **__ See Section 3.0 of application for Commissioning Period Emissions**

§4.10 Continuous Emission Monitoring System (CEMS) – *check all that apply:*

☐ Opacity – Make __________________ Model ___________ Year ____________

Automatic Calibration Valve: Zero ____________ Span ___________

☐ TRS – Make __________________ Model ___________ Year ____________

Automatic Calibration Valve: Zero ____________ Span ___________

☒ NO_x - Make **TBD** Model **TBD** Year **TBD**

Automatic Calibration Valve: Zero ____________ Span ___________

☐ CO – Make __________________ Model ___________ Year ____________

Automatic Calibration Valve: Zero ____________ Span ___________

☐ O_2 – Make __________________ Model ___________ Year ____________

Automatic Calibration Valve: Zero ____________ Span ___________

☐ CO_2 – Make __________________ Model ___________ Year ____________

Automatic Calibration Valve: Zero ____________ Span ___________

☐ Other (*specify*): ____

Make __________________ Model ___________ Year ____________

Automatic Calibration Valve: Zero ____________ Span ___________

§4.11 Emissions Control Analysis (*not required for Title V Operating permit applications*)

Best Available Control Technology (BACT) is required for all sources obtaining a MAQP. The BACT analysis should be conducted separately for each pollutant emitted from each emitting unit and must include a listing of all technologically feasible control options. Control costs (cost per ton of air pollutant controlled) should be calculated for each option. Options may then be eliminated for economic, energy or environmental reasons. The control option that is selected should have controls or control costs similar to other recently permitted similar sources and should be capable of achieving appropriate emission standards. If necessary, a separate start-up/shut-down BACT analyses should be conducted.

Lowest Achievable Emission Rate (LAER) is required for major stationary sources and major modifications located in a nonattainment area. LAER is also required for major stationary sources or major modifications located in an area designated as attainment or unclassified under 40 CFR 81.327, but would cause or contribute to a violation of the National Ambient Air Quality Standards (NAAQS) in a nearby nonattainment area. The LAER analysis shall demonstrate that the emission rate proposed is equivalent to the most stringent emission rate achievable or contained in any state implementation plan for a similar source.

Attach BACT/LAER Analysis Results, as applicable.

Applicable Requirement (*check all that apply*): ☒ BACT ☐ LAER

<u>Please refer to Section 5 of the Application</u>

§4.12 Stack Height and Dispersion Technique Analysis (*not required for Title V Operating Permit applications*)

If applicable, supply a stack height and dispersion technique analysis demonstrating compliance with the requirements of the Stack Heights and Dispersion Technique Rule (ARM 17.8, Subchapter 4)

<u>Please refer to Section 4 of the Application for discussion of regulatory compliance</u>

Emitting Unit ID: **EU3**
Emitting Unit Name: **Cooling Tower**

§4.1 Emitting Unit Overview:

Narrative Process Equipment/Process Description (*attach additional sheets as necessary*) **See Application Section 2.**

Proposed Operational Limitations (*if any*) ____________________

Source Classification Code (SCC)/ Description: **38500101/Industrial Processes/Cooling Tower/Process Cooling/Mechanical Draft**

(*Note: SCC Codes can be found at the following website*: http://cfpub.epa.gov/oarweb/download/WebFIRESCCs.csv)

Regulatory Programs: Indicate all air pollution control programs applicable to this emitting unit:

- ☐ NSPS: 40 CFR 60, Subpart(s):
- ☐ NESHAPS: 40 CFR 61, Subpart(s):
- ☐ MACT: 40 CFR 63, Subpart(s):
- ☐ Title V Operating Permit – Significant Emitting Unit
- ☐ Acid Rain (Title IV)
- ☐ Risk Management Plan
- ☐ CAM Plan
- ☐ Other: ____________________

§4.2 Process Information (*include units*):

Type of Material Processed **HRSG Feedwater**

Average Process Rate (tons/hr, gal/hr, etc.) ____________________

Maximum Rated Design Process Rate (tons/hr, gal/hr, etc.) **28,000 gpm circulating flow, 412 gpm evaporation rate, 0.56 gpm drift flow**

§4.3 Process Identification

Make **TBD** Model **TBD**

Type **TBD** Size **TBD**

Year of Manufacture/Reconstruction **TBD** Year of Installation **TBD**

Power Source Natural Gas

If applicable, provide the following generator information:

Rated Output of the generator (kW) _______

Rated Size of Engine powering the generator (hp) _ _______

§4.4 Fuel/Combustion Information:

(For variable parameters, indicate the maximum value or a range)

Fuel Type(s) __**NA**____

Average Fuel Combustion Rate: ____________________

Maximum Rated Combustion Rate: ____________________

Heat Content (Btu rating) Sulfur Content (%) Ash Content (%)

§4.5 Emitting Unit Location

Latitude (in decimal degrees): **47.5535N** Longitude (in decimal degrees): **111.0331 W**

Datum (NAD27, NAD83, etc.): **NAD27**

§4.6 Stack Information (*if applicable*)**:**

Height (feet) **45** Inside Diameter (feet) **15**

Exit Gas Temperature (˚F) **70** Exit Gas Flow Rate (ACFM) **286292**

Exit Gas Velocity (ft/sec) **27** Exit Gas Moisture Content (%) **Unk**

Stack Type (check one):

- ☐ Downward Exit
- ☐ Multiple Actual Stacks
- ☐ Fugitive Source
- ☐ Horizontal Exit
- ☐ Building Roof Vent
- ☐ Process Vent
- ☒ Vertical Exit
- ☐ Vertical Exit with Cap

§4.7 Approximate Operating Schedule:

Hours/Day **24 hr/day** Days/Week **7 days/wk**

Hours/Year **8760 hrs/yrs** Weeks/Year **52 wks/hr**

§4.8 Air Pollution Control Equipment and Practices

Primary and Secondary Air Pollution Control Equipment and/or Procedure Description:

Primary Air Pollution Control Equipment Description:

Make **NA** Model **NA**

Type **NA** Size **NA**

Year of Manufacture **NA** Year of Installation **NA**

Fuel Type(s) Estimated Control Efficiency **NA**

Estimated Capital Equipment Cost (*not required for Title V Operating Permit applications*) _NA________

§4.9 Shakedown Procedures (*not required for Title V Operating Permit applications*)

Describe any shakedown procedures that are expected to affect emissions, including the duration of the shakedown period:

____

____

____

§4.10 Continuous Emission Monitoring System (CEMS) – *check all that apply:*

☐ Opacity – Make __________________ Model ___________ Year ____________

Automatic Calibration Valve: Zero ____________ Span ___________

☐ TRS – Make __________________ Model ___________ Year ____________

Automatic Calibration Valve: Zero ____________ Span ___________

☐ NO_x - Make __________________ Model ___________ Year ____________

Automatic Calibration Valve: Zero ____________ Span ___________

☐ CO – Make __________________ Model ___________ Year ____________

Automatic Calibration Valve: Zero ____________ Span ___________

☐ O_2 – Make __________________ Model ___________ Year ____________

Automatic Calibration Valve: Zero ____________ Span ___________

☐ CO_2 – Make __________________ Model ___________ Year ____________

Automatic Calibration Valve: Zero ____________ Span ___________

☐ Other (*specify*): ____

Make __________________ Model ___________ Year ____________

Automatic Calibration Valve: Zero ____________ Span ___________

§4.11 Emissions Control Analysis (*not required for Title V Operating permit applications*)

Best Available Control Technology (BACT) is required for all sources obtaining a MAQP. The BACT analysis should be conducted separately for each pollutant emitted from each emitting unit and must include a listing of all technologically feasible control options. Control costs (cost per ton of air pollutant controlled) should be calculated for each option. Options may then be eliminated for economic, energy or environmental reasons. The control option that is selected should have controls or control costs similar to other recently permitted similar sources and should be capable of achieving appropriate emission standards. If necessary, a separate start-up/shut-down BACT analyses should be conducted.

Lowest Achievable Emission Rate (LAER) is required for major stationary sources and major modifications located in a nonattainment area. LAER is also required for major stationary sources or major modifications located in an area designated as attainment or unclassified under 40 CFR 81.327, but would cause or contribute to a violation of the National Ambient Air Quality Standards (NAAQS) in a nearby nonattainment area. The LAER analysis shall demonstrate that the emission rate proposed is equivalent to the most stringent emission rate achievable or contained in any state implementation plan for a similar source.

Attach BACT/LAER Analysis Results, as applicable.

Applicable Requirement (*check all that apply*): ☐ BACT ☐ LAER

§4.12 Stack Height and Dispersion Technique Analysis (*not required for Title V Operating Permit applications*)

If applicable, supply a stack height and dispersion technique analysis demonstrating compliance with the requirements of the Stack Heights and Dispersion Technique Rule (ARM 17.8, Subchapter 4)

Emitting Unit ID: **EU4**
Emitting Unit Name: **Miscellaneous Building Heaters**

§4.1 Emitting Unit Overview:

Narrative Process Equipment/Process Description (*attach additional sheets as necessary*) **See Application Section 2.**_____________________________

Proposed Operational Limitations (*if any*) ____

____

Source Classification Code (SCC)/ Description: **10500106 - External Combustion Boilers/Space Heaters/Industrial/Natural Gas**

(*Note: SCC Codes can be found at the following website*: http://cfpub.epa.gov/oarweb/download/WebFIRESCCs.csv)

Regulatory Programs: Indicate all air pollution control programs applicable to this emitting unit:

- ☐ NSPS: 40 CFR 60, Subpart(s):
- ☐ NESHAPS: 40 CFR 61, Subpart(s):
- ☐ MACT: 40 CFR 63, Subpart(s):
- ☐ Title V Operating Permit – Significant Emitting Unit
- ☐ Acid Rain (Title IV)
- ☐ Risk Management Plan
- ☐ CAM Plan
- ☐ Other: ____

§4.2 Process Information (*include units*):

Type of Material Processed **NA**____

Average Process Rate (tons/hr, gal/hr, etc.) **NA**______________________________

Maximum Rated Design Process Rate (tons/hr, gal/hr, etc.) **NA**______

§4.3 Process Identification

Make **TBD** Model **TBD**

Type **TBD** Size **TBD**

Year of Manufacture/Reconstruction **TBD** Year of Installation **TBD**

Power Source **Natural Gas**

If applicable, provide the following generator information:

Rated Output of the generator (kW) _______

Rated Size of Engine powering the generator (hp) ________

§4.4 Fuel/Combustion Information:

(For variable parameters, indicate the maximum value or a range)

Fuel Type(s) __**Natural Gas**______________________________

Average Fuel Combustion Rate: **NA**____________________

Maximum Rated Combustion Rate: **<2.8 MMBtu/hr**____________________

Heat Content (Btu rating) **1000 Btu/scf** Sulfur Content (%) **0.5 gr/dscf** Ash Content (%) NA

§4.5 Emitting Unit Location

Latitude (in decimal degrees): **Various (See application Section 6)** Longitude (in decimal degrees): **Various (See application Section 6)**

Datum (NAD27, NAD83, etc.): **NAD27**

§4.6 Stack Information (*if applicable*)**:**

Height (feet) Various **(See application Section 6)** Inside Diameter (feet) **Various**

Exit Gas Temperature (˚F) **550** Exit Gas Flow Rate (ACFM) **Various**

Exit Gas Velocity (ft/sec) **Various** Exit Gas Moisture Content (%) **Unk**

Stack Type (check one):

☐ Downward Exit ☐ Multiple Actual Stacks ☐ Fugitive Source

☐ Horizontal Exit ☐ Building Roof Vent ☐ Process Vent

☒ Vertical Exit ☐ Vertical Exit with Cap

§4.7 Approximate Operating Schedule:

Hours/Day **24 hr/day** Days/Week **7 days/wk**

Hours/Year **8760 hrs/yrs** Weeks/Year **52 wks/hr**

§4.8 Air Pollution Control Equipment and Practices

Primary and Secondary Air Pollution Control Equipment and/or Procedure Description:

Primary Air Pollution Control Equipment Description:

Make **NA** Model **NA**

Type **NA** Size **NA**

Year of Manufacture **NA** Year of Installation **NA**

Fuel Type(s) Estimated Control Efficiency **NA**

Estimated Capital Equipment Cost (*not required for Title V Operating Permit applications*) _**NA**________

§4.9 Shakedown Procedures (*not required for Title V Operating Permit applications*)

Describe any shakedown procedures that are expected to affect emissions, including the duration of the shakedown period:

____
____
____

§4.10 Continuous Emission Monitoring System (CEMS) – *check all that apply:*

☐ Opacity – Make __________________ Model ___________ Year ____________

Automatic Calibration Valve: Zero ____________ Span ___________

☐ TRS – Make __________________ Model ___________ Year ____________

Automatic Calibration Valve: Zero ____________ Span ___________

☐ NO_x - Make __________________ Model ___________ Year ____________

Automatic Calibration Valve: Zero ____________ Span ___________

☐ CO – Make __________________ Model ___________ Year ____________

Automatic Calibration Valve: Zero ____________ Span ___________

☐ O_2 – Make __________________ Model ___________ Year ____________

Automatic Calibration Valve: Zero ____________ Span ___________

☐ CO_2 – Make __________________ Model ___________ Year ____________

Automatic Calibration Valve: Zero ____________ Span ___________

☐ Other (*specify*): ____

Make __________________ Model ___________ Year ____________

Automatic Calibration Valve: Zero ____________ Span ___________

§4.11 Emissions Control Analysis (*not required for Title V Operating permit applications*)

Best Available Control Technology (BACT) is required for all sources obtaining a MAQP. The BACT analysis should be conducted separately for each pollutant emitted from each emitting unit and must include a listing of all technologically feasible control options. Control costs (cost per ton of air pollutant controlled) should be calculated for each option. Options may then be eliminated for economic, energy or environmental reasons. The control option that is selected should have controls or control costs similar to other recently permitted similar sources and should be capable of achieving appropriate emission standards. If necessary, a separate start-up/shut-down BACT analyses should be conducted.

Lowest Achievable Emission Rate (LAER) is required for major stationary sources and major modifications located in a nonattainment area. LAER is also required for major stationary sources or major modifications located in an area designated as attainment or unclassified under 40 CFR 81.327, but would cause or contribute to a violation of the National Ambient Air Quality Standards (NAAQS) in a nearby nonattainment area. The LAER analysis shall demonstrate that the emission rate proposed is equivalent to the most stringent emission rate achievable or contained in any state implementation plan for a similar source.

Attach BACT/LAER Analysis Results, as applicable.

Applicable Requirement (*check all that apply*): ☐ BACT ☐ LAER

§4.12 Stack Height and Dispersion Technique Analysis (*not required for Title V Operating Permit applications*)

If applicable, supply a stack height and dispersion technique analysis demonstrating compliance with the requirements of the Stack Heights and Dispersion Technique Rule (ARM 17.8, Subchapter 4)

Emitting Unit ID: **EU5**
Emitting Unit Name: **Black Start Emergency Generator**

§4.1 Emitting Unit Overview:

Narrative Process Equipment/Process Description (*attach additional sheets as necessary*) **See Application Section 2.** ______________________________

Proposed Operational Limitations (*if any*) ____

____

Source Classification Code (SCC)/ Description: **20100102 - Internal Combustion Engines/Electric Generation/Distillate Oil (Diesel)/Reciprocating**

(*Note: SCC Codes can be found at the following website*: http://cfpub.epa.gov/oarweb/download/WebFIRESCCs.csv)

Regulatory Programs: Indicate all air pollution control programs applicable to this emitting unit:

- ☒ NSPS: 40 CFR 60, Subpart(s): (**See application Section 4)**
- ☐ NESHAPS: 40 CFR 61, Subpart(s): (**See application Section 4)**
- ☐ MACT: 40 CFR 63, Subpart(s): (**See application Section 4)**
- ☒ Title V Operating Permit – Significant Emitting Unit
- ☐ Acid Rain (Title IV)
- ☐ Risk Management Plan
- ☐ CAM Plan
- ☐ Other: ____

§4.2 Process Information (*include units*):

Type of Material Processed **NA** ____

Average Process Rate (tons/hr, gal/hr, etc.) **NA** ______________________________

Maximum Rated Design Process Rate (tons/hr, gal/hr, etc.) **NA** ______

§4.3 Process Identification

Make **TBD** Model **TBD**

Type **TBD** Size **TBD**

Year of Manufacture/Reconstruction **TBD** Year of Installation **TBD**

Power Source **Distillate Fuel Oil**

If applicable, provide the following generator information:

Rated Output of the generator (kW) **1500 kW (net)**_______

Rated Size of Engine powering the generator (hp) _**approx 2500 hp** _______

§4.4 Fuel/Combustion Information:

(For variable parameters, indicate the maximum value or a range)

Fuel Type(s) __**Distillate Fuel Oil**____

Average Fuel Combustion Rate: **NA**____________________

Maximum Rated Combustion Rate: **14.57 MMBtu/hr**____________________

Heat Content (Btu rating) **Various** Sulfur Content (%) **0.05%** Ash Content (%) **NA**

§4.5 Emitting Unit Location

Latitude (in decimal degrees): **47.5516N** Longitude (in decimal degrees): **111.0345 W**

Datum (NAD27, NAD83, etc.): **NAD27**

§4.6 Stack Information (*if applicable*)**:**

Height (feet) **35** Inside Diameter (feet) **2.5**

Exit Gas Temperature (˚F) **763.5** Exit Gas Flow Rate (ACFM) **11060**

Exit Gas Velocity (ft/sec) **37.55** Exit Gas Moisture Content (%) **Unk**

Stack Type (check one):

- ☐ Downward Exit
- ☐ Multiple Actual Stacks
- ☐ Fugitive Source
- ☐ Horizontal Exit
- ☐ Building Roof Vent
- ☐ Process Vent
- ☒ Vertical Exit
- ☐ Vertical Exit with Cap

§4.7 Approximate Operating Schedule:

Hours/Day **24 hr/day** Days/Week **7 days/wk**

Hours/Year **500 hrs/yr** Weeks/Year

§4.8 Air Pollution Control Equipment and Practices

Primary and Secondary Air Pollution Control Equipment and/or Procedure Description:

Primary Air Pollution Control Equipment Description:

Make **NA** Model **NA**

Type **NA** Size **NA**

Year of Manufacture **NA** Year of Installation **NA**

Fuel Type(s) Estimated Control Efficiency **NA**

Estimated Capital Equipment Cost (*not required for Title V Operating Permit applications*) _**NA**________

§4.9 Shakedown Procedures (*not required for Title V Operating Permit applications*)

Describe any shakedown procedures that are expected to affect emissions, including the duration of the shakedown period:

____
____
____

§4.10 Continuous Emission Monitoring System (CEMS) – *check all that apply:*

☐ Opacity – Make __________________ Model ___________ Year ____________

Automatic Calibration Valve: Zero ____________ Span ___________

☐ TRS – Make __________________ Model ___________ Year ____________

Automatic Calibration Valve: Zero ____________ Span ___________

☐ NO_x - Make __________________ Model ___________ Year

Automatic Calibration Valve: Zero ____________ Span ___________

☐ CO – Make __________________ Model ___________ Year ____________

Automatic Calibration Valve: Zero ____________ Span ___________

☐ O_2 – Make __________________ Model ___________ Year ____________

Automatic Calibration Valve: Zero ____________ Span ___________

☐ CO_2 – Make __________________ Model ___________ Year ____________

Automatic Calibration Valve: Zero ____________ Span ___________

☐ Other (*specify*): ____

Make __________________ Model ___________ Year ____________

Automatic Calibration Valve: Zero ____________ Span ___________

§4.11 Emissions Control Analysis (*not required for Title V Operating permit applications*)

Best Available Control Technology (BACT) is required for all sources obtaining a MAQP. The BACT analysis should be conducted separately for each pollutant emitted from each emitting unit and must include a listing of all technologically feasible control options. Control costs (cost per ton of air pollutant controlled) should be calculated for each option. Options may then be eliminated for economic, energy or environmental reasons. The control option that is selected should have controls or control costs similar to other recently permitted similar sources and should be capable of achieving appropriate emission standards. If necessary, a separate start-up/shut-down BACT analyses should be conducted.

Lowest Achievable Emission Rate (LAER) is required for major stationary sources and major modifications located in a nonattainment area. LAER is also required for major stationary sources or major modifications located in an area designated as attainment or unclassified under 40 CFR 81.327, but would cause or contribute to a violation of the National Ambient Air Quality Standards (NAAQS) in a nearby nonattainment area. The LAER analysis shall demonstrate that the emission rate proposed is equivalent to the most stringent emission rate achievable or contained in any state implementation plan for a similar source.

Attach BACT/LAER Analysis Results, as applicable.

Applicable Requirement (*check all that apply*): ☒ BACT ☐ LAER

<u>Please refer to Section 5 of the Application</u>

§4.12 Stack Height and Dispersion Technique Analysis (*not required for Title V Operating Permit applications*)

If applicable, supply a stack height and dispersion technique analysis demonstrating compliance with the requirements of the Stack Heights and Dispersion Technique Rule (ARM 17.8, Subchapter 4)

<u>Please refer to Section 4 of the Application for discussion of regulatory compliance</u>

Emitting Unit ID: **EU6**
Emitting Unit Name: **Firepump**

§4.1 Emitting Unit Overview:

Narrative Process Equipment/Process Description (*attach additional sheets as necessary*) **See Application Section 2.**

Proposed Operational Limitations (*if any*) ____

Source Classification Code (SCC)/ Description: **20300101 - Internal Combustion Engines/Commercial/Institutional/Distillate Oil (Diesel)/Reciprocating**

(*Note: SCC Codes can be found at the following website*: http://cfpub.epa.gov/oarweb/download/WebFIRESCCs.csv)

Regulatory Programs: Indicate all air pollution control programs applicable to this emitting unit:

- ☒ NSPS: 40 CFR 60, Subpart(s): (**See application Section 4)**
- ☐ NESHAPS: 40 CFR 61, Subpart(s):
- ☐ MACT: 40 CFR 63, Subpart(s):
- ☒ Title V Operating Permit – Significant Emitting Unit
- ☐ Acid Rain (Title IV)
- ☐ Risk Management Plan
- ☐ CAM Plan
- ☐ Other: __________________________________

§4.2 Process Information (*include units*):

Type of Material Processed _**NA**__________________________________

Average Process Rate (tons/hr, gal/hr, etc.) __**NA**____________________________

Maximum Rated Design Process Rate (tons/hr, gal/hr, etc.) _**NA**______

§4.3 Process Identification

Make **TBD** Model **TBD**

Type **TBD** Size **TBD**

Year of Manufacture/Reconstruction **TBD** Year of Installation **TBD**

Power Source **Distillate Fuel Oil**

If applicable, provide the following generator information:

Rated Output of the generator (kW) _______

Rated Size of Engine powering the generator (hp) _**approx 300 hp** _______

§4.4 Fuel/Combustion Information:

(For variable parameters, indicate the maximum value or a range)

Fuel Type(s) __**Distillate Fuel Oil**____

Average Fuel Combustion Rate: **NA**____________________

Maximum Rated Combustion Rate: **2.51 MMBtu/hr**____________________

Heat Content (Btu rating) **Various** Sulfur Content (%) **0.05%** Ash Content (%) **NA**

§4.5 Emitting Unit Location

Latitude (in decimal degrees): **47.5520N** Longitude (in decimal degrees): **111.0474 W**

Datum (NAD27, NAD83, etc.): **NAD27**

§4.6 Stack Information (*if applicable*)**:**

Height (feet) **25** Inside Diameter (feet) **1.25**

Exit Gas Temperature (˚F) **1032** Exit Gas Flow Rate (ACFM) **2055**

Exit Gas Velocity (ft/sec) **27.9** Exit Gas Moisture Content (%) **Unk**

Stack Type (check one):

- ☐ Downward Exit
- ☐ Multiple Actual Stacks
- ☐ Fugitive Source
- ☐ Horizontal Exit
- ☐ Building Roof Vent
- ☐ Process Vent
- ☒ Vertical Exit
- ☐ Vertical Exit with Cap

§4.7 Approximate Operating Schedule:

Hours/Day **24 hr/day** Days/Week **7 days/wk**

Hours/Year **500 hrs/yr** Weeks/Year

§4.8 Air Pollution Control Equipment and Practices

Primary and Secondary Air Pollution Control Equipment and/or Procedure Description:

Primary Air Pollution Control Equipment Description:

Make **NA** Model **NA**

Type **NA** Size **NA**

Year of Manufacture **NA** Year of Installation **NA**

Fuel Type(s) Estimated Control Efficiency **NA**

Estimated Capital Equipment Cost (*not required for Title V Operating Permit applications*) _**NA**________

§4.9 Shakedown Procedures (*not required for Title V Operating Permit applications*)

Describe any shakedown procedures that are expected to affect emissions, including the duration of the shakedown period:

____

____

____

§4.10 Continuous Emission Monitoring System (CEMS) – *check all that apply:*

☐ Opacity – Make __________________ Model ___________ Year ____________

Automatic Calibration Valve: Zero ____________ Span ___________

☐ TRS – Make __________________ Model ___________ Year ____________

Automatic Calibration Valve: Zero ____________ Span ___________

☐ NO_x - Make __________________ Model ___________ Year

Automatic Calibration Valve: Zero ____________ Span ___________

☐ CO – Make __________________ Model ___________ Year ____________

Automatic Calibration Valve: Zero ____________ Span ___________

☐ O_2 – Make __________________ Model ___________ Year ____________

Automatic Calibration Valve: Zero ____________ Span ___________

☐ CO_2 – Make __________________ Model ___________ Year ____________

Automatic Calibration Valve: Zero ____________ Span ___________

☐ Other (*specify*): ____

Make __________________ Model ___________ Year ____________

Automatic Calibration Valve: Zero ____________ Span ___________

§4.11 Emissions Control Analysis (*not required for Title V Operating permit applications*)

Best Available Control Technology (BACT) is required for all sources obtaining a MAQP. The BACT analysis should be conducted separately for each pollutant emitted from each emitting unit and must include a listing of all technologically feasible control options. Control costs (cost per ton of air pollutant controlled) should be calculated for each option. Options may then be eliminated for economic, energy or environmental reasons. The control option that is selected should have controls or control costs similar to other recently permitted similar sources and should be capable of achieving appropriate emission standards. If necessary, a separate start-up/shut-down BACT analyses should be conducted.

Lowest Achievable Emission Rate (LAER) is required for major stationary sources and major modifications located in a nonattainment area. LAER is also required for major stationary sources or major modifications located in an area designated as attainment or unclassified under 40 CFR 81.327, but would cause or contribute to a violation of the National Ambient Air Quality Standards (NAAQS) in a nearby nonattainment area. The LAER analysis shall demonstrate that the emission rate proposed is equivalent to the most stringent emission rate achievable or contained in any state implementation plan for a similar source.

Attach BACT/LAER Analysis Results, as applicable.

Applicable Requirement (*check all that apply*): ☒ BACT ☐ LAER

<u>Please refer to Section 5 of the Application</u>

§4.12 Stack Height and Dispersion Technique Analysis (*not required for Title V Operating Permit applications*)

If applicable, supply a stack height and dispersion technique analysis demonstrating compliance with the requirements of the Stack Heights and Dispersion Technique Rule (ARM 17.8, Subchapter 4)

<u>Please refer to Section 4 of the Application for discussion of regulatory compliance</u>

§ 5.0 Project and Site Information

Note: This section is not required to be completed for Title V Operating Permit applications.

Identify the landowner of the proposed project site and the current land use (industrial, agricultural, residential, etc.): **_ See Appendix G of application**

Indicate the approximate distance to the nearest home and/or structure not associated with the proposed project site: **__ See Appendix G of application**

Summarize the aesthetic character of the proposed project site and the surrounding community or neighborhood. Include a description of recreational opportunities and any unique cultures in the area that may be affected by the proposed project:
__ See Appendix G of application

Describe the noise levels created by the proposed project: **__ See Appendix G of application**

Summarize other industrial activities at or near the site: **__ See Appendix G of application**

List other permits and/or approvals which have been obtained or will be obtained for this project (including MPDES permits, open cut permit, hazardous waste permit, etc.): **_ See Appendix G of application**

Indicate the number of employees currently employed and the increase or decrease in the number of people employed at this site as a result of the proposed project: _ See Appendix G of application

Describe any upgrades of utilities that may be necessary to meet the power demands for this proposed project: **_ See Appendix G of application**

Identify the amount of land that will be disturbed, in acres, as a result of this proposed project: **_ See Appendix G of application ________**

Identify any fish or wildlife habitat, animal or bird species, or any known migration or movement of animals at the project site: **_ See Appendix G of application**

Identify any plant species (including types of trees, shrubs, grasses, crops, and aquatic plants) at the proposed project site: **_ See Appendix G of application**

Describe any proposed discharges into surface water or onto the proposed project site: **_ See Appendix G of application**

Identify any potential impacts to wetlands and/or changes in the drainage patterns at the proposed project site: **_ See Appendix G of application**

Summarize the soils and geology of the project site. Include a description of any disruption, displacement, erosion, compaction, moisture loss, or over-covering of soil that would reduce the productivity or fertility of the soil at the site: **_ See Appendix G of application**

Summarize any access to recreational activities or wilderness areas near the proposed project site: **_ See Appendix G of application**

Describe any state, county, city, United States Forest Service (USFS), Bureau of Land Management (BLM), or tribal zoning or management plans and/or goals that might affect the site: **_ See Appendix G of application**

§ 6.0 Instructions on Public Notice For Montana Air Quality Permit

Note: This section is not required to be completed for Title V Operating Permit applications.

The applicant shall publish the following notification no earlier than 10 days prior to the date the applicant's MAQP application will be submitted to the Department, and no later than 10 days following the date of submittal. The notice shall be published **once** in the legal notice section of a newspaper of general circulation in the area affected. (*Note: MAQP applications for solid waste incinerators, subject to 75-10-221, Montana Code Annotated (MCA), or hazardous waste incinerators or boilers or industrial furnaces, subject to 75-10-406, MCA, must publish **three** public notices, each on separate days, in the legal notice section of a newspaper in the county in which the source is proposed be located.*) Any fees associated with publication of this notice are the responsibility of the permit applicant. Questions regarding an appropriate newspaper should be addressed to the Department.

An Affidavit of Publication of Public Notice must be submitted with the application or the permit application will be deemed incomplete. This notice is required by the air quality rules. **The notice to be published must contain all text, excluding the text in italics, within the box below.**

Public Notice

Notice of Application for a Montana Air Quality Permit (MAQP), pursuant to Sections 75-2-211 and 75-2-215, MCA, and the Air Quality Rules). **Southern Montana Electric Generation and Transmission Cooperative, Inc.**

Name of Applicant(s)

has filed on or about **04/24/2009** an application for a modification to an

has filed / will file *Date*

existing MAQP from the Montana Department of Environmental Quality. Applicant(s) seeks approval of its application for:

the construction of a combined cycle combustion turbine electric generation facility located near Great Falls, Cascade County, Montana. The facility will have the capacity to nominally produce 120 MW of electricity firing natural gas.

(Brief description of source for which permit is being applied, and a narrative description of the site location such as nearby towns, roads, landmarks, etc.)

The legal description of the site is: Section **24 and 25,** Township **21N,** Range **5E** in **Cascade** County, Montana.

Within 40 days of the receipt of a completed application, the Department will make a preliminary determination whether the permit should be issued, issued with conditions, or denied. Any member of the public with questions or who wishes to receive notice of the preliminary determination, and the location where a copy of the application and the Department's analysis of it can be reviewed, or to submit comments on the preliminary determination, must contact the Department at Department of Environmental Quality, Air Resources Management Bureau, Air Permitting Section Supervisor at P.O. Box 200901, Helena, MT 59620-0901, telephone (406) 444-3490. Any comments on the preliminary determination must be submitted to the Department within the specified timeframe (within 15 or 30 days after the preliminary determination is issued).

§ 7.0 Applicable Requirements

§7.1 Applicable Requirements

Attach a complete listing and description of all applicable air pollution control requirements, including rules and regulations which have been promulgated at the time of the submittal of the application, but which will become effective at a later date. Explain any proposed exemptions from otherwise applicable requirements. Describe or reference any applicable test methods for determining compliance with each applicable requirement.

§7.2 Additional Requirements

Additional requirements may apply. A description of the requirements listed below is included in the Section 7.2 Supplement included on page 16 of this application. **Note which of the following requirements apply to this permit application** (*check each that applies*):

☒ Ambient Air Quality Impact Analysis

☐ Alternative Siting Analysis

☐ Alternative Operating Scenario

☐ Compliance Schedule/Plan

☐ Compliance Certification

☐ Additional Requirements for solid or hazardous waste incinerators or BIFS subject to 75-10-406, MCA

☐ Additional Requirements for Commercial Medical and Commercial Hazardous Waste Incinerators, including BIFS Subject to 75-10-406, MCA

§ 8.0 Certification of Truth, Accuracy, and Completeness

I hereby certify that, to the best of my knowledge, information and belief, formed after reasonable inquiry, the information provided in this permit application is true, accurate, and complete.

(Name, title and signature of corporate officer, responsible official, authorized representative, or designated representative under Title IV 1990 FCAA.)

Name: **Tim Gregori**
(Print or Type)

Title: **Manager** Phone: **406-294-9527** Email: **gregori@mcn.net**

Signature T-R. Gr— Date **04/24/2009**
(Original Signature Required)

APPLICATION CHECKLIST

The following information must be submitted in order for the application to be considered complete. Additional information may be required by the Department. Please contact the Department if there are any questions or if the applicant would like a pre-application meeting with Department personnel.

___**x**___ Completed Application Form
___**x**___ Application Fee
___**x**___ Site Map (Not required for Title V Operating Permit applications)
___**x**___ Process Flow Diagram (Not required for Title V Operating Permit applications)
___**x**___ Emission Inventory Calculations
___**x**___ BACT/LAER Analysis (Not required for Title V Operating Permit applications)
___**x**___ Stack Height and Dispersion Techniques Analysis (if applicable, not required for Title V Operating Permit applications)
___**x**___ Modeling/Risk Assessment Analysis (if applicable, not required for Title V Operating Permit applications)
___**x**___ List of Applicable Requirements
___**x**___ Affidavit of Public Notice (Not required for Title V Operating permit applications)
___**x**___ Certification of Truth, Accuracy, and Completeness – Original Signature (if application form is submitted electronically)

Supplement to Section 7.2 Additional Requirements

- **Ambient Air Quality Impact Analysis** (Not required for Title V Operating Permit applications)

  An ambient air quality impact analysis should include the following:

  1. Existing Air Quality Status – a narrative description of the existing air quality status and copies of any existing air monitoring data reports or dispersion modeling.
  2. Ambient Air Quality Monitoring Requirements – a listing and description of all applicable state or federal ambient air quality monitoring requirements and a detailed description of any proposed ambient air monitoring.
  3. Ambient Air Quality Dispersion Modeling – a description and results of all required ambient air quality dispersion modeling.
  4. Air Quality Related Values Analysis – an analysis of the impairment to visibility, soils, and vegetation that would occur as a result of the source or modification and general commercial, residential, industrial, and other growth associated with the source or modification. (Only required for PSD permit applications.)
  5. Visibility Analysis – a demonstration that emissions from the source will not cause or contribute to an adverse impact on visibility within a federal Class 1 area and that the source is in compliance with the requirements of the Visibility Impact Assessment rules. (Only required for PSD permit applications.)
  6. PSD Increment Analysis – a demonstration of compliance with PSD ambient air increments. (Only required for PSD permit applications.)

- **Alternative Siting Analysis** (Not required for Title V Operating Permit applications.)

  An analysis of alternative sites, sizes, production processes, and environmental control techniques for the proposed source which demonstrates that benefits of the proposed source significantly outweigh the environmental and social costs imposed as a result of its location, construction or modification. This analysis is only required for major stationary sources and major modifications located in a nonattainment area, or for major stationary sources or major modifications located in an area designated as attainment or unclassified under 40 CFR 81.327, but would cause or contribute to a violations of NAAQS in a nearby nonattainment area (i.e., for those sources required to obtain an MAQP and comply with the requirements of subchapters 9 and 10 of the air quality rules).

- **Alternative Operating Scenarios** (Not required for MAQP applications)

  Sufficient information, as necessary, to define any reasonably anticipated alternative operating scenarios included in the Title V Operating Permit, including location, process, regulatory, and emission data.

- **Compliance Schedule/Plan** (Not required for MAQP applications. Only required for Title V Operating Permit applications for sources already operating.)

  The Compliance Schedule/Plan must include, at a minimum, a description of the compliance status of the source with respect to all applicable requirements, as follows:

  a. For applicable requirements that the source is currently in compliance with, a description of how compliance will be maintained, including a statement that the source will continue to comply with applicable requirements with which it is in compliance;
  b. For applicable requirements that will become effective during the permit term, a statement that the source will (in a timely manner) comply with all applicable requirements that become effective during the permit term, including rules and regulations which have been promulgated at the time of the submittal of the application, but which will become effective at a later date, and a schedule for complying with the applicable requirements; and
  c. For applicable requirements that the source is not currently in compliance with, a narrative description of how the source will (in a timely manner) achieve compliance with all applicable requirements with which the source is not currently in compliance. The compliance schedule shall also include a schedule of measures, including an enforceable sequence of actions with milestones, leading to compliance with all requirements. The compliance schedule shall resemble and be at least as stringent as that contained in any judicial consent decree or administrative order to which the source is subject. The schedule for submission of certified progress reports shall be no less frequent than once very six months.

The Compliance Schedule content requirements apply to Title IV (acid rain) sources, except as specifically superseded by 40 CFR Part 72 with regard to the schedule and the methods the source will use to achieve compliance with the acid rain emission limitations.

- **Compliance Certification**

  The following certifications must be submitted:

  1. Certification of compliance with all applicable requirements signed by a responsible official; except, in the case of an affected source under the acid rain program, the designated representative of the source shall make this certification. (Not required for MAQP applications.)
  2. A statement of methods used for determining compliance, including a description of the monitoring, recordkeeping, reporting requirements, and test methods. (Not required for MAQP applications. Only required for Title V Operating Permit applications for sources already operating).
  3. A proposed schedule for submitting compliance certifications that is no less than annually during the permit term. (Not required for MAQP applications. Only required for Title V Operating Permit applications for sources already operating).
  4. Certification that all sources owned by the applicant are in compliance with all applicable rules and regulations. (Not required for Title V Operating Permit applications. Only required for PSD permit applications).

- **Additional Requirements for Solid and Hazardous Waste Incinerators or BIFs Subject to 75-10-406, MCA** (Not required for Title V Operating Permit applications. Only required for MAQP applications for Solid or Hazardous Waste Incinerators or Boilers and Industrial Furnaces (BIFs) subject to 75-10-406, MCA.)

  The following information must be submitted:

  1. A health risk assessment showing that the projected emissions and ambient concentrations will constitute a negligible risk to the public health, safety, and welfare and to the environment. That health risk assessment will include evaluation of cumulative risk both to the human health and the environment through all known exposure pathways.
  2. A BACT analysis for all air pollutants, including hazardous air pollutants (HAPs).

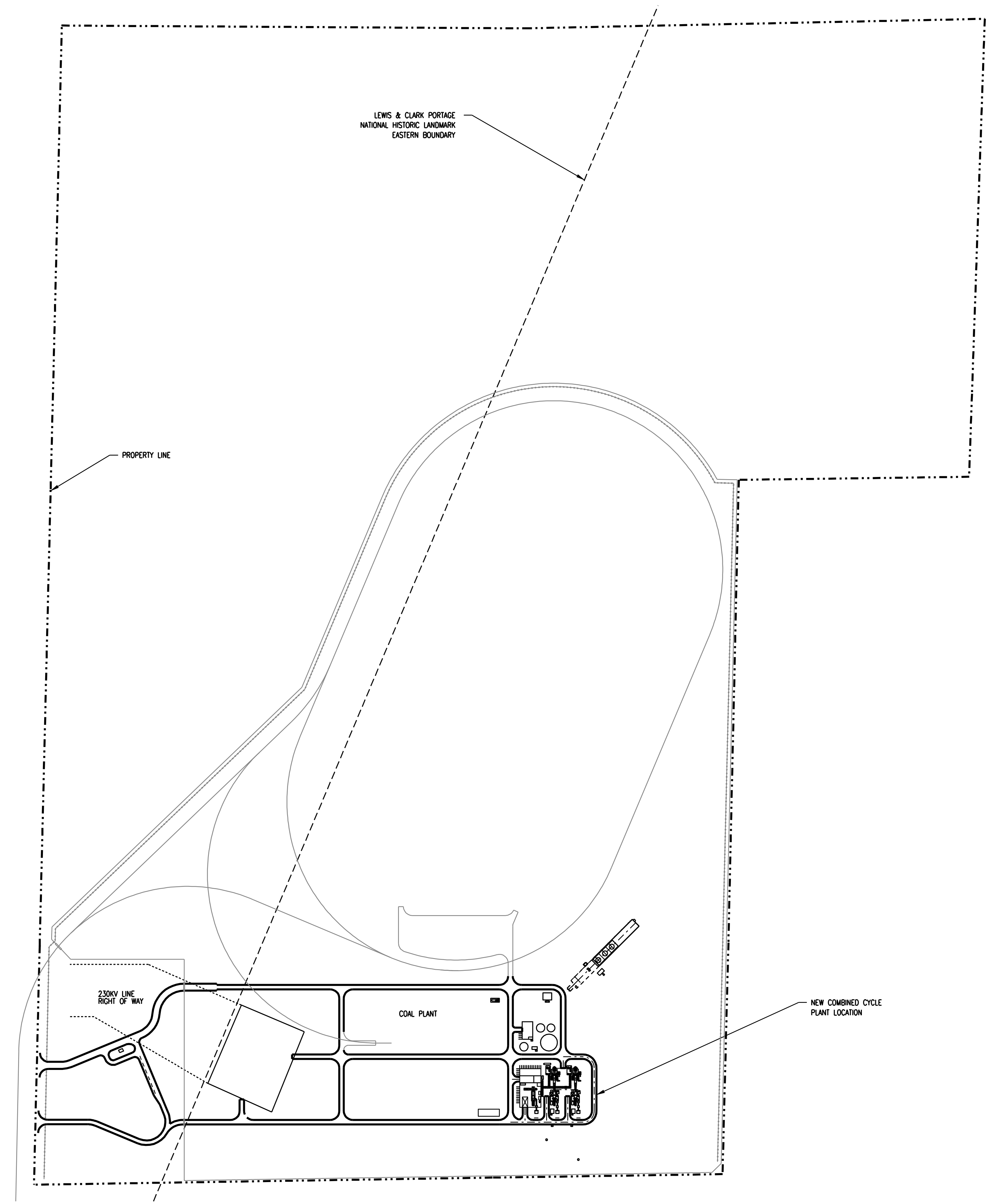
3. Three public notices, the form for which is included with the application form, must be published in a newspaper of general circulation in the county where the source is to be located (Section 6 of the permit applications).
4. Ambient air quality impact analysis that describes the ambient impact of all air pollutants including HAPs.

- **Additional requirements for Commercial Medial and Commercial Hazardous Waste Incinerators, Including BIFs Subject to 75-10-406 MCA** (Not required for Title V Operating Permit applications.)

  The following information must be submitted:

1. A complete description of all the types, amounts, and sources of chlorinated plastics and other materials included in the waste stream that may be a source of, or lead to the creation of chlorinated dioxins, furans, heavy metals, or carcinogens.
2. A LAER analysis, unless BACT is adequate to prevent exceedance of the applicable federal standards.
3. A listing and demonstration of compliance with the applicable federal standards.
4. Compliance disclosure statement containing the following information:
   a. The name, business address, and social security number of the applicant and each principal.
   b. A description of any civil or administrative complaint filed within the five years prior to the submittal of the application against the applicant or any principal for violation of an environmental protection law in Montana and whether the complaint resulted in a civil or administrative penalty.
   c. A description of all judgements of criminal conviction entered against the applicant, or any principal, for the violation of an environmental protection law in another state the five years prior to the submittal of the application that resulted from the operation of a BIF that, if located in Montana, would be subject to the requirements of 75-10-406, MCA.

APPENDIX B: PLANT LAYOUT AND DESIGN DATA



PRELIMINARY ISSUE FOR REVIEW
NOT FOR CONSTRUCTION 04/15/09

NO.	REVISIONS	DSGN	CHKD	APVD	DATE

Stanley Consultants INC.

9200 East Mineral Avenue, Suite 400, Englewood, Colorado 80112-3416
www.stanleyconsultants.com

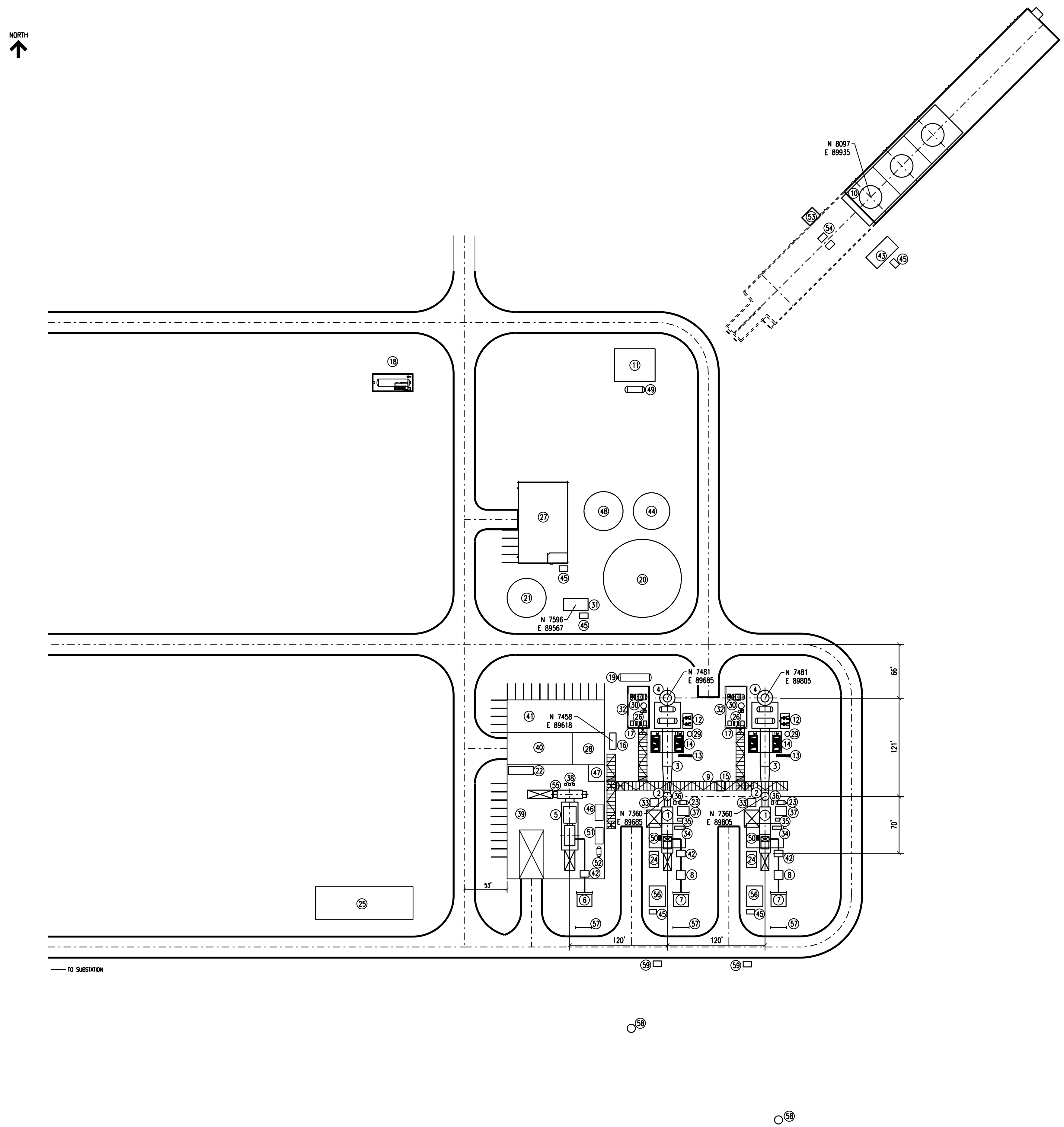
SME
Electric Generation & Transmission Cooperative, Inc.

HIGHWOOD GENERATING STATION
COMBINED CYCLE PLANT
GREAT FALLS, MONTANA

GENERAL ARRANGEMENT
OVERALL SITE PLAN
AIR PERMIT

DESIGNED	C. MOORE
DRAWN	M. McGINNIS
CHECKED	M. PAYNE
APPROVED	
APPROVED	K. CAVANAUGH
DATE	04/15/09

SCALE: 1" = 250'-0"
PROJ_NO. 21920
REV.
SK90-102



LEGEND

1. GAS TURBINE GENERATOR
* 2. SIMPLE CYCLE STACK
3. HRSG
* 4. COMBINED CYCLE STACK
5. STEAM TURBINE GENERATOR
6. STG GSU
7. GTG GSU
8. UNIT AUX TRANSFORMER
9. PIPE RACK
* 10. COOLING TOWER
11. FUEL GAS COMPRESSOR AREA
12. HRSG – AMMONIA SKID
13. HRSG – BURNER SKID
14. HRSG – STAIR TOWER
15. CEMS ENCLOSURE
* 16. STANDBY DIESEL GENERATOR
17. BOILER FEED PUMPS
18. AMMONIA STORAGE
19. OIL / WATER SEPARATOR
20. SERVICE WATER TANK
21. DEMINERALIZED WATER TANK
22. AIR COMPRESSOR SKID
23. WATER WASH DRAIN TANK
24. GAS TURBINE PEECC
25. WAREHOUSE
26. LP ECONOMIZER RECIRC PUMPS
27. WATER TREATMENT BUILDING
28. ELECTRICAL ROOM
29. BLOWDOWN TANK
30. CHEMICAL FEED EQUIPMENT
* 31. FIRE WATER PUMP HOUSE
32. BOILER FEEDWATER PUMP BUILDING
33. GTG – FIN FAN COOLER
34. GTG – NOX WATER INJECTION SYSTEM
35. GTG – SPRINT SKID
36. GTG – EVAP COOLER SKID
37. GTG – AUX SKID
38. CONDENSATE PUMPS
39. STG BUILDING
40. MAINTENANCE AREA
41. ADMIN – CONTROL AREA
42. GENERATOR BREAKER
43. COOLING TOWER PDC BUILDING
44. CLARIFIER
45. SUS TRANSFORMERS
46. LUBE OIL SKID
47. LABORATORY
48. RAW WATER TANK
49. HYDROCARBON DRAINS TANK
50. CO2 FIRE SUPPRESSION SYSTEM
51. VACUUM PUMP SKIDS
52. GLAND SEAL CONDENSER
53. COOLING TOWER CHEMICAL FEED
54. CIRCULATING WATER PUMPS
55. CONDENSER
56. SWITCHGEAR PDC BLDG
57. DEAD-END STRUCTURE
58. 230KV TRANSMISSION POLE
59. DISTRIBUTION TRANSFORMER

* = EMISSION POINTS

PRELIMINARY ISSUE FOR REVIEW
NOT FOR CONSTRUCTION 04/20/09

NO.	REVISIONS	DSGN	CHKD	APVD	DATE

Stanley Consultants INC.

9200 East Mineral Avenue, Suite 400, Englewood, Colorado 80112-3416
www.stanleyconsultants.com

SME
Electric Generation & Transmission Cooperative, Inc.

HIGHWOOD GENERATING STATION
COMBINED CYCLE PLANT
GREAT FALLS, MONTANA

GENERAL ARRANGEMENT
SITE PLAN
AIR PERMIT

DESIGNED C. MOORE
DRAWN M. McGINNIS
CHECKED M. PAYNE
APPROVED
APPROVED K. CAVANAUGH
DATE 04/15/09

SCALE: 1" = 50'-0"
PROJ_NO. 21920
REV.
SK90-101

ITEM #	DESCRIPTION	QUANTITY	WIDTH	LENGTH	HEIGHT / DEPTH = (D)
1	COMBUSTION TURBINE GENERATOR	2	20'	70'	43'
2	SIMPLE CYCLE STACK	2	10' Ø	-	80'
3	HRSG	2	20'	121'	70'
4	COMBINED CYCLE STACK	2	10" Ø	-	105'
5	STEAM TURBINE	1	75	40'	20' (inside #39)
6	STG GSU	1	18'	15'	20'
7	CTG GSU	2	18'	15'	20'
8	UNIT AUX TRANSFORMER	2	11'	11'	13'
9	PIPE RACK	total	12'	387'	20'
10	COOLING TOWER	1	60'	220'	45'
11	FUEL GAS COMPRESSOR AREA	1	50'	40'	15'
12	HRSG - AMMONIA SKID	2	11'	18'	12'
13	HRSG - BURNER SKID	2	16'	4'	8'
14	HRSG - STAIR TOWER	2	40'	25'	61'
15	CEMS ENCLOSURE	2	14'	18'	10'
16	STANDBY DIESEL GENERATOR	1	5'	13'	10'
17	BOILER FEED PUMPS	2	4'	6'	SEE ITEM #32
18	AMMONIA STORAGE	1	50'	22'	40'
19	OIL WATER SEPARATOR	1	10' Ø	40'	20' (D)
20	SERVICE WATER TANK	1	70' Ø	-	50'
21	DEMINERALIZED WATER TANK	1	30' Ø	-	40'
22	AIR COMPRESSOR SKID	1	30'	10'	SEE ITEM #39
23	WATER WASH DRAIN TANK	2	5' Ø	12'	10' (D)
24	GAS TURBINE CONTROL MODULE	2	12'	20'	12'
25	WAREHOUSE	1	120'	40'	25'
26	LP ECONOMIZER RECIRC PUMPS	2	2'	5'	SEE ITEM #32
27	WATER TREATMENT BUILDING	1	60'	100'	25'
28	ELECTRICAL ROOM	1	40'	40'	SEE ITEM #39
29	BLOWDOWN TANK	2	6' Ø	-	18'
30	CHEMICAL FEED EQUIPMENT	1	7' Ø	16'	SEE ITEM #32
31	FIRE WATER PUMP HOUSE	1	30'	15'	15'
32	BOILER FEEDWATER PUMP BUILDING	2	27'	45'	25'
33	CTG - FIN FAN COOLER	2	10'	10'	20'
34	CTG - NOX WATER INJECTION SYSTEM	2	12'	4'	8'
35	CTG - SPRINT SKID	2	6'	4'	7'
36	CTG - EVAP COOLER SKID	2	3'	4'	6'
37	CTG - AUX SKID	2	14'	11'	12'
38	CONDENSATE PUMPS	3	2'	2'	4'
39	STG BUILDING	1	120'	220'	65'
40	MAINTENANCE AREA	1	80'	40'	SEE ITEM #39
41	ADMIN - CONTROL AREA	1	120'	40'	SEE ITEM #39
42	GEN BRKR	6	11'	8'	6'
43	COOLING TOWER ELECTRICAL BUILDING	1	30'	15'	20'

44	CLARIFIER	1	30' Ø	-	15'
45	SUS TRANSFORMERS	4	9'	6'	8'
46	LUBE OIL SKID	1	10'	20'	16'
47	LABORATORY	1	20'	20'	SEE ITEM #39
48	RAW WATER TANK	1	75' Ø	-	50'
49	HYDRO CARBON DRAINS TANK	1	7' Ø	24'	8'
50	CO2 FIRE SUPPRESSION SYSTEM	1	3'	6'	8'
51	VACUUM PUMP SKID	1	10'	20'	6'
52	GLAND SEAL CONDENSER	1	5' Ø	10'	5'
53	COOLING TOWER CHEMICAL FEED	1	18'	14'	16'
54	CIRC WATER PUMPS	3	10'	7'	8'
55	CONDENSER				SEE ITEM #39
56	SWITCHGEAR PDC BUILDING				19'
57	DEAD-END STRUCTURE				45'
58	230 kV TRANSMISSION POLE				45'
59	DISTRIBUTION TRANSFORMER				10'

GUARANTEE
PROJECT: SME ELECTRIC
LOCATION: MT USA

KW AT GEN TERMS	40152
BTU/KW-HR, LHV	8568
(KJ/KW-HR, LHV)	9039

EMISSIONS ARE VALID FOR T2 WITHIN -10F-100F AND A GTG LOAD DOWN TO 60%

NOX: 25 PPMVD AT 15% O2 (51 mg/Nm3)
CO: 55 PPMVD AT 15% O2 (69 mg/Nm3)
VOC: 4.0 PPMVD AT 15% O2 (3 mg/Nm3)
PM10: 4 LB/HR (2 kg/hr)

John Metcalf
Johnny Metcalf
Performance Engineer
Date: 02/24/09

NOT VALID WITHOUT SIGNATURE

VALID UNTIL 05/25/09

BASIS OF GUARANTEE:	BASE LOAD, GAS FUEL NOZZLE SYSTEM NO BLEED OR EXTRACTED POWER
ENGINE:	(1) GE LM6000PF-SPRINT-25 DLE GAS TURBINE
FUEL:	19293Btu/lb / (44876 kJ/kg) LHV, GAS FUEL (#900-2085)
FUEL SPEC:	MID-TD-0000-1 LATEST REVISION
FUEL TEMP:	SITE FUEL TEMPERATURE OF 76.9°F(25.0°C)
GENERATOR:	BDAX 290ERT
GENERATOR OUTPUT	13.8kV, 60 Hz
POWER FACTOR:	≥ 0.85
AMBIENT TEMP:	91.5°F / (33.1°C)
AMBIENT RH:	17.0%
INLET CONDITIONING:	EVAP TO 65.6°F / (18.7°C) AT 78.4% RH
ALTITUDE:	3300.0ft / (1005.8m)
INLET FILTER LOSS:	≤ 5.00 inH_2O / (127.0 mmH_2O)
EXHAUST LOSS:	≤ 13.00 inH_2O / (330.2 mmH_2O)
NOX CONTROL:	DLE
ENGINE CONDITION:	NEW AND CLEAN ≤ 200 SITE FIRED HOURS
FIELD TEST METHODS	
PERFORMANCE:	GE ENERGY SGTGPTM
NOX:	EPA METHOD 20
CO:	EPA METHOD 10
VOC:	EPA METHOD 25A/18
PM10:	EPA METHOD 5 / 202

BASIS OF GUARANTEE IS NOT FOR DESIGN, REFER TO PROJECT DRAWINGS FOR DESIGN REQUIREMENTS.
SI VALUES ARE FOR REFERENCE PURPOSES ONLY.

THIS GUARANTEE SUPERSEDES ANY PREVIOUS GUARANTEES PRESENTED

Conditions for VOC Emissions Guarantee

1. Fuel must meet GE specification MID-TD-000-01.

2. The timing of test to coincide with lowest site ambient VOCs levels.

3. Gas turbine must run for a minimum of 300 total fired hours at base load prior to testing.
4. Gas turbine inlet and exhaust system must be free of any dirt,sand,mud,rust,oil or any other contaminates.
5. Re-testing (at purchaser's expense) must be allowed, if required.

6. GE receives a copy of the final test results.

7. A compressor wash prior to testing is highly recommended.

Conditions for PM10 Emissions Guarantee

1. Fuel must meet GE specification MID-TD-000-01.

2. The timing of test to coincide with lowest site ambient particulate levels.

3. Gas turbine must run for a minimum of 300 total fired hours at base load prior to testing.
4. Combustion turbine must be run for a minimum of 300 total fired hours prior to any particulate testing; combustion turbine must be operating a minimum of 3 - 4 hours at base load prior to PM / PM10 test run.
5. Gas turbine inlet and exhaust system must be free of any dirt,sand,mud,rust,oil or any other contaminates.
6. Sampling probe internal surfaces must be made of chemically inert and non-catalytic material such as quartz.
7. The filter material shall be quartz.

8. Probe wash shall be high purity acetone per EPA Method 5.

9. Re-testing (at purchaser's expense) must be allowed, if required.

10. GE receives a copy of the final test results.

11. A compressor wash prior to testing is highly recommended.

12. The area around the turbine is to be treated (e.g.sprayed down with water) to minimize airborne dust.

Estimated Average Engine Performance NOT FOR GUARANTEE, REFER TO PROJECT F&ID FOR DESIGN

GE Energy

Performance By: **Johnny Metcalf**
Project Info:

Engine: **LM6000 PF-SPRINT-25**
Deck Info: **G0125O - 8f6.scp**
Generator: **BDAX 290ERT 60Hz, 13.8kV, 0.85PF (14839)**
Fuel: **Site Gas Fuel#900-2085, 19293 Btu/lb,LHV**

Date: **02/24/2009**
Time: **10:52:54 AM**
Version: **3.8.0**

Case #	**100**
Ambient Conditions	
Dry Bulb, °F	91.5
Wet Bulb, °F	61.1
RH, %	17.0
Altitude, ft	3300.0
Ambient Pressure, psia	13.026
Engine Inlet	
Comp Inlet Temp, °F	65.6
RH, %	78.4
Conditioning	EVAP
Tons or kBtu/hr	0
Pressure Losses	
Inlet Loss, inH20	5.00
Volute Loss, inH20	4.00
Exhaust Loss, inH20	13.00
kW, Gen Terms	**40152**
Est. Btu/kW-hr, LHV	**8396**
Guar. Btu/kW-hr, LHV	**8568**
Fuel Flow	
MMBtu/hr, LHV	337.1
lb/hr	17474
NOx Control	**DLE**
SPRINT	**LPC**
lb/hr	8258
Control Parameters	
HP Speed, RPM	10417
LP Speed, RPM	3600
PS3 - CDP, psia	391.8
T3CRF - CDT, °F	963
T48IN, °R	2043
T48IN, °F	1583
Exhaust Parameters	
Temperature, °F	865.2
lb/sec	249.1
lb/hr	896580
Energy, Btu/s- Ref 0 °R	84663
Energy, Btu/s- Ref T2 °F	52054
Cp, Btu/lb-R	0.2746
Emissions (NOT FOR USE IN ENVIRONMENTAL PERMITS)	
NOx ppmvd Ref 15% O2	25
NOx as NO2, lb/hr	34
CO ppmvd Ref 15% O2	55
CO, lb/hr	45.58
CO2, lb/hr	44033.82
HC ppmvd Ref 15% O2	22
HC, lb/hr	10.42
SOX as SO2, lb/hr	0.00

Estimated Average Engine Performance NOT FOR GUARANTEE, REFER TO PROJECT F&ID FOR DESIGN

GE Energy

Performance By: **Johnny Metcalf**
Project Info:

Engine: **LM6000 PF-SPRINT-25**
Deck Info: **G0125O - 8f6.scp**
Generator: **BDAX 290ERT 60Hz, 13.8kV, 0.85PF (14839)**
Fuel: **Site Gas Fuel#900-2085, 19293 Btu/lb,LHV**

Date: **02/24/2009**
Time: **10:52:54 AM**
Version: **3.8.0**

Case #	**100**	
Exh Wght % Wet (NOT FOR USE IN ENVIRONMENTAL PERMITS)		
AR	1.2358	
N2	72.6290	
O2	15.2561	
CO2	4.9113	
H20	5.9589	
SO2	0.0000	
CO	0.0051	
HC	0.0012	
NOX	0.0026	
Exh Mole % Dry (NOT FOR USE IN ENVIRONMENTAL PERMITS)		
AR	0.9631	
N2	80.7097	
O2	14.8427	
CO2	3.4741	
H20	0.0000	
SO2	0.0000	
CO	0.0056	
HC	0.0023	
NOX	0.0026	
Exh Mole % Wet (NOT FOR USE IN ENVIRONMENTAL PERMITS)		
AR	0.8731	
N2	73.1747	
O2	13.4570	
CO2	3.1498	
H20	9.3359	
SO2	0.0000	
CO	0.0051	
HC	0.0021	
NOX	0.0023	
Aero Energy Fuel Number	**900-2085 (SME Electric)**	
	Volume %	**Weight %**
Hydrogen	0.0000	0.0000
Methane	90.9710	82.7127
Ethane	1.5290	2.6057
Ethylene	0.0000	0.0000
Propane	0.7810	1.9518
Propylene	0.0000	0.0000
Butane	0.5280	1.7393
Butylene	0.0000	0.0000
Butadiene	0.0000	0.0000
Pentane	0.2150	0.8791
Cyclopentane	0.0000	0.0000
Hexane	0.0510	0.2491
Heptane	0.0000	0.0000
Carbon Monoxide	0.0000	0.0000
Carbon Dioxide	0.5000	1.2472
Nitrogen	5.4260	8.6150
Water Vapor	0.0000	0.0000
Oxygen	0.0000	0.0000
Hydrogen Sulfide	0.0000	0.0000
Ammonia	0.0000	0.0000
Btu/lb, LHV	19293	
Btu/scf, LHV	899	
Btu/scf, HHV	996	
Btu/lb, HHV	21373	
Fuel Temp, °F	76.9	
NOx Scalar	0.951	
Specific Gravity	0.61	

Estimated Average Engine Performance NOT FOR GUARANTEE, REFER TO PROJECT F&ID FOR DESIGN

GE Energy

Performance By: **Johnny Metcalf**
Project Info:

Engine: **LM6000 PF-SPRINT-25**
Deck Info: **G0125O - 8f6.scp**
Generator: **BDAX 290ERT 60Hz, 13.8kV, 0.85PF (14839)**
Fuel: **Site Gas Fuel#900-2085, 19293 Btu/lb,LHV**

Date: **02/24/2009**
Time: **11:00:22 AM**
Version: **3.8.0**

Case #	**100**
Ambient Conditions	
Dry Bulb, °C	33.1
Wet Bulb, °C	16.1
RH, %	17.0
Altitude, m	1005.8
Ambient Pressure, kPa	89.812
Engine Inlet	
Comp Inlet Temp, °C	18.7
RH, %	78.4
Conditioning	EVAP
Tons or kBtu/hr	0
Pressure Losses	
Inlet Loss, mmH2O	127.00
Volute Loss, mmH2O	101.60
Exhaust Loss, mmH2O	330.20
kW, Gen Terms	**40152**
Est. kJ/kWh, LHV	**8859**
Guar. kJ/kWh, LHV	**9039**
Fuel Flow	
GJ/hr, LHV	355.7
kg/hr	7926
NOx Control	**DLE**
SPRINT	**LPC**
kg/hr	3746
Control Parameters	
HP Speed, RPM	10417
LP Speed, RPM	3600
PS3 - CDP, kPa	2701.6
T3CRF - CDT, °C	517
T48IN, °K	1135
T48IN, °C	862
Exhaust Parameters	
Temperature, °C	462.9
kg/sec	113.0
kg/hr	406686
Energy, KJ/s- Ref 0 °K	89325
Energy, KJ/s- Ref T2 °C	54920
Kj/kg-R	1.1495
Emissions (NOT FOR USE IN ENVIRONMENTAL PERMITS)	
NOx mg/Nm3 Ref 15% O2	51
NOx as NO2, kg/hr	15
CO mg/Nm3 Ref 15% O2	69
CO, kg/hr	20.67
CO2, kg/hr	19973.61
HC mg/Nm3 Ref 15% O2	16
HC, kg/hr	4.72
SOX as SO2, kg/hr	0.00

Estimated Average Engine Performance NOT FOR GUARANTEE, REFER TO PROJECT F&ID FOR DESIGN

GE Energy

Performance By: **Johnny Metcalf**
Project Info:

Engine: **LM6000 PF-SPRINT-25**
Deck Info: **G0125O - 8f6.scp**
Generator: **BDAX 290ERT 60Hz, 13.8kV, 0.85PF (14839)**
Fuel: **Site Gas Fuel#900-2085, 19293 Btu/lb,LHV**

Date: **02/24/2009**
Time: **11:00:22 AM**
Version: **3.8.0**

Case #	**100**
Exh Wght % Wet (NOT FOR USE IN ENVIRONMENTAL PERMITS)	
AR	1.2358
N2	72.6290
O2	15.2561
CO2	4.9113
H20	5.9589
SO2	0.0000
CO	0.0051
HC	0.0012
NOX	0.0026
Exh Mole % Dry (NOT FOR USE IN ENVIRONMENTAL PERMITS)	
AR	0.9631
N2	80.7097
O2	14.8427
CO2	3.4741
H20	0.0000
SO2	0.0000
CO	0.0056
HC	0.0023
NOX	0.0026
Exh Mole % Wet (NOT FOR USE IN ENVIRONMENTAL PERMITS)	
AR	0.8731
N2	73.1747
O2	13.4570
CO2	3.1498
H20	9.3359
SO2	0.0000
CO	0.0051
HC	0.0021
NOX	0.0023

Aero Energy Fuel Number	**900-2085 (SME Electric)**	
	Volume %	**Weight %**
Hydrogen	0.0000	0.0000
Methane	90.9710	82.7127
Ethane	1.5290	2.6057
Ethylene	0.0000	0.0000
Propane	0.7810	1.9518
Propylene	0.0000	0.0000
Butane	0.5280	1.7393
Butylene	0.0000	0.0000
Butadiene	0.0000	0.0000
Pentane	0.2150	0.8791
Cyclopentane	0.0000	0.0000
Hexane	0.0510	0.2491
Heptane	0.0000	0.0000
Carbon Monoxide	0.0000	0.0000
Carbon Dioxide	0.5000	1.2472
Nitrogen	5.4260	8.6150
Water Vapor	0.0000	0.0000
Oxygen	0.0000	0.0000
Hydrogen Sulfide	0.0000	0.0000
Ammonia	0.0000	0.0000
kJ/kg, LHV	44875	
kJ/Nm3, LHV	35320	
kJ/Nm3, HHV	39128	
kJ/kg, HHV	49712	
Fuel Temp, °C	25.0	
NOx Scalar	0.951	
Specific Gravity	0.61	

Estimated Average Engine Performance NOT FOR GUARANTEE, REFER TO PROJECT F&ID FOR DESIGN

GE Energy

Performance By: **Johnny Metcalf**
Project Info:

Engine: **LM6000 PF-SPRINT-25**
Deck Info: **G0125O - 8f6.scp**
Generator: **BDAX 290ERT 60Hz, 13.8kV, 0.85PF (14839)**
Fuel: **Site Gas Fuel#900-2085, 19293 Btu/lb,LHV**

Date: **02/23/2009**
Time: **2:25:51 PM**
Version: **3.8.0**

Case #	100	101	102	103	104	105	106	107	108
Ambient Conditions									
Dry Bulb, °F	57.4	57.4	57.4	91.5	91.5	91.5	-17.0	-17.0	-17.0
Wet Bulb, °F	48.2	48.2	48.2	61.1	61.1	61.1	-17.7	-17.7	-17.7
RH, %	52.7	52.7	52.7	17.0	17.0	17.0	50.0	50.0	50.0
Altitude, ft	3300.0	3300.0	3300.0	3300.0	3300.0	3300.0	3300.0	3300.0	3300.0
Ambient Pressure, psia	13.026	13.026	13.026	13.026	13.026	13.026	13.026	13.026	13.026
Engine Inlet									
Comp Inlet Temp, °F	49.5	49.5	49.5	65.6	65.6	65.6	0.0	2.0	5.0
RH, %	91.2	91.2	91.2	78.4	78.4	78.4	19.8	17.9	15.3
Conditioning	EVAP	EVAP	EVAP	EVAP	EVAP	EVAP	HEAT	HEAT	HEAT
Tons or kBtu/hr	0	0	0	0	0	0	4021	3750	4294
Pressure Losses									
Inlet Loss, inH20	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00
Volute Loss, inH20	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00
Exhaust Loss, inH20	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00
Percent Load	**100**	**75**	**60**	**100**	**75**	**60**	**100**	**75**	**60**
kW, Gen Terms	**42873**	**32155**	**25725**	**40152**	**30115**	**24089**	**44625**	**33470**	**26774**
Est. Btu/kW-hr, LHV	**8281**	**8808**	**9395**	**8396**	**8876**	**9574**	**8118**	**8726**	**9500**
Guar. Btu/kW-hr, LHV	**8450**	**8988**	**9587**	**8568**	**9058**	**9769**	**8284**	**8904**	**9694**
Fuel Flow									
MMBtu/hr, LHV	355.0	283.2	241.7	337.1	267.3	230.6	362.3	292.1	254.4
lb/hr	18402	14680	12527	17474	13856	11954	19068	15372	13387
NOx Control	**DLE**	**DLE**	**DLE**	**DLE**	**DLE**	**DLE**	**DLE**	**DLE**	**DLE**
SPRINT	**LPC**	**OFF**	**OFF**	**LPC**	**OFF**	**OFF**	**OFF**	**OFF**	**OFF**
lb/hr	7803	0	0	8258	0	0	0	0	0
Control Parameters									
HP Speed, RPM	10379	10143	10005	10417	10202	10046	10110	9893	9829
LP Speed, RPM	3600	3600	3600	3600	3600	3600	3600	3600	3600
PS3 - CDP, psia	409.2	345.8	287.8	391.8	329.4	276.5	419.6	340.9	295.4
T3CRF - CDT, °F	954	940	896	963	954	908	925	866	846
T48IN, °R	2047	1995	1999	2043	1995	2002	2032	1989	1992
T48IN, °F	1587	1535	1539	1583	1535	1543	1572	1530	1532
Exhaust Parameters									
Temperature, °F	855.8	853.6	904.1	865.2	866.5	918.8	834.4	851.0	888.9
lb/sec	260.5	227.8	188.4	249.1	216.5	180.6	269.8	224.6	194.0
lb/hr	937634	820104	678069	896580	779299	650261	971137	808515	698559
Energy, Btu/s- Ref 0 °R	87526	75679	65213	84663	72903	63470	87816	74037	65966
Energy, Btu/s- Ref T2 °F	54602	46521	41121	52054	44250	39572	57482	48117	43430
Cp, Btu/lb-R	0.2732	0.2705	0.2727	0.2746	0.2719	0.2741	0.2683	0.2689	0.2704
Emissions (NOT FOR USE IN ENVIRONMENTAL PERMITS)									
NOx ppmvd Ref 15% O2	25	-999	-999	25	-999	-999	25	-999	-999
NOx as NO2, lb/hr	36	29	24	34	27	23	37	29	26
CO ppmvd Ref 15% O2	55	55	55	55	55	55	55	55	55
CO, lb/hr	48.00	38.25	32.65	45.58	36.10	31.16	48.96	39.46	34.37
CO2, lb/hr	46371.81	37037.75	31595.51	44033.82	34957.73	30150.53	48162.09	38831.47	33815.64
HC ppmvd Ref 15% O2	22	22	22	22	22	22	22	22	22
HC, lb/hr	10.97	8.74	7.46	10.42	8.25	7.12	11.19	9.02	7.85
SOX as SO2, lb/hr	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Maximum Emissions									
NOx ppmvd Ref 15% O2	**25**	**25**	**25**	**25**	**25**	**25**	**25**	**25**	**25**
NOx as NO2, lb/hr	**36**	**29**	**24**	**34**	**27**	**23**	**37**	**29**	**26**
CO ppmvd Ref 15% O2	**55**	**55**	**55**	**55**	**55**	**55**	**55**	**55**	**55**
CO, lb/hr	**48.00**	**38.25**	**32.65**	**45.58**	**36.10**	**31.16**	**48.96**	**39.46**	**34.37**
HC ppmvd Ref 15% O2	**22**	**22**	**22**	**22**	**22**	**22**	**22**	**22**	**22**
HC, lb/hr	**10.97**	**8.74**	**7.46**	**10.42**	**8.25**	**7.12**	**11.19**	**9.02**	**7.85**
VOC ppmvd Ref 15% O2	**4.00**	**4.00**	**4.00**	**4.00**	**4.00**	**4.00**	**4.00**	**4.00**	**4.00**
VOC, lb/hr	**2.0**	**1.6**	**1.4**	**1.9**	**1.5**	**1.3**	**2.0**	**1.7**	**1.5**
PM10, lb/hr	**4.00**	**4.00**	**4.00**	**4.00**	**4.00**	**4.00**	**4.00**	**4.00**	**4.00**
.Grains/100scf	**0.46082**								
95% Conv. To SO2 - 5% Conv. To SO3									
SO2 lbs/hr	0.4834	0.3857	0.3291	0.4591	0.3640	0.3140	0.4934	0.3978	0.3464
SO3 lbs/hr	0.0318	0.0254	0.0217	0.0302	0.0240	0.0207	0.0325	0.0262	0.0228

Estimated Average Engine Performance NOT FOR GUARANTEE, REFER TO PROJECT F&ID FOR DESIGN

GE Energy

Performance By: **Johnny Metcalf**
Project Info:

Engine: **LM6000 PF-SPRINT-25**
Deck Info: **G0125O - 8f6.scp**
Generator: **BDAX 290ERT 60Hz, 13.8kV, 0.85PF (14839)**
Fuel: **Site Gas Fuel#900-2085, 19293 Btu/lb,LHV**

Date: **02/23/2009**
Time: **2:25:51 PM**
Version: **3.8.0**

Case #	**100**	**101**	**102**	**103**	**104**	**105**	**106**	**107**	**108**
Exh Wght % Wet (NOT FOR USE IN ENVIRONMENTAL PERMITS)									
AR	1.2420	1.2548	1.2541	1.2358	1.2498	1.2490	1.2625	1.2628	1.2626
N2	72.9909	73.7327	73.6938	72.6290	73.4367	73.3960	74.1957	74.2124	74.2020
O2	15.3180	16.0337	15.8114	15.2561	15.9873	15.7535	15.8041	15.8966	15.8370
CO2	4.9456	4.6066	4.7528	4.9113	4.5756	4.7294	4.9594	4.8975	4.9375
H20	5.4947	4.3640	4.4794	5.9589	4.7424	4.8636	3.7696	3.7221	3.7523
SO2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO	0.0051	0.0048	0.0049	0.0051	0.0047	0.0049	0.0050	0.0050	0.0050
HC	0.0012	0.0011	0.0011	0.0012	0.0011	0.0011	0.0012	0.0011	0.0011
NOX	0.0026	0.0024	0.0025	0.0026	0.0024	0.0025	0.0026	0.0026	0.0026
Exh Mole % Dry (NOT FOR USE IN ENVIRONMENTAL PERMITS)									
AR	0.9631	0.9607	0.9616	0.9631	0.9607	0.9616	0.9614	0.9611	0.9613
N2	80.7151	80.5020	80.5833	80.7097	80.4951	80.5810	80.5742	80.5413	80.5626
O2	14.8300	15.3261	15.1369	14.8427	15.3421	15.1422	15.0259	15.1042	15.0537
CO2	3.4813	3.2016	3.3082	3.4741	3.1925	3.3052	3.4283	3.3833	3.4124
H20	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO	0.0057	0.0052	0.0054	0.0056	0.0052	0.0054	0.0055	0.0054	0.0054
HC	0.0023	0.0021	0.0022	0.0023	0.0021	0.0022	0.0022	0.0022	0.0022
NOX	0.0026	0.0024	0.0024	0.0026	0.0024	0.0024	0.0025	0.0025	0.0025
Exh Mole % Wet (NOT FOR USE IN ENVIRONMENTAL PERMITS)									
AR	0.8800	0.8945	0.8936	0.8731	0.8888	0.8879	0.9039	0.9043	0.9040
N2	73.7470	74.9489	74.8798	73.1747	74.4749	74.4029	75.7520	75.7810	75.7629
O2	13.5497	14.2689	14.0655	13.4570	14.1946	13.9813	14.1266	14.2115	14.1568
CO2	3.1808	2.9807	3.0741	3.1498	2.9538	3.0518	3.2231	3.1834	3.2091
H20	8.6329	6.8981	7.0777	9.3359	7.4789	7.6669	5.9848	5.9104	5.9577
SO2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO	0.0052	0.0048	0.0050	0.0051	0.0048	0.0050	0.0051	0.0051	0.0051
HC	0.0021	0.0019	0.0020	0.0021	0.0019	0.0020	0.0021	0.0021	0.0021
NOX	0.0024	0.0022	0.0023	0.0023	0.0022	0.0023	0.0023	0.0023	0.0023

Aero Energy Fuel Number	**900-2085 (SME Electric)**		**10-1 (GEDEF)**	
	Volume %	**Weight %**	**Volume %**	**Weight %**
Hydrogen	0.0000	0.0000	0.0000	0.0000
Methane	90.9710	82.7127	84.5000	71.8447
Ethane	1.5290	2.6057	5.5800	8.8924
Ethylene	0.0000	0.0000	0.0000	0.0000
Propane	0.7810	1.9518	2.0500	4.7909
Propylene	0.0000	0.0000	0.0000	0.0000
Butane	0.5280	1.7393	0.7800	2.4027
Butylene	0.0000	0.0000	0.0000	0.0000
Butadiene	0.0000	0.0000	0.0000	0.0000
Pentane	0.2150	0.8791	0.1800	0.6883
Cyclopentane	0.0000	0.0000	0.0000	0.0000
Hexane	0.0510	0.2491	0.1700	0.7764
Heptane	0.0000	0.0000	0.0000	0.0000
Carbon Monoxide	0.0000	0.0000	0.0000	0.0000
Carbon Dioxide	0.5000	1.2472	0.6700	1.5628
Nitrogen	5.4260	8.6150	5.9300	8.8044
Water Vapor	0.0000	0.0000	0.0000	0.0000
Oxygen	0.0000	0.0000	0.1400	0.2374
Hydrogen Sulfide	0.0000	0.0000	0.0000	0.0000
Ammonia	0.0000	0.0000	0.0000	0.0000
Btu/lb, LHV	19293		19000	
Btu/scf, LHV	899		946	
Btu/scf, HHV	996		1047	
Btu/lb, HHV	21373		20996	
Fuel Temp, °F	76.9		77.0	
NOx Scalar	0.951		0.998	
Specific Gravity	0.61		0.65	

Estimated Average Engine Performance NOT FOR GUARANTEE, REFER TO PROJECT F&ID FOR DESIGN

GE Energy

Performance By: **Johnny Metcalf**
Project Info:

Engine: **LM6000 PF-SPRINT-25**
Deck Info: **G0125O - 8f6.scp**
Generator: **BDAX 290ERT 60Hz, 13.8kV, 0.85PF (14839)**
Fuel: **Site Gas Fuel#900-2085, 19293 Btu/lb,LHV**

Date: **02/23/2009**
Time: **2:25:51 PM**
Version: **3.8.0**

Case #	**100**	**101**	**102**	**103**	**104**	**105**	**106**	**107**	**108**
Engine Exhaust									
Exhaust Avg. Mol. Wt., Wet Basis	28.3	28.5	28.5	28.2	28.4	28.4	28.6	28.6	28.6
Exhaust Flow, ACFM	577139	500908	430265	557403	481778	418050	581959	490621	436215
Exhaust Flow, SCFM	195644	170428	139849	187806	162248	134542	200708	165715	143070
Exhaust Flow, Btu/lb	336	334	348	340	338	353	326	331	342
Exhaust Flow, Calories/s	22056613	19071203	16433766	21335159	18371560	15994555	22129597	18657204	16623414
Inlet Flow Wet, pps	256.5	232.8	202.8	245.1	216.6	196.2	268.2	223.9	221.4
Inlet Flow Dry, pps	254.5	231.0	201.2	242.1	214.0	193.8	268.2	223.8	221.3
Shaft HP	58595	44059	35357	54899	41298	33143	60977	45837	36776
Generator Information									
Capacity kW	60552	60950	60950	51714	51714	51714	60552	74673	74673
Efficiency	0.9791	0.9787	0.9757	0.9808	0.9779	0.9747	0.9763	0.9792	0.9763
Inlet Temp, °F	57.4	57.4	57.4	91.5	91.5	91.5	-17.0	-17.0	-17.0
Gear Box Loss	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Burner Mode	ABC	AB	AB	ABC	ABC	AB	ABC	AB	AB
TRQ48, Torque Limit Cold End	106111	82445	63189	99962	77072	59764	108849	80053	65174
Correct Control Parameters									
PS3JQA, psia	414.955	350.663	291.847	397.310	334.032	280.389	425.501	345.694	299.554
XN25R3, rpm									
8th Stage Bleed									
Flow, pps	0.0	4.5	3.7	0.0	4.2	3.5	0.0	4.3	3.8
Pressure, psia	0.000	112.967	92.781	0.000	106.660	89.396	0.000	109.415	94.887
Temperature, °R	0	1061	1028	0	1068	1039	0	999	990
CDP Bleed									
Flow, pps	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pressure, psia	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Est. Gas Pressure at Baseplate, psig	**564.4**	**462.7**	**387.7**	**536.0**	**437.4**	**370.8**	**572.6**	**462.5**	**399.6**
CardPack	**8f6**	**8f6**	**8f6**	**8f6**	**8f6**	**8f6**	**8f6**	**8f6**	**8f6**
Exhaust CardPack	**7f5**	**7f5**	**7f5**	**7f5**	**7f5**	**7f5**	**7f5**	**7f5**	**7f5**
NSI	**304**	**439**	**439**	**304**	**439**	**439**	**315**	**0**	**0**
NSI	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
NSI	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Emissions Data from Stanley Consultants

Data as of 3/4/2009

Black Numbers are Estimates
Red Numbers are Guarantees

PF	Plant Load (MW)	120 MW	75% GT Load	60% GT Load
-17.7 Deg	Per Gas Turbine Only			
	NOx(ppm) ref 15% O2	25	25	25
	NO2 lb/hr	37	29	26
	CO(ppm) ref 15% O2	55	55	55
	CO lb/hr	48.96	39.46	34.37
	VOC(ppm)ref 15% O2	4	4	4
	lb/hr	2	1.7	1.5
	SO2lb/hr	0.4934	0.3978	0.3464
	SO3lb/hr	0.0325	0.0262	0.0228
	S lb/hr	GE	GE	GE
	PM10 lb/hr	4	4	4
	Plant Load (MW)	120	85	72
	Plant Energy Input (MMBtu/hr)	497.04	378.42	348.984
	Duct Burner Energy Input HHV(MMBtu/hr)	55.25	0	0
	Duct Burner Exit Temp (Deg F)	1006	848	888
	Stack Exit Temp (Deg F)	218	216	212
	GT Exhaust Flow (kpph)	963	801	695
	GT Gross Power (MW)	43.7	33.1	27
	GT Load (%)	100	75	60
	GT Guar. Btu/kWh, LHV	8284	8904	9694
	Cominbed Cycle Exhaust Flow (kpph)	966	801	695
57.4 Deg F and 52.7% RH	NOx(ppm) ref 15% O2	25	25	25
	NO2 lb/hr	36	29	24
	CO(ppm) ref 15% O2	55	55	55
	CO lb/hr	48	38.25	32.65
	VOC(ppm)ref 15% O2	4	4	4
	lb/hr	2	1.6	1.4
	SO2lb/hr	0.4834	0.3857	0.3291
	SO3lb/hr	0.0318	0.0254	0.0217
	S lb/hr	GE	GE	GE
	PM10 lb/hr	4	4	4
	Plant Load (MW)	120	84	71
	Plant Energy Input (MMBtu/hr)	507	377.496	340.3385
	Duct Burner Energy Input HHV(MMBtu/hr)	68.15	0	0
	Duct Burner Exit Temp (Deg F)	1079	852	899
	Stack Exit Temp (Deg F)	223	222	205
	GT Exhaust Flow (kpph)	932	797	680
	GT Gross Power (MW)	42	32	26
	GT Load (%)	100	75	60
	GT Guar. Btu/kWh, LHV	8450	8988	9587
	Cominbed Cycle Exhaust Flow (kpph)	935	797	680
91.5 Deg	NOx(ppm) ref 15% O2	25	25	25
	NO2 lb/hr	34	27	23
	CO(ppm) ref 15% O2	55	55	55
	CO lb/hr	45.6	36.1	31.16
	VOC(ppm)ref 15% O2	4	4	4
	lb/hr	1.9	1.5	1.3
	SO2lb/hr	0.4591	0.364	0.314
	SO3lb/hr	0.0302	0.024	0.0207
	S lb/hr	GE	GE	GE
	PM10 lb/hr	4	4	4
	Plant Load (MW)	120	79	67
	Plant Energy Input (MMBtu/hr)	514.08	357.791	327.2615
	Duct Burner Energy Input HHV(MMBtu/hr)	103.5	0	0
	Duct Burner Exit Temp (Deg F)	1211	863	913
	Stack Exit Temp (Deg F)	220	221	206
	GT Exhaust Flow (kpph)	894	781	654
	GT Gross Power (MW)	40	30	24
	GT Load (%)	100	75	60
	GT Guar. Btu/kWh, LHV	8568	9058	9769
	Cominbed Cycle Exhaust Flow (kpph)	899	781	654

AFTER CATALYSTS:

HRSG Emissions w/ PF LM6000	120 MW	75% GT Load	50% GT Load
NO2 lb/hr	GE	GE	GE
CO(ppm) ref 15% O2	2	2	GE
CO lb/hr	GE	GE	GE
VOC(ppm)ref 15% O2	4	4	GE
lb/hr	GE	GE	GE
SO2lb/hr	GE	GE	GE
PM10 lb/hr	GE	GE	GE

APPENDIX C: EMISSIONS INVENTORY

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Combustion Turbines

EMISSION INVENTORY SUMMARY PAGE

All data as of 4/23/2009

Project Characteristics

Maximum Guaranteed Heat Rate (LHV), Turbines =	369.7	MMBtu/hr	(-17.7℉, 100% load)
Maximum Heat Rate, Duct Burners =	103.5	MMBtu/hr	(91.5℉)
Maximum Combined Heat Rate =	447.5	MMBtu/hr	(91.5℉, 1 00% load)
Maximum Turbine Generation, each =	44.6	MWe	(-17.7℉, 100% load, Power Factor 1.0)
Maximum Plant Generation, including Duct Burners =	120	MWe	

Phase I Annual PTE
Annual Emissions (tpy) (for each turbine, divide the "Turbines, SC and SUSD" by 2)
Simple Cycle, 3200 hours limitation

Source	NOX	CO	VOC	PM10	SO2
Turbines, SC, Max	117.06	367.03	12.48	15.36	1.82
Cooling Tower	---	---	---	1.14	---
Building Heaters	1.68	1.01	0.07	0.09	0.01
EDG	6.68	0.26	0.14	0.03	0.18
Firepump	0.92	0.21	0.03	0.04	0.03
Total	126.34	368.52	12.72	16.66	1.94

Phase II Annual PTE
Annual Emissions (tpy) (for each turbine, divide the "Turbines, SC and SUSD" by 2)
Simple Cycle 3200 hours limitation
Combined Cycle, No hourly limitation 5251 hours remaining, outside SUSD

Source	NOX	CO	VOC	PM10	SO2
Turbines, Max, all cases	162.18	378.30	20.11	63.10	6.05
Cooling Tower	---	---	---	1.14	---
Building Heaters	1.68	1.01	0.07	0.09	0.01
EDG	6.68	0.26	0.14	0.03	0.09
Firepump	0.92	0.21	0.03	0.04	0.02
Total	171.46	379.78	20.35	64.40	6.16

Hourly Emissions (lb/hr)

Source	NOX	CO	VOC	PM10/PM2.5	SO2	
Turbines, SC, each	36.58	48.96	2.03	4.80	0.57	(steady-state operations)
Turbines, SC, SUSD, each	36.58	114.70	3.90	4.80	0.57	(any hour when a simple cycle startup or shutdown occur
Turbines, CC, each	4.16	2.03	1.86	7.20	0.69	(steady-state operations)
Turbines, CC, SU, each	26.12	76.20	1.86	7.20	0.69	(any hour when a combined cycle startup occurs)
Turbines, CC, SD, each	12.33	4.15	1.86	7.20	0.69	(any hour when a combined cycle shutdown occurs)
Cooling Tower	---	---	---	0.26	---	(derived from annual)
Building Heaters, total	0.38	0.23	0.02	0.02	0.00	(derived from annual)
EDG	26.70	1.10	0.06	0.10	0.37	
Firepump	3.68	0.85	0.14	0.14	0.06	

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Combustion Turbines

MODELING INPUT SUMMARY

All data as of 4/23/2009

Turbines, each

Simple Cycle Stack

Flow Case	Flowrate (ACFM)	Temp (°F)	Stack Dia (ft)	Stack Ht (ft)	NOX_HR (lb/hr)	NOX_AN (tpy)	CO_HR (lb/hr)	PM_HR (lb/hr)	PM_ANN (tpy)	SO2_HR (lb/hr)	SO2_ANN (tpy)	SO4 (lb/hr)
High	851959	865	10	80	36.58	160.22	48.96	4.80	21.02	0.57	2.50	0.057
SUSD	497149	871			36.58	160.22	114.70	4.80	21.02	0.57	2.50	0.057

Combined Cycle Mode

Flow Case	Flowrate (ACFM)	Temp (°F)	Stack Dia (ft)	Stack Ht (ft)	NOX_HR (lb/hr)	NOX_AN (tpy)	CO_HR (lb/hr)	PM_HR (lb/hr)	PM_ANN (tpy)	SO2_HR (lb/hr)	SO2_ANN (tpy)	SO4 (lb/hr)
High	312899	223	10	105	4.16	18.22	2.03	7.20	31.54	0.69	3.02	0.583
SUSD	260227	216			26.12	114.41	76.20	7.20	31.55	0.69	3.02	0.583

Black Start Generator

Flow Case	Flowrate (ACFM)	Temp (°F)	Stack Dia (ft)	Stack Ht (ft)	NOX_HR (lb/hr)	NOX_AN (tpy)	CO_HR (lb/hr)	PM_HR (lb/hr)	PM_ANN (tpy)	SO2_HR (lb/hr)	SO2_ANN (tpy)	SO4 (lb/hr)
High	11060	763.5	2.5	35	26.70	6.68	1.10	0.10	0.03	0.37	1.6206	---
SUSD	11060	763.5			26.70	6.68	1.10	0.10	0.03	0.37	1.6206	---

Firepump

Flow Case	Flowrate (ACFM)	Temp (°F)	Stack Dia (ft)	Stack Ht (ft)	NOX_HR (lb/hr)	NOX_AN (tpy)	CO_HR (lb/hr)	PM_HR (lb/hr)	PM_ANN (tpy)	SO2_HR (lb/hr)	SO2_ANN (tpy)	SO4 (lb/hr)
High	2055	1032	1.25	25	3.68	0.92	0.85	0.14	0.04	0.06	0.02	---
SUSD	2055	1032			3.68	0.92	0.85	0.14	0.04	0.06	0.02	---

Cooling Tower - Total emissions

Flow Case	Flowrate (ACFM)	Temp (°F)	Stack Dia (ft)	Stack Ht (ft)	NOX_HR (lb/hr)	NOX_AN (tpy)	CO_HR (lb/hr)	PM_HR (lb/hr)	PM_ANN (tpy)	SO2_HR (lb/hr)	SO2_ANN (tpy)	SO4 (lb/hr)
High	286291.5	70	15	45	---	---	---	0.087	0.38	---	---	---
SUSD	286291.5	70			---	---	---	0.087	0.38	---	---	---

Building Heaters

Heater Name	Flowrate (ACFM)	Temp (°F)	Stack Dia (ft)	Stack Ht (ft)	NOX_HR (lb/hr)	NOX_AN (tpy)	CO_HR (lb/hr)	PM_HR (lb/hr)	PM_ANN (tpy)	SO2_HR (lb/hr)	SO2_ANN (tpy)	SO4 (lb/hr)
Turbine Enclosures (2 each west and east)	1000	550	0.5	45	0.034	0.150	0.0206	0.00186	0.0082	0.000147	0.0006	---
Admin/Maintenance/Electrical/STG Building	4000	550	1	60	0.137	0.601	0.0824	0.00745	0.0326	0.000588	0.0026	---
Water Treatment Building	2000	550	1	30	0.069	0.301	0.0412	0.00373	0.0163	0.000294	0.0013	---
Warehouse	2000	550	1	30	0.069	0.301	0.0412	0.00373	0.0163	0.000294	0.0013	---
Water Pump house	1000	550	0.5	21	0.034	0.150	0.0206	0.00186	0.0082	0.000147	0.0006	---
Fuel Gas Compressor Building	1000	550	0.5	20	0.034	0.150	0.0206	0.00186	0.0082	0.000147	0.0006	---
CEMS Enclosures (2ea)	200	550	0.5	15	0.007	0.030	0.0041	0.00037	0.0016	0.000029	0.0001	---

Southern Montana Electric Generation and Transmission Cooperative, Inc.
Highwood Generating Station gas plant
GE LM6000PF Combustion Turbines

MAX PTE ANALYSIS

Threshold, Simple Cycle 100 tpy
Threshold, Combined Cycle 100 tpy

Simple Cycle, 3200 hours limitation
3200 hours steady-state operation

Source	Pollutant (tpy)				
	NOX	CO	VOC	PM	SO2
Turbines, SC, Steady	117.06	156.67	6.50	15.36	1.82

Simple Cycle, 3200 hours limitation
1460 hours SC SUSD conditions (includes fractional steady-state)
1740 steady-state operation, remaining

Source	Pollutant (tpy)				
	NOX	CO	VOC	PM	SO2
Turbines, SC, Steady	63.65	85.19	3.53	8.35	0.99
Turbines, SC, SUSD	53.41	167.46	5.69	7.01	0.83
Turbines, SC, Total	117.06	252.65	9.23	15.36	1.82

Simple Cycle, 3200 hours limitation
3200 hours SC SUSD conditions (includes fractional steady-state)
0 steady-state operation, remaining

Source	Pollutant (tpy)				
	NOX	CO	VOC	PM	SO2
Turbines, SC, Steady	0.00	0.00	0.00	0.00	0.00
Turbines, SC, SUSD	117.06	367.03	12.48	15.36	1.82
Turbines, SC, Total	117.06	367.03	12.48	15.36	1.82

Maximum Phase I operations (max simple cycle case)

Source	Pollutant (tpy)					
	NOX	CO	VOC	PM	SO2	Notes
Turbines, SC, Max	117.06	367.03	12.48	15.36	1.82	1
Cooling Tower	---	---	---	1.14	---	
Building Heaters	1.68	1.01	0.07	0.09	0.01	
EDG	6.68	0.26	0.14	0.03	0.09	
Firepump	0.92	0.21	0.03	0.04	0.02	
Total	126.34	368.52	12.72	16.66	1.94	2

Combined Cycle, No hourly limitation, steady-state operation

Source	Pollutant (tpy)				
	NOX	CO	VOC	PM	SO2
Turbines, CC	36.43	17.75	16.31	63.10	6.05

Combined Cycle Only Operations, w/ SUSD
No hourly limitation
730 hours CC SU conditions (includes fractional steady-state)
730 hours CC SD conditions (includes fractional steady-state)
7300 steady-state combined cycle operation remaining

Source	Pollutant (tpy)				
	NOX	CO	VOC	PM	SO2
Turbines, CC, Steady	30.36	14.79	13.59	52.58	5.04
Turbines, CC, SU	19.07	55.63	1.36	5.26	0.50
Turbines, CC, SD	9.00	3.03	1.36	5.26	0.50
Turbines, CC, Total	58.43	73.44	16.31	63.10	6.05

Max Case Turbine Operations

Simple Cycle	3200	hours limitation
	1460	hours maximum SUSD value (includes fractional steady-state)
Combined cycle	4100	steady-state combined cycle operation remaining

	Pollutant					
Source	NOX[5]	CO[6]	VOC[6]	PM[7]	SO2[7]	Notes
Turbines, SC, Steady hours	3200	---	---	---	---	
Turbines, SC, Steady (tpy)	117.06	---	---	---	---	
Turbines, SC, SUSD, hours	---	3200	3200	---	---	
Turbines, SC, SUSD (tpy)	---	367.03	12.48	---	---	
Turbines, CC, Steady hours	4100	5560	5560	8760	8760	
Turbines, CC, Steady (tpy)	17.05	11.26	7.64	63.10	6.05	
Turbines, CC, SU hours	730	---	---	---	---	
Turbines, CC, SU (tpy)	19.07	---	---	---	---	
Turbines, CC, SD hours	730	---	---	---	---	
Turbines, CC, SD (tpy)	9.00	---	---	---	---	
Turbines, Both, Total	162.18	378.30	20.11	63.10	6.05	

Max PTE Case Summary

	Pollutant (tpy)					Notes
Source	NOX	CO	VOC	PM	SO2	3
Turbines, Max, all cases	162.18	378.30	20.11	63.10	6.05	
Cooling Tower	---	---	---	1.14	---	
Building Heaters	1.68	1.01	0.07	0.09	0.01	
EDG	6.68	0.26	0.14	0.03	0.09	4
Firepump	0.92	0.21	0.03	0.04	0.02	
Total	171.46	379.78	20.35	64.40	6.16	

Notes and References

1. Maximum Emissions are selected for the PTE analysis, i.e. if emissions are higher when SUSD occurs at maximum, then that value is selected. If emissions are maximum when the plant operates continuously at steady-state, then that value is used.
2. These values represent the Phase I Maximum PTE for the facility
3. Note 1 applies, however, this value represents the maximum turbine emissions from all operation cases: simple cycle steady-state, simple cycle with SUSD, combined cycle steady-state, combined cycle SUSD
4. These values represent the Phase II Maximum PTE for the facility
5. The maximum PTE case for NOX occurs when the plant operates in simple cycle mode for the full 3200 hour limit, regardless of steady-state or SUSD mode. The next highest NOX emissions would come from the maximum combined cycle SU and SD, and the remaining 4100 hours operation at combined cycle steady-state operations.
6. The maximum PTE case for CO and VOC are when the simple cycle turbines operate in SUSD for the entire 3200 hour limit (unrealistic), and the remainder of the year the combined cycle operations at steady-state (as the SUSD cases were maximum for the simple cycle turbines)
7. The maximum PTE case for PM and SO2 are derived from combined cycle operation at steady-state because fuel use is maximum with duct burners operating.

Southern Montana Electric Generation and Transmission Cooperative, Inc.
Highwood Generating Station gas plant
GE LM6000PF Combustion Turbines

CRITERIA POLLUTANTS AT 100% LOAD - SIMPLE CYCLE

Number of Gen Units = 2
Turbine type = PF
Fuel = Natural Gas
Control Equipment = Water Inj
Hours of Operation, per turbine = 8,760 hrs/hr

100% Load

-17.7 °F Scenario with Water Injection - Natural Ga s

Pollutant	Uncontrolled (lbs/hr)	% Control	Controlled (lbs/hr)	Controlled (tpy)	Controlled (tpy - 2 units)	Notes
NO_X	36.58	0%	36.58	160.22	320.44	a,b
CO	48.96	0%	48.96	214.44	428.89	a
VOC	2.03	0%	2.03	8.89	17.78	a
PM/PM_{10}	4.60	0%	4.60	20.15	40.30	e
SO_2	0.57	0%	0.57	2.50	4.99	d

57.4 °F Scenario with Water Injection - Natural Gas

Pollutant	Uncontrolled (lbs/hr)	% Control	Controlled (lbs/hr)	Controlled (tpy)	Controlled (tpy - 2 units)	Notes
NO_X	35.86	0%	35.86	157.07	314.13	a,b
CO	48.00	0%	48.00	210.24	420.48	a
VOC	1.99	0%	1.99	8.72	17.43	a
PM/PM_{10}	4.77	0%	4.77	20.89	41.79	e
SO_2	0.56	0%	0.56	2.45	4.91	d

91.5 °F Scenario with Water Injection - Natural Gas

Pollutant	Uncontrolled (lbs/hr)	% Control	Controlled (lbs/hr)	Controlled (tpy)	Controlled (tpy - 2 units)	Notes
NO_X	34.03	0%	34.03	149.05	298.10	a,b
CO	45.58	0%	45.58	199.64	399.28	a
VOC	2.03	0%	2.03	8.89	17.78	a
PM/PM_{10}	4.80	0%	4.80	21.02	42.05	e
SO_2	0.53	0%	0.53	2.32	4.64	d

75% Load

-17.7 °F Scenario with Water Injection - Natural Ga s

Pollutant	Uncontrolled (lbs/hr)	% Control	Controlled (lbs/hr)	Controlled (tpy)	Controlled (tpy - 2 units)	Notes
NO_X	29.46	0%	29.46	129.03	258.07	a,b
CO	39.46	0%	39.46	172.83	345.67	a
VOC	1.67	0%	1.67	7.31	14.63	a
PM_{10}	3.62	0%	3.62	15.86	31.71	e
SO_2	0.46	0%	0.46	2.01	4.03	d

57.4 °F Scenario with Water Injection - Natural Gas

Pollutant	Uncontrolled (lbs/hr)	% Control	Controlled (lbs/hr)	Controlled (tpy)	Controlled (tpy - 2 units)	Notes
NO_X	28.56	0%	28.56	125.09	250.19	a,b
CO	38.25	0%	38.25	167.54	335.07	a
VOC	1.62	0%	1.62	7.10	14.19	a
PM_{10}	3.76	0%	3.76	16.47	32.94	e
SO_2	0.45	0%	0.45	1.97	3.94	d

91.5 °F Scenario with Water Injection - Natural Gas

Pollutant	Uncontrolled (lbs/hr)	% Control	Controlled (lbs/hr)	Controlled (tpy)	Controlled (tpy - 2 units)	Notes
NO_X	26.95	0%	26.95	118.04	236.08	a,b
CO	36.10	0%	36.10	158.12	316.24	a
VOC	1.53	0%	1.53	6.70	13.40	a
PM_{10}	3.77	0%	3.77	16.51	33.03	e
SO_2	0.42	0%	0.42	1.84	3.68	d

Southern Montana Electric Generation and Transmission Cooperative, Inc.
Highwood Generating Station gas plant
GE LM6000PF Combustion Turbines

CRITERIA POLLUTANTS AT 100% LOAD - SIMPLE CYCLE

60% Load

-17.7 °F Scenario with Water Injection - Natural Ga s

Pollutant	Uncontrolled (lbs/hr)	% Control	Controlled (lbs/hr)	Controlled (tpy)	Controlled (tpy - 2 units)	Notes
NO_X	25.66	0%	25.66	112.39	224.78	a,b
CO	34.37	0%	34.37	150.54	301.08	a
VOC	1.46	0%	1.46	6.39	12.79	a
PM_{10}	2.52	0%	2.52	11.04	22.08	e
SO_2	0.40	0%	0.40	1.75	3.50	d

57.4 °F Scenario with Water Injection - Natural Gas

Pollutant	Uncontrolled (lbs/hr)	% Control	Controlled (lbs/hr)	Controlled (tpy)	Controlled (tpy - 2 units)	Notes
NO_X	24.38	0%	24.38	106.78	213.57	a,b
CO	32.65	0%	32.65	143.01	286.01	a
VOC	1.38	0%	1.38	6.04	12.09	a
PM_{10}	2.65	0%	2.65	11.61	23.21	e
SO_2	0.38	0%	0.38	1.66	3.33	d

91.5 °F Scenario with Water Injection - Natural Gas

Pollutant	Uncontrolled (lbs/hr)	% Control	Controlled (lbs/hr)	Controlled (tpy)	Controlled (tpy - 2 units)	Notes
NO_X	23.26	0%	23.26	101.88	203.76	a,b
CO	31.16	0%	31.16	136.48	272.96	a
VOC	1.32	0%	1.32	5.78	11.56	a
PM_{10}	2.76	0%	2.76	12.09	24.18	e
SO_2	0.36	0%	0.36	1.58	3.15	d

MAX Emission Rate; Single Temperature Case with natural gas

Pollutant	Max ER Natural Gas per turbine (lb/hr)	Max ER Natural Gas per turbine (tpy)	Load Case
NO_X	36.58	160.22	100%, -17.7 °F
CO	48.96	214.44	100%, -17.7 °F
VOC	2.03	8.89	100%, -17.7 °F
PM/PM_{10} (front and back half)	4.80	21.02	100%, 91.5 °F
SO_X	0.57	2.50	100%, -17.7 °F

Notes:

a. Data from "LM6000PF Max Emissions (2).xls"
b. Assumes water injection
c. Values assume SPRINT system active (EVAP Inlet Conditioning)
d. Data from "Sulfur calculations v01 (2009-02-23).xls"
e. Data from "Primary turbine PM Recalc v01 (2009-02-25).xls"

Southern Montana Electric Generation and Transmission Cooperative, Inc.
Highwood Generating Station gas plant
GE LM6000PF Combustion Turbines

CRITERIA POLLUTANTS AT 100% LOAD - COMBINED CYCLE

Number of Gen Units = 2
Turbine type = PC
Fuel = Natural Gas
Control Equipment = Water Inj, oxy cat and SCR
Hours of Operation, per turbine = 8,760 hrs/hr

100% Load with Duct Burners

-17.7 °F Scenario with Water Injection - Natural Ga s

Pollutant	Uncontrolled (lbs/hr)	% Control	Controlled (lbs/hr)	Controlled (tpy)	Controlled (tpy - 2 units)	Notes
NO_X	36.58	89%	4.13	18.10	36.20	g
CO	48.96	96%	2.01	8.82	17.63	g
VOC	1.73	0%	1.73	7.56	15.12	g
PM/PM_{10}	5.81	0%	5.81	25.47	50.93	e
SO_2	0.65	0%	0.65	2.83	5.66	d

57.4 °F Scenario with Water Injection - Natural Gas

Pollutant	Uncontrolled (lbs/hr)	% Control	Controlled (lbs/hr)	Controlled (tpy)	Controlled (tpy - 2 units)	Notes
NO_X	35.86	88%	4.16	18.22	36.43	g
CO	48.00	96%	2.03	8.87	17.75	g
VOC	1.74	0%	1.74	7.61	15.22	g
PM/PM_{10}	6.30	0%	6.30	27.61	55.23	e
SO_2	0.65	0%	0.65	2.87	5.74	d

91.5 °F Scenario with Water Injection - Natural Gas

Pollutant	Uncontrolled (lbs/hr)	% Control	Controlled (lbs/hr)	Controlled (tpy)	Controlled (tpy - 2 units)	Notes
NO_X	34.03	88%	4.04	17.71	35.43	g
CO	45.58	96%	1.97	8.63	17.26	g
VOC	1.69	0%	1.69	7.40	14.80	g
PM/PM_{10}	7.20	0%	7.20	31.55	63.10	e
SO_2	0.69	0%	0.69	3.02	6.05	d

100% Load

-17.7 °F Scenario with Water Injection - Natural Ga s

Pollutant	Uncontrolled (lbs/hr)	% Control	Controlled (lbs/hr)	Controlled (tpy)	Controlled (tpy - 2 units)	Notes
NO_X	36.58	89%	4.12	18.04	36.08	g
CO	48.96	96%	2.01	8.79	17.58	g
VOC	1.72	0%	1.72	7.54	15.07	g
PM/PM_{10}	4.60	0%	4.60	20.15	40.30	e
SO_2	0.56	0%	0.56	2.45	4.91	d

57.4 °F Scenario with Water Injection - Natural Gas

Pollutant	Uncontrolled (lbs/hr)	% Control	Controlled (lbs/hr)	Controlled (tpy)	Controlled (tpy - 2 units)	Notes
NO_X	35.86	88%	4.15	18.16	36.32	g
CO	48.00	96%	2.02	8.84	17.69	g
VOC	1.73	0%	1.73	7.58	15.17	g
PM/PM_{10}	4.77	0%	4.77	20.88	41.77	e
SO_2	0.55	0%	0.55	2.41	4.81	d

91.5 °F Scenario with Water Injection - Natural Gas

Pollutant	Uncontrolled (lbs/hr)	% Control	Controlled (lbs/hr)	Controlled (tpy)	Controlled (tpy - 2 units)	Notes
NO_X	34.03	88%	4.02	17.61	35.23	g
CO	45.58	96%	1.96	8.58	17.16	g
VOC	1.68	0%	1.68	7.36	14.72	g
PM/PM_{10}	4.80	0%	4.80	21.02	42.04	e
SO_2	0.530	0%	0.53	2.32	4.65	d

Southern Montana Electric Generation and Transmission Cooperative, Inc.
Highwood Generating Station gas plant
GE LM6000PF Combustion Turbines

CRITERIA POLLUTANTS AT 100% LOAD - COMBINED CYCLE

75% Load

-17.7 ℉ Scenario with Water Injection - Natural Ga s

Pollutant	Uncontrolled (lbs/hr)	% Control	Controlled (lbs/hr)	Controlled (tpy)	Controlled (tpy - 2 units)	Notes
NO_X	29.46	88%	3.46	15.16	30.33	g
CO	39.46	96%	1.69	7.39	14.77	g
VOC	1.45	0%	1.45	6.33	12.67	g
PM_{10}	3.65	0%	3.65	15.99	31.98	e
SO_2	0.46	0%	0.46	2.00	4.00	d

57.4 ℉ Scenario with Water Injection - Natural Gas

Pollutant	Uncontrolled (lbs/hr)	% Control	Controlled (lbs/hr)	Controlled (tpy)	Controlled (tpy - 2 units)	Notes
NO_X	28.56	88%	3.45	15.13	30.26	g
CO	38.25	96%	1.68	7.37	14.74	g
VOC	1.44	0%	1.44	6.32	12.64	g
PM_{10}	3.82	0%	3.82	16.71	33.42	e
SO_2	0.45	0%	0.45	1.95	3.90	d

91.5 ℉ Scenario with Water Injection - Natural Gas

Pollutant	Uncontrolled (lbs/hr)	% Control	Controlled (lbs/hr)	Controlled (tpy)	Controlled (tpy - 2 units)	Notes
NO_X	26.95	87%	3.42	14.97	29.95	g
CO	36.10	95%	1.67	7.29	14.59	g
VOC	1.43	0%	1.43	6.25	12.51	g
PM_{10}	3.77	0%	3.77	16.50	33.00	e
SO_2	0.421	0%	0.42	1.84	3.68	d

60% Load

-17.7 ℉ Scenario with Water Injection - Natural Ga s

Pollutant	Uncontrolled (lbs/hr)	% Control	Controlled (lbs/hr)	Controlled (tpy)	Controlled (tpy - 2 units)	Notes
NO_X	25.66	88%	2.97	13.02	26.03	g
CO	34.37	95%	1.81	7.93	15.85	g
VOC	1.86	0%	1.86	8.16	16.31	g
PM_{10}	2.61	0%	2.61	11.44	22.88	e
SO_2	0.41	0%	0.41	1.77	3.55	d

57.4 ℉ Scenario with Water Injection - Natural Gas

Pollutant	Uncontrolled (lbs/hr)	% Control	Controlled (lbs/hr)	Controlled (tpy)	Controlled (tpy - 2 units)	Notes
NO_X	24.38	88%	2.95	12.94	25.87	g
CO	32.65	94%	1.85	8.10	16.21	g
VOC	1.85	0%	1.85	8.10	16.21	g
PM_{10}	2.75	0%	2.75	12.06	24.12	e
SO_2	0.39	0%	0.39	1.69	3.38	d

91.5 ℉ Scenario with Water Injection - Natural Gas

Pollutant	Uncontrolled (lbs/hr)	% Control	Controlled (lbs/hr)	Controlled (tpy)	Controlled (tpy - 2 units)	Notes
NO_X	23.26	88%	2.87	12.56	25.13	g
CO	31.16	94%	1.75	7.65	15.30	g
VOC	1.80	0%	1.80	7.87	15.74	g
PM_{10}	2.76	0%	2.76	12.10	24.20	e
SO_2	0.363	0%	0.36	1.59	3.18	d

Southern Montana Electric Generation and Transmission Cooperative, Inc.
Highwood Generating Station gas plant
GE LM6000PF Combustion Turbines

CRITERIA POLLUTANTS AT 100% LOAD - COMBINED CYCLE

MAX Emission Rate; Single Temperature Case with natural gas

Pollutant	Max ER Natural Gas per turbine (lb/hr)	Max ER Natural Gas per turbine (tpy)	Load Case
NO_X	4.16	18.22	100% DB, 57.4°F
CO	2.03	8.87	100% DB, 57.4 °F
VOC	1.86	8.16	60%, -17.7 °F
PM/PM_{10} (front and back half)	7.20	31.55	100% DB, 91.5 °F
SO_X	0.69	3.02	100% DB, 91.5 °F

Notes:

a. Data from "EmissionsINFO-Rev2 (2009-02-26.xls)"
b. Not Used
c. Not Used
d. Data from "Sulfur calculations v01 (2009-02-23).xls"
e. Data from "Primary turbine PM Recalc v01 (2009-02-25).xls"
f. Not Used
g. Post control values from "CC" Tab of this spreadsheet
h. Uncontrolled values from respective turbine simple cycle (SC) tabs of this spreadsheet

Southern Montana Electric Generation and Transmission Cooperative, Inc.
Highwood Generating Station gas plant
GE LM6000PF Combustion Turbines

COMBINED CYCLE GUARANTEE EMISSION CALCULATIONS

Concentrations (ppm)

Pollutant	PF				Notes
	Loads				
	100% Burn	**100%**	**75%**	**60%**	
NOX	2.5	2.5	2.5	2.5	h
CO	2	2	2	2.5	h
VOC	4	4	4	6	h

Guaranteed Heat rate per turbine (btu/kWh)

Temp (℉)	PF			Notes
	Loads			
	100%	**75%**	**60%**	
-17.7	8,284	8,904	9,694	l
57.4	8,450	8,988	9,587	l
91.5	8,568	9,058	9,769	l

GT Gross Power (MW)

Temp (℉)	PF			Notes
	Loads			
	100%	**75%**	**60%**	
-17.7	44.6	33.5	26.8	l
57.4	42.9	32.2	25.7	l
91.5	40.2	30.1	24.1	l

Heat rate per turbine (MMbtu/hr)

Temp (℉)	PF			Notes
	Loads			
	100%	**75%**	**60%**	
-17.7	369.7	298.0	259.5	
57.4	362.3	289.0	246.6	
91.5	344.0	272.8	235.3	

Heat rate per duct burner, HHV (MMbtu/hr)

Temp (℉)	PF	Notes
	100% Burn	
-17.7	55.3	k
57.4	68.2	k
91.5	103.5	k

Heat rate per turbine, post burner (MMbtu/hr)

Temp (℉)	PF				Notes
	Loads				
	100% Burn	**100%**	**75%**	**60%**	
-17.7	424.9	369.7	298.0	259.5	
57.4	430.4	362.3	289.0	246.6	
91.5	447.5	344.0	272.8	235.3	

Exhaust temperature, post burner (°F)

Temp (°F)	PF				Notes
	Loads				
	100% Burn	100%	75%	60%	
-17.7	1,022	846	736	718	b,d,e,f,g
57.4	1,034	856	784	766	a,b,d,g
91.5	1,046	865	866	945	b,d

Duct Burner Exit Temp (degR)

Temp (°F)	PF			
	Loads			
	100% Burn	100%	75%	60%
-17.7	1,482	1,306	1,195	1,178
57.4	1,494	1,315	1,244	1,226
91.5	1,505	1,325	1,326	1,404

Stack Exhaust Flowrate (lb/hr)

Temp (°F)	PF				
	Loads				
	100% Burn	100%	75%	60%	Notes
-17.7	966,000	963,000	810,000	695,000	k
57.4	935,000	932,000	797,000	680,000	k
91.5	899,000	894,000	781,000	654,000	k

Stack Molecular Weight, Wet (lb/lb-mol)

Temp (°F)	PF				
	Loads				
	100% Burn	100%	75%	60%	Notes
-17.7	28.6	28.6	28.6	28.6	e,g,i,l
57.4	28.3	28.3	28.5	28.5	b,g,i,l
91.5	28.2	28.2	28.4	28.4	b,i,l

Stack Molar % Water (%)

Temp (°F)	PF				
	Loads				
	100% Burn	100%	75%	60%	Notes
-17.7	6.0	6.0	5.9	6.0	e,g,i,l
57.4	8.6	8.6	6.9	7.1	b,g,i,l
91.5	9.3	9.3	7.5	7.7	b,i,l

Stack Molecular Weight, Dry (lb/lb-mol)

Temp (°F)	PF			
	Loads			
	100% Burn	100%	75%	60%
-17.7	26.9	26.9	26.9	26.9
57.4	25.9	25.9	26.5	26.5
91.5	25.6	25.6	26.3	26.2

Pollutant Molecular Weights	
Density of Air @ STP	0.0749
Molecular Weight of Air	28.97
Molecular Weight of NO2	46.01
Molecular Weight of CO	28.01
Molecular Weight of VOC (as carbon)	12.01

Stack Emission Rate - NOX, Dry (lb/hr)

Temp (°F)	PF			
	Loads			
	100% Burn	100%	75%	60%
-17.7	4.13	4.12	3.46	2.97
57.4	4.16	4.15	3.45	2.95
91.5	4.04	4.02	3.42	2.87

Stack Emission Rate - CO, Dry (lb/hr)

Temp (°F)	PF			
	Loads			
	100% Burn	100%	75%	60%
-17.7	2.0	2.0	1.7	1.8
57.4	2.0	2.0	1.7	1.8
91.5	2.0	2.0	1.7	1.7

Stack Emission Rate - VOC, Dry (lb/hr)

Temp (°F)	PF			
	Loads			
	100% Burn	100%	75%	60%
-17.7	1.73	1.72	1.45	1.86
57.4	1.74	1.73	1.44	1.85
91.5	1.69	1.68	1.43	1.80

Notes:
a. Data from "HGSCC Emissions 2-13-09.xls" from Stanley Consultants
b. Data from "LM6000PC_loadvaried.pdf" from vendor
c. Inlet air heated to 20 °F
d. Data from "LM6000PF_loadvaried.pdf" from vendor
e. Data from "LM6000PC_heated.pdf" from vendor
f. Data from "LM6000PF_heated.pdf" from vendor
g. Highlighted values not provided by turbine vendor, they have been scaled from available data for each model
h. Highlighted values not provided by turbine vendor, assumed to be equal to the PC turbine at 50% load for each temperature
i. Molecular weights for 100% load with burners are assumed to be equal to 100% load without burners
k. Data from "Emissions INFO-Rev3 (gnb edits).xls"
l. PF Model data from "LM6000PF Max Emissions (2).xls"

Southern Montana Electric Generation and Transmission Cooperative, Inc.
Highwood Generating Station gas plant
GE LM6000PF Combustion Turbines

STARTUP / SHUTDOWN EMISSIONS

GE-defined SUSD emissions

(Simple Cycle Data from "709300 PERF_ISO LM6000PF SPRINT-25 Startup.pdf")
(Simple Cycle Data from "709300 PERF_ISO LM6000PF SPRINT-25 Shutdown.pdf")
(Combined Cycle Data from "CC_SUSD Calcs.xls")

		Estimated Startup			
		Quantities per Generating Unit			
		Simple Cycle Natural Gas[2]		Combined Cycle Natural Gas[1]	
Parameter	Units	Startup	Shutdown	Startup	Shutdown
Ambient Temperature	Deg F	59.0	59.0	59.0	59.0
NOx as NO2	lbs	4.50	3.50	26.12	9.6
CO	lbs	20.00	16.50	76.20	2.8
VOC	lbs	0.94	0.29	1.53	0.07
PM (Method 5 and 202)	lbs	0.79	0.64	4.80	1.60
SO2	lbs	0.09	0.08	0.57	0.19
Nominal Duration	min	9.9	8.0	60.0	20.0

Limitations of SUSD for each turbine (both physical and fuel limitations)

	Simple Cycle	Combined Cycle
Hourly startups	3	1
Hourly shutdowns	3	1

		Maximum Hourly Startup and Shutdown Emission Rates			
		Quantities per Turbine			
		Simple Cycle Natural Gas		Combined Cycle Natural Gas	
Parameter	Units	Startup	Shutdown	Startup	Shutdown
Ambient Temperature	Deg F	59.0	59.0	59.0	59.0
NOx as NO2	lbs/hr	13.50	10.50	26.1	9.56
CO	lbs/hr	60.00	49.50	76.2	2.80
VOC	lbs/hr	2.81	0.87	1.5	0.07
PM (Method 5 and 202)	lbs/hr	2.37	1.92	4.8	1.60
SO2	lbs/hr	0.28	0.23	0.6	0.19

	Estimated Hourly Maximum Emissions including Startup								
	Quantities per Turbine								
	Simple Cycle Natural Gas								
Parameter	SU hourly Emissions (lbs/hr)	Time in SU (mins)	SD hourly Emissions (lbs/hr)	Time in SD (mins)	% of hour in SUSD	Max Steady-State Hourly Emissions (lb/hr)	Fractional Steady State hourly Emissions (lb/hr)	Sum, SUSD and fract hourly emissions (lb/hr)	Simple Cycle SUSD hourly emission rate[3] (lb/hr)
NOx as NO2	13.50	29.6	10.50	24.0	89%	36.58	3.9	27.88	36.58
CO	60.00	29.6	49.50	24.0	89%	48.96	5.2	114.70	114.70
VOC	2.81	29.6	0.87	24.0	89%	2.03	0.2	3.90	3.90
PM (Method 5 and 202)	2.37	29.6	1.92	24.0	89%	4.80	0.5	4.80	4.80
SO2	0.28	29.6	0.23	24.0	89%	0.57	0.1	0.57	0.57

	Estimated Hourly Maximum Emissions including Startup						
	Quantities per Turbine						
	Combined Cycle Natural Gas						
Parameter	SU hourly Emissions (lbs/hr)	Time in SU (mins)	% of hour in SU	Max Steady-State Hourly Emissions (lb/hr)	Fractional Steady State hourly Emissions (lb/hr)	Sum, SU and fract hourly emissions (lb/hr)	Combined Cycle SU hourly emission rate[3] (lb/hr)
NOx as NO2	26.12	60.00	100%	4.16	0.0	26.12	26.12
CO	76.20	60.00	100%	2.03	0.0	76.20	76.20
VOC	1.53	60.00	100%	1.86	0.0	1.53	1.86
PM (Method 5 and 202)	4.80	60.00	100%	7.20	0.0	4.80	7.20
SO2	0.57	60.00	100%	0.69	0.0	0.57	0.69

Parameter	Estimated Hourly Maximum Emissions including Shutdown Quantities per Turbine Combined Cycle Natural Gas						
	SD hourly Emissions (lbs/hr)	Time in SD (mins)	% of hour in SD	Max Steady-State Hourly Emissions (lb/hr)	Fractional Steady State hourly Emissions (lb/hr)	Sum, SD and fract hourly emissions (lb/hr)	Combined Cycle SD hourly emission rate[3] (lb/hr)
NOx as NO2	9.56	20.00	33%	4.16	2.8	12.33	12.33
CO	2.80	20.00	33%	2.03	1.4	4.15	4.15
VOC	0.07	20.00	33%	1.86	1.2	1.31	1.86
PM (Method 5 and 202)	1.60	20.00	33%	7.20	4.8	6.40	7.20
SO2	0.19	20.00	33%	0.69	0.5	0.65	0.69

Parameter	SUSD Emissions Calculation for proposed limits for hours when a SUSD occurs Quantities per Turbine Both Simple Cycle or Combined Cycle, which ever is greater					
	Simple Cycle SUSD hourly emissions (lb/hr)	Combined Cycle SU hourly emissions (lb/hr)	Combined Cycle SD hourly emissions (lb/hr)	Max SUSD hourly emissions[4] (lb/hr)	Max SUSD hrs per year	Maximum Annual SU Emissions (tpy)
NOx as NO2	36.58	26.12	12.33	36.58	1460	26.70
CO	114.70	76.20	4.15	114.70	1460	83.73
VOC	3.90	1.86	1.86	3.90	1460	2.85
PM (Method 5 and 202)	4.80	7.20	7.20	7.20	1460	5.26
SO2	0.57	0.69	0.69	0.69	1460	0.50

Notes and References

1. Combined cycle lb/event SUSD emissions calculated in spreadsheet "CC SUSD Calcs.xls"
2. Simple cycle NOX, CO, and VOC SUSD emissions provided by GE, PM and SO2 based on duration of SUSD, scaled from steady-state emissions.
3. For some pollutants, because SUSD conditions are at low flowrates, have emissions that are less than steady-state operations. Some pollutants have higher concentrations at low turbine loads, and therefore result in higher mass emissions. The higher of the two values (steady-state, or SUSD) are selected as the appropriate SUSD value.
4. For the purposes of calculating maximum PTE, the highest value for any SU and SD case is used. Individual limits for simple cycle and combined cycle will be proposed for the permit however.

Southern Montana Electric Generation and Transmission Cooperative, Inc.
Highwood Generating Station gas plant
GE LM6000PF Combustion Turbines

MISC EQUIPMENT EMISSIONS

Building Heaters

Natural Gas: AP-42 1.4	**1020 Btu/scf**		**Emissions**						
Building Location	Heat Rate	Natural Gas Use 10^6 scf/hr	NOX (lb/hr)	SO2 (lb/hr)	CO (lb/hr)	VOC (lb/hr)	Pb (lb/hr)	PM10 (Total) (lb/hr)	PM2.5 (lb/hr)
Turbine Enclosures	0.25 MMBtu/hr	0.0002	0.03	0.0001	0.021	0.001	0.0000001	0.002	0.002
Admin/Maintenance/Electrical/STG Buildin	1 MMBtu/hr	0.0010	0.14	0.0006	0.082	0.005	0.0000005	0.007	0.007
Water Treatment Building	0.5 MMBtu/hr	0.0005	0.07	0.0003	0.041	0.003	0.0000002	0.004	0.004
Warehouse	0.5 MMBtu/hr	0.0005	0.07	0.0003	0.041	0.003	0.0000002	0.004	0.004
Water Pump house	0.25 MMBtu/hr	0.0002	0.03	0.0001	0.021	0.001	0.0000001	0.002	0.002
Fuel Gas Compressor Building	0.25 MMBtu/hr	0.0002	0.03	0.0001	0.021	0.001	0.0000001	0.002	0.002
CEMS Enclosures (2ea)	0.05 MMBtu/hr	0.0000	0.01	0.0000	0.004	0.000	0.0000000	0.000	0.000
Total Building Heaters	2.8 MMBtu/hr	0.0027	0.38	0.0016	0.23	0.015	0.0000014	0.021	0.021
			(tpy)	(tpy)	(tpy)	(tpy)	(tpy)	(tpy)	(tpy)
Total Building Heaters	2.8 MMBtu/hr	0.0027	1.68	0.01	1.01	0.07	0.00	0.09	0.09

	Emission Factors
Pollutant	**Natural Gas**
NOx	140 lb/10^6 scf
CO	84 lb/10^6 scf
SO2	0.6 lb/10^6 scf
PM (Total)	7.6 lb/10^6 scf
VOC	5.5 lb/10^6 scf
Pb	0.0005 lb/10^6 scf

Natural Gas: AP-42 1.4

Emergency Generator

Caterpillar 1500 ekW Tier II	1500 kWe	
Diesel Generator Set	1875 kVA	
	2514.375 hp	(763.5 °F exhaust, 11060 cfm)
Fuel Flow	104.8 gal/hr @ 100%	
Heat Input Rate	14.57 MMBtu/hr	
Hours of operation per year	500.00 hours	

	Caterpillar 1250 ekVA Diesel Generator Set			Reference
NOx	4.82 g/hp-hr	26.7 lb/hr	6.68 tpy	Caterpillar
CO	0.19 g/hp-hr	1.1 lb/hr	0.26 tpy	Caterpillar
HC	0.1 g/hp-hr	0.6 lb/hr	0.14 tpy	Caterpillar
SO2 (500 ppm S)	0.025 lb/MMBtu	0.37 lb/hr	0.09 tpy	AP-42 Table 3.3-1
PM	0.023 g/hp-hr	0.1 lb/hr	0.03 tpy	Caterpillar
PM_{10}	--- ---	0.10 lb/hr	0.03 tpy	AP-42 Table 3.4-2
$PM_{2.5}$	--- ---	0.10 lb/hr	0.03 tpy	AP-42 Table 3.4-2

SO_2 Calculations

Liquid Fuel (No. #2 Fuel Oil)	
S % by weight	0.05%
Fuel feed lb/hr	734
SO2 lb/hr	**0.37**

Diesel = density = 0.84
1 gal H20 = density =1.0= 8.337 lb/gal
Diesel (lb/gal)
7.0

Emergency Fire Pump

Caterpillar 230 ekW	230 Kw
Diesel Generator Set	308.43 hp
Fuel Flow	17.9 gal/hr @ 100%
Heat Input Rate	2.51 MMBtu/hr
Hours of operation per year	500.00 hours

	Caterpillar 230 ekW Diesel Generator Set			Reference
Nox	5.41 g/hp-hr	3.68 lb/hr	0.92 tpy	Caterpillar
CO	1.25 g/hp-hr	0.85 lb/hr	0.21 tpy	Caterpillar
HC	0.2 g/hp-hr	0.14 lb/hr	0.03 tpy	Caterpillar
SO2 (500 ppm)	0.025 lb/MMBtu	0.06 lb/hr	0.02 tpy	AP-42 Table 3.3-1
$PM/PM_{10}/PM_{2.5}$	0.211 g/hp-hr	0.14 lb/hr	0.04 tpy	Caterpillar (AP-42 Table 3.3-1 for PM2.5)

SO_2 Calculations

Liquid Fuel (Distillate #2 Oil)	
S % by weight	0.05%
Fuel feed lb/hr	125
SO2 lb/hr	**0.06**

Diesel = density = 0.84
1 gal H20 = density =1.0= 8.337 lb/gal
Diesel (lb/gal)
7.0

Large Stationary Industrial Engine PM Speciation

Filterable particulate	lb/MMBtu	% of total PM	From AP-42 Table 3.4-2
< 1 µm	0.0478	69%	
< 3 µm	0.0479	69%	
< 10 µm	0.0496	71%	
Total filterable particulate	0.062	89%	
Condensable particulate	0.0077	11%	
Total PM-10c	0.0573	82%	
Total particulates	0.0697	---	
Total PM2.5	0.0556	80%	(Assumes all condensible is $PM_{2.5}$)

Southern Montana Electric Generation and Transmission Cooperative, Inc.
Highwood Generating Station gas plant
GE LM6000PF Combustion Turbines

COOLING TOWER EMISSIONS

Hourly Worst-Case Conditions

			Notes
Drift flow	0.56	gpm	a
Circulating flow	28,000	gpm	a
% Drift	0.002%		b,c
Concentration cycles (#	5	cycles	a
Evaporation rate	412	gpm	a
Total dissolved solids	186	mg/l	

Emission Rate

Pollutant	Rate	Rate	Rate	Notes
	mg/min	lb/hr	tpy	
PM_{10}	1,971	0.26	1.14	d

Notes:
a. Data from Stanley Water Balance "21920_PF-010_A_021009_water balance.pdf"
b. Drift value is assumed
c. Drift is based directly on the flow through the cooling tower, and ignores effects due to changes in air density or fluid temperatures.
d. Assumes continuous use of cooling tower, regardless of load, ambient temperature, ambient humidity

Inlet Water Quality
The TDS of the supply water is 186 mg/Liter
The consituents of the particles in the water are:

	Percentage
SiO2	0.0090%
CaCO3	0.0033%
Ca3(PO4)2	0.0017%
SrSO4	0.0003%
FeCl2	0.0000%
(NH4)Cl	0.0000%
CaSO4	0.0691%
MgSO4	0.0299%
MgCl2	0.0000%
KCl	0.0000%
NaF	0.0010%
NaNO3	0.0003%
NaHCO3	0.0274%
Na2SO4	0.0001%
NaCl	0.0105%
Water	99.8476%
Total	100.0000%
Total Solids	

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000 Simple Cycle Turbines

COMBINED CYCLE STARTUP EMISSIONS CALCULATIONS

Turbine Exhaust Concentrations, Simple Cycle Startup (ppm)

		minutes																								
Notes	Pollutant	2	3	4	5	6.0	6.2	6.4	6.6	6.8	7	7.2	7.4	7.6	7.8	8	8.2	8.4	8.6	8.8	9.0	9.2	9.4	9.6	9.8	10
b	NOX	51	51	51	51	51	55.5	61	48	39.5	41	40	34.5	47	37	37.5	30	26	25	25	25	25	25	25	25	25
b	CO	600	600	600	600	600	535	480	260	110	115	125	135	140	150	125	35	40	45	50	55	55	55	55	55	55
b	VOC	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	9	9	9	9	9	9

Combined Cycle Time equivalency to Simple Cycle Startup Time

		minutes																												
Notes		2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
c	Simple Cycle Time	2	3	4	5	6	6.07	6.15	6.22	6.30	6.37	6.44	6.52	6.59	6.67	6.74	6.81	6.89	6.96	7.04	7.11	7.19	7.26	7.33	7.41	7.48	7.56	7.63	7.70	7.78

		minutes																													
Notes		31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54	55	56	57	58	59	60
c	Simple Cycle Time	7.85	7.93	8.00	8.07	8.15	8.22	8.30	8.37	8.44	8.52	8.59	8.67	8.74	8.81	8.89	8.96	9.04	9.11	9.19	9.26	9.33	9.41	9.48	9.56	9.63	9.70	9.78	9.85	9.93	10.00

		minutes																												
Notes	Pollutant	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
d	NOX	51	51	51	51	51	51	51	55.5	55.5	55.5	61	61	61	48	48	39.5	39.5	39.5	41	41	41	40	40	34.5	34.5	34.5	47	47	47
d	CO	600	600	600	600	600	600	600	535	535	535	480	480	480	260	260	110	110	110	115	115	115	125	125	135	135	135	140	140	140
d	VOC	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11

		minutes																													
Notes	Pollutant	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54	55	56	57	58	59	60
d	NOX	37	37	37.5	37.5	37.5	30	30	30	26	26	26	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
d	CO	150	150	125	125	125	35	35	35	40	40	40	45	45	50	50	50	55	55	55	55	55	55	55	55	55	55	55	55	55	55
d	VOC	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	9	9	9	9	9	9	9	9	9	9	9	9	9	9

SCR Temp (°F)

		minutes																												
Notes	Temp (°F)	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
h,j	**ISO (59.0)**	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	82	104	126	148	170	192	214	236	258	280	302	324

		minutes																													
Notes	Temp (°F)	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54	55	56	57	58	59	60
h,j	**ISO (59.0)**	346	368	390	412	434	456	478	500	522	544	566	588	610	632	632	632	632	632	632	632	632	632	632	632	632	632	632	632	632	632

SCR effectiveness

		temperature													
Notes	Temp (°F)	500	505	515	525	535	545	555	565	575	585	595	605	615	625
h	**ISO (59.0)**	84.5%	85.1%	85.9%	86.6%	87.1%	87.7%	88.3%	88.8%	89.2%	89.5%	89.7%	89.8%	89.9%	90.0%

SCR control

	minutes																												
Temp (°F)	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
ISO (59.0)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

	minutes																													
Temp (°F)	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54	55	56	57	58	59	60
ISO (59.0)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	84.5%	85.9%	87.1%	88.8%	89.5%	89.8%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%

CO Temp (°F)

		minutes																												
Notes	Temp (°F)	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
h,j	**ISO (59.0)**	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	82	104	126	148	170	192	214	236	258	280	302	324

		minutes																													
Notes	Temp (°F)	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54	55	56	57	58	59	60
h,j	**ISO (59.0)**	346	368	390	412	434	456	478	500	522	544	566	588	610	632	654	676	698	720	742	764	786	808	830	852	874	896	918	940	962	984

CO effectiveness

	temperature																
Temp (°F)	300	320	340	360	380	400	420	440	460	480	500	520	540	560	580	600	620
ISO (59.0)	81.5%	83.4%	85.4%	87.5%	89.6%	91.0%	91.2%	91.5%	91.8%	92.0%	92.3%	92.6%	92.8%	93.2%	93.3%	93.4%	93.5%

	temperature																
Temp (°F)	640	660	680	700	720	740	760	780	800	820	840	860	880	900	920	940	960
ISO (59.0)	93.6%	93.7%	93.8%	93.9%	94.0%	94.1%	94.2%	94.3%	94.4%	94.4%	94.5%	94.6%	94.7%	94.8%	94.9%	94.9%	95.0%

CO control

	minutes																												
Temp (°F)	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
ISO (59.0)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	81.5%	83.4%

	minutes																													
Temp (°F)	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54	55	56	57	58	59	60
ISO (59.0)	85.4%	87.5%	89.6%	91.0%	91.2%	91.5%	91.8%	92.3%	92.6%	92.8%	93.2%	93.3%	93.4%	93.5%	93.6%	93.7%	93.8%	94.0%	94.1%	94.2%	94.3%	94.4%	94.4%	94.5%	94.6%	94.7%	94.8%	94.9%	95.0%	95.0%

Turbine Exhaust Flowrate (lb/sec)

		minutes																												
Notes	Temp (°F)	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
e	**ISO (59.0)**	114	114	114	114	114	117	120	124	127	130	133	137	140	143	146	149	153	156	159	162	166	169	172	175	178	182	185	188	191

		minutes																													
Notes	Temp (°F)	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54	55	56	57	58	59	60
e	**ISO (59.0)**	195	198	201	204	207	211	214	217	220	224	227	230	233	236	240	243	246	249	253	256	259	262	265	269	272	275	278	282	285	288

Stack Molecular Weight, Wet (lb/lb-mol)

		minutes																												
Notes	Temp (°F)	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
f,i	**ISO (59.0)**	28.85	28.85	28.85	28.85	28.85	28.84	28.83	28.82	28.81	28.80	28.79	28.78	28.77	28.76	28.75	28.74	28.73	28.72	28.71	28.70	28.69	28.68	28.67	28.66	28.65	28.64	28.63	28.62	28.61

		minutes																													
Notes	Temp (°F)	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54	55	56	57	58	59	60
f,i	**ISO (59.0)**	28.60	28.59	28.58	28.57	28.56	28.55	28.54	28.53	28.52	28.51	28.51	28.50	28.49	28.48	28.47	28.46	28.45	28.44	28.43	28.42	28.41	28.40	28.39	28.38	28.37	28.36	28.35	28.34	28.33	28.32

Stack Molar % Water (%)

		minutes																												
Notes	Temp (°F)	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
g,i	**ISO (59.0)**	4.25	4.25	4.25	4.25	4.25	4.32	4.40	4.48	4.56	4.64	4.71	4.79	4.87	4.95	5.02	5.10	5.18	5.26	5.34	5.41	5.49	5.57	5.65	5.72	5.80	5.88	5.96	6.04	6.11

		minutes																													
Notes	Temp (°F)	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54	55	56	57	58	59	60
g,i	**ISO (59.0)**	6.19	6.27	6.35	6.42	6.50	6.58	6.66	6.74	6.81	6.89	6.97	7.05	7.12	7.20	7.28	7.36	7.44	7.51	7.59	7.67	7.75	7.82	7.90	7.98	8.06	8.13	8.21	8.29	8.37	8.45

Stack Molecular Weight, Dry (lb/lb-mol)

		minutes																												
Notes	Temp (°F)	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
	ISO (59.0)	27.6	27.6	27.6	27.6	27.6	27.6	27.6	27.5	27.5	27.5	27.4	27.4	27.4	27.3	27.3	27.3	27.2	27.2	27.2	27.1	27.1	27.1	27.1	27.0	27.0	27.0	26.9	26.9	26.9

		minutes																													
Notes	Temp (°F)	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54	55	56	57	58	59	60
	ISO (59.0)	26.8	26.8	26.8	26.7	26.7	26.7	26.6	26.6	26.6	26.6	26.5	26.5	26.5	26.4	26.4	26.4	26.3	26.3	26.3	26.2	26.2	26.2	26.1	26.1	26.1	26.1	26.0	26.0	26.0	25.9

Pollutant Molecular Weights
Molecular Weight of NO2 46.01 lb/lb-mol
Molecular Weight of CO 28.01 lb/lb-mol
Molecular Weight of VOC 44.10 lb/lb-mol
(as propane)

Stack Emission Rate - NOX, Dry (lbs)

		minutes																												
Notes	Temp (°F)	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
	ISO (59.0) NOX	0.58	0.58	0.58	0.58	0.58	0.60	0.62	0.69	0.71	0.73	0.82	0.84	0.86	0.69	0.71	0.60	0.61	0.62	0.66	0.68	0.69	0.69	0.70	0.62	0.63	0.64	0.89	0.91	0.92

		minutes																													
Notes	Temp (°F)	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54	55	56	57	58	59	60
	ISO (59.0) NOX	0.74	0.75	0.78	0.79	0.80	0.65	0.66	0.10	0.08	0.08	0.07	0.06	0.06	0.06	0.06	0.06	0.06	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.08	0.08

Sum 26.12 lbs NOX/startup

Stack Emission Rate - CO, Dry (lb/hr)

		minutes																												
Notes	Temp (°F)	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
	ISO (59.0)	4.16	4.16	4.16	4.16	4.16	4.28	4.41	4.04	4.15	4.26	3.92	4.02	4.12	2.29	2.34	1.01	1.04	1.06	1.13	1.16	1.18	1.31	1.34	1.47	1.50	1.53	1.62	0.30	0.28

		minutes																													
Notes	Temp (°F)	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54	55	56	57	58	59	60
	ISO (59.0)	0.27	0.23	0.16	0.14	0.14	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05

Sum 76.2 lbs CO/startup

Stack Emission Rate - VOC (as propane), Dry (lb/hr)

		minutes																												
Notes	Temp (°F)	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
	ISO (59.0)	0.040	0.040	0.040	0.040	0.040	0.041	0.042	0.044	0.045	0.046	0.047	0.048	0.050	0.051	0.052	0.053	0.054	0.056	0.057	0.058	0.059	0.060	0.062	0.063	0.064	0.065	0.067	0.013	0.011

		minutes																													
Notes	Temp (°F)	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54	55	56	57	58	59	60
	ISO (59.0)	0.010	0.009	0.008	0.007	0.007	0.007	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.005	0.005	0.005	0.004	0.004	0.004	0.005	0.004	0.004	0.004	0.004	0.004	0.004	0.004

Sum 1.53 lbs VOC/startup

Notes:
a. Reserved
b. Data from "709300 PERF_ISO LM6000PF SPRINT-25 Startup.pdf" from GE
c. Combined Cycle startup will begin (2-6 minutes) just like Simply Cycle up to Acceleration to Base Load, which will be throttled to 90 minutes long to control heating of HRSG
d. Extended Combined Cycle concentrations are determined via lookup tables, from time extended from 6 mins to 90 mins
e. Exhaust mass flow rate increases almost linearly from 114 lb/sec at 6 mins to 288 lb/sec at 10 mins in simply cycle mode
f. Molecular Weight, wet was provided by vendor for nominal operations only, value was graphically determined via trendline, see chart tab "MW Exh"
g. Exhaust Molar % of water was provided by vendor for nomial operations only, value was graphically determined via trendline, see chart tab "% Water"
h. Data from "Typical CO-SCR Conversion Rates Not Guaranteed.pdf" from Vogt Power International
i. Data from "LM6000PF Max Emissions.xls" from vendor
j. Data provided by Vogt is for HP Drum Temp in HRSG, SCR follows same temp curve, curve was continued past HP drum temp to reach optimum SCR operating temperature
k. CO oxidation catalyst assumed to follow SCR temp curve as conservative assumption of heating, because vendor did not provide oxidation catalyst temperature curve.

Data for Charts

Stack Molecular Weight, Wet (lb/lb-mol)

Notes	Temp (℉)	100%	75%	60%
i	**57.4**	28.3	28.5	28.5

Stack Molecular Weight, Wet (lb/lb-mol)

Notes	Temp (℉)	100%	75%	60%
i	**57.4**	8.633	6.898	7.078

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000 Simple Cycle Turbines

COMBINED CYCLE SHUTDOWN EMISSIONS CALCULATIONS

Turbine Exhaust Concentrations, Simple Cycle Shutdown (ppm)

		minutes																				
Notes	Pollutant	0	0.2	0.4	0.6	0.8	1.0	1.2	1.4	1.6	1.8	2.0	2.2	2.4	2.6	2.8	3	4.0	5	6	7.0	8
b	NOX	25	25	25	25	25	25	25.9	31	36.5	37.5	36	40.5	40	50.5	58.5	51	51	51	51	51	51
b	CO	55	55	55	55	52	50	40	50	145	145	130	125	110	310	510	580	580	580	580	580	580
b	VOC	9	9	9	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7

Combined Cycle Time equivalency to Simple Cycle Startup Time

		minutes																				
Notes		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
c	Simple Cycle Time	0	0.2	0.4	0.6	0.8	1	1.2	1.4	1.6	1.8	2	2.2	2.4	2.6	2.8	3	4	5	6	7	8

Turbine Exhaust Concentrations, Simple Cycle Startup (ppm)

		minutes																				
Notes	Pollutant	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
d	NOX	25	25	25	25	25	25	25.9	31	36.5	36.5	36	40.5	40	50.5	58.5	51	51	51	51	51	51
d	CO	55	55	55	55	52	50	40	50	145	145	130	125	110	310	510	580	580	580	580	580	580
d	VOC	9	9	9	9	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7

SCR Temp (°F)

		minutes																				
Notes	Temp (°F)	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
h,j	**ISO (59.0)**	632	610	588	566	544	522	500	478	456	434	412	390	368	346	324	302	302	302	302	302	302

SCR effectiveness

		temperature															
Notes	Temp (°F)	60	499	500	505	515	525	535	545	555	565	575	585	595	605	615	625
h	**ISO (59.0)**	0%	0%	84.5%	85.1%	85.9%	86.6%	87.1%	87.7%	88.3%	88.8%	89.2%	89.5%	89.7%	89.8%	89.9%	90.0%

SCR control

	minutes																				
Temp (°F)	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
ISO (59.0)	90.0%	89.8%	89.5%	88.8%	87.1%	85.9%	84.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

CO Temp (°F)

		minutes																				
Notes	Temp (°F)	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
h,j	**ISO (59.0)**	984	962	940	918	896	874	852	830	808	786	764	742	720	698	676	654	632	610	588	566	544

CO effectiveness

	temperature																																	
Temp (°F)	300	320	340	360	380	400	420	440	460	480	500	520	540	560	580	600	620	640	660	680	700	720	740	760	780	800	820	840	860	880	900	920	940	960
ISO (59.0)	81.5%	83.4%	85.4%	87.5%	89.6%	91.0%	91.2%	91.5%	91.8%	92.0%	92.3%	92.6%	92.8%	93.2%	93.3%	93.4%	93.5%	93.6%	93.7%	93.8%	93.9%	94.0%	94.1%	94.2%	94.3%	94.4%	94.4%	94.5%	94.6%	94.7%	94.8%	94.9%	94.9%	95.0%

CO control

	minutes																				
Temp (°F)	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
ISO (59.0)	95.0%	95.0%	94.9%	94.8%	94.7%	94.6%	94.5%	94.4%	94.4%	94.3%	94.2%	94.1%	94.0%	93.8%	93.7%	93.6%	93.5%	93.4%	93.3%	93.2%	92.8%

Turbine Exhaust Flowrate (lb/sec)

		minutes																				
Notes	Temp (°F)	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
e	**ISO (59.0)**	288	277	265	254	242	231	219	208	196	185	173	162	150	139	127	116	116	116	116	116	116

Stack Molecular Weight, Wet (lb/lb-mol)

		minutes																				
Notes	Temp (°F)	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
f,i	**ISO (59.0)**	28.32	28.35	28.39	28.42	28.46	28.50	28.53	28.57	28.60	28.64	28.67	28.71	28.74	28.78	28.81	28.85	28.85	28.85	28.85	28.85	28.85

Stack Molar % Water (%)

		minutes																				
Notes	Temp (℉)	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
g,i	**ISO (59.0)**	8.45	8.17	7.89	7.61	7.33	7.05	6.77	6.49	6.21	5.93	5.65	5.37	5.09	4.81	4.53	4.25	4.25	4.25	4.25	4.25	4.25

Stack Molecular Weight, Dry (lb/lb-mol)

		minutes																				
Notes	Temp (℉)	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
	ISO (59.0)	25.9	26.0	26.2	26.3	26.4	26.5	26.6	26.7	26.8	26.9	27.1	27.2	27.3	27.4	27.5	27.6	27.6	27.6	27.6	27.6	27.6

Pollutant Molecular Weights

Molecular Weight of NO2	46.01	lb/lb-mol
Molecular Weight of CO	28.01	lb/lb-mol
Molecular Weight of VOC (as carbon)	44.10	lb/lb-mol

Stack Emission Rate - NOX, Dry (lbs)

		minutes																				
Notes	Temp (℉)	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
	ISO (59.0) NOX	0.08	0.07	0.07	0.07	0.08	0.08	0.09	0.67	0.74	0.69	0.64	0.67	0.61	0.71	0.75	0.59	0.59	0.59	0.59	0.59	0.59
	Sum	9.56	lbs NOX/shutdown																			

Stack Emission Rate - CO, Dry (lb/hr)

		minutes																				
Notes	Temp (℉)	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
	ISO (59.0)	0.05	0.05	0.05	0.05	0.04	0.04	0.03	0.04	0.10	0.10	0.08	0.07	0.06	0.16	0.25	0.26	0.27	0.27	0.27	0.28	0.29
	Sum	2.8	lbs CO/shutdown																			

Stack Emission Rate - VOC (as carbon), Dry (lb/hr)

		minutes																				
Notes	Temp (℉)	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
	ISO (59.0)	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.003	0.003	0.003	0.003	0.003	0.003	0.002	0.002	0.002	0.003	0.003	0.003
	Sum	0.069	lbs VOC/startup																			

Notes:

a. Reserved
b. Data from "709300 PERF_ISO LM6000PF SPRINT-25 Shutdown.pdf" from GE
c. Combined Cycle shutdown will end (15-20 minutes) just like Simply Cycle from sync idle to Fuel Cutoff, minutes 0-15 will be throttled to allow HRSG to cool more evenly from full load
d. Extended Combined Cycle concentrations are determined via lookup tables, from time extended from 0 mins to 14 mins
e. Exhaust mass flow rate increases almost linearly from 288 lb/sec at 0 mins to 114 lb/sec at 3 mins in simply cycle mode, therefore linear scaling is applied
f. Molecular Weight, wet was provided by vendor for nominal operations only, value was graphically determined via trendline, see chart tab "MW Exh"
g. Exhaust Molar % of water was provided by vendor for nomial operations only, value was graphically determined via trendline, see chart tab "% Water"
h. Data from "Typical CO-SCR Conversion Rates Not Guaranteed.pdf" from Vogt Power International
i. Data from "LM6000PF Max Emissions.xls" from vendor
j. Data provided by Vogt is for HP Drum Temp in HRSG, SCR follows same temp curve, curve was continued past HP drum temp to reach optimum SCR operating temperature
k. CO oxidation catalyst assumed to follow SCR temp curve as conservative assumption of heating, because vendor did not provide oxidation catalyst temperature curve.

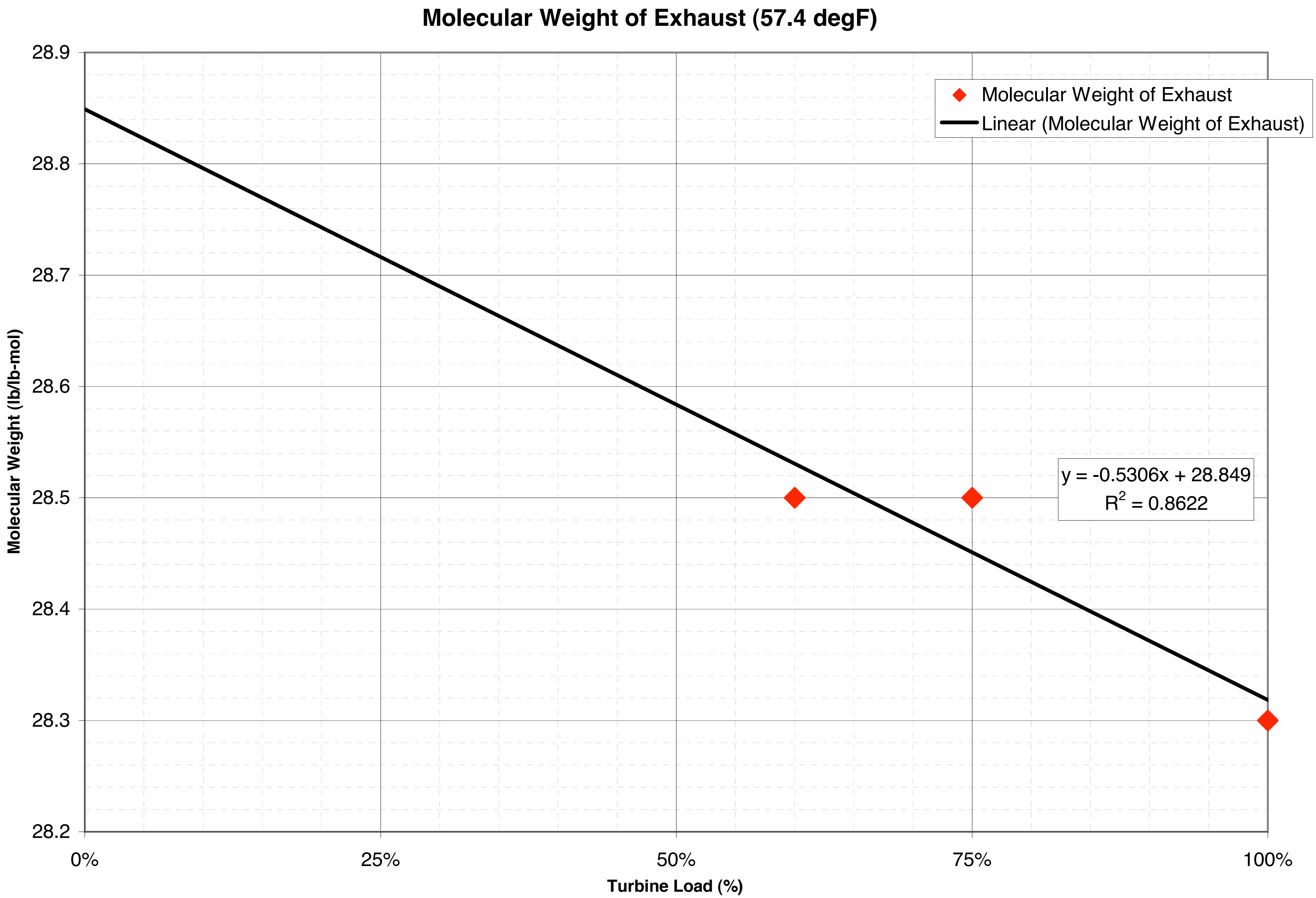
Data for Charts

Stack Molecular Weight, Wet (lb/lb-mol)

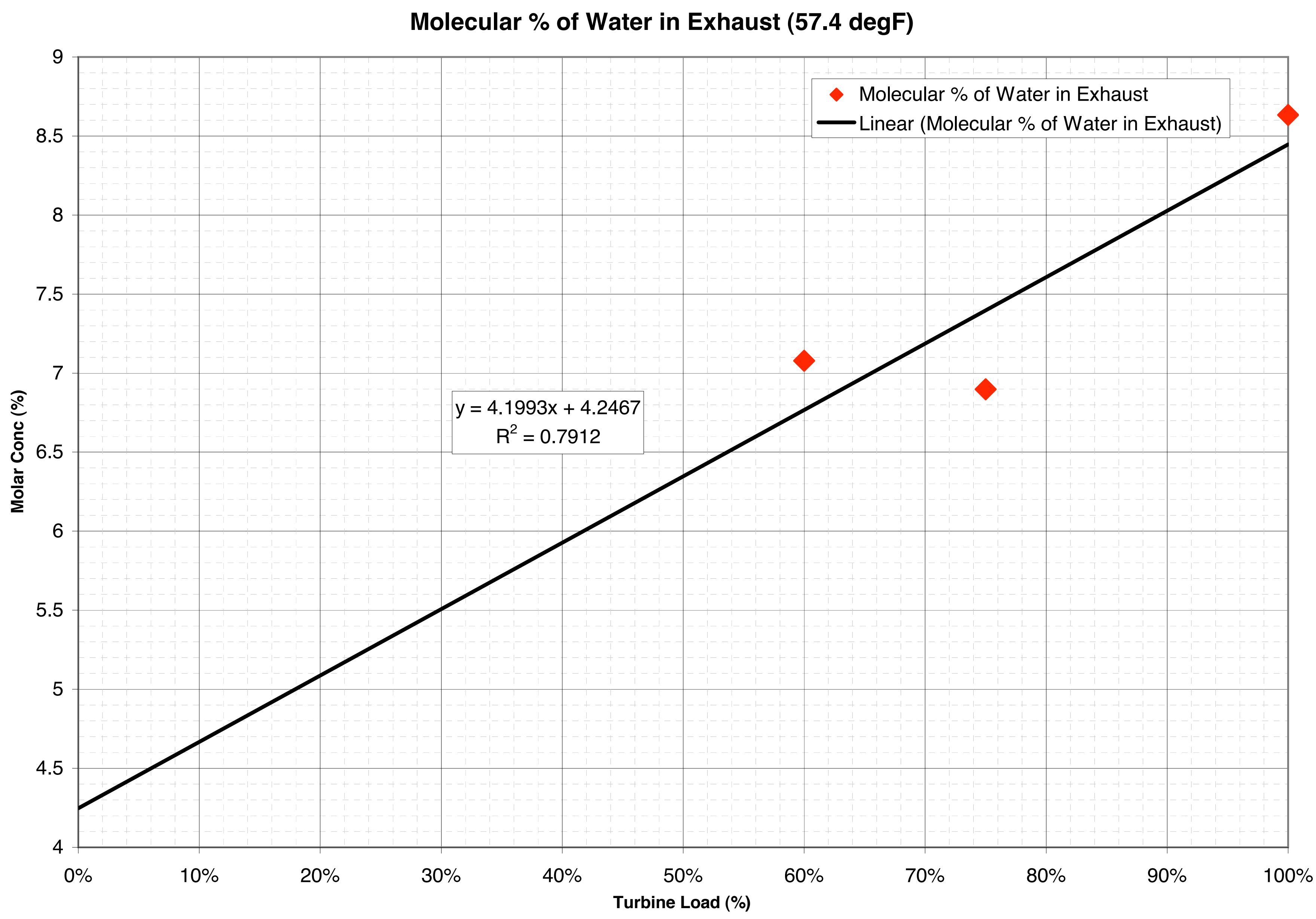
Notes	Temp (℉)	100%	75%	60%
i	**57.4**	28.3	28.5	28.5

Stack Molecular Weight, Wet (lb/lb-mol)

Notes	Temp (℉)	100%	75%	60%
i	**57.4**	8.633	6.898	7.078



Molecular Weight of Exhaust (57.4 degF)
28.9
28.8
28.7
28.6
28.5
28.4
28.3
28.2
Molecular Weight (lb/lb-mol)
0%
25%
50%
75%
100%
Turbine Load (%)
Molecular Weight of Exhaust
Linear (Molecular Weight of Exhaust)
y = -0.5306x + 28.849
R2 = 0.8622


Molecular % of Water in Exhaust (57.4 degF)
Molecular % of Water in Exhaust
Linear (Molecular % of Water in Exhaust)
y = 4.1993x + 4.2467
R2 = 0.7912
Molar Conc (%)
Turbine Load (%)
9
8.5
8
7.5
7
6.5
6
5.5
5
4.5
4
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Combustion Turbines

PRIMARY TURBINE PM EMISSION RATE CALCULATIONS - SIMPLE CYCLE

Natural Gas PM calculations to scale PM emissions with turbine fuel use, including ammonium sulfate formation

lbs/hr ammonium sulfate formed from S in natural gas

Temp (℉)	PF Loads 100%	75%	60%	Notes
-17.7	0.60	0.39	0.26	e
57.4	0.77	0.57	0.48	e
91.5	0.80	0.60	0.59	e

Guaranteed Heat rate per turbine (btu/kWh)

Temp (℉)	PF Loads 100%	75%	60%	Notes
-17.7	8,284	8,904	9,694	f,g
57.4	8,450	8,988	9,587	f,g
91.5	8,568	9,058	9,769	f,g

GT Gross Power (MW)

Temp (℉)	PF Loads 100%	75%	60%	Notes
-17.7	44.6	33.5	26.8	f,g
57.4	42.9	32.2	25.7	f,g
91.5	40.2	30.1	24.1	f,g

Heat rate per turbine (MMbtu/hr)

Temp (℉)	PF Loads 100%	75%	60%	Notes
-17.7	369.7	298.0	259.5	a,b,c,d
57.4	362.3	289.0	246.6	a,b
91.5	344.0	272.8	235.3	a,b

Heat Rate % of 100% load value, at each temperature

Temp (℉)	PF Loads 100%	75%	60%	Notes
-17.7	100.0%	80.6%	70.2%	
57.4	100.0%	79.8%	68.1%	
91.5	100.0%	79.3%	68.4%	

Vendor Quoted Turbine Direct PM Emission Rates (lb/hr)

Temp (℉)	PF Loads 100%	75%	60%	Notes
-17.7	4.0	4.0	4.0	f
57.4	4.0	4.0	4.0	f
91.5	4.0	4.0	4.0	f

Scaled Turbine Direct PM Emission Rates (lb/hr)

Temp (℉)	PF Loads 100%	75%	60%	Notes
-17.7	4.00	3.22	2.26	
57.4	4.00	3.19	2.17	
91.5	4.00	3.17	2.17	

PM-10 as PM-2.5	
Natural Gas	100%

Natural Gas Primary PM-2.5 Emission Rates, (lb/hr)

Temp (℉)	PF Loads 100%	75%	60%	Notes
-17.7	4.00	3.22	2.26	
57.4	4.00	3.19	2.17	
91.5	4.00	3.17	2.17	

Natural Gas total PM-2.5 Emission Rates, incl. ammonium sulfate formation (lb/hr)

Temp (℉)	PF Loads 100%	75%	60%	Notes
-17.7	4.60	3.62	2.52	
57.4	4.77	3.76	2.65	
91.5	4.80	3.77	2.76	

Natural Gas PM/PM-10 Emission Rates, incl. ammonium sulfate formation (lb/hr)

Temp	PF			
	Loads			
(°F)	100%	75%	60%	Notes
-17.7	4.60	3.62	2.52	
57.4	4.77	3.76	2.65	
91.5	4.80	3.77	2.76	

Notes:

a. Data from "LM6000PC_loadvaried.pdf" from vendor
b. Data from "LM6000PF_loadvaried.pdf" from vendor
c. Data from "LM6000PC_heated.pdf" from vendor
d. Data from "LM6000PF_heated.pdf" from vendor
e. Data from "Sulfur calculations v01 (2009-02-23).xls"
f. Data from "EmissionsINFO-Rev2 (2009-02-26).xls"
g. PF model data from "LM6000PF Max Emissions (2).xls"
h. Although slightly temperatures were evaluated on other project, the calculations based on this data will be conservatively increased to account for those differences
i. 75% load values were not provided by vendor, value was linearly interpolated
j. Assumed full conversion of ammonium bisulfate into ammonium sulfate

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Combustion Turbines

PRIMARY TURBINE PM EMISSION RATE CALCULATIONS - COMBINED CYCLE

Natural Gas PM calculations to scale PM emissions with turbine fuel use, including ammonium sulfate formation

lbs/hr ammonium sulfate formed from S in natural gas

	PC				PD				PF				
	Loads				Loads				Loads				
Temp (℉)	100% Burn	100%	75%	50%	100% Burn	100%	75%	50%	100% Burn	100%	75%	50%	Notes
-17.7									0.59	0.60	0.39	0.26	e
57.4									0.77	0.77	0.57	0.48	e
91.5									0.79	0.80	0.60	0.59	e

Heat rate per turbine (MMbtu/hr)

	PC				PD				PF				Notes
	Loads				Loads				Loads				
Temp (℉)	100% Burn	100%	75%	50%	100% Burn	100%	75%	50%	100% Burn	100%	75%	50%	
-17.7									369.7	369.7	298.0	259.5	a,b,c,d
57.4									362.3	362.3	289.0	246.6	a,b
91.5									344.0	344.0	272.8	235.3	a,b

Heat rate per duct burner, HHV (MMbtu/hr)

	PC	PD	PF	Notes
	Loads			
Temp (℉)	100% Burn	100% Burn	100% Burn	
-17.7			110.50	k
57.4			136.30	k
91.5			207.00	k

Heat rate per turbine, post burner (MMbtu/hr)

	PC				PD				PF				Notes
	Loads				Loads				Loads				
Temp (℉)	100% Burn	100%	75%	50%	100% Burn	100%	75%	50%	100% Burn	100%	75%	50%	
-17.7									480.2	369.7	298.02	259.55	
57.4									498.6	362.3	289.0	246.6	
91.5									551.0	344.0	272.8	235.3	

Heat Rate % of 100% load value, at each temperature

	PC				PD				PF				
	Loads				Loads				Loads				
Temp (℉)	100% Burn	100%	75%	50%	100% Burn	100%	75%	50%	100% Burn	100%	75%	50%	Notes
-17.7									129.9%	100.0%	80.6%	70.2%	
57.4									137.6%	100.0%	79.8%	68.1%	
91.5									160.2%	100.0%	79.3%	68.4%	

Vendor Quoted Turbine Direct PM Emission Rates (lb/hr)

	PC				PD				PF				
	Loads				Loads				Loads				
Temp (℉)	100% Burn	100%	75%	50%	100% Burn	100%	75%	50%	100% Burn	100%	75%	50%	Notes
-17.7									Unk	4.0	4.0	4.0	f
57.4									Unk	4.0	4.0	4.0	f
91.5									Unk	4.0	4.0	4.0	f

Scaled Turbine Direct PM Emission Rates (lb/hr)

	PC				PD				PF				
	Loads				Loads				Loads				
Temp (℉)	100% Burn	100%	75%	50%	100% Burn	100%	75%	50%	100% Burn	100%	75%	50%	Notes
-17.7									5.20	4.00	3.22	2.26	
57.4									5.50	4.00	3.19	2.17	
91.5									6.41	4.00	3.17	2.17	

PM-10 as PM-2.5		Source:
Natural Gas	100%	Worst case assumption based on DEQ reluctance to use AP-42 emission rates for speciation

Natural Gas Primary PM-2.5 Emission Rates, (lb/hr)

	PC				PD				PF				
	Loads				Loads				Loads				
Temp (℉)	100% Burn	100%	75%	50%	100% Burn	100%	75%	50%	100% Burn	100%	75%	50%	Notes
-17.7									5.20	4.00	3.22	2.26	
57.4									5.50	4.00	3.19	2.17	
91.5									6.41	4.00	3.17	2.17	

Natural Gas total PM-2.5 Emission Rates, incl. ammonium sulfate formation (lb/hr)

	PC				PD				PF				
	Loads				Loads				Loads				
Temp (℉)	100% Burn	100%	75%	50%	100% Burn	100%	75%	50%	100% Burn	100%	75%	50%	Notes
-17.7									5.79	4.60	3.62	2.52	
57.4									6.27	4.77	3.76	2.65	
91.5									7.19	4.80	3.77	2.76	

Natural Gas PM/PM-10 Emission Rates, incl. ammonium sulfate formation (lb/hr)

	PC				PD				PF				
	Loads				Loads				Loads				
Temp (℉)	100% Burn	100%	75%	50%	100% Burn	100%	75%	50%	100% Burn	100%	75%	50%	Notes
-17.7									5.79	4.60	3.62	2.52	
57.4									6.27	4.77	3.76	2.65	
91.5									7.19	4.80	3.77	2.76	

Notes:
a. Data from "LM6000PC_loadvaried.pdf" from vendor
b. Data from "LM6000PF_loadvaried.pdf" from vendor
c. Data from "LM6000PC_heated.pdf" from vendor
d. Data from "LM6000PF_heated.pdf" from vendor
e. Data from "Sulfur calculations v01 (2009-02-23).xls"
f. Data from "EmissionsINFO2-18-09.xls"

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Combustion Turbines

NATURAL GAS SOX CALCULATIONS BASED ON FUEL SULFUR CONTENT - SIMPLE CYCLE

Assumed fuel sulfur	0.5 gr/100 scf	per 40CFR72.2 definition for 'pipeline quality natural gas"

Heat rate per turbine (btu/kWh)

	PC			PD			PF			Notes
	Loads			Loads			Loads			
Temp (F)	100%	75%	50%	100%	75%	50%	100%	75%	60%	
-17.7							8,284	8,904	9,694	k,m
57.4							8,450	8,988	9,587	k,l,m
91.5							8,568	9,058	9,769	k,m

GT Gross Power (MW)

	PC			PD			PF			Notes
	Loads			Loads			Loads			
Temp (F)	100%	75%	50%	100%	75%	50%	100%	75%	60%	
-17.7							44.6	33.5	26.8	n
57.4							42.9	32.2	25.7	l,n
91.5							40.2	30.1	24.1	n

Heat rate per turbine (MMbtu/hr)

	PC			PD			PF			Notes
	Loads			Loads			Loads			
Temp (F)	100%	75%	50%	100%	75%	50%	100%	75%	60%	
-17.7							369.7	298.0	259.5	
57.4							362.3	289.0	246.6	
91.5							344.0	272.8	235.3	

Vendor Assumed Fuel Heat Content (LHV)	946 Btu/scf	Notes a,b,c,d

Heat rate per turbine (scf/hr)

	PC			PD			PF			Notes
	Loads			Loads			Loads			
Temp (F)	100%	75%	50%	100%	75%	50%	100%	75%	60%	
-17.7							390,775	315,028	274,363	
57.4							382,957	305,506	260,704	
91.5							363,660	288,353	248,758	

Mass Flow Rate of Sulfur (lb/hr)

	PC			PD			PF			Notes
	Loads			Loads			Loads			
Temp (F)	100%	75%	50%	100%	75%	50%	100%	75%	60%	
-17.7							0.28	0.23	0.20	
57.4							0.27	0.22	0.19	
91.5							0.26	0.21	0.18	

Maximum Ammonia Slip	10 ppm

Stack Exit Gas Flow per turbine (kpph)

	PC			PD			PF			Notes
	Loads			Loads			Loads			
Temp (F)	100%	75%	50%	100%	75%	50%	100%	75%	60%	
-17.7							963.0	801.0	695.0	k
57.4							932.0	797.0	680.0	k
91.5							894.0	781.0	654.0	k

Mass Flow Rate of Ammonia slip per turbine (lbs/hr)

	PC			PD			PF			Notes
	Loads			Loads			Loads			
Temp (F)	100%	75%	50%	100%	75%	50%	100%	75%	60%	
-17.7							9.6	8.0	7.0	
57.4							9.3	8.0	6.8	
91.5							8.9	7.8	6.5	

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Combustion Turbines

NATURAL GAS SOX CALCULATIONS BASED ON FUEL SULFUR CONTENT - SIMPLE CYCLE
Molar flow rate of Ammonia (lb-mol/hr)

	PC			PD			PF			Notes
	Loads			Loads			Loads			
Temp (°F)	100%	75%	50%	100%	75%	50%	100%	75%	60%	
-17.7							0.57	0.47	0.41	
57.4							0.55	0.47	0.40	
91.5							0.52	0.46	0.38	

molecular weight

ammonia (NH3)	17.03056	lb/lb-mol
ammonium sulfate (NH4)2SO4	132.1406	lb/lb-mol
sulfur (S)	32.0066	lb/lb-mol
SO2	64.0054	lb/lb-mol
SO3	80.0048	lb/lb-mol

Molar rate of sulfur (lb-mol/hr)

	PC			PD			PF			Notes
	Loads			Loads			Loads			
Temp (°F)	100%	75%	50%	100%	75%	50%	100%	75%	60%	
-17.7							0.0087	0.0070	0.0061	
57.4							0.0085	0.0068	0.0058	
91.5							0.0081	0.0064	0.0056	

Sulfur Oxides mass emission rates (lb/hr) (to estimate primary SO3 formation)

Temp (°F)		100%	80%	75%	70%	50%	Notes
-16	SO2	0.488	0.401	0.379	0.358	0.277	e,h,i
	SO3	0.032	0.026	0.025	0.024	0.018	e,h,i
39.5	SO2	0.489	0.403	0.382	0.361	0.279	f,h,i
	SO3	0.032	0.026	0.025	0.024	0.018	f,h,i
81.5	SO2	0.443	0.368	0.350	0.332	0.260	g,h,i
	SO3	0.029	0.024	0.023	0.022	0.017	g,h,i

Sulfur Oxides molar emission rates (lb-mols/hr) (to estimate primary SO3 formation)

Temp (°F)		100%	80%	75%	70%	50%
-16	SO2	0.00762	---	0.00593	---	0.00433
	SO3	0.00040	---	0.00031	---	0.00023
	% SO3 total	5.0%	---	5.0%	---	5.0%
39.5	SO2	0.00765	---	0.00596	---	0.00436
	SO3	0.00040	---	0.00031	---	0.00023
	% SO3 total	5.0%	---	5.0%	---	5.0%
81.5	SO2	0.00691	---	0.00547	---	0.00406
	SO3	0.00036	---	0.00029	---	0.00021
	% SO3 total	5.0%	---	5.0%	---	5.0%

therefore, approx 5% of turbine S emissions are SO3

Assume 10% of primary SOX is SO3

If assume that only SO2 converted before stack exit is available for (NH4)2SO4 formation, using vendor conversion numbers…

Total reported alternative vendor catalytic conversion of SO2 to SO3 (interpolation used to fill in loads not provided in alternative vendor conversio

Temp (°F)		100%	80%	75%	70%	50%	Notes
-16	CO Cat	46%	36%	35%	33%	22%	e,h,i
39.5	Total SO3 conv.	64%	64%	58%	52%	55%	f,h,i
81.5		70%	65%	65%	65%	77%	g,h,i
-16	SCR Cat	2%	2%	2%	2%	2%	e,h,i
39.5	Total SO3 conv.	2%	2%	2%	2%	2%	f,h,i
81.5		2%	2%	2%	2%	2%	g,h,i
-16	total	48%	38%	37%	35%	24%	h,i
39.5	Total SO3 conv.	66%	66%	60%	54%	57%	h,i
81.5		72%	67%	67%	67%	79%	h,i

lb-mols of SO3 converted = lb-mol of ammonium sulfate formed

	PC			PD			PF			Notes
	Loads			Loads			Loads			
Temp (°F)	100%	75%	50%	100%	75%	50%	100%	75%	60%	
-17.7							0.0046	0.0030	0.0019	
57.4							0.0059	0.0044	0.0036	
91.5							0.0061	0.0045	0.0045	

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Combustion Turbines

NATURAL GAS SOX CALCULATIONS BASED ON FUEL SULFUR CONTENT - SIMPLE CYCLE

emission rate of (NH4)2SO4 (lb/hr)

	PC			PD			PF			Notes
	Loads			Loads			Loads			
Temp (℉)	**100%**	**75%**	**50%**	**100%**	**75%**	**50%**	**100%**	**75%**	**60%**	
-17.7							0.61	0.40	0.26	j
57.4							0.78	0.58	0.47	j
91.5							0.80	0.60	0.59	j

to maintain maximum conservativeness, SO2 emissions are not reduced by portion converted to sulfate by CO and SCR catalysts.

SOX emissions (lb/hr)

	PC			PD			PF			Notes
	Loads			Loads			Loads			
Temp (℉)	**100%**	**75%**	**50%**	**100%**	**75%**	**50%**	**100%**	**75%**	**60%**	
-17.7							0.57	0.46	0.40	
57.4							0.56	0.45	0.38	
91.5							0.53	0.42	0.36	

Notes:
a. Data from "LM6000PC_loadvaried.pdf" from vendor
b. Data from "LM6000PF_loadvaried.pdf" from vendor
c. Data from "LM6000PC_heated.pdf" from vendor
d. Data from "LM6000PF_heated.pdf" from vendor
e. Data from "C08-105 -16 Amb Non-Calc Rev D1.xls" from GE LM6000PC bids from other project
f. Data from "C08-105 +39.5 Amb Non-Calc Rev D1.xls" from GE LM6000PC bids from other project
g. Data from "C08-105 81.5 Amb Non-Calc Rev D1.xls" from GE LM6000PC bids from other project
h. Although slightly temperatures were evaluated on other project, the calculations based on this data will be conservatively increased to account for those diff
i. 75% load values were not provided by vendor, value was linearly interpolated
j. Assumed full conversion of ammonium bisulfate into ammonium sulfate
k. Data from "EmissionsINFO-Rev2 (2009-02-26).xls" from Stanley
l. PD model data from "SME_GE_APPS_PD.xls from Stanley
m. PD model data from "2-12-09GEModified_PD_A.xls" from Stanley
n. PF model data from "LM6000PF Max Emissions (2).xls"

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GE LM6000PF Combustion Turbines

NATURAL GAS SOX CALCULATIONS BASED ON FUEL SULFUR CONTENT - COMBINED CYCLE

Assumed fuel sulfur	0.5 gr/100 scf	per 40CFR72.2 definition for 'pipeline quality natural gas"

Heat rate per turbine (MMbtu/hr)

	PC				PD				PF				Notes
	Loads				Loads				Loads				
Temp (℉)	100% Burn	100%	75%	50%	100% Burn	100%	75%	50%	100% Burn	100%	75%	50%	
-17.7									369.7	369.7	298.0	259.5	a,b,c,d
57.4									362.3	362.3	289.0	246.6	a,b
91.5									344.0	344.0	272.8	235.3	a,b

Heat rate per duct burner, HHV (MMbtu/hr)

	PC	PD	PF	Notes
	Loads			
Temp (℉)	100% Burn	100% Burn	100% Burn	
-17.7			55.3	k
57.4			68.2	k
91.5			103.5	k

Heat rate per turbine, post burner (MMbtu/hr)

	PC				PD				PF				Notes
	Loads				Loads				Loads				
Temp (℉)	100% Burn	100%	75%	50%	100% Burn	100%	75%	50%	100% Burn	100%	75%	50%	
-17.7									424.9	369.7	298.02	259.55	
57.4									430.4	362.3	289.0	246.6	
91.5									447.5	344.0	272.8	235.3	

Vendor Assumed Fuel Heat Content (LHV)	946 Btu/scf	Notes a,b,c,d

Heat rate per turbine (scf/hr)

	PC				PD				PF				Notes
	Loads				Loads				Loads				
Temp (℉)	100% Burn	100%	75%	50%	100% Burn	100%	75%	50%	100% Burn	100%	75%	50%	
-17.7									449,179	390,775	315,028	274,363	a,b,c,d
57.4									454,997	382,957	305,506	260,704	a,b
91.5									473,068	363,660	288,353	248,758	a,b

Mass Flow Rate of Sulfur (lb/hr)

	PC				PD				PF				Notes
	Loads				Loads				Loads				
Temp (℉)	100% Burn	100%	75%	50%	100% Burn	100%	75%	50%	100% Burn	100%	75%	50%	
-17.7									0.32	0.28	0.23	0.20	
57.4									0.32	0.27	0.22	0.19	
91.5									0.34	0.26	0.21	0.18	

Maximum Ammonia Slip	10 ppm

Stack Exit Gas Flow per turbine (kpph)

	PC				PD				PF				Notes
	Loads				Loads				Loads				
Temp (℉)	100% Burn	100%	75%	50%	100% Burn	100%	75%	50%	100% Burn	100%	75%	50%	
-17.7									966.0	963.0	801.0	601.8	k
57.4									935.0	932.0	797.0	625.0	k
91.5									899.0	894.0	781.0	596.0	k

Mass Flow Rate of Ammonia slip per turbine (lbs/hr)

	PC				PD				PF				Notes
	Loads				Loads				Loads				
Temp (℉)	100% Burn	100%	75%	50%	100% Burn	100%	75%	50%	100% Burn	100%	75%	50%	
-17.7									9.7	9.6	8.0	6.0	
57.4									9.4	9.3	8.0	6.3	
91.5									9.0	8.9	7.8	6.0	

Molar flow rate of Ammonia (lb-mol/hr)

	PC				PD				PF				Notes
	Loads				Loads				Loads				
Temp (℉)	100% Burn	100%	75%	50%	100% Burn	100%	75%	50%	100% Burn	100%	75%	50%	
-17.7									0.57	0.57	0.47	0.35	
57.4									0.55	0.55	0.47	0.37	
91.5									0.53	0.52	0.46	0.35	

molecular weight

ammonia (NH3)	17.0306 lb/lb-mol
ammonium sulfate (NH4)2SO4	132.1406 lb/lb-mol
sulfur (S)	32.0066 lb/lb-mol
SO2	64.0054 lb/lb-mol
SO3	80.0048 lb/lb-mol

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NATURAL GAS SOX CALCULATIONS BASED ON FUEL SULFUR CONTENT - COMBINED CYCLE

Molar rate of sulfur (lb-mol/hr)

	PC				PD				PF				Notes
	Loads				Loads				Loads				
Temp (℉)	100% Burn	100%	75%	50%	100% Burn	100%	75%	50%	100% Burn	100%	75%	50%	
-17.7									0.010	0.0087	0.007	0.006	
57.4									0.010	0.0085	0.007	0.006	
91.5									0.011	0.0081	0.0064	0.0056	

Sulfur Oxides mass emission rates (lb/hr) (to estimate primary SO3 formation)

Temp (℉)		100%	80%	75%	70%	50%	Notes
-16	SO2	0.488	0.401	0.379	0.358	0.277	e,h,i
	SO3	0.032	0.026	0.025	0.024	0.018	e,h,i
39.5	SO2	0.489	0.403	0.382	0.361	0.279	f,h,i
	SO3	0.032	0.026	0.025	0.024	0.018	f,h,i
81.5	SO2	0.443	0.368	0.350	0.332	0.260	g,h,i
	SO3	0.029	0.024	0.023	0.022	0.017	g,h,i

Sulfur Oxides molar emission rates (lb-mols/hr) (to estimate primary SO3 formation)

Temp (℉)		100%	80%	75%	70%	50%
-16	SO2	0.00762	---	0.00593	---	0.00433
	SO3	0.00040	---	0.00031	---	0.00023
	% SO3 total	5.0%	---	5.0%	---	5.0%
39.5	SO2	0.00765	---	0.00596	---	0.00436
	SO3	0.00040	---	0.00031	---	0.00023
	% SO3 total	5.0%	---	5.0%	---	5.0%
81.5	SO2	0.00691	---	0.00547	---	0.00406
	SO3	0.00036	---	0.00029	---	0.00021
	% SO3 total	5.0%	---	5.0%	---	5.0%

therefore, approx 5% of turbine S emissions are SO3
Assume 10% of primary SOX is SO3

If assume that only SO2 converted before stack exit is available for (NH4)2SO4 formation, using vendor conversion numbers…

Total reported alternative vendor catalytic conversion of SO2 to SO3 (interpolation used to fill in loads not provided in alternative vendor conversions)

Temp (℉)		100%	80%	75%	70%	50%	Notes
-16	CO Cat	46%	36%	35%	33%	22%	e,h,i
39.5	Total SO3 conv.	64%	64%	58%	52%	55%	f,h,i
81.5		70%	65%	65%	65%	77%	g,h,i
-16	SCR Cat	2%	2%	2%	2%	2%	e,h,i
39.5	Total SO3 conv.	2%	2%	2%	2%	2%	f,h,i
81.5		2%	2%	2%	2%	2%	g,h,i
-16	total	48%	38%	37%	35%	24%	h,i
39.5	Total SO3 conv.	66%	66%	60%	54%	57%	h,i
81.5		72%	67%	67%	67%	79%	h,i

lb-mols of SO3 converted = lb-mol of ammonium sulfate formed

	PC				PD				PF				Notes
	Loads				Loads				Loads				
Temp (℉)	100% Burn	100%	75%	50%	100% Burn	100%	75%	50%	100% Burn	100%	75%	50%	
-17.7									0.0053	0.0046	0.0030	0.0019	
57.4									0.0070	0.0059	0.0044	0.0036	
91.5									0.0079	0.0061	0.0045	0.0045	

emission rate of (NH4)2SO4 (lb/hr)

	PC				PD				PF				Notes
	Loads				Loads				Loads				
Temp (℉)	100% Burn	100%	75%	50%	100% Burn	100%	75%	50%	100% Burn	100%	75%	50%	
-17.7									0.59	0.61	0.40	0.26	j
57.4									0.77	0.78	0.58	0.47	j
91.5									0.79	0.80	0.60	0.59	j

to maintain maximum conservativeness, SO2 emissions are not reduced by portion converted to sulfate by CO and SCR catalysts.

SOX emissions (lb/hr)

	PC				PD				PF				Notes
	Loads				Loads				Loads				
Temp (℉)	100% Burn	100%	75%	50%	100% Burn	100%	75%	50%	100% Burn	100%	75%	50%	
-17.7									0.66	0.57	0.46	0.40	
57.4									0.67	0.56	0.45	0.38	
91.5									0.69	0.53	0.42	0.36	

Notes:
a. Data from "LM6000PC_loadvaried.pdf" from vendor
b. Data from "LM6000PF_loadvaried.pdf" from vendor
c. Data from "LM6000PC_heated.pdf" from vendor
d. Data from "LM6000PF_heated.pdf" from vendor
e. Data from "C08-105 -16 Amb Non-Calc Rev D1.xls" from GE LM6000PC bids from other project
f. Data from "C08-105 +39.5 Amb Non-Calc Rev D1.xls" from GE LM6000PC bids from other project
g. Data from "C08-105 81.5 Amb Non-Calc Rev D1.xls" from GE LM6000PC bids from other project
h. Although slightly temperatures were evaluated on other project, the calculations based on this data will be conservatively increased to account for those differences
i. 75% load values were not provided by vendor, value was linearly interpolated
j. Assumed full conversion of ammonium bisulfate into ammonium sulfate
k. Data from "EmissionsINFO02-18-09.xls"

Southern Montana Electric Transmission and Generation Cooperative
Highwood Generating Station
Total HAPS Summary

HAPS EMISSION INVENTORY - SUMMARY

Potential HAP Emissions

Hazardous Air Pollutant	CAS Number	Emissions from Natural Gas Turbines (tpy)	Emissions from Black Start Generator (tpy)	Emissions from Emergency Fire Pump (tpy)	Total Facility Emissions (tpy)
Organic HAPs					
1,3-Butadiene	106-99-0	0.002	0.0E+00	2.45E-05	0.002
Acetaldeyde	75-07-0	0.157	9.2E-05	4.81E-04	0.157
Acrolein	107-02-8	0.025	2.9E-05	5.80E-05	0.025
Benzene	71-43-2	0.047	2.8E-03	5.85E-04	0.050
Ethyl benzene	100-41-4	0.125	0.00	0.00	0.125
Formaldehyde	50-00-0	2.783	2.9E-02	7.40E-04	2.813
Naphthalene	91-20-3	0.005	4.7E-04	5.32E-05	0.006
Polycyclical Aromatic Hydrocarbons (PAH)	PAH	0.009	7.7E-04	1.05E-04	0.010
Propylene Oxide	75-56-9	0.114	1.0E-02	1.62E-03	0.125
Toluene	108-88-3	0.510	1.0E-03	2.57E-04	0.511
Xylenes	1330-20-7	0.251	7.0E-04	1.79E-04	0.252
Total Organic HAPs		**4.03**	**0.045**	**0.004**	**4.08**
Inorganic HAPs					
Lead	7439-92-1	0.00	0.00	0.00	0.00
Total Inorganic HAPs		**0.00**	**0.00**	**0.00**	**0.00**
Total Calculated Maximum Potential HAP Emissions		**4.03**	**0.045**	**0.004**	**4.08**

Southern Montana Electric Transmission and Generation Cooperative
Highwood Generating Station
GE LM6000PF Generating Units

HAPS EMISSION INVENTORY - TURBINES

Design Values			Notes
Number of Swiftpac in operation:	2		
Max Heat Rate of Turbines:			
Natural Gas	447.5	MMBtu/hr	d
Hours of operation:			
Natural Gas	8760	hours/year	

Potential HAP Emissions - Turbine

Hazardous Air Pollutant	**CAS Number**	**Emission Factor for Natural Gas (lb/MMBtu)**	**Emissions from Natural Gas (per turbine) (lb/hr)**	**Total Emissions (tpy)**	**Notes**
Organic HAPs					
1,3-Butadiene	106-99-0	4.3E-07	1.9E-04	0.002	b
Acetaldeyde	75-07-0	4.0E-05	1.8E-02	0.16	b
Acrolein	107-02-8	6.4E-06	2.9E-03	0.025	b
Benzene	71-43-2	1.2E-05	5.4E-03	0.05	b
Ethyl benzene	100-41-4	3.2E-05	1.4E-02	0.13	b
Formaldehyde	50-00-0	7.1E-04	3.2E-01	2.8	b
Naphthalene	91-20-3	1.3E-06	5.8E-04	0.005	b
Polycyclical Aromatic Hydrocarbons (PAH)	PAH	2.2E-06	9.8E-04	0.009	b
Propylene Oxide	75-56-9	2.9E-05	1.3E-02	0.11	b
Toluene	108-88-3	1.3E-04	5.8E-02	0.5	b
Xylenes	1330-20-7	6.4E-05	2.9E-02	0.25	b
Total Organic HAPs				**4.03**	
Inorganic HAPs					
Lead	7439-92-1	0.00	0.00	0.00	a,c
Total Inorganic HAPs				**0.00**	
Total Calculated Maximum Potential HAP Emissions				**4.03**	

Notes:

a. AP-42 Table 3.1-2a

b. AP-42 Table 3.1-3

c. Lead emissions listed as ND, none detected

d. Assumes duct burner firing, most fuel combusted is during combined cycle operations and duct firing, therefore

Southern Montana Electric Transmission and Generation Cooperative
Highwood Generating Station
Black Start Diesel Generator

HAPS EMISSION INVENTORY - BLACK START EMERGENCY GENERATOR

Design Values

Max Heat Rate of Engine:	14.57	MMBtu/hr
Hours of operation:	500	hours/year

Potential HAP Emissions - Black Start Emergency Diesel Generator

Hazardous Air Pollutant	CAS Number	Emission Factor for Diesel (lb/MMBtu)	Emissions from Emergency Generator (lb/hr)	Emissions from Emergency Generator (tpy)	Notes
Organic HAPs					
1,3-Butadiene	106-99-0	0.00	0.00	0.00	c
Acetaldehyde	75-07-0	2.52E-05	3.7E-04	9.18E-05	a
Acrolein	107-02-8	7.88E-06	1.1E-04	2.87E-05	a
Benzene	71-43-2	7.76E-04	1.1E-02	2.83E-03	a
Ethyl benzene	100-41-4	0.00	0.00	0.00	c
Formaldehyde	50-00-0	7.89E-03	1.1E-01	2.87E-02	a
Naphthalene	91-20-3	1.30E-04	1.9E-03	4.74E-04	b
Polycyclical Aromatic Hydrocarbons (PAH)	PAH	2.12E-04	3.1E-03	7.72E-04	b
Propylene Oxide	75-56-9	2.79E-03	4.1E-02	1.02E-02	a
Toluene	108-88-3	2.81E-04	4.1E-03	1.02E-03	a
Xylenes	1330-20-7	1.93E-04	2.8E-03	7.03E-04	a
Total Organic HAPs				**0.045**	
Inorganic HAPs					
Lead	7439-92-1	0.00	0.00	0.00	c
Total Inorganic HAPs				**0.000**	
Total Calculated Maximum Potential HAP Emissions				**0.045**	

Notes:

a. AP-42 Table 3.4-3

b. AP-42 Table 3.4-4

c. Not listed in AP-42

Southern Montana Electric Transmission and Generation Cooperative
Highwood Generating Station
Emergency Fire Pump

HAPS EMISSION INVENTORY - EMERGENCY FIRE PUMP

Design Values

Max Heat Rate of Engine:	2.51	MMBtu/hr
Hours of operation:	500	hours/year

Potential HAP Emissions - Emergency Fire Pump

Hazardous Air Pollutant	CAS Number	Emission Factor for Diesel (lb/MMBtu)	Emissions from Fire Pump (lb/hr)	Emissions from Fire Pump (tpy)	Notes
Organic HAPs					
1,3-Butadiene	106-99-0	3.91E-05	9.8E-05	2.45E-05	a
Acetaldehyde	75-07-0	7.67E-04	1.9E-03	4.81E-04	a
Acrolein	107-02-8	9.25E-05	2.3E-04	5.80E-05	a
Benzene	71-43-2	9.33E-04	2.3E-03	5.85E-04	a
Ethyl benzene	100-41-4	0.00	0.00	0.00E+00	b
Formaldehyde	50-00-0	1.18E-03	3.0E-03	7.40E-04	a
Naphthalene	91-20-3	8.48E-05	2.1E-04	5.32E-05	a
Polycyclical Aromatic Hydrocarbons (PAH)	PAH	1.68E-04	4.2E-04	1.05E-04	a
Propylene Oxide	75-56-9	2.58E-03	6.5E-03	1.62E-03	a
Toluene	108-88-3	4.09E-04	1.0E-03	2.57E-04	a
Xylenes	1330-20-7	2.85E-04	7.2E-04	1.79E-04	a
Total Organic HAPs				**0.004**	a
Inorganic HAPs					
Lead	7439-92-1	0.00	0.00	0.00	b
Total Inorganic HAPs				**0.000**	
Total Calculated Maximum Potential HAP Emissions				**0.004**	

Notes:

a. AP-42 Table 3.3-2

b. Not listed in AP-42

APPENDIX D: RBLC DATABASE SEARCH RESULTS

Southern Montana Electric
Highwood Generating Station
GE LM6000 Simple Cycle Turbines

RBLC BACT Research Summary Tables - Simple Cycle

NOX

RBLC ID	Permit Date	Facility Name	Turbine Type	Description	Control	Limit	Units	Avg
IL*	in review	Standard Energy Ventures - DuPage	PWPS FT-8 SWIFTPAC		WI, SCR	0.157	LB/MMBTU	
CT-0143	---	PPL WALLINGFORD ENERGY, LLC		---	SCR, DLE	2.5	PPM	---
NY*	01/21/2001	NEW YORK POWER AUTHORITY		---	SCR	2.5	PPM	1-hr
CA-0954	05/21/2001	CALPEAK CALPEAK POWER – PANOCHE	PWPS FT-8 SWIFTPAC	---	SCR, DLN	3.4	PPM	3-hr
CA-1095	12/07/2001	EL COLTON, LLC		---	SCR	3.5	PPM	3-hr
CA-1151	06/27/2001	CALPEAK CALPEAK POWER - EL CAJON	PWPS FT-8 SWIFTPAC	Peaking (no hrs limit)	SCR, DLN	3.5	PPM	1-hr
PA*	02/01/2001	ALLEGHENY ENERGY SUPPLY WESTMORELAND	LM6000		DLE, SCR	3.5	PPM	
FL-0261	10/26/2004	CITY OF TALLAHASSEE ARVAH B. HOPKINS GEN. STATION		Peaking (5840 hrs/yr) (4000 hrs FO/yr)	SCR, Water Inj	5	PPM	---
KY*	under review	East Kentucky Power Cooperative - J. K.Smith Plant	GE LMS100	Peaking (4000 hrs/yr)	WI, SCR	5	PPM	1-hr
NE*	04/04/2002	Lincoln Electric System Salt Valley Station	LM6000		SCR	5	PPM	30-day
TX*	09/12/2003	BROWNSVILLE PUBLIC UTILITY		---	SCR	5	PPM	---
TX*	03/28/2003	CITY OF BRIAN		---	SCR	5	PPM	---
TX-0388	02/12/2002	AUSTIN ELECTRIC UTILITY SAND HILL ENERGY CENTER		Peaking	DLN	5	PPM	30-day
TX-0457	06/26/2003	CITY PUBLIC SERVICE LEON CREEK PLANT		---	SCR	5	PPM	---
UT*	06/15/2001	PACIFICORP WEST VALLEY CITY		---	SCR, Water Inj	5	PPM	30-day
UT*	04/03/2002	PACIFICORP GADSBY		---	SCR, Water Inj	5	PPM	30-day
WA*	10/26/2001	BENTON COUNTY PUD FINLEY CONBUSTION TURBINE PROJECT	PWPS FT-8 SWIFTPAC	---	SCR, Water Inj	5	PPM	---
WA-0312	07/18/2003	PUGET SOUND ENERGY FREDONIA ENERGY STATION	PWPS FT-8 SWIFTPAC	---	SCR	5	PPM	3-hr
FL-0272	09/12/2005	KEYS ENERGY SERVICES STOCK ISLAND POWER PLANT		FO Fired	SCR, Water Inj	9	PPM	---
TX-0405	12/15/2000	WESTVACO TEXAS LP	LM6000	Turbine w/o Duct Burners	DLN, SCR	9	PPM	
WA*	07/03/2001	PIERCE POWER	GE TM2500		DLN, SCR	9	PPM	24-HR
NE*	04/04/2002	Lincoln Electric System Salt Valley Station	LM6000		SCR	10	PPM	3-hr
IL*	02/01/2000	Spectrum Energy - Central Ill. Power - St. Peter	LM6000		WI	20	lb/hr	
AR*	02/28/2000	Wrightsville Energy Power facility	GE LM6000	Peaking (5250 hrs/yr)	Steam Inj	25	PPM	
FL*	not issued	TECO Bayside Power Station	PWPS FT-8 SWIFTPAC	3500 hr limit	WI	25	PPM	
IN-0095	12/07/2001	ALLEGHENY ENERGY SUPPLY CO, LLC		Peaking (3500 hrs/yr)	Water Inj	25	PPM	24-hr
KS*	04-17-2007	Westar Energy Emporia Energy Center	LM6000	Peaking (4,300 hrs/yr)	WI	25	PPM	24-hr
MI-0268	06/26/2000	KM POWER COMPANY		Peaking	Steam Inj	25	PPM	30-day
NE*	04/04/2002	Lincoln Electric System Salt Valley Station	LM6000		BYPASS	25	PPM	3-hr
OR-0030	06/22/2001	PACIFICORP KLAMATH FALLS FACILITY	PWPS FT-8 SWIFTPAC	Operates @ 100% load	Water Inj	25	PPM	24-hr
PA-0159	09/29/2000	HANDSOME LAKE ENERGY, L.L.C.	PWPS FT-8 SWIFTPAC	NG Fired	Water Inj	25	PPM	---
PA-0171	07/10/2001	ALLEGHENY ENERGY SUPPLY COMPANY, LLC HARRISON CITY	LM6000	NG Fired	SCR, Water Inj	25	PPM	---
SD-0002	03/20/2001	BLACK HILLS POWER AND LIGHT COMPANY LANGE COMBUSTION TURBINES		Peaking NG Fired	DLN	25	PPM	---
VA-0244	05/01/2000	WOLF HILLS ENERGY LLC	PWPS FT-8 SWIFTPAC	NG Fired	Water Inj	25	PPM	---
WV*	07/10/2000	TENASKA BIG SANDY	PWPS FT-8 SWIFTPAC	Peaking (1314 hrs/yr)	Water Inj	25	PPM	---
WY-0054	03/01/2000	BLACK HILLS POWER & LIGHT NEIL SIMPSON II		NG Fired	DLN	25	PPM	24-hr
WY*	02/27/1998	TWO ELK GENERATION PARTNERS	GE LM5000		gcp	25	PPM	1-HR
AR*	unk	Jonesboro City Water & Lights	GE LM2500			38.9	lb/hr	
VI-0008	01/03/2001	VIRGIN ISLANDS WATER AND POWER AUTHORITY (VIWAPA) KRUM BAY ST. THOMAS GEN. STATION	PWPS FT-8 SWIFTPAC	Peaking (no hrs limit) Fuel Oil Fired	Water Inj	42	PPM	24-hr
IL*	05/01/2000	Rolls-Royce Power ventures - Lockport	Trent		DLN	60.4	lb/hr	
PA-0195	7/6/2000	ALLEGHENY ENERGY SUPPLY GANS CT POWER STATION	LM6000		WI	73.9	PPM	
FL-0266	06/29/2005	SEMINOLE ELECTRIC COMPANY RICHARD J. MIDULLA GEN. STATION (formerly PAYNE CREEK GEN. STATION)	PWPS FT-8 SWIFTPAC	Peaking (2500 hrs/yr) (500 hrs FO/year)	Water Inj	20 NG 42 FO	PPM	24-hr
ID*	09/09/2002	MOUNTAIN VIEW POWER, LLC		---	Water Inj	25 NG	PPM	---
IN*	07/15/1999	PSI CINERGY WABASH PEAKING STATION		Peaking (3000 hrs/yr)	DLN, Water Inj	25 NG 28 FO	PPM	---
IL*	02/04/1999	Dynegy, Rock Rd. Power	GE LM5000	Peaking (1,300 hrs/yr)		25 NG 42 FO	PPM	
MO*	07/25/2002	EMPIRE ENERGY DISTRICT EMPIRE ENERGY CENTER	PWPS FT-8 SWIFTPAC	Dual Fuel, Peaking (3,300 hrs/yr)	Water Inj	25 NG 42 FO	PPM	3-hr
NE-0012	07/29/1999	OMAHA PUBLIC POWER DISTRICT	PWPS FT-8 SWIFTPAC	Peaking (2,000 hrs/yr/turbine) Dual Fuel	Water Inj	25 NG 42 FO	PPM	---
SC*	draft permit	Duke Energy - Lee Steam Station	LM6000	Peaking (4,400 hrs NG, 3,900 FO)	---	25 NG 42 FO	PPM	
VA-0259	01/31/2002	BUCHANAN GENERATION LLC ALLEGHENY ENERGY SUPPLY		NG/FO	Water Inj	25 NG 42 FO	PPM	---
TX-0295	01/17/2002	SOUTH TEXAS ELECTRIC COOP SAM RAYBURN GEN. STATION		720 hrs FO/yr	SCR	5 NG 5 FO	PPM	---
DE*	10/20/2000	NRG Energy	LM6000	synthetic minor	LNB	73 FO	lb/hr	1-hr
TX-0497		INEOS CHOCOLATE BAYOU FACILITY						

* - from EPA Region IV database

RBLC BACT Research Summary Tables - Simple Cycle

CO

RBLC ID	Permit Date	Facility Name	Turbine Type	Description	Control	Limit	Units	Avg
IL*	in review	Standard Energy Ventures - DuPage	PWPS FT-8 SWIFTPAC		OXY CAT	0.0219	LB/MMBTU	
NE*	04/04/2002	Lincoln Electric System Salt Valley Station	LM6000		SCR	5	PPM	30-day
NY*	01/21/2001	NEW YORK POWER AUTHORITY		---	OXY CAT	5	PPM	1-hr
CA-1095	12/07/2001	EL COLTON, LLC		---	OXY CAT	6	PPM	3-hr
FL-0261	10/26/2004	CITY OF TALLAHASSEE ARVAH B. HOPKINS GEN. STATION		Peaking (5840 hrs/yr) (4000 hrs FO/yr)	OXY CAT	6	PPM	---
FL*	not issued	TECO Bayside Power Station	PWPS FT-8 SWIFTPAC	3500 hr limit	OXY CAT	6	PPM	
KY*	under review	East Kentucky Power Cooperative - J. K.Smith Plant	GE LMS100	Peaking (4000 hrs/yr)	OXY CAT	6	PPM	3-hr
TX-0388	02/12/2002	AUSTIN ELECTRIC UTILITY SAND HILL ENERGY CENTER		Peaking	OXY CAT	9	PPM	30-day
UT*	06/15/2001	PACIFICORP WEST VALLEY CITY		---	OXY CAT	10	PPM	30-day
UT*	04/03/2002	PACIFICORP GADSBY		---	OXY CAT	10	PPM	8-hr block
VI-0008	01/03/2001	VIRGIN ISLANDS WATER AND POWER AUTHORITY (VIWAPA) KRUM BAY ST. THOMAS GEN. STATION	PWPS FT-8 SWIFTPAC	Peaking (no hrs limit) Fuel Oil Fired	---	10	PPM	3-hr
WA*	10/26/2001	BENTON COUNTY PUD FINLEY CONBUSTION TURBINE PROJECT	PWPS FT-8 SWIFTPAC	---	OXY CAT	10	PPM	---
WA*	07/03/2001	PIERCE POWER	GE TM2500		OXY CAT	10	PPM	1-HR
NE*	04/04/2002	Lincoln Electric System Salt Valley Station	LM6000		OXY CAT	13	lb/hr	3-hr
CT-0143	---	PPL WALLINGFORD ENERGY, LLC		---	OXY CAT	16	PPM	---
OR-0030	06/22/2001	PACIFICORP KLAMATH FALLS FACILITY	PWPS FT-8 SWIFTPAC	Operates @ 100% load	OXY CAT	16	PPM	8-hr
FL-0272	09/12/2005	KEYS ENERGY SERVICES STOCK ISLAND POWER PLANT		FO Fired	---	20	PPM	---
TX-0405	12/15/2000	WESTVACO TEXAS LP	LM6000	Turbine w/o Duct Burners	OXY CAT	22	PPM	
VA-0259	01/31/2002	BUCHANAN GENERATION LLC ALLEGHENY ENERGY SUPPLY		NG/FO		24	PPM	---
AR*	unk	Jonesboro City Water & Lights	GE LM2500			25	lb/hr	
OK-0042	11/30/2000	WESTER FARMERS ELEC COOP ANADARKO	GE LM6000		WI	25	PPM	
PA-0159	09/29/2000	HANDSOME LAKE ENERGY, L.L.C.	PWPS FT-8 SWIFTPAC	NG Fired	OXY CAT	25	PPM	1-hr
PA-0171	07/10/2001	ALLEGHENY ENERGY SUPPLY COMPANY, LLC HARRISON CITY		NG Fired	OXY CAT	25	PPM	---
SD-0002	03/20/2001	BLACK HILLS POWER AND LIGHT COMPANY LANGE COMBUSTION TURBINES		Peaking NG Fired		25	PPM	---
VA-0244	05/01/2000	WOLF HILLS ENERGY LLC	PWPS FT-8 SWIFTPAC	NG Fired	OXY CAT	25	PPM	---
WY-0054	03/01/2000	BLACK HILLS POWER & LIGHT NEIL SIMPSON II		NG Fired		25	PPM	24-hr
WY*	02/27/1998	TWO ELK GENERATION PARTNERS	GE LM5000		gcp	25	PPM	1-HR
IL*	02/01/2000	Spectrum Energy - Central Ill. Power - St. Peter	LM6000			30.3	lb/hr	
TX*	09/12/2003	BROWNSVILLE PUBLIC UTILITY		---		32	PPM	---
TX*	03/28/2003	CITY OF BRIAN		---		32	PPM	---
IL*	02/04/1999	Dynegy, Rock Rd. Power	GE LM5000	Peaking (1,300 hrs/yr)		38	lb/hr	
CA-1151	06/27/2001	CALPEAK CALPEAK POWER - EL CAJON	PWPS FT-8 SWIFTPAC	Peaking (no hrs limit)	OXY CAT	50	PPM	3-hr
MI-0268	06/26/2000	KM POWER COMPANY		Peaking		60	PPM	30-day
NE*	04/04/2002	Lincoln Electric System Salt Valley Station	LM6000		BYPASS	60	lb/hr	3-hr
IL*	05/01/2000	Rolls-Royce Power ventures - Lockport	Rolls-Royce Trent		DLN	60.4	lb/hr	
KS*	04-17-2007	Westar Energy Emporia Energy Center	LM6000	Peaking (4,300 hrs/yr)		63.8	lb/hr	
AR*	02/28/2000	Wrightsville Energy Power facility	GE LM6000	Peaking (5250 hrs/yr)	Steam Inj	66	PPM	
NE-0012	07/29/1999	OMAHA PUBLIC POWER DISTRICT	PWPS FT-8 SWIFTPAC	Peaking (2,000 hrs/yr/turbine) Dual Fuel		139	PPM	---
DE*	10/20/2000	NRG Energy	LM6000	synthetic minor	GCP	165	lb/hr	1-hr
PA-0195	7/6/2000	ALLEGHENY ENERGY SUPPLY GANS CT POWER STATION			WI	166	PPM	
ID*	09/09/2002	MOUNTAIN VIEW POWER, LLC		---	OXY CAT	10 NG 6 FO	PPM	---
TX-0295	01/17/2002	SOUTH TEXAS ELECTRIC COOP SAM RAYBURN GEN. STATION		720 hrs FO/yr	OXY CAT	15 NG 15 FO	PPM	---
IN-0095	12/07/2001	ALLEGHENY ENERGY SUPPLY CO, LLC		Peaking (3500 hrs/yr)	---	25-100 (temp. depend.)	PPM	24-hr
IN*	07/15/1999	PSI CINERGY WABASH PEAKING STATION		Peaking (3000 hrs/yr)		42 NG 6 FO	PPM	---

* - from EPA Region IV database

VOC

RBLC ID	Permit Date	Facility Name	Turbine Type	Description	Control	Limit	Units	Avg
TX-0405	12/15/2000	WESTVACO TEXAS LP	LM6000	Turbine w/o Duct Burners	OXY CAT	1.98	PPM	
CA-0954	05/21/2001	CALPEAK CALPEAK POWER – PANOCHE	PWPS FT-8 SWIFTPAC	---	---	2	PPM	3-hr
CA-1095	12/07/2001	EL COLTON, LLC		---	OXY CAT	2	PPM	3-hr
CA-1151	06/27/2001	CALPEAK CALPEAK POWER - EL CAJON	PWPS FT-8 SWIFTPAC	Peaking (no hrs limit)	OXY CAT	2	PPM	---
FL-0261	10/26/2004	CITY OF TALLAHASSEE ARVAH B. HOPKINS GEN. STATION		Peaking (5840 hrs/yr) (4000 hrs FO/yr)	---	3	PPM	---
PA-0195	7/6/2000	ALLEGHENY ENERGY SUPPLY GANS CT POWER STATION			WI	5	lb/hr	
FL-0272	09/12/2005	KEYS ENERGY SERVICES STOCK ISLAND POWER PLANT		FO Fired	---	8	PPM	---
TX-0388	02/12/2002	AUSTIN ELECTRIC UTILITY SAND HILL ENERGY CENTER		Peaking	---	8	PPM	---
VI-0008	01/03/2001	VIRGIN ISLANDS WATER AND POWER AUTHORITY (VIWAPA) KRUM BAY ST. THOMAS GEN. STATION	PWPS FT-8 SWIFTPAC	Peaking (no hrs limit) Fuel Oil Fired	---	8	PPM	---

RBLC BACT Research Summary Tables - Simple Cycle

PM/PM10

RBLC ID	Permit Date	Facility Name	Turbine Type	Description	Control	Limit	Units	Avg
OR-0030	06/22/2001	PACIFICORP KLAMATH FALLS FACILITY	PWPS FT-8 SWIFTPAC	Operates @ 100% load	---	1.76	lb/hr	---
NE-0012	07/29/1999	OMAHA PUBLIC POWER DISTRICT	PWPS FT-8 SWIFTPAC	Peaking (2,000 hrs/yr/turbine) Dual Fuel	---	2 NG 7 OIL	lb/hr	---
FL-0261	10/26/2004	CITY OF TALLAHASSEE ARVAH B. HOPKINS GEN. STATION		Peaking (5840 hrs/yr) (4000 hrs FO/yr)	---	2.45	lb/hr	---
IN-0095	12/07/2001	ALLEGHENY ENERGY SUPPLY CO, LLC		Peaking (3500 hrs/yr)	---	2.7	lb/hr	---
PA-0195	7/6/2000	ALLEGHENY ENERGY SUPPLY GANS CT POWER STATION				3	lb/hr	
VA-0244	05/01/2000	WOLF HILLS ENERGY LLC	PWPS FT-8 SWIFTPAC	NG Fired	PQNG	3	lb/hr	---
VA-0259	01/31/2002	BUCHANAN GENERATION LLC ALLEGHENY ENERGY SUPPLY		NG/FO	---	3 NG 10.3 OIL	lb/hr	---
TX-0295	01/17/2002	SOUTH TEXAS ELECTRIC COOP SAM RAYBURN GEN. STATION		720 hrs FO/yr	---	3 NG 5 LF	lb/hr	---
NY-0093	03/31/2005	TRIGEN-NASSAU ENERGY CORPORATION	LM6000	turbine		4.66	lb/hr	
MI-0268	06/26/2000	KM POWER COMPANY		Peaking	---	4.9	lb/hr	---
SD-0002	03/20/2001	BLACK HILLS POWER AND LIGHT COMPANY LANGE COMBUSTION TURBINES		Peaking NG Fired	---	6	lb/hr	---
TX-0388	02/12/2002	AUSTIN ELECTRIC UTILITY SAND HILL ENERGY CENTER		Peaking	---	6.21	lb/hr	---
VI-0008	01/03/2001	VIRGIN ISLANDS WATER AND POWER AUTHORITY (VIWAPA) KRUM BAY ST. THOMAS GEN. STATION	PWPS FT-8 SWIFTPAC	Peaking (no hrs limit) Fuel Oil Fired	ASH SULFUR LIMITS	9 PM 22.6 PM10	lb/hr	---
TX-0457	06/26/2003	CITY PUBLIC SERVICE LEON CREEK PLANT		---	---	11.3	lb/hr	---
FL-0272	09/12/2005	KEYS ENERGY SERVICES STOCK ISLAND POWER PLANT		FO Fired	---	25 front & back half 13.9 front	lb/hr	---

SO2

RBLC ID	Permit Date	Facility Name	Turbine Type	Description	Control	Limit	Units	Avg
CT-0146	10/10/1991	PRATT AND WHITNEY UNITED TECHNOLOGIES CORPORATION	PWPS FT-8 SWIFTPAC	Combined Cycle, Dual Fuel	---	0.17 NG 54.19 FO	lb/hr	---
TX-0388	02/12/2002	AUSTIN ELECTRIC UTILITY SAND HILL ENERGY CENTER		Peaking	PQNG	0.3	lb/hr	---
PA-0159	09/29/2000	HANDSOME LAKE ENERGY, L.L.C.	PWPS FT-8 SWIFTPAC	NG Fired	150 ppm S fuel	0.7	lb/hr	1-hr
FL-0261	10/26/2004	CITY OF TALLAHASSEE ARVAH B. HOPKINS GEN. STATION		Peaking (5840 hrs/yr) (4000 hrs FO/yr)	PQNG	1.13	lb/hr	---
CT-0143	---	PPL WALLINGFORD ENERGY, LLC		---	---	1.26	lb/hr	---
TX-0457	06/26/2003	CITY PUBLIC SERVICE LEON CREEK PLANT		---	---	1.3	lb/hr	---
WA-0312	07/18/2003	PUGET SOUND ENERGY FREDONIA ENERGY STATION	PWPS FT-8 SWIFTPAC	---	PQNG 100 ppm S Oil	1.5	lb/hr	3-hr
TX-0295	01/17/2002	SOUTH TEXAS ELECTRIC COOP SAM RAYBURN GEN. STATION		720 hrs FO/yr	---	2.2 NG 21 FO	lb/hr	---
OR-0030	06/22/2001	PACIFICORP KLAMATH FALLS FACILITY	PWPS FT-8 SWIFTPAC	Operates @ 100% load	PQNG	2.24	lb/hr	24-hr
PA-0195	7/6/2000	ALLEGHENY ENERGY SUPPLY GANS CT POWER STATION				2.5	lb/hr	
VA-0259	01/31/2002	BUCHANAN GENERATION LLC ALLEGHENY ENERGY SUPPLY		NG/FO	---	2.5 NG 23.9 FO	lb/hr	---
PA-0171	07/10/2001	ALLEGHENY ENERGY SUPPLY COMPANY, LLC HARRISON CITY		NG Fired	Low Sulfur Fuels	4.8	lb/hr	---
NE-0012	07/29/1999	OMAHA PUBLIC POWER DISTRICT	PWPS FT-8 SWIFTPAC	Peaking (2,000 hrs/yr/turbine) Dual Fuel	PQNG Clean Fuels	14	lb/hr	---
FL-0272	09/12/2005	KEYS ENERGY SERVICES STOCK ISLAND POWER PLANT		FO Fired	Low Sulfur Fuels	23.6	lb/hr	---
VI-0008	01/03/2001	VIRGIN ISLANDS WATER AND POWER AUTHORITY (VIWAPA) KRUM BAY ST. THOMAS GEN. STATION	PWPS FT-8 SWIFTPAC	Peaking (no hrs limit) Fuel Oil Fired	2000 ppm S fuel	52.1	lb/hr	---

NH4 Slip

RBLC ID	Permit Date	Facility Name	Turbine Type	Description	Control	Limit	Units	Avg
TX-0405	12/15/2000	WESTVACO TEXAS LP	LM6000	Turbine and Duct Burners		7	PPM	

Southern Montana Electric
Highwood Generating Station
GE LM6000 Simple Cycle Turbines

RBLC BACT Research Summary Tables - Combined Cycle

NOX

RBLC ID	Permit Date	Facility Name	Turbine Type	Description	Control	Limit	Units	Avg	Notes
TX-0497		INEOS CHOCOLATE BAYOU FACILITY			DLE, SCR	11.43	lb/hr	3-HR	
MI-0362		MIDLAND COGENERATION (MCV)				42	PPMVD		
MI-0362		MIDLAND COGENERATION (MCV)			DLE	25	PPMVD		1 unit w/ DLE, NO2 control $8500/ton
CT-0146	10/10/1991	PRATT AND WHITNEY UNITED TECHNOLOGIES CORPORATION	PWPS FT-8 SWIFTPAC	Combined Cycle, Dual Fuel	SCR, WI	9	PPM	---	
WY-0061	04/04/2003	BLACK HILLS CORP./NEIL SIMPSON TWO	LM6000	TURBINE, COMBINED CYCLE, & DUCT BURNER	DLE, SCR	2.5	PPM	24-HR	$3670/ton
WA-0289	02/22/2002	TRANSALTA CENTRALIA GENERATION LLC	LM6000		WI, SCR	3	PPM	3-HR	$3292/ton
OK-0055	2/12/2002	MUSTANG ENERGY PROJECT		COMBUSTION TURBINES W/DUCT BURNERS	SCR	25	PPM		
OK-0056	2/12/2002	HORSESHOE ENERGY PROJECT	LM6000	3504 hrs/year op limit	SCR	12.5	PPM		
TX-0405	12/15/2000	WESTVACO TEXAS LP	LM6000	Turbine and Duct Burners	DLE, SCR	5	PPM		
NV-0034	11/13/2000	LAS VEGAS COGENERATION FACILITY	LM6000		WI, SCR	2	PPM	3-HR	$4061/ton
LA-0146	05/10/2000	SHELL CHEMICAL COMPANY - GEISMAR PLANT	LM6000		SCR	9	PPM		
AR-0024	02/28/2000	WRIGHTSVILLE POWER FACILITY	LM6000	turbine and Duct Burners	Steam Injection	25	PPM		
CA-0950	01/11/2000	VALERO REFINING COMPANY	LM6000PC	LAER	SCR	2.5	PPM	1-HR	
NY-0093	03/31/2005	TRIGEN-NASSAU ENERGY CORPORATION	LM6000	turbine w/ duct burner	SCR	2.5	PPM	1-HR	
PA*	06/26/2001	ALLEGHENY FRANKLIN	LM6000	4000 hrs/year op limit	WI	0.59523	lb/MMBtu		
IL*	05/01/2000	Constellation Power Univ. Park	GE LM6000			8.3	lb/hr		
AR*	07/29/2001	Jonesboro City Water & Lights	GE LM6000			56	lb/hr		
NE*	04/04/2002	Lincoln Electric System Salt Valley Station	LM6000		SCR	10	PPM	3-hr	
NE*	04/04/2002	Lincoln Electric System Salt Valley Station	LM6000		SCR	3.5	PPM	30-day	

* - from EPA Region IV database

CO

RBLC ID	Permit Date	Facility Name	Turbine Type	Description	Control	Limit	Units	Avg	Notes
WA-0289	02/22/2002	TRANSALTA CENTRALIA GENERATION LLC	LM6000		OXY CAT	1.5	PPM	8-HR	85% to 100% load
NV-0034	11/13/2000	LAS VEGAS COGENERATION FACILITY	LM6000PC		OXY CAT	2	PPM	1-HR	1 unit w/ DLE, NO2 control $55,000/ton
WA-0289	02/22/2002	TRANSALTA CENTRALIA GENERATION LLC	LM6000		OXY CAT	3	PPM	1-HR	
CA-0950	01/11/2000	VALERO REFINING COMPANY	LM6000PC	LAER	OXY CAT	6	PPM	1-HR	
NY-0093	03/31/2005	TRIGEN-NASSAU ENERGY CORPORATION	LM6000	turbine w/ duct burner, > 75%	OXY CAT	9	PPM	1-HR	
MI-0362		MIDLAND COGENERATION (MCV)				12	PPMVD		
NY-0093	03/31/2005	TRIGEN-NASSAU ENERGY CORPORATION	LM6000	turbine w/ duct burner, 50% to 75%		12	PPM	1-HR	
PA*	06/26/2001	ALLEGHENY FRANKLIN	LM6000	4000 hrs/year op limit	WI	12	lb/hr		
IL*	05/01/2000	Constellation Power Univ. Park	GE LM6000			12	lb/hr		
TX-0497		INEOS CHOCOLATE BAYOU FACILITY			GCP	15	PPMVD		
TX-0405	12/15/2000	WESTVACO TEXAS LP	LM6000	Turbine and Duct Burners	OXY CAT	22	PPM		
LA-0146	05/10/2000	SHELL CHEMICAL COMPANY - GEISMAR PLANT	LM6000		GCP	25	PPM		
WY-0061	04/04/2003	BLACK HILLS CORP./NEIL SIMPSON TWO	LM6000	TURBINE, COMBINED CYCLE, & DUCT BURNER	GCP	37.2	PPM	1-HR	
OK-0055	2/12/2002	MUSTANG ENERGY PROJECT		COMBUSTION TURBINES W/DUCT BURNERS	GCP	40	PPM	Annual Avg	
OK-0056	2/12/2002	HORSESHOE ENERGY PROJECT	LM6000	3504 hrs/year op limit as simple cycle	GCP	40	PPM		
AR*	07/29/2001	Jonesboro City Water & Lights	GE LM6000			56	lb/hr		
AR-0024	02/28/2000	WRIGHTSVILLE POWER FACILITY	LM6000	turbine and Duct Burners	GCP	66	PPM		
CT-0146	10/10/1991	PRATT AND WHITNEY UNITED TECHNOLOGIES CORPORATION	PWPS FT-8 SWIFTPAC	Combined Cycle, Dual Fuel		27 NG 47.1 OIL	PPM	---	

* - from EPA Region IV database

VOC

RBLC ID	Permit Date	Facility Name	Turbine Type	Description	Control	Limit	Units	Avg	Notes
TX-0497		INEOS CHOCOLATE BAYOU FACILITY			GCP	6.14	lb/hr		
OK-0055	2/12/2002	MUSTANG ENERGY PROJECT		COMBUSTION TURBINES W/DUCT BURNERS	GCP	5.59589	lb/hr		each turbine
OK-0056	2/12/2002	HORSESHOE ENERGY PROJECT	LM6000	3504 hrs/year op limit	OXY CAT	6	PPM		
TX-0405	12/15/2000	WESTVACO TEXAS LP	LM6000	Turbine and Duct Burners, NMNE	OXY CAT	2.75	PPM		
NV-0034	11/13/2000	LAS VEGAS COGENERATION FACILITY	LM6000		OXY CAT	2	lb/hr		
CA-0950	01/11/2000	VALERO REFINING COMPANY	LM6000PC	LAER	OXY CAT	2	PPM	1-HR	

RBLC BACT Research Summary Tables - Combined Cycle

PM10

RBLC ID	Permit Date	Facility Name	Turbine Type	Description	Control	Limit	Units	Avg	Notes
TX-0497		INEOS CHOCOLATE BAYOU FACILITY			Fuel Selection	10.03	lb/hr		
CT-0146	10/10/1991	PRATT AND WHITNEY UNITED TECHNOLOGIES CORPORATION	PWPS FT-8 SWIFTPAC	Combined Cycle, Dual Fuel	---	3.91 NG 10.05 OIL	PPM	---	
WA-0289	02/22/2002	TRANSALTA CENTRALIA GENERATION LLC	LM6000		GCP, Fuel Selection	4.1	LB/HR	3-HR	
OK-0055	2/12/2002	MUSTANG ENERGY PROJECT		COMBUSTION TURBINES W/DUCT BURNERS	GCP, Low Ash Fuel	0.007	lb/MMBtu		
OK-0056	2/12/2002	HORSESHOE ENERGY PROJECT	LM6000	3504 hrs/year op limit		0.0117	lb/MMBtu		
NV-0034	11/13/2000	LAS VEGAS COGENERATION FACILITY	LM6000PC		Fuel Selection	2.5	lb/hr		
LA-0146	05/10/2000	SHELL CHEMICAL COMPANY - GEISMAR PLANT	LM6000		GCP	5.2	lb/hr		
CA-0950	01/11/2000	VALERO REFINING COMPANY	LM6000PC	LAER	OXY CAT	4.98	lb/hr		
NY-0093	03/31/2005	TRIGEN-NASSAU ENERGY CORPORATION	LM6000	turbine w/ duct burner		8.42	lb/hr		

SO2

RBLC ID	Permit Date	Facility Name	Turbine Type	Description	Control	Limit	Units	Avg	Notes
TX-0497		INEOS CHOCOLATE BAYOU FACILITY			Fuel Selection	12.66	lb/hr		5 gr/100 dscf
OK-0055	2/12/2002	MUSTANG ENERGY PROJECT		COMBUSTION TURBINES W/DUCT BURNERS	GCP	3.550228	lb/hr		2 gr/100 scf
OK-0056	2/12/2002	HORSESHOE ENERGY PROJECT	LM6000	3504 hrs/year op limit	Fuel Selection	0.0056	lb/MMBtu		
NV-0034	11/13/2000	LAS VEGAS COGENERATION FACILITY	LM6000		Fuel Selection	0.3	lb/hr		
CA-0950	01/11/2000	VALERO REFINING COMPANY	LM6000PC	LAER	Amine Scrubber	21.5	lb/hr		51 PPM fuel Sulfur

H2SO4

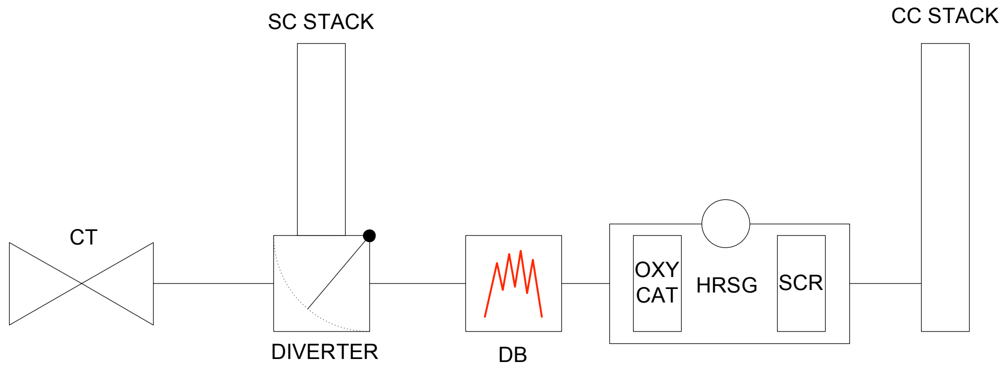
RBLC ID		Facility Name	Turbine Type		Control	Limit	Units	Avg	Notes
TX-0497		INEOS CHOCOLATE BAYOU FACILITY			Fuel Selection	1.34	lb/hr		5 gr/100 dscf

NH4 Slip

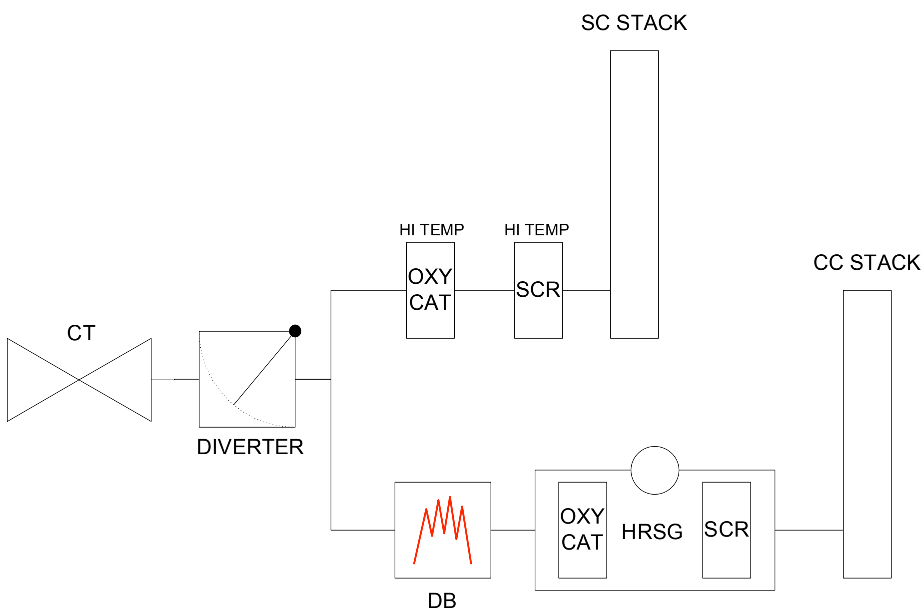
RBLC ID	Permit Date	Facility Name	Turbine Type	Description	Control	Limit	Units	Avg	Notes
TX-0405	12/15/2000	WESTVACO TEXAS LP	LM6000	Turbine and Duct Burners		7	PPM		
NV-0034	11/13/2000	LAS VEGAS COGENERATION FACILITY	LM6000		Fuel Selection	5.83	lb/hr	3-HR	
CA-0950	01/11/2000	VALERO REFINING COMPANY	LM6000PC	LAER		3.53	PPM		
CA-0950	01/11/2000	VALERO REFINING COMPANY	LM6000PC	BACT		10	PPM		

APPENDIX E: BACT ECONOMIC ANALYSIS

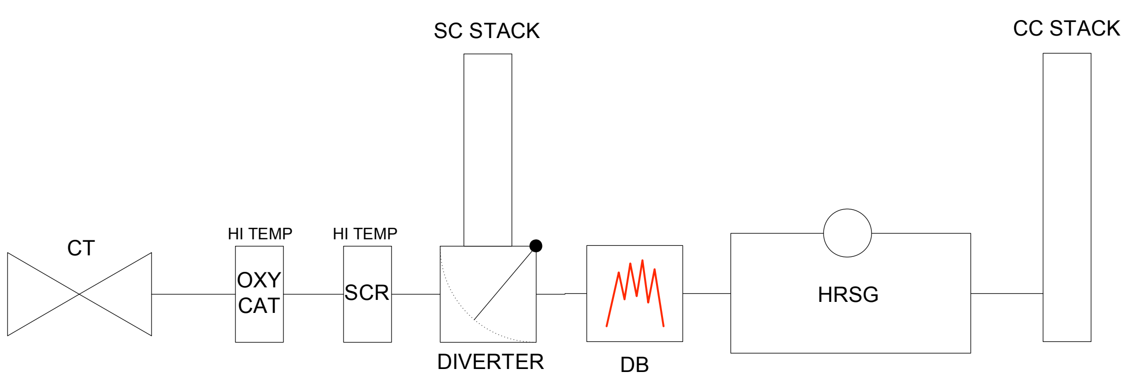
T1 - SC DIVERTER, OXY CAT/SCR DOWNSTREAM OF HRSG



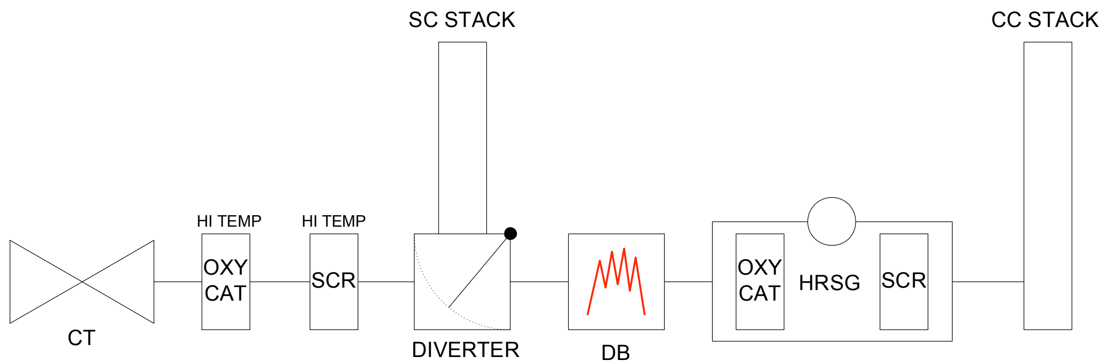
T2 - PARALLEL, DUPLICATE OXY CAT/SCR SYSTEMS



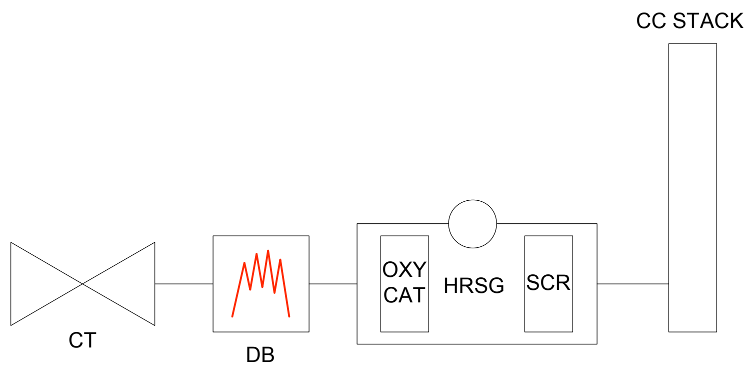
T3 - SHARE SCR



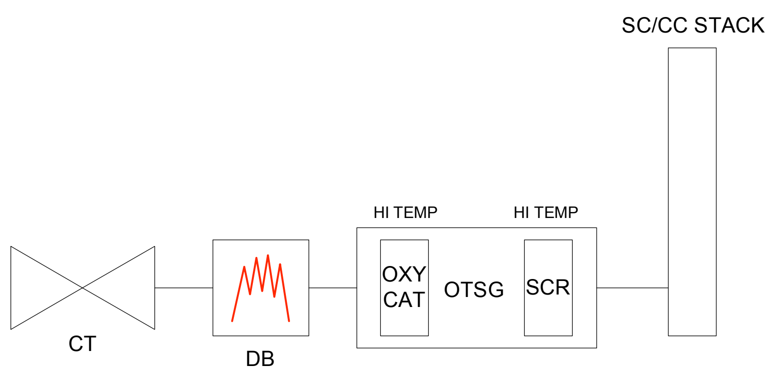
T4 - SC DIVERTER, SERIES OXY CAT/SCR



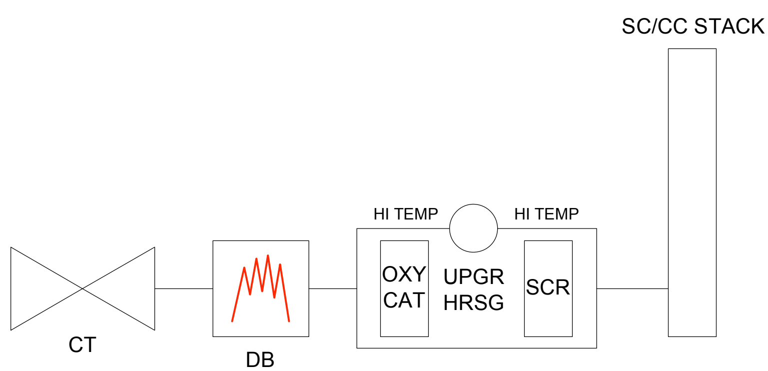
S1 - ELIMINATE SC OPTION ENTIRELY



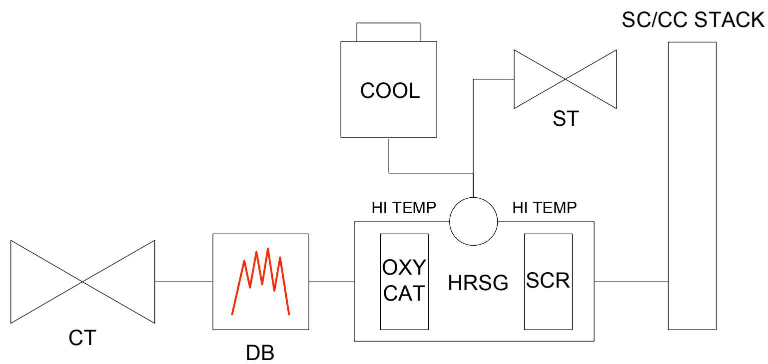
S2 -OTSG



S3 - UPGRADED HRSG



S4 - DUMP CONDENSER



Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Simple Cycle Turbines
CO BACT Economic Analysis
Cases T1, T2, S1 - Combined Cycle

Background Calculations

Assumed Hours of Operation	8760	
Capacity Factor of Plant	0.9	(Reference 9)

	Uncontrolled Emissions						
Source	CO (lb/hr)	CO (tpy)	VOC (lb/hr)	VOC (tpy)	Q (acfm)	T_i (°F)	
LM6000PF	48.98	193.1	2.03	8.0	581,959	1046	Reference 6
Duct Burners	8.69	34.3	0.57	2.2			

Heat rate of Duct Burners	103.50	MMBtu/hr max	Reference 6
Assumed fuel Heat Content	1000.00	btu/scf	
Duct Burner CO Emission Factor	84.00	lb/MMscf	Reference 8
Duct Burner VOC Emission Factor	5.50	lb/MMscf	Reference 8

			Reference
Q =	200,708	scfm	Reference 7
T_i =	1506	°R	
	836	K	
PPI 1988 =	112.6		Reference 1, Other industrial machinery - PCU33329-33329-
PPI Jan 2009 =	166.4		Reference 1, Other industrial machinery (Preliminary) - PCU33329-33329-
PPI Adjustment Factor =	1.48		

RCO Calculations:

RCO Equipment cost = $340,000 Reference 5
Additional Plenum Material = $275,000 Reference 9
RCO Equipment Cost = $615,000 (Mar 2009 $, Actual)

T_{reqd} = 800 °F (catalyst inlet air)
Cp_i = 7.63 Btu/lb-mole*°F (Reference 3, Table A-2E)
Cp_{reqd} = 7.44 Btu/lb-mole*°F (Reference 3, Table A-2E)

$\Delta H^\wedge = (Cp_{reqd})(T_{reqd}-T_{base}) - (Cp_i)(T_i - T_{base})$
= -2,016 Btu/lb-mole

ΔH^ is negative, no additional fuel required to heat process stream
Fuel to Raise Temp = 0 Mscf/yr Natural Gas

RTO Calculations:

RTO Equipment Cost = $2.204 \times 10^5 + 11.57\,Q$ (Reference 2, Eq. 2.33)
(Valid for 10,000 < Q < 100,000)
RTO Equipment Cost[1] = [(383,000 + 15.3 * Q) + (464,000 + 19.1 * Q)]/2

RTO Equipment Cost = $3,643,910 (1988 $, Calculated)
RTO Equipment Cost = $5,384,961 (Jan 2009 $, Calculated)

T_{reqd} = 1600 °F (catalyst inlet air)
Cp_i = 7.63 Btu/lb-mole*°F (Reference 3, Table A-2E)
Cp_{reqd} = 8.05 Btu/lb-mole*°F (Reference 3, Table A-2E)

$\Delta H^\wedge = (Cp_{reqd})(T_{reqd}-T_{base}) - (Cp_i)(T_i - T_{base})$
= 4,861 Btu/lb-mole
n_{air} = PV/RT = 529 lb-mole/min
Q = DH = n DH^ = 2,572,393 Btu/min
Q = DH = n DH^ = 154,343,605 Btu/hr
Q = DH = n DH^ = 154.34 MMBtu/hr

Required Energy Input = 154.34 MMBtu/hr
Energy Recovery = 90%
Fuel to Raise Temp = 128,767 Mscf/yr Natural Gas

[1] Because Q is outside bounds of OAQPS Eqn 2.33, alternative cost calculations were sought.
Equations 6.13 (85%) and 6.14 (95%) of Reference 4 were averaged to obtain an estimate for 90% energy recovery

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Simple Cycle Turbines
Capital Costs - Oxidation Catalyst

Total Capital Costs for Oxidation Catalyst

Cost Item	Factor	Cost
DIRECT COSTS		
Purchased equipment costs		
Catalyst + auxiliary equipment	A	$615,000
Instrumentation	0.10 A	$61,500
Sales taxes	0.00 A	$0
Freight	0.05 A	$30,750
Purchased equipment cost, PEC	B = 1.15 A	**$707,250**
Direct installation costs		
Foundations & supports	0.08 B	$56,580
Handling & erection	0.14 B	$99,015
Electrical	0.04 B	$28,290
Piping	0.02 B	$14,145
Insulation for ductwork	0.01 B	$7,073
Painting	0.01 B	$7,073
Direct installation cost	0.30 B	**$212,175**
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
Total Direct Cost, DC	1.30 B + SP + Bldg.	**$919,425**
INDIRECT COSTS (Installation)		
Engineering	0.10 B	$70,725
Construction and field expenses	0.05 B	$35,363
Contractor fees	0.10 B	$70,725
Start-up	0.02 B	$14,145
Performance test	0.01 B	$7,073
Contingencies	0.03 B	$21,218
Total Indirect Cost, IC	0.31 B	**$219,248**
TOTAL CAPITAL INVESTMENT (TCI) = DC + IC	1.61 B + SP + Bldg.	**$1,138,673**

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Simple Cycle Turbines
Annual Costs - Oxidation Catalyst

Total Annual Costs for Oxidation Catalyst

Cost Item					Cost
DIRECT ANNUAL COSTS					
Operating Labor					
Operator		0.5 hrs/shift		30.00 $/hr	$16,200
Supervisor		15% of operator			$2,430
Operating Materials					
Catalyst Replacement (90% of total direct cost, 3 yr life)					$275,828
Maintenance					
Labor		0.5 hrs/shift		30.00 $/hr	$16,200
Material		100% of maint. labor			$16,200
Utilities					
Natural Gas	0 (kft/yr)		5.60 $/kft3		$0
Electricity	0 (kWh/yr)		0.042 $/kWh		$0
INDIRECT COSTS (Installation)					
Overhead	60% of sum of operating labor and materials and maintenance labor and materials.				$30,618
Administrative Charges			2% of TCI		$22,773
Property Taxes			1% of TCI		$11,387
Insurance			1% of TCI		$11,387
Capital Recovery Factor (Annualized Capital Cost, 10 yrs at 10%)					$185,314
TOTAL ANNUAL COST					**$588,336**

Southern Montana Electric Generation and Transmission Cooperative

Highwood Generating Station

GE LM6000PF Simple Cycle Turbines

Capital Costs - Regenerative Thermal Oxidizer (RTO)

Total Capital Costs for RTO

Cost Item	Factor	Cost
DIRECT COSTS		
Purchased equipment costs		
RTO + auxiliary equipment	A	$5,384,961
Instrumentation	0.10 A	$538,496
Sales taxes	0.00 A	$0
Freight	0.05 A	$269,248
Purchased equipment cost, PEC	B = 1.15 A	**$6,192,705**
Direct installation costs		
Foundations & supports	0.08 B	$495,416
Handling & erection	0.14 B	$866,979
Electrical	0.04 B	$247,708
Piping	0.02 B	$123,854
Insulation for ductwork	0.01 B	$61,927
Painting	0.01 B	$61,927
Direct installation cost	0.30 B	**$1,857,811**
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
Total Direct Cost, DC	1.30 B + SP + Bldg.	**$8,050,516**
INDIRECT COSTS (Installation)		
Engineering	0.10 B	$619,270
Construction and field expenses	0.05 B	$309,635
Contractor fees	0.10 B	$619,270
Start-up	0.02 B	$123,854
Performance test	0.01 B	$61,927
Contingencies	0.03 B	$185,781
Total Indirect Cost, IC	0.31 B	**$1,919,738**
TOTAL CAPITAL INVESTMENT (TCI) = DC + IC	1.61 B + SP + Bldg.	**$9,970,254**

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Simple Cycle Turbines
Annual Costs - Regenerative Thermal Oxidizer (RTO)

Total Annual Costs for RTO

Cost Item						Cost
DIRECT ANNUAL COSTS						
Operating Labor						
Operator		0.5	hrs/shift	30.00	$/hr	$16,200
Supervisor		15%	of operator			$2,430
Operating Materials						-
Maintenance						
Labor		0.5	hrs/shift	30.00	$/hr	$16,200
Material		100%	of maint. labor			$16,200
Utilities						
Natural Gas	128,767	(kft3/yr)	$5.60	$/kft3		$721,093
Electricity	0	(kWh/yr)	$0.042	$/kWh		$0
INDIRECT ANNUAL COSTS, IC						
Overhead		60% of sum of operating labor and materials and maintenance labor and materials.				$30,618
Administrative Charges				2%	of TCI	$199,405
Property Taxes				1%	of TCI	$99,703
Insurance				1%	of TCI	$99,703
Capital Recovery Factor (Annualized Capital Cost, 10 yrs at 10%)						$1,622,613
TOTAL ANNUAL COST						**$2,824,164**

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Simple Cycle Turbines
CO BACT Economic Analysis
Cases T1, T2, S1 - Combined Cycle

Emissions from Additional Fuel Combustion		SO_2	NO_X	CO	VOC	PM10	
Emission Factor (lb/10^6 ft^3)		0.6	140	84	5.5	7.6	Reference 8
RTO Emissions (ton/yr)		0.0	9.0	5.4	0.4	0.5	
RCO Emissions (ton/yr)		0.0	0.0	0.0	0.0	0.0	

CO Summary:

Unit	Uncontrolled Emissions (tpy)	Control Efficiency (%)	Tons Removed (tpy)	Total Annual Cost	Cost-Effectiveness ($/ton)
RTO	233	95%	221	$2,824,164	$12,772
RCO	227	96%	219	$588,336	$2,682

VOC Summary:

Unit	Uncontrolled Emissions (tpy)	Control Efficiency (%)	Tons Removed (tpy)	Total Annual Cost	Cost-Effectiveness ($/ton)
RTO	10.6	95%	10.1	$2,824,164	$280,444
RCO	10.2	30%	3.1	$588,336	$191,399

Combined Summary:

Unit	Uncontrolled Emissions (tpy)	Control Efficiency (%)	Tons Removed (tpy)	Total Annual Cost	Cost-Effectiveness ($/ton)
RTO	243.4	95%	231.2	$2,824,164	$12,216
RCO	237.6	94%	222.4	$588,336	$2,645

References
1. Bureau of Labor and Statistics, Producers Price Index
2. OAQPS, 6th Ed, Section 3.2
3. *Thermodynamics an Engineering Approach* , Cengel/Boles, 4th Edition
4. *Estimating Costs of Air Pollution Controls* , 1990
5. Capital costs from vendor quote, Vogt Power International
6. Data from "EmissionsINFO-Rev3.xls" from Stanley Consultants
7. Data from "LM6000PF Max Emissions.xls"
8. AP-42 Table 1.4-1
9. Data from Stanley Consultants

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Simple Cycle Turbines
CO BACT Economic Analysis
Case T2, T3, T4 - Simple Cycle

Background Calculations

Assumed Hours of Operation: 3200

Source	Uncontrolled Emissions CO (lb/hr)	CO (tpy)	VOC (lb/hr)	VOC (tpy)	Q (acfm)	T_i (°F)	
LM6000PF	48.96	78.3	2.03	3.2	581,959	865	Reference 6

		Reference
Q =	200,708 scfm	Reference 7
T_i =	1325 °R	
	736 K	
PPI 1988 =	112.6	Reference 1, Other industrial machinery - PCU33329-33329-
PPI Jan 2009 =	166.4	Reference 1, Other industrial machinery (Preliminary) - PCU33329-33329-
PPI Adjustment Factor =	1.48	

RCO Calculations:

Total Control System Cost = $4,200,000 (high quote, both turbines, Reference 8)
$2,300,000 (low quote, both turbines, Reference 9)
$3,250,000 average of two quotes
Total Control System Cost = $1,625,000 per turbine
High Temperature
CO Catalyst Cost = $340,000 (Reference 5)
SCR Cost = $590,000 (Reference 5)
CO Catalyst % of total = 36.56%
High Temp CO Catalyst Cost = $594,086 (Mar 2009$)
Duct Plenum Costs = $275,000 (Mar 2009$)
RCO Equipment Cost = $869,086 (March 2009 $, Actual)

T_{reqd} = 800 °F (catalyst inlet air)
Cp_i = 7.49 Btu/lb-mole*°F (Reference 3, Table A-2E)
Cp_{reqd} = 7.44 Btu/lb-mole*°F (Reference 3, Table A-2E)

$\Delta H^{\wedge} = (Cp_{reqd})(T_{reqd}-T_{base}) - (Cp_i)(T_i - T_{base})$
= -524 Btu/lb-mole

ΔH^ is negative, no additional fuel required to heat process stream
Fuel to Raise Temp = 0 Mscf/yr Natural Gas

RTO Calculations:

RTO Equipment Cost = $2.204 \times 10^5 + 11.57\ Q$ (Reference 2, Eq. 2.33)
(Valid for 10,000 < Q < 100,000)
RTO Equipment Cost[1] = [(383,000 + 15.3 * Q) + (464,000 + 19.1 * Q)]/2

RTO Equipment Cost = $3,643,910 (1988 $, Calculated)
RTO Equipment Cost = $5,384,961 (Jan 2009 $, Calculated)

T_{reqd} = 1600 °F (catalyst inlet air)
Cp_i = 7.49 Btu/lb-mole*°F (Reference 3, Table A-2E)
Cp_{reqd} = 8.05 Btu/lb-mole*°F (Reference 3, Table A-2E)

$\Delta H^{\wedge} = (Cp_{reqd})(T_{reqd}-T_{base}) - (Cp_i)(T_i - T_{base})$
= 6,354 Btu/lb-mole
$n_{air} = PV/RT$ = 601 lb-mole/min
$Q = DH = n\ DH^{\wedge}$ = 3,821,671 Btu/min
$Q = DH = n\ DH^{\wedge}$ = 229,300,261 Btu/hr
$Q = DH = n\ DH^{\wedge}$ = 229.30 MMBtu/hr

Required Energy Input = 229.30 MMBtu/hr
Energy Recovery = 90%
Fuel to Raise Temp = 191,302 Mscf/yr Natural Gas

[1] Because Q is outside bounds of OAQPS Eqn 2.33, alternative cost calculations were sought.
Equations 6.13 (85%) and 6.14 (95%) of Reference 4 were averaged to obtain an estimate for 90% energy recovery

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Simple Cycle Turbines
Capital Costs - Oxidation Catalyst

Total Capital Costs for Oxidation Catalyst		
Cost Item	**Factor**	**Cost**
DIRECT COSTS		
Purchased equipment costs		
Catalyst + auxiliary equipment	A	$869,086
Instrumentation	0.10 A	$86,909
Sales taxes	0.00 A	$0
Freight	0.05 A	$43,454
Purchased equipment cost, PEC	B = 1.15 A	**$999,449**
Direct installation costs		
Foundations & supports	0.08 B	$79,956
Handling & erection	0.14 B	$139,923
Electrical	0.04 B	$39,978
Piping	0.02 B	$19,989
Insulation for ductwork	0.01 B	$9,994
Painting	0.01 B	$9,994
Direct installation cost	0.30 B	**$299,835**
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
Total Direct Cost, DC	1.30 B + SP + Bldg.	**$1,299,284**
INDIRECT COSTS (Installation)		
Engineering	0.10 B	$99,945
Construction and field expenses	0.05 B	$49,972
Contractor fees	0.10 B	$99,945
Start-up	0.02 B	$19,989
Performance test	0.01 B	$9,994
Contingencies	0.03 B	$29,983
Total Indirect Cost, IC	0.31 B	**$309,829**
TOTAL CAPITAL INVESTMENT (TCI) = DC + IC	1.61 B + SP + Bldg.	**$1,609,113**

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Simple Cycle Turbines
Annual Costs - Oxidation Catalyst

Total Annual Costs for Oxidation Catalyst

Cost Item					Cost
DIRECT ANNUAL COSTS					
Operating Labor					
Operator		0.5 hrs/shift		30.00 $/hr	$16,200
Supervisor		15% of operator			$2,430
Operating Materials					
Catalyst Replacement (90% of total direct cost, 3 yr life)					$389,785
Maintenance					
Labor		0.5 hrs/shift		30.00 $/hr	$16,200
Material		100% of maint. labor			$16,200
Utilities					
Natural Gas	0 (kft/yr)		5.60 $/kft3		$118,947
Electricity	0 (kWh/yr)		0.042 $/kWh		$0
INDIRECT COSTS (Installation)					
Overhead	60% of sum of operating labor and materials and maintenance labor and materials.				$30,618
Administrative Charges			2% of TCI		$32,182
Property Taxes			1% of TCI		$16,091
Insurance			1% of TCI		$16,091
Capital Recovery Factor (Annualized Capital Cost, 10 yrs at 10%)					$261,876
TOTAL ANNUAL COST					**$916,620**

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Simple Cycle Turbines
Capital Costs - Regenerative Thermal Oxidizer (RTO)

Total Capital Costs for RTO

Cost Item	Factor	Cost
DIRECT COSTS		
Purchased equipment costs		
RTO + auxiliary equipment	A	$5,384,961
Instrumentation	0.10 A	$538,496
Sales taxes	0.00 A	$0
Freight	0.05 A	$269,248
Purchased equipment cost, PEC	B = 1.15 A	**$6,192,705**
Direct installation costs		
Foundations & supports	0.08 B	$495,416
Handling & erection	0.14 B	$866,979
Electrical	0.04 B	$247,708
Piping	0.02 B	$123,854
Insulation for ductwork	0.01 B	$61,927
Painting	0.01 B	$61,927
Direct installation cost	0.30 B	**$1,857,811**
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
Total Direct Cost, DC	1.30 B + SP + Bldg.	**$8,050,516**
INDIRECT COSTS (Installation)		
Engineering	0.10 B	$619,270
Construction and field expenses	0.05 B	$309,635
Contractor fees	0.10 B	$619,270
Start-up	0.02 B	$123,854
Performance test	0.01 B	$61,927
Contingencies	0.03 B	$185,781
Total Indirect Cost, IC	0.31 B	**$1,919,738**
TOTAL CAPITAL INVESTMENT (TCI) = DC + IC	1.61 B + SP + Bldg.	**$9,970,254**

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Simple Cycle Turbines
Annual Costs - Regenerative Thermal Oxidizer (RTO)

Total Annual Costs for RTO

Cost Item						Cost
DIRECT ANNUAL COSTS						
Operating Labor						
Operator		0.5	hrs/shift	30.00	$/hr	$16,200
Supervisor		15%	of operator			$2,430
Operating Materials						-
Maintenance						
Labor		0.5	hrs/shift	30.00	$/hr	$16,200
Material		100%	of maint. labor			$16,200
Utilities						
Natural Gas	191,302	(kft3/yr)	$5.60	$/kft3		$1,071,291
Electricity	0	(kWh/yr)	$0.042	$/kWh		$0
INDIRECT ANNUAL COSTS, IC						
Overhead		60% of sum of operating labor and materials and maintenance labor and materials.				$30,618
Administrative Charges			2%	of TCI		$199,405
Property Taxes			1%	of TCI		$99,703
Insurance			1%	of TCI		$99,703
Capital Recovery Factor (Annualized Capital Cost, 10 yrs at 10%)						$1,622,613
TOTAL ANNUAL COST						**$3,174,362**

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Simple Cycle Turbines
CO BACT Economic Analysis
Case T2, T3, T4 - Simple Cycle

Emissions from Additional Fuel Combustion	**SO_2**	**NO_X**	**CO**	**VOC**	**PM10**
Emission Factor (lb/10^6 ft^3)	0.6	140	84	5.5	7.6
RTO Emissions (ton/yr)	0.1	13.4	8.0	0.5	0.7
RCO Emissions (ton/yr)	0.0	0.0	0.0	0.0	0.0

CO Summary:

Unit	**Uncontrolled Emissions (tpy)**	**Control Efficiency (%)**	**Tons Removed (tpy)**	**Total Annual Cost**	**Cost-Effectiveness ($/ton)**
RTO	86	95%	82	$3,174,362	$38,687
RCO	78	96%	75	$916,620	$12,205

VOC Summary:

Unit	**Uncontrolled Emissions (tpy)**	**Control Efficiency (%)**	**Tons Removed (tpy)**	**Total Annual Cost**	**Cost-Effectiveness ($/ton)**
RTO	3.8	95%	3.6	$3,174,362	$885,364
RCO	3.2	30%	1.0	$916,620	$940,702

Combined Summary:

Unit	**Uncontrolled Emissions (tpy)**	**Control Efficiency (%)**	**Tons Removed (tpy)**	**Total Annual Cost**	**Cost-Effectiveness ($/ton)**
RTO	90.1	95%	85.6	$3,174,362	$37,067
RCO	81.6	93%	76.1	$916,620	$12,048

References
1. Bureau of Labor and Statistics, Producers Price Index
2. OAQPS, 6th Ed, Section 3.2
3. *Thermodynamics an Engineering Approach* , Cengel/Boles, 4th Edition
4. *Estimating Costs of Air Pollution Controls* , 1990
5. Capital costs from vendor quote, Vogt Power International
6. Data from "EmissionsINFO-Rev3.xls" from Stanley Consultants
7. Data from "LM6000PF Max Emissions.xls"
8. Quote from Braden Manufacturing, LLC.
9. Quote from Turner Envirologic
10. Data from Stanley Consultants

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Simple Cycle Turbines
CO BACT Economic Analysis
Case T3 - Combined Cycle

Background Calculations

Assumed Hours of Operation	8760	
Capacity Factor of Plant	0.9	(Reference 9)

	Uncontrolled Emissions						
	CO	CO	VOC	VOC	Q	T_i	
Source	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(acfm)	(°F)	
LM6000PF	48.98	193	2.03	8.0	581,959	1046	Reference 6
Uncontrolled duct burners	8.69	34.3	0.57	2.2			Calculated

Heat rate of Duct Burners	103.50	MMBtu/hr max	Reference 6
Assumed fuel Heat Content	1000.00	btu/scf	
Duct Burner CO Emission Factor	84.00	lb/MMscf	Reference 8
Duct Burner VOC Emission Factor	5.50	lb/MMscf	Reference 8

			Reference
Q =	200,708	scfm	Reference 7
T_i =	1506	°R	
	836	K	
PPI 1988 =	112.6		Reference 1, Other industrial machinery - PCU33329-33329-
PPI Jan 2009 =	166.4		Reference 1, Other industrial machinery (Preliminary) - PCU33329-33329-
PPI Adjustment Factor =	1.48		

RCO Calculations:

Total Control System Cost =	$4,200,000	(high quote, both turbines, Reference 8)
	$2,300,000	(low quote, both turbines, Reference 9)
	$3,250,000	average of two quotes
Total Control System Cost = Combined cycle	$1,625,000	per turbine
CO Catalyst Cost =	$340,000	(Reference 5)
SCR Cost =	$590,000	(Reference 5)
CO Catalyst % of total =	36.56%	
SC CO Catalyst Cost =	$594,086	
Duct Plenum Costs =	$275,000	
RCO Equipment Cost =	$694,086	(Mar 2009 $, Actual)

T_{reqd} =	800	°F	(catalyst inlet air)
Cp_i =	7.63	Btu/lb-mole*°F	(Reference 3, Table A-2E)
Cp_{reqd} =	7.44	Btu/lb-mole*°F	(Reference 3, Table A-2E)

$\Delta H^{\wedge} = (Cp_{reqd})(T_{reqd}-T_{base}) - (Cp_i)(T_i - T_{base})$

= -2,016 Btu/lb-mole

ΔH^ is negative, no additional fuel required to heat process stream

Fuel to Raise Temp = 0 Mscf/yr Natural Gas

RTO Calculations:

RTO Equipment Cost = 2.204 X 10^5 + 11.57 (Reference 2, Eq. 2.33)
(Valid for 10,000 < Q < 100,000)

RTO Equipment Cost[1] = [(383,000 + 15.3 * Q) + (464,000 + 19.1 * Q)]/2

RTO Equipment Cost = $3,643,910 (1988 $, Calculated)
RTO Equipment Cost = $5,384,961 (Jan 2009 $, Calculated)

T_{reqd} =	1600	°F	(catalyst inlet air)
Cp_i =	7.63	Btu/lb-mole*°F	(Reference 3, Table A-2E)
Cp_{reqd} =	8.05	Btu/lb-mole*°F	(Reference 3, Table A-2E)

$\Delta H^{\wedge} = (Cp_{reqd})(T_{reqd}-T_{base}) - (Cp_i)(T_i - T_{base})$

=	4,861	Btu/lb-mole
$n_{air} = PV/RT$ =	529	lb-mole/min
$Q = DH = n\,DH^{\wedge}$ =	2,572,393	Btu/min
$Q = DH = n\,DH^{\wedge}$ =	154,343,605	Btu/hr
$Q = DH = n\,DH^{\wedge}$ =	154.34	MMBtu/hr
Required Energy Input =	154.34	MMBtu/hr
Energy Recovery =	90%	
Fuel to Raise Temp =	**128,767**	**Mscf/yr Natural Gas**

[1] Because Q is outside bounds of OAQPS Eqn 2.33, alternative cost calculations were sought.
Equations 6.13 (85%) and 6.14 (95%) of Reference 4 were averaged to obtain an estimate for 90% energy recovery

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Simple Cycle Turbines
CO BACT Economic Analysis
Case T3 - Combined Cycle

Total Capital Costs for Oxidation Catalyst

Cost Item	Factor	Cost
DIRECT COSTS		
Purchased equipment costs		
Catalyst + auxiliary equipment	A	$694,086
Instrumentation	0.10 A	$69,409
Sales taxes	0.00 A	$0
Freight	0.05 A	$34,704
Purchased equipment cost, PEC	B = 1.15 A	**$798,199**
Direct installation costs		
Foundations & supports	0.08 B	$63,856
Handling & erection	0.14 B	$111,748
Electrical	0.04 B	$31,928
Piping	0.02 B	$15,964
Insulation for ductwork	0.01 B	$7,982
Painting	0.01 B	$7,982
Direct installation cost	0.30 B	**$239,460**
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
Total Direct Cost, DC	1.30 B + SP + Bldg.	**$1,037,659**
INDIRECT COSTS (Installation)		
Engineering	0.10 B	$79,820
Construction and field expenses	0.05 B	$39,910
Contractor fees	0.10 B	$79,820
Start-up	0.02 B	$15,964
Performance test	0.01 B	$7,982
Contingencies	0.03 B	$23,946
Total Indirect Cost, IC	0.31 B	**$247,442**
TOTAL CAPITAL INVESTMENT (TCI) = DC + IC	1.61 B + SP + Bldg.	**$1,285,100**

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Simple Cycle Turbines
CO BACT Economic Analysis
Case T3 - Combined Cycle

Total Annual Costs for Oxidation Catalyst

Cost Item						Cost	Notes
DIRECT ANNUAL COSTS							
Operating Labor							
Operator		0.5	hrs/shift	30.00	$/hr	$16,200	
Supervisor		15%	of operator			$2,430	
Operating Materials							
Catalyst Replacement (90% of total direct cost, 3 yr life)						$311,298	
Maintenance							
Labor		0.5	hrs/shift	30.00	$/hr	$16,200	
Material		100%	of maint. labor			$16,200	
Utilities							
Natural Gas	21,241	(kft/yr)		5.60	$/kft3	$118,947	a
Electricity	0	(kWh/yr)		0.042	$/kWh	$0	
INDIRECT COSTS (Installation)							
Overhead		60% of sum of operating labor and materials and maintenance labor and materials.				$30,618	
Administrative Charges				2%	of TCI	$25,702	
Property Taxes				1%	of TCI	$12,851	
Insurance				1%	of TCI	$12,851	
Capital Recovery Factor (Annualized Capital Cost, 10 yrs at 10%)						$209,144	
TOTAL ANNUAL COST						**$772,441**	

Notes:
a) annualized data provided by Stanley Consultants for back pressure loss of simple cycle control system

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Simple Cycle Turbines
CO BACT Economic Analysis
Case T3 - Combined Cycle

Total Capital Costs for Regenerative Thermal Oxidizer

Cost Item	Factor	Cost
DIRECT COSTS		
Purchased equipment costs		
RTO + auxiliary equipment	A	$5,384,961
Instrumentation	0.10 A	$538,496
Sales taxes	0.00 A	$0
Freight	0.05 A	$269,248
Purchased equipment cost, PEC	B = 1.15 A	**$6,192,705**
Direct installation costs		
Foundations & supports	0.08 B	$495,416
Handling & erection	0.14 B	$866,979
Electrical	0.04 B	$247,708
Piping	0.02 B	$123,854
Insulation for ductwork	0.01 B	$61,927
Painting	0.01 B	$61,927
Direct installation cost	0.30 B	**$1,857,811**
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
Total Direct Cost, DC	1.30 B + SP + Bldg.	**$8,050,516**
INDIRECT COSTS (Installation)		
Engineering	0.10 B	$619,270
Construction and field expenses	0.05 B	$309,635
Contractor fees	0.10 B	$619,270
Start-up	0.02 B	$123,854
Performance test	0.01 B	$61,927
Contingencies	0.03 B	$185,781
Total Indirect Cost, IC	0.31 B	**$1,919,738**
TOTAL CAPITAL INVESTMENT (TCI) = DC + IC	1.61 B + SP + Bldg.	**$9,970,254**

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Simple Cycle Turbines
CO BACT Economic Analysis
Case T3 - Combined Cycle

Total Annual Costs for Regenerative Thermal Oxidizer (RTO)

Cost Item							Cost
DIRECT ANNUAL COSTS							
Operating Labor							
Operator		0.5	hrs/shift		30.00	$/hr	$16,200
Supervisor		15%	of operator				$2,430
Operating Materials							-
Maintenance							
Labor		0.5	hrs/shift		30.00	$/hr	$16,200
Material		100%	of maint. labor				$16,200
Utilities							
Natural Gas	128,767	(kft3/yr)		$5.60	$/kft3		$721,093
Electricity	0	(kWh/yr)		$0.042	$/kWh		$0
INDIRECT ANNUAL COSTS, IC							
Overhead		60% of sum of operating labor and materials and maintenance labor and materials.					$30,618
Administrative Charges				2%	of TCI		$199,405
Property Taxes				1%	of TCI		$99,703
Insurance				1%	of TCI		$99,703
Capital Recovery Factor (Annualized Capital Cost, 10 yrs at 10%)							$1,622,613
TOTAL ANNUAL COST							**$2,824,164**

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Simple Cycle Turbines
CO BACT Economic Analysis
Case T3 - Combined Cycle

Emissions from Additional Fuel Combustion	SO_2	NO_X	CO	VOC	PM10
Emission Factor ($lb/10^6\ ft^3$)	0.6	140	84	5.5	7.6
RTO Emissions (ton/yr)	0.0	9.0	5.4	0.4	0.5
RCO Emissions (ton/yr)	0.0	0.0	0.0	0.0	0.0

CO Summary:

Unit	Uncontrolled Emissions (tpy)	Control Efficiency (%)	Tons Removed (tpy)	Effective Control Efficiency (%)	Total Annual Cost	Cost-Effectiveness ($/ton)
RTO	233	95%	221	95%	$2,824,164	$12,772
RCO	227	96%	186	82%	$772,441	$4,147

VOC Summary:

Unit	Uncontrolled Emissions (tpy)	Control Efficiency (%)	Tons Removed (tpy)	Effective Control Efficiency (%)	Total Annual Cost	Cost-Effectiveness ($/ton)
RTO	10.6	95%	10.1	95%	$2,824,164	$280,444
RCO	10.2	30%	2.4	23%	$772,441	$321,759

Combined Summary:

Unit	Uncontrolled Emissions (tpy)	Control Efficiency (%)	Tons Removed (tpy)	Effective Control Efficiency (%)	Total Annual Cost	Cost-Effectiveness ($/ton)
RTO	243.4	95%	231.2	95%	$2,824,164	$12,216
RCO	237.6	79%	188.7	79%	$772,441	$4,094

References
1. Bureau of Labor and Statistics, Producers Price Index
2. OAQPS, 6th Ed, Section 3.2
3. *Thermodynamics an Engineering Approach* , Cengel/Boles, 4th Edition
4. *Estimating Costs of Air Pollution Controls* , 1990
5. Capital costs from vendor quote, Vogt Power International
6. Data from "EmissionsINFO-Rev3.xls" from Stanley Consultants
7. Data from "LM6000PF Max Emissions.xls"
8. AP-42 Table 1.4-1
9. Data from Stanley Consultants

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Simple Cycle Turbines
CO BACT Economic Analysis
Case T4 - Combined Cycle

Background Calculations

Assumed Hours of Operation	8760	
Capacity Factor	0.9	(Reference 9)

Source	Uncontrolled Emissions CO (lb/hr)	CO (tpy)	VOC (lb/hr)	VOC (tpy)	Q (acfm)	T_i (°F)	
LM6000PF	48.98	193.1	2.03	8.0	581,959	1046	Reference 6
Duct Burners	8.69	34.3	0.57	2.2			

Heat rate of Duct Burners	103.50	MMBtu/hr max	Reference 6
Assumed fuel Heat Content	1000.00	btu/scf	
Duct Burner CO Emission Factor	84.00	lb/MMscf	Reference 8
Duct Burner VOC Emission Factor	5.50	lb/MMscf	Reference 8

			Reference
Q =	200,708	scfm	Reference 7
T_i =	1506	°R	
	836	K	
PPI 1988 =	112.6		Reference 1, Other industrial machinery - PCU33329-33329-
PPI Jan 2009 =	166.4		Reference 1, Other industrial machinery (Preliminary) - PCU33329-33329-
PPI Adjustment Factor =	1.48		

RCO Calculations:

Total Control System Cost =	$4,200,000	(high quote, both turbines, Reference 8)
	$2,300,000	(low quote, both turbines, Reference 9)
	$3,250,000	average of two quotes
Total Control System Cost = Combined cycle	$1,625,000	per turbine
CO Catalyst Cost =	$340,000	(Reference 5)
SCR Cost =	$590,000	(Reference 5)
CO Catalyst % of total =	36.56%	
SC CO Catalyst Cost =	$594,086	
Duct Plenum Costs =	$550,000	(Reference 8)
ID Fan Costs =	$500,000	(due to large back pressure caused by series catalysts)
RCO Equipment Cost =	$1,984,086	(March 2009 $, Actual)

T_{reqd} =	800	°F	(catalyst inlet air)
Cp_i =	7.63	Btu/lb-mole*°F	(Reference 3, Table A-2E)
Cp_{reqd} =	7.44	Btu/lb-mole*°F	(Reference 3, Table A-2E)

$\Delta H^{\wedge} = (Cp_{reqd})(T_{reqd}-T_{base}) - (Cp_i)(T_i - T_{base})$

= -2,016 Btu/lb-mole

ΔH^ is negative, no additional fuel required to heat process stream

Fuel to Raise Temp = 0 Mscf/yr Natural Gas

RTO Calculations:

RTO Equipment Cost = $2.204 \times 10^5 + 11.57\,Q$ (Reference 2, Eq. 2.33)
(Valid for 10,000 < Q < 100,000)

RTO Equipment Cost[1] = [(383,000 + 15.3 * Q) + (464,000 + 19.1 * Q)]/2

RTO Equipment Cost =	$3,643,910	(1988 $, Calculated)
RTO Equipment Cost =	$5,384,961	(Jan 2009 $, Calculated)

T_{reqd} =	1600	°F	(catalyst inlet air)
Cp_i =	7.63	Btu/lb-mole*°F	(Reference 3, Table A-2E)
Cp_{reqd} =	8.05	Btu/lb-mole*°F	(Reference 3, Table A-2E)

$\Delta H^{\wedge} = (Cp_{reqd})(T_{reqd}-T_{base}) - (Cp_i)(T_i - T_{base})$

=	4,861	Btu/lb-mole
$n_{air} = PV/RT$ =	529	lb-mole/min
$Q = DH = n\,DH^{\wedge}$ =	2,572,393	Btu/min
$Q = DH = n\,DH^{\wedge}$ =	154,343,605	Btu/hr
$Q = DH = n\,DH^{\wedge}$ =	154.34	MMBtu/hr
Required Energy Input =	154.34	MMBtu/hr
Energy Recovery =	90%	
Fuel to Raise Temp =	**128,767**	**Mscf/yr Natural Gas**

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Simple Cycle Turbines
CO BACT Economic Analysis
Case T4 - Combined Cycle

[1] Because Q is outside bounds of OAQPS Eqn 2.33, alternative cost calculations were sought.
Equations 6.13 (85%) and 6.14 (95%) of Reference 4 were averaged to obtain an estimate for 90% energy recovery

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Simple Cycle Turbines
CO BACT Economic Analysis
Case T4 - Combined Cycle

Total Capital Costs for Oxidation Catalyst

Cost Item	Factor	Cost
DIRECT COSTS		
Purchased equipment costs		
Catalyst + auxiliary equipment	A	$1,984,086
Instrumentation	0.10 A	$198,409
Sales taxes	0.00 A	$0
Freight	0.05 A	$99,204
Purchased equipment cost, PEC	B = 1.15 A	**$2,281,699**
Direct installation costs		
Foundations & supports	0.08 B	$182,536
Handling & erection	0.14 B	$319,438
Electrical	0.04 B	$91,268
Piping	0.02 B	$45,634
Insulation for ductwork	0.01 B	$22,817
Painting	0.01 B	$22,817
Direct installation cost	0.30 B	**$684,510**
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
Total Direct Cost, DC	1.30 B + SP + Bldg.	**$2,966,209**
INDIRECT COSTS (Installation)		
Engineering	0.10 B	$228,170
Construction and field expenses	0.05 B	$114,085
Contractor fees	0.10 B	$228,170
Start-up	0.02 B	$45,634
Performance test	0.01 B	$22,817
Contingencies	0.03 B	$68,451
Total Indirect Cost, IC	0.31 B	**$707,327**
TOTAL CAPITAL INVESTMENT (TCI) = DC + IC	1.61 B + SP + Bldg.	**$3,673,535**

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Simple Cycle Turbines
CO BACT Economic Analysis
Case T4 - Combined Cycle

Total Annual Costs for Oxidation Catalyst

Cost Item					Cost	Notes
DIRECT ANNUAL COSTS						
Operating Labor						
Operator		0.5 hrs/shift		30.00 $/hr	$16,200	
Supervisor		15% of operator			$2,430	
Operating Materials						
Catalyst Replacement (90% of total direct cost, 3 yr life)					$889,863	
Maintenance						
Labor		0.5 hrs/shift		30.00 $/hr	$16,200	
Material		100% of maint. labor			$16,200	
Utilities						
Natural Gas	21,241	(kft3/yr)	5.60 $/kft3		$118,947	a
Electricity	772,632	(kWh/yr)	0.042 $/kWh		$32,451	b
INDIRECT COSTS (Installation)						
Overhead		60% of sum of operating labor and materials and maintenance labor and materials.			$30,618	
Administrative Charges			2% of TCI		$73,471	
Property Taxes			1% of TCI		$36,735	
Insurance			1% of TCI		$36,735	
Capital Recovery Factor (Annualized Capital Cost, 10 yrs at 10%)					$597,851	
TOTAL ANNUAL COST					**$1,867,700**	

Notes:
a) annualized data provided by Stanley Consultants for back pressure loss of simple cycle control system
b) includes 98 kW from SCR economic analysis for increased electricity use from ID Fan

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Simple Cycle Turbines
CO BACT Economic Analysis
Case T4 - Combined Cycle

Total Capital Costs for Regenerative Thermal Oxidizer (RTO)

Cost Item	Factor	Cost
DIRECT COSTS		
Purchased equipment costs		
RTO + auxiliary equipment	A	$5,384,961
Instrumentation	0.10 A	$538,496
Sales taxes	0.00 A	$0
Freight	0.05 A	$269,248
Purchased equipment cost, PEC	B = 1.15 A	**$6,192,705**
Direct installation costs		
Foundations & supports	0.08 B	$495,416
Handling & erection	0.14 B	$866,979
Electrical	0.04 B	$247,708
Piping	0.02 B	$123,854
Insulation for ductwork	0.01 B	$61,927
Painting	0.01 B	$61,927
Direct installation cost	0.30 B	**$1,857,811**
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
Total Direct Cost, DC	1.30 B + SP + Bldg.	**$8,050,516**
INDIRECT COSTS (Installation)		
Engineering	0.10 B	$619,270
Construction and field expenses	0.05 B	$309,635
Contractor fees	0.10 B	$619,270
Start-up	0.02 B	$123,854
Performance test	0.01 B	$61,927
Contingencies	0.03 B	$185,781
Total Indirect Cost, IC	0.31 B	**$1,919,738**
TOTAL CAPITAL INVESTMENT (TCI) = DC + IC	1.61 B + SP + Bldg.	**$9,970,254**

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Simple Cycle Turbines
CO BACT Economic Analysis
Case T4 - Combined Cycle

Total Annual Costs for Regenerative Thermal Oxidizer (RTO)

Cost Item					Cost
DIRECT ANNUAL COSTS					
Operating Labor					
Operator		0.5 hrs/shift		30.00 $/hr	$16,200
Supervisor		15% of operator			$2,430
Operating Materials					-
Maintenance					
Labor		0.5 hrs/shift		30.00 $/hr	$16,200
Material		100% of maint. labor			$16,200
Utilities					
Natural Gas	128,767 (kft3/yr)		$5.60 $/kft3		$721,093
Electricity	0 (kWh/yr)		$0.042 $/kWh		$0
INDIRECT ANNUAL COSTS, IC					
Overhead	60% of sum of operating labor and materials and maintenance labor and materials.				$30,618
Administrative Charges			2% of TCI		$199,405
Property Taxes			1% of TCI		$99,703
Insurance			1% of TCI		$99,703
Capital Recovery Factor (Annualized Capital Cost, 10 yrs at 10%)					$1,622,613
TOTAL ANNUAL COST					**$2,824,164**

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Simple Cycle Turbines
CO BACT Economic Analysis
Case T4 - Combined Cycle

Emissions from Additional Fuel Combustion		SO_2	NO_X	CO	VOC	PM10
Emission Factor ($lb/10^6\ ft^3$)		0.6	140	84	5.5	7.6
RTO Emissions (ton/yr)		0.0	9.0	5.4	0.4	0.5
RCO Emissions (ton/yr)		0.0	0.0	0.0	0.0	0.0

CO Summary:

Unit	Uncontrolled Emissions (tpy)	Control Efficiency (%)	Tons Removed (tpy)	Total Annual Cost	Cost-Effectiveness ($/ton)
RTO	233	95%	221	$2,824,164	$12,772
RCO	227	96%	219	$1,867,700	$8,515

VOC Summary:

Unit	Uncontrolled Emissions (tpy)	Control Efficiency (%)	Tons Removed (tpy)	Total Annual Cost	Cost-Effectiveness ($/ton)
RTO	10.6	95%	10.1	$2,824,164	$280,444
RCO	10.2	30%	3.1	$1,867,700	$607,605

Combined Summary:

Unit	Uncontrolled Emissions (tpy)	Control Efficiency (%)	Tons Removed (tpy)	Total Annual Cost	Cost-Effectiveness ($/ton)
RTO	243.4	95%	231.2	$2,824,164	$12,216
RCO	237.6	94%	222.4	$1,867,700	$8,397

References
1. Bureau of Labor and Statistics, Producers Price Index
2. OAQPS, 6th Ed, Section 3.2
3. *Thermodynamics an Engineering Approach* , Cengel/Boles, 4th Edition
4. *Estimating Costs of Air Pollution Controls* , 1990
5. Capital costs from vendor quote, Vogt Power International
6. Data from "EmissionsINFO-Rev3.xls" from Stanley Consultants
7. Data from "LM6000PF Max Emissions.xls"
8. AP-42 Table 1.4-1
9. Data from Stanley Consultants

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Simple Cycle Turbines
CO BACT Economic Analysis
Case S2 - Simple Cycle

Background Calculations

Assumed Hours of Operation: 3200

Source	Uncontrolled Emissions CO (lb/hr)	CO (tpy)	VOC (lb/hr)	VOC (tpy)	Q (acfm)	T_i (°F)	
LM6000PF	48.96	78.3	2.03	3.2	581,959	865	Reference 6

		Reference
Q =	200,708 scfm	Reference 7
T_i =	1325 °R	
	736 K	
PPI 1988 =	112.6	Reference 1, Other industrial machinery - PCU33329-33329-
PPI Jan 2009 =	166.4	Reference 1, Other industrial machinery (Preliminary) - PCU33329-33329-
PPI Adjustment Factor =	1.48	

RCO Calculations:

Total Control System Cost = $4,200,000 (high quote, both turbines, Reference 8)
$2,300,000 (low quote, both turbines, Reference 9)
$3,250,000 average of two quotes
Total Control System Cost = $1,625,000 per turbine
Combined cycle
CO Catalyst Cost = $340,000 (Reference 5)
SCR Cost = $590,000 (Reference 5)
CO Catalyst % of total = 36.56%
SC CO Catalyst Cost = $594,086
Duct Plenum Costs = $275,000
OTSG Costs = $8,921,727 (Incr. Cost Diff. OTSG vs. HRSG, Reference 10)
RCO Equipment Cost = $9,790,813 (Mar 2009 $, Actual, Ref 5)

T_{reqd} = 800 °F (catalyst inlet air)
Cp_i = 7.49 Btu/lb-mole*°F (Reference 3, Table A-2E)
Cp_{reqd} = 7.44 Btu/lb-mole*°F (Reference 3, Table A-2E)

$\Delta H^{\wedge} = (Cp_{reqd})(T_{reqd}-T_{base}) - (Cp_i)(T_i - T_{base})$
= -524 Btu/lb-mole

ΔH^ is negative, no additional fuel required to heat process stream
Fuel to Raise Temp = 0 Mscf/yr Natural Gas

RTO Calculations:

RTO Equipment Cost = $2.204 \times 10^5 + 11.57\ Q$ (Reference 2, Eq. 2.33)
(Valid for 10,000 < Q < 100,000)
RTO Equipment Cost[1] = [(383,000 + 15.3 * Q) + (464,000 + 19.1 * Q)]/2

RTO Equipment Cost = $3,643,910 (1988 $, Calculated)
RTO Equipment Cost = $5,384,961 (Jan 2009 $, Calculated)

T_{reqd} = 1600 °F (catalyst inlet air)
Cp_i = 7.49 Btu/lb-mole*°F (Reference 3, Table A-2E
Cp_{reqd} = 8.05 Btu/lb-mole*°F (Reference 3, Table A-2E

$\Delta H^{\wedge} = (Cp_{reqd})(T_{reqd}-T_{base}) - (Cp_i)(T_i - T_{base})$
= 6,354 Btu/lb-mole
$n_{air} = PV/RT$ = 601 lb-mole/min
$Q = DH = n\ DH^{\wedge}$ = 3,821,671 Btu/min
$Q = DH = n\ DH^{\wedge}$ = 229,300,261 Btu/hr
$Q = DH = n\ DH^{\wedge}$ = 229.30 MMBtu/hr

Required Energy Input = 229.30 MMBtu/hr
Energy Recovery = 90%
Fuel to Raise Temp = 191,302 Mscf/yr Natural Gas

[1] Because Q is outside bounds of OAQPS Eqn 2.33, alternative cost calculations were sought.
Equations 6.13 (85%) and 6.14 (95%) of Reference 4 were averaged to obtain an estimate for 90% energy recovery

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Simple Cycle Turbines
CO BACT Economic Analysis
Case S2 - Simple Cycle

Total Capital Costs for Oxidation Catalyst

Cost Item	Factor	Cost
DIRECT COSTS		
Purchased equipment costs		
Catalyst + auxiliary equipment	A	$9,790,813
Instrumentation	0.10 A	$979,081
Sales taxes	0.00 A	$0
Freight	0.05 A	$489,541
Purchased equipment cost, PEC	B = 1.15 A	**$11,259,435**
Direct installation costs		
Foundations & supports	0.08 B	$900,755
Handling & erection	0.14 B	$1,576,321
Electrical	0.04 B	$450,377
Piping	0.02 B	$225,189
Insulation for ductwork	0.01 B	$112,594
Painting	0.01 B	$112,594
Direct installation cost	0.30 B	**$3,377,830**
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
Total Direct Cost, DC	1.30 B + SP + Bldg.	**$14,637,265**
INDIRECT COSTS (Installation)		
Engineering	0.10 B	$1,125,943
Construction and field expenses	0.05 B	$562,972
Contractor fees	0.10 B	$1,125,943
Start-up	0.02 B	$225,189
Performance test	0.01 B	$112,594
Contingencies	0.03 B	$337,783
Total Indirect Cost, IC	0.31 B	**$3,490,425**
TOTAL CAPITAL INVESTMENT (TCI) = DC + IC	1.61 B + SP + Bldg.	**$18,127,690**

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Simple Cycle Turbines
CO BACT Economic Analysis
Case S2 - Simple Cycle

Total Annual Costs for Oxidation Catalyst

Cost Item			Cost	Notes
DIRECT ANNUAL COSTS				
Operating Labor				
Operator	0.5 hrs/shift	30.00 $/hr	$16,200	
Supervisor	15% of operator		$2,430	
Operating Materials				
Catalyst Replacement (90% of total direct cost, 3 yr life)			$4,391,179	
Maintenance				
Labor	0.5 hrs/shift	30.00 $/hr	$16,200	
Material	100% of maint. labor		$16,200	
Utilities				
Natural Gas	0 (kft/yr)	5.60 $/kft3	$118,947	a
Electricity	0 (kWh/yr)	0.042 $/kWh	$0	
INDIRECT COSTS (Installation)				
Overhead	60% of sum of operating labor and materials and maintenance labor and materials.		$30,618	
Administrative Charges		2% of TCI	$362,554	
Property Taxes		1% of TCI	$181,277	
Insurance		1% of TCI	$181,277	
Capital Recovery Factor (Annualized Capital Cost, 10 yrs at 10%)			$2,950,198	
TOTAL ANNUAL COST			**$8,267,080**	

Notes:
a) annualized data provided by Stanley Consultants for back pressure loss of simple cycle control system

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Simple Cycle Turbines
CO BACT Economic Analysis
Case S2 - Simple Cycle

Total Capital Costs for Regenerative Thermal Oxidizer (RTO)

Cost Item	Factor	Cost
DIRECT COSTS		
Purchased equipment costs		
RTO + auxiliary equipment	A	$5,384,961
Instrumentation	0.10 A	$538,496
Sales taxes	0.00 A	$0
Freight	0.05 A	$269,248
Purchased equipment cost, PEC	B = 1.15 A	**$6,192,705**
Direct installation costs		
Foundations & supports	0.08 B	$495,416
Handling & erection	0.14 B	$866,979
Electrical	0.04 B	$247,708
Piping	0.02 B	$123,854
Insulation for ductwork	0.01 B	$61,927
Painting	0.01 B	$61,927
Direct installation cost	0.30 B	**$1,857,811**
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
Total Direct Cost, DC	1.30 B + SP + Bldg.	**$8,050,516**
INDIRECT COSTS (Installation)		
Engineering	0.10 B	$619,270
Construction and field expenses	0.05 B	$309,635
Contractor fees	0.10 B	$619,270
Start-up	0.02 B	$123,854
Performance test	0.01 B	$61,927
Contingencies	0.03 B	$185,781
Total Indirect Cost, IC	0.31 B	**$1,919,738**
TOTAL CAPITAL INVESTMENT (TCI) = DC + IC	1.61 B + SP + Bldg.	**$9,970,254**

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Simple Cycle Turbines
CO BACT Economic Analysis
Case S2 - Simple Cycle

Total Annual Costs for Regenerative Thermal Oxidizer (RTO)

Cost Item							Cost
DIRECT ANNUAL COSTS							
Operating Labor							
Operator		0.5	hrs/shift		30.00	$/hr	$16,200
Supervisor		15%	of operator				$2,430
Operating Materials							-
Maintenance							
Labor		0.5	hrs/shift		30.00	$/hr	$16,200
Material		100%	of maint. labor				$16,200
Utilities							
Natural Gas	191,302	(kft3/yr)	$5.60	$/kft3			$1,071,291
Electricity	0	(kWh/yr)	$0.042	$/kWh			$0
INDIRECT ANNUAL COSTS, IC							
Overhead	60% of sum of operating labor and materials and maintenance labor and materials.						$30,618
Administrative Charges			2%	of TCI			$199,405
Property Taxes			1%	of TCI			$99,703
Insurance			1%	of TCI			$99,703
Capital Recovery Factor (Annualized Capital Cost, 10 yrs at 10%)							$1,622,613
TOTAL ANNUAL COST							**$3,174,362**

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Simple Cycle Turbines
CO BACT Economic Analysis
Case S2 - Simple Cycle

Emissions from Additional Fuel Combustion	**SO_2**	**NO_X**	**CO**	**VOC**	**PM10**
Emission Factor (lb/10^6 ft^3)	0.6	140	84	5.5	7.6
RTO Emissions (ton/yr)	0.1	13.4	8.0	0.5	0.7
RCO Emissions (ton/yr)	0.0	0.0	0.0	0.0	0.0

CO Summary:

Unit	Uncontrolled Emissions (tpy)	Control Efficiency (%)	Tons Removed (tpy)	Total Annual Cost	Cost-Effectiveness ($/ton)
RTO	86	95%	82	$3,174,362	$38,687
RCO	78	96%	75	$8,267,080	$110,099

VOC Summary:

Unit	Uncontrolled Emissions (tpy)	Control Efficiency (%)	Tons Removed (tpy)	Total Annual Cost	Cost-Effectiveness ($/ton)
RTO	3.8	95%	3.6	$3,174,362	$885,364
RCO	3.2	30%	1.0	$8,267,080	$8,484,278

Combined Summary:

Unit	Uncontrolled Emissions (tpy)	Control Efficiency (%)	Tons Removed (tpy)	Total Annual Cost	Cost-Effectiveness ($/ton)
RTO	90.1	95%	85.6	$3,174,362	$37,067
RCO	81.6	93%	76.1	$8,267,080	$108,688

References
1. Bureau of Labor and Statistics, Producers Price Index
2. OAQPS, 6th Ed, Section 3.2
3. *Thermodynamics an Engineering Approach* , Cengel/Boles, 4th Edition
4. *Estimating Costs of Air Pollution Controls* , 1990
5. Capital costs from vendor quote, Vogt Power International
6. Data from "EmissionsINFO-Rev3.xls" from Stanley Consultants
7. Data from "LM6000PF Max Emissions.xls" from GE
8. Vendor Quote from Braden Manufacturing, LLC.
9. Vendor Quote from Turner Envirologic
10. Vendor Quote from Stanley Consultants

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Combustion Turbines
CO BACT Economic Analysis
Case S2 - Combined Cycle

Background Calculations

Assumed Hours of Operation	8760	
Capacity Factor of Plant	0.9	(Reference 9)

	Uncontrolled Emissions						
Source	CO (lb/hr)	CO (tpy)	VOC (lb/hr)	VOC (tpy)	Q (acfm)	T_i (°F)	
LM6000PF	48.98	193.1	2.03	8.0	581,959	1046	Reference 6
Duct Burners	8.69	34.3	0.57	2.2			

Heat rate of Duct Burners	103.50	MMBtu/hr max	Reference 6
Assumed fuel Heat Content	1000.00	btu/scf	
Duct Burner CO Emission Factor	84.00	lb/MMscf	Reference 8
Duct Burner VOC Emission Factor	5.50	lb/MMscf	Reference 8

			Reference
Q =	200,708	scfm	Reference 7
T_i =	1506	°R	
	836	K	
PPI 1988 =	112.6		Reference 1, Other industrial machinery - PCU33329-33329-
PPI Jan 2009 =	166.4		Reference 1, Other industrial machinery (Preliminary) - PCU33329-33329-
PPI Adjustment Factor =	1.48		

<u>RCO Calculations:</u>

Total Control System Cost =	$4,200,000	(high quote, both turbines, Reference 8)
	$2,300,000	(low quote, both turbines, Reference 9)
	$3,250,000	average of two quotes
Total Control System Cost = Combined cycle	$1,625,000	per turbine
Lo Temp CO Catalyst Cost =	$340,000	(Reference 5)
Lo Temp SCR Cost =	$590,000	(Reference 5)
CO Catalyst % of total =	36.56%	
Hi Temp CO Catalyst Cost =	$594,086	
Duct Plenum Costs =	$275,000	
OTSG Costs =	$8,921,727	(Incr. Cost Incr. OTSG vs. HRSG, Reference 8)
RCO Equipment Cost =	$9,790,813	(Mar 2009 $, Actual, Ref 5)

T_{reqd} =	800	°F	(catalyst inlet air)
Cp_i =	7.63	Btu/lb-mole*°F	(Reference 3, Table A-2E)
Cp_{reqd} =	7.44	Btu/lb-mole*°F	(Reference 3, Table A-2E)

$\Delta H^{\wedge} = (Cp_{reqd})(T_{reqd}-T_{base}) - (Cp_i)(T_i - T_{base})$
= -2,016 Btu/lb-mole

ΔH^ is negative, no additional fuel required to heat process stream
Fuel to Raise Temp = 0 Mscf/yr Natural Gas

<u>RTO Calculations:</u>

RTO Equipment Cost =	$2.204 \times 10^5 + 11.57\ Q$	(Reference 2, Eq. 2.33) (Valid for 10,000 < Q < 100,000)
RTO Equipment Cost[1] =	[(383,000 + 15.3 * Q) + (464,000 + 19.1 * Q)]/2	
RTO Equipment Cost =	$3,643,910	(1988 $, Calculated)
RTO Equipment Cost =	$5,384,961	(Jan 2009 $, Calculated)

T_{reqd} =	1600	°F	(catalyst inlet air)
Cp_i =	7.63	Btu/lb-mole*°F	(Reference 3, Table A-2E)
Cp_{reqd} =	8.05	Btu/lb-mole*°F	(Reference 3, Table A-2E)

$\Delta H^{\wedge} = (Cp_{reqd})(T_{reqd}-T_{base}) - (Cp_i)(T_i - T_{base})$

=	4,861	Btu/lb-mole
n_{air} = PV/RT =	529	lb-mole/min
Q = DH = n DH^ =	2,572,393	Btu/min
Q = DH = n DH^ =	154,343,605	Btu/hr
Q = DH = n DH^ =	154.34	MMBtu/hr
Required Energy Input =	154.34	MMBtu/hr
Energy Recovery =	90%	
Fuel to Raise Temp =	**128,767**	**Mscf/yr Natural Gas**

[1] Because Q is outside bounds of OAQPS Eqn 2.33, alternative cost calculations were sought.
Equations 6.13 (85%) and 6.14 (95%) of Reference 4 were averaged to obtain an estimate for 90% energy recovery

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Combustion Turbines
CO BACT Economic Analysis
Case S2 - Combined Cycle

Total Capital Costs for Oxidation Catalyst

Cost Item	Factor	Cost
DIRECT COSTS		
Purchased equipment costs		
Catalyst + auxiliary equipment	A	$9,790,813
Instrumentation	0.10 A	$979,081
Sales taxes	0.00 A	$0
Freight	0.05 A	$489,541
Purchased equipment cost, PEC	B = 1.15 A	**$11,259,435**
Direct installation costs		
Foundations & supports	0.08 B	$900,755
Handling & erection	0.14 B	$1,576,321
Electrical	0.04 B	$450,377
Piping	0.02 B	$225,189
Insulation for ductwork	0.01 B	$112,594
Painting	0.01 B	$112,594
Direct installation cost	0.30 B	**$3,377,830**
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
Total Direct Cost, DC	1.30 B + SP + Bldg.	**$14,637,265**
INDIRECT COSTS (Installation)		
Engineering	0.10 B	$1,125,943
Construction and field expenses	0.05 B	$562,972
Contractor fees	0.10 B	$1,125,943
Start-up	0.02 B	$225,189
Performance test	0.01 B	$112,594
Contingencies	0.03 B	$337,783
Total Indirect Cost, IC	0.31 B	**$3,490,425**
TOTAL CAPITAL INVESTMENT (TCI) = DC + IC	1.61 B + SP + Bldg.	**$18,127,690**

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Combustion Turbines
CO BACT Economic Analysis
Case S2 - Combined Cycle

Total Annual Costs for Oxidation Catalyst

Cost Item					Cost	Notes
DIRECT ANNUAL COSTS						
Operating Labor						
Operator		0.5 hrs/shift		30.00 $/hr	$16,200	
Supervisor		15% of operator			$2,430	
Operating Materials						
Catalyst Replacement (90% of total direct cost, 3 yr life)					$4,391,179	
Maintenance						
Labor		0.5 hrs/shift		30.00 $/hr	$16,200	
Material		100% of maint. labor			$16,200	
Utilities						
Natural Gas	21,241	(kft/yr)	5.60 $/kft3		$118,947	a
Electricity	0	(kWh/yr)	0.042 $/kWh		$0	
INDIRECT COSTS (Installation)						
Overhead		60% of sum of operating labor and materials and maintenance labor and materials.			$30,618	
Administrative Charges			2% of TCI		$362,554	
Property Taxes			1% of TCI		$181,277	
Insurance			1% of TCI		$181,277	
Capital Recovery Factor (Annualized Capital Cost, 10 yrs at 10%)					$2,950,198	
TOTAL ANNUAL COST					**$8,267,080**	

Notes:
a) annualized data provided by Stanley Consultants for back pressure loss of simple cycle control system

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Combustion Turbines
CO BACT Economic Analysis
Case S2 - Combined Cycle

Total Capital Costs for Regenerative Thermal Oxidizer (RTO)

Cost Item	Factor	Cost
DIRECT COSTS		
Purchased equipment costs		
RTO + auxiliary equipment	A	$5,384,961
Instrumentation	0.10 A	$538,496
Sales taxes	0.00 A	$0
Freight	0.05 A	$269,248
Purchased equipment cost, PEC	B = 1.15 A	**$6,192,705**
Direct installation costs		
Foundations & supports	0.08 B	$495,416
Handling & erection	0.14 B	$866,979
Electrical	0.04 B	$247,708
Piping	0.02 B	$123,854
Insulation for ductwork	0.01 B	$61,927
Painting	0.01 B	$61,927
Direct installation cost	0.30 B	**$1,857,811**
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
Total Direct Cost, DC	1.30 B + SP + Bldg.	**$8,050,516**
INDIRECT COSTS (Installation)		
Engineering	0.10 B	$619,270
Construction and field expenses	0.05 B	$309,635
Contractor fees	0.10 B	$619,270
Start-up	0.02 B	$123,854
Performance test	0.01 B	$61,927
Contingencies	0.03 B	$185,781
Total Indirect Cost, IC	0.31 B	**$1,919,738**
TOTAL CAPITAL INVESTMENT (TCI) = DC + IC	1.61 B + SP + Bldg.	**$9,970,254**

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Combustion Turbines
CO BACT Economic Analysis
Case S2 - Combined Cycle

Total Annual Costs for Regenerative Thermal Oxidizer (RTO)

Cost Item					Cost
DIRECT ANNUAL COSTS					
Operating Labor					
Operator		0.5 hrs/shift		30.00 $/hr	$16,200
Supervisor		15% of operator			$2,430
Operating Materials					-
Maintenance					
Labor		0.5 hrs/shift		30.00 $/hr	$16,200
Material		100% of maint. labor			$16,200
Utilities					
Natural Gas	128,767 (kft3/yr)		$5.60 $/kft3		$721,093
Electricity	0 (kWh/yr)		$0.042 $/kWh		$0
INDIRECT ANNUAL COSTS, IC					
Overhead	60% of sum of operating labor and materials and maintenance labor and materials.				$30,618
Administrative Charges			2% of TCI		$199,405
Property Taxes			1% of TCI		$99,703
Insurance			1% of TCI		$99,703
Capital Recovery Factor (Annualized Capital Cost, 10 yrs at 10%)					$1,622,613
TOTAL ANNUAL COST					**$2,824,164**

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
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Case S2 - Combined Cycle

Emissions from Additional Fuel Combustion	SO_2	NO_X	CO	VOC	PM10
Emission Factor ($lb/10^6\ ft^3$)	0.6	140	84	5.5	7.6
RTO Emissions (ton/yr)	0.0	9.0	5.4	0.4	0.5
RCO Emissions (ton/yr)	0.0	0.0	0.0	0.0	0.0

CO Summary:

Unit	Uncontrolled Emissions (tpy)	Control Efficiency (%)	Tons Removed (tpy)	Total Annual Cost	Cost-Effectiveness ($/ton)
RTO	233	95%	221	$2,824,164	$12,772
RCO	227	96%	219	$8,267,080	$37,689

VOC Summary:

Unit	Uncontrolled Emissions (tpy)	Control Efficiency (%)	Tons Removed (tpy)	Total Annual Cost	Cost-Effectiveness ($/ton)
RTO	10.6	95%	10.1	$2,824,164	$280,444
RCO	10.2	30%	3.1	$8,267,080	$2,689,467

Combined Summary:

Unit	Uncontrolled Emissions (tpy)	Control Efficiency (%)	Tons Removed (tpy)	Total Annual Cost	Cost-Effectiveness ($/ton)
RTO	243.4	95%	231.2	$2,824,164	$12,216
RCO	237.6	94%	222.4	$8,267,080	$37,168

References
1. Bureau of Labor and Statistics, Producers Price Index
2. OAQPS, 6th Ed, Section 3.2
3. *Thermodynamics an Engineering Approach* , Cengel/Boles, 4th Edition
4. *Estimating Costs of Air Pollution Controls* , 1990
5. Capital costs from vendor quote, Vogt Power International
6. Data from "EmissionsINFO-Rev3.xls" from Stanley Consultants
7. Data from "LM6000PF Max Emissions.xls"
8. Quote from Stanley Consultants based on actual costs from similar project
9. Data from Stanley Consultants

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Simple Cycle Turbines
CO BACT Economic Analysis
Case S3 - Combined Cycle

Background Calculations

Assumed Hours of Operation	8760	
Capacity Factor of Plant	0.9	(Reference 9)

	Uncontrolled Emissions						
Source	CO (lb/hr)	CO (tpy)	VOC (lb/hr)	VOC (tpy)	Q (acfm)	T_i (°F)	
LM6000PF	48.98	193.1	2.03	8.0	581,959	1046	Reference 6
Duct Burners	8.69	34.3	0.57	2.2			

Heat rate of Duct Burners	103.50	MMBtu/hr max	Reference 6
Assumed fuel Heat Content	1000.00	btu/scf	
Duct Burner CO Emission Factor	84.00	lb/MMscf	Reference 8
Duct Burner VOC Emission Factor	5.50	lb/MMscf	Reference 8

			Reference
Q =	200,708	scfm	Reference 7
T_i =	1506	°R	
	836	K	
PPI 1988 =	112.6		Reference 1, Other industrial machinery - PCU33329-33329-
PPI Jan 2009 =	166.4		Reference 1, Other industrial machinery (Preliminary) - PCU33329-33329-
PPI Adjustment Factor =	1.48		

RCO Calculations:

Total Control System Cost =	$4,200,000	(high quote, both turbines, Reference 8)
	$2,300,000	(low quote, both turbines, Reference 9)
	$3,250,000	average of two quotes
Total Control System Cost = Combined cycle	$1,625,000	per turbine
Lo Temp CO Catalyst Cost =	$340,000	(Reference 5)
Lo Temp SCR Cost =	$590,000	(Reference 5)
CO Catalyst % of total =	36.56%	
Hi Temp CO Catalyst Cost =	$594,086	
Duct Plenum Costs =	$275,000	
RCO Equipment Cost =	$869,086	(Mar 2009 $, Actual, Ref 5)

T_{reqd} =	800	°F	(catalyst inlet air)
Cp_i =	7.63	Btu/lb-mole*°F	(Reference 3, Table A-2E)
Cp_{reqd} =	7.44	Btu/lb-mole*°F	(Reference 3, Table A-2E)

$\Delta H^\wedge = (Cp_{reqd})(T_{reqd}-T_{base}) - (Cp_i)(T_i - T_{base})$

= -2,016 Btu/lb-mole

ΔH^ is negative, no additional fuel required to heat process stream

Fuel to Raise Temp = 0 Mscf/yr Natural Gas

RTO Calculations:

RTO Equipment Cost = $2.204 \times 10^5 + 11.57\ Q$ (Reference 2, Eq. 2.33)
(Valid for 10,000 < Q < 100,000)

RTO Equipment Cost[1] = [(383,000 + 15.3 * Q) + (464,000 + 19.1 * Q)]/2

RTO Equipment Cost =	$3,643,910	(1988 $, Calculated)
RTO Equipment Cost =	$5,384,961	(Jan 2009 $, Calculated)

T_{reqd} =	1600	°F	(catalyst inlet air)
Cp_i =	7.63	Btu/lb-mole*°F	(Reference 3, Table A-2E)
Cp_{reqd} =	8.05	Btu/lb-mole*°F	(Reference 3, Table A-2E)

$\Delta H^\wedge = (Cp_{reqd})(T_{reqd}-T_{base}) - (Cp_i)(T_i - T_{base})$

=	4,861	Btu/lb-mole
$n_{air} = PV/RT$ =	529	lb-mole/min
$Q = DH = n\ DH^\wedge$ =	2,572,393	Btu/min
$Q = DH = n\ DH^\wedge$ =	154,343,605	Btu/hr
$Q = DH = n\ DH^\wedge$ =	154.34	MMBtu/hr
Required Energy Input =	154.34	MMBtu/hr
Energy Recovery =	90%	
Fuel to Raise Temp =	**128,767**	**Mscf/yr Natural Gas**

[1] Because Q is outside bounds of OAQPS Eqn 2.33, alternative cost calculations were sought.
Equations 6.13 (85%) and 6.14 (95%) of Reference 4 were averaged to obtain an estimate for 90% energy recovery

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Simple Cycle Turbines
CO BACT Economic Analysis
Case S3 - Combined Cycle

Total Capital Costs for Oxidation Catalyst

Cost Item	Factor	Cost
DIRECT COSTS		
Purchased equipment costs		
Catalyst + auxiliary equipment	A	$869,086
Instrumentation	0.10 A	$86,909
Sales taxes	0.00 A	$0
Freight	0.05 A	$43,454
Purchased equipment cost, PEC	B = 1.15 A	**$999,449**
Direct installation costs		
Foundations & supports	0.08 B	$79,956
Handling & erection	0.14 B	$139,923
Electrical	0.04 B	$39,978
Piping	0.02 B	$19,989
Insulation for ductwork	0.01 B	$9,994
Painting	0.01 B	$9,994
Direct installation cost	0.30 B	**$299,835**
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
Total Direct Cost, DC	1.30 B + SP + Bldg.	**$1,299,284**
INDIRECT COSTS (Installation)		
Engineering	0.10 B	$99,945
Construction and field expenses	0.05 B	$49,972
Contractor fees	0.10 B	$99,945
Start-up	0.02 B	$19,989
Performance test	0.01 B	$9,994
Contingencies	0.03 B	$29,983
Total Indirect Cost, IC	0.31 B	**$309,829**
TOTAL CAPITAL INVESTMENT (TCI) = DC + IC	1.61 B + SP + Bldg.	**$1,609,113**

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Simple Cycle Turbines
CO BACT Economic Analysis
Case S3 - Combined Cycle

Total Annual Costs for Oxidation Catalyst

Cost Item					Cost	Notes
DIRECT ANNUAL COSTS						
Operating Labor						
Operator		0.5 hrs/shift		30.00 $/hr	$16,200	
Supervisor		15% of operator			$2,430	
Operating Materials						
Catalyst Replacement (90% of total direct cost, 3 yr life)					$389,785	
Maintenance						
Labor		0.5 hrs/shift		30.00 $/hr	$16,200	
Material		100% of maint. labor			$16,200	
Utilities						
Natural Gas	21,241 (kft/yr)		5.60 $/kft3		$118,947	a
Electricity	0 (kWh/yr)		0.042 $/kWh		$0	
INDIRECT COSTS (Installation)						
Overhead		60% of sum of operating labor and materials and maintenance labor and materials.			$30,618	
Administrative Charges			2% of TCI		$32,182	
Property Taxes			1% of TCI		$16,091	
Insurance			1% of TCI		$16,091	
Capital Recovery Factor (Annualized Capital Cost, 10 yrs at 10%)					$261,876	
TOTAL ANNUAL COST					**$916,620**	

Notes:
a) annualized data provided by Stanley Consultants for back pressure loss of simple cycle control system

Southern Montana Electric Generation and Transmission Cooperative

Highwood Generating Station

GE LM6000PF Simple Cycle Turbines

CO BACT Economic Analysis

Case S3 - Combined Cycle

Total Capital Costs for Regenerative Thermal Oxidizer (RTO)

Cost Item	Factor	Cost
DIRECT COSTS		
Purchased equipment costs		
RTO + auxiliary equipment	A	$5,384,961
Instrumentation	0.10 A	$538,496
Sales taxes	0.00 A	$0
Freight	0.05 A	$269,248
Purchased equipment cost, PEC	B = 1.15 A	**$6,192,705**
Direct installation costs		
Foundations & supports	0.08 B	$495,416
Handling & erection	0.14 B	$866,979
Electrical	0.04 B	$247,708
Piping	0.02 B	$123,854
Insulation for ductwork	0.01 B	$61,927
Painting	0.01 B	$61,927
Direct installation cost	0.30 B	**$1,857,811**
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
Total Direct Cost, DC	1.30 B + SP + Bldg.	**$8,050,516**
INDIRECT COSTS (Installation)		
Engineering	0.10 B	$619,270
Construction and field expenses	0.05 B	$309,635
Contractor fees	0.10 B	$619,270
Start-up	0.02 B	$123,854
Performance test	0.01 B	$61,927
Contingencies	0.03 B	$185,781
Total Indirect Cost, IC	0.31 B	**$1,919,738**
TOTAL CAPITAL INVESTMENT (TCI) = DC + IC	1.61 B + SP + Bldg.	**$9,970,254**

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Simple Cycle Turbines
CO BACT Economic Analysis
Case S3 - Combined Cycle

Total Annual Costs for Regenerative Thermal Oxidizer (RTO)

Cost Item					Cost
DIRECT ANNUAL COSTS					
Operating Labor					
Operator		0.5 hrs/shift		30.00 $/hr	$16,200
Supervisor		15% of operator			$2,430
Operating Materials					-
Maintenance					
Labor		0.5 hrs/shift		30.00 $/hr	$16,200
Material		100% of maint. labor			$16,200
Utilities					
Natural Gas	128,767 (kft3/yr)		$5.60 $/kft3		$721,093
Electricity	0 (kWh/yr)		$0.042 $/kWh		$0
INDIRECT ANNUAL COSTS, IC					
Overhead	60% of sum of operating labor and materials and maintenance labor and materials.				$30,618
Administrative Charges			2% of TCI		$199,405
Property Taxes			1% of TCI		$99,703
Insurance			1% of TCI		$99,703
Capital Recovery Factor (Annualized Capital Cost, 10 yrs at 10%)					$1,622,613
TOTAL ANNUAL COST					**$2,824,164**

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Simple Cycle Turbines
CO BACT Economic Analysis
Case S3 - Combined Cycle

Emissions from Additional Fuel Combustion	**SO_2**	**NO_X**	**CO**	**VOC**	**PM10**
Emission Factor (lb/10^6 ft^3)	0.6	140	84	5.5	7.6
RTO Emissions (ton/yr)	0.0	9.0	5.4	0.4	0.5
RCO Emissions (ton/yr)	0.0	0.0	0.0	0.0	0.0

CO Summary:

Unit	Uncontrolled Emissions (tpy)	Control Efficiency (%)	Tons Removed (tpy)	Total Annual Cost	Cost-Effectiveness ($/ton)
RTO	233	95%	221	$2,824,164	$12,772
RCO	227	96%	219	$916,620	$4,179

VOC Summary:

Unit	Uncontrolled Emissions (tpy)	Control Efficiency (%)	Tons Removed (tpy)	Total Annual Cost	Cost-Effectiveness ($/ton)
RTO	10.6	95%	10.1	$2,824,164	$280,444
RCO	10.2	30%	3.1	$916,620	$298,197

Combined Summary:

Unit	Uncontrolled Emissions (tpy)	Control Efficiency (%)	Tons Removed (tpy)	Total Annual Cost	Cost-Effectiveness ($/ton)
RTO	243.4	95%	231.2	$2,824,164	$12,216
RCO	237.6	94%	222.4	$916,620	$4,121

References
1. Bureau of Labor and Statistics, Producers Price Index
2. OAQPS, 6th Ed, Section 3.2
3. *Thermodynamics an Engineering Approach* , Cengel/Boles, 4th Edition
4. *Estimating Costs of Air Pollution Controls* , 1990
5. Capital costs from vendor quote, Vogt Power International
6. Data from "EmissionsINFO-Rev3.xls" from Stanley Consultants
7. Data from "LM6000PF Max Emissions.xls"
8. Quote from Stanley Consultants based on actual costs from similar project
9. Data from Stanley Consultants

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Simple Cycle Turbines
CO BACT Economic Analysis
Case S4 - Simple Cycle

Background Calculations

Assumed Hours of Operation: 3200

Source	Uncontrolled Emissions CO (lb/hr)	CO (tpy)	VOC (lb/hr)	VOC (tpy)	Q (acfm)	T_i (°F)	
LM6000PF	48.98	78.4	2.03	3.2	581,959	865	Reference 6

		Reference
Q =	200,708 scfm	Reference 7
T_i =	1325 °R	
	736 K	
PPI 1988 =	112.6	Reference 1, Other industrial machinery - PCU33329-33329-
PPI Jan 2009 =	166.4	Reference 1, Other industrial machinery (Preliminary) - PCU33329-33329-
PPI Adjustment Factor =	1.48	

RCO Calculations:

Low Temperature CO Catalyst Cost =	$340,000	(Reference 5)
Lo Temperature SCR Cost =	$590,000	(Reference 5)
Duct Plenum Costs =	$275,000	(Reference 9)
Dump Condenser Costs =	$1,099,924	(Reference 8)
RCO Equipment Cost =	$1,714,924	(Mar 2009 $, Actual)

T_{reqd} =	800 °F	(catalyst inlet air)
Cp_i =	7.49 Btu/lb-mole*°F	(Reference 3, Table A-2E)
Cp_{reqd} =	7.44 Btu/lb-mole*°F	(Reference 3, Table A-2E)

$\Delta H^{\wedge} = (Cp_{reqd})(T_{reqd}-T_{base}) - (Cp_i)(T_i - T_{base})$

= -524 Btu/lb-mole

ΔH^ is negative, no additional fuel required to heat process stream

Fuel to Raise Temp = 0 Mscf/yr Natural Gas

RTO Calculations:

RTO Equipment Cost = $2.204 \times 10^5 + 11.57\ Q$ (Reference 2, Eq. 2.33)
(Valid for 10,000 < Q < 100,000)

RTO Equipment Cost[1] = [(383,000 + 15.3 * Q) + (464,000 + 19.1 * Q)]/2

RTO Equipment Cost = $3,643,910 (1988 $, Calculated)
RTO Equipment Cost = $5,384,961 (Jan 2009 $, Calculated)

T_{reqd} =	1600 °F	(catalyst inlet air)
Cp_i =	7.49 Btu/lb-mole*°F	(Reference 3, Table A-2E)
Cp_{reqd} =	8.05 Btu/lb-mole*°F	(Reference 3, Table A-2E)

$\Delta H^{\wedge} = (Cp_{reqd})(T_{reqd}-T_{base}) - (Cp_i)(T_i - T_{base})$

=	6,354 Btu/lb-mole
n_{air} = PV/RT =	601 lb-mole/min
Q = DH = n DH^ =	3,821,671 Btu/min
Q = DH = n DH^ =	229,300,261 Btu/hr
Q = DH = n DH^ =	229.30 MMBtu/hr
Required Energy Input =	229.30 MMBtu/hr
Energy Recovery =	90%
Fuel to Raise Temp =	**191,302 Mscf/yr Natural Gas**

[1] Because Q is outside bounds of OAQPS Eqn 2.33, alternative cost calculations were sought.
Equations 6.13 (85%) and 6.14 (95%) of Reference 4 were averaged to obtain an estimate for 90% energy recovery

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Simple Cycle Turbines
CO BACT Economic Analysis
Case S4 - Simple Cycle

Total Capital Costs for Oxidation Catalyst

Cost Item	Factor	Cost
DIRECT COSTS		
Purchased equipment costs		
Catalyst + auxiliary equipment	A	$1,714,924
Instrumentation	0.10 A	$171,492
Sales taxes	0.00 A	$0
Freight	0.05 A	$85,746
Purchased equipment cost, PEC	B = 1.15 A	**$1,972,162**
Direct installation costs		
Foundations & supports	0.08 B	$157,773
Handling & erection	0.14 B	$276,103
Electrical	0.04 B	$78,886
Piping	0.02 B	$39,443
Insulation for ductwork	0.01 B	$19,722
Painting	0.01 B	$19,722
Direct installation cost	0.30 B	**$591,649**
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
Total Direct Cost, DC	1.30 B + SP + Bldg.	**$2,563,811**
INDIRECT COSTS (Installation)		
Engineering	0.10 B	$197,216
Construction and field expenses	0.05 B	$98,608
Contractor fees	0.10 B	$197,216
Start-up	0.02 B	$39,443
Performance test	0.01 B	$19,722
Contingencies	0.03 B	$59,165
Total Indirect Cost, IC	0.31 B	**$611,370**
TOTAL CAPITAL INVESTMENT (TCI) = DC + IC	1.61 B + SP + Bldg.	**$3,175,181**

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Simple Cycle Turbines
CO BACT Economic Analysis
Case S4 - Simple Cycle

Total Annual Costs for Oxidation Catalyst

Cost Item					Cost	Notes
DIRECT ANNUAL COSTS						
Operating Labor						
Operator	0.5	hrs/shift	30.00	$/hr	$16,200	
Supervisor	15%	of operator			$2,430	
Operating Materials						
Catalyst Replacement (90% of total direct cost, 3 yr life)					$769,143	
Maintenance						
Labor	0.5	hrs/shift	30.00	$/hr	$16,200	
Material	100%	of maint. labor			$16,200	
Utilities						
Natural Gas	0	(kft/yr)	5.60	$/kft3	$118,947	a
Electricity	440,977	(kWh/yr)	0.042	$/kWh	$18,521	
INDIRECT COSTS (Installation)						
Overhead	60% of sum of operating labor and materials and maintenance labor and materials.				$30,618	
Administrative Charges			2%	of TCI	$63,504	
Property Taxes			1%	of TCI	$31,752	
Insurance			1%	of TCI	$31,752	
Capital Recovery Factor (Annualized Capital Cost, 10 yrs at 10%)					$516,746	
TOTAL ANNUAL COST					**$1,632,013**	

Notes:
a) annualized data provided by Stanley Consultants for back pressure loss of simple cycle control system

Southern Montana Electric Generation and Transmission Cooperative
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CO BACT Economic Analysis
Case S4 - Simple Cycle

Total Capital Costs for Regenerative Thermal Oxidizer (RTO)

Cost Item	Factor	Cost
DIRECT COSTS		
Purchased equipment costs		
RTO + auxiliary equipment	A	$5,384,961
Instrumentation	0.10 A	$538,496
Sales taxes	0.00 A	$0
Freight	0.05 A	$269,248
Purchased equipment cost, PEC	B = 1.15 A	**$6,192,705**
Direct installation costs		
Foundations & supports	0.08 B	$495,416
Handling & erection	0.14 B	$866,979
Electrical	0.04 B	$247,708
Piping	0.02 B	$123,854
Insulation for ductwork	0.01 B	$61,927
Painting	0.01 B	$61,927
Direct installation cost	0.30 B	**$1,857,811**
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
Total Direct Cost, DC	1.30 B + SP + Bldg.	**$8,050,516**
INDIRECT COSTS (Installation)		
Engineering	0.10 B	$619,270
Construction and field expenses	0.05 B	$309,635
Contractor fees	0.10 B	$619,270
Start-up	0.02 B	$123,854
Performance test	0.01 B	$61,927
Contingencies	0.03 B	$185,781
Total Indirect Cost, IC	0.31 B	**$1,919,738**
TOTAL CAPITAL INVESTMENT (TCI) = DC + IC	1.61 B + SP + Bldg.	**$9,970,254**

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Total Annual Costs for Regenerative Thermal Oxidizer (RTO)

Cost Item					Cost
DIRECT ANNUAL COSTS					
Operating Labor					
Operator		0.5 hrs/shift		30.00 $/hr	$16,200
Supervisor		15% of operator			$2,430
Operating Materials					-
Maintenance					
Labor		0.5 hrs/shift		30.00 $/hr	$16,200
Material		100% of maint. labor			$16,200
Utilities					
Natural Gas	191,302 (kft3/yr)		$5.60 $/kft3		$1,071,291
Electricity	0 (kWh/yr)		$0.042 $/kWh		$0
INDIRECT ANNUAL COSTS, IC					
Overhead	60% of sum of operating labor and materials and maintenance labor and materials.				$30,618
Administrative Charges			2% of TCI		$199,405
Property Taxes			1% of TCI		$99,703
Insurance			1% of TCI		$99,703
Capital Recovery Factor (Annualized Capital Cost, 10 yrs at 10%)					$1,622,613
TOTAL ANNUAL COST					**$3,174,362**

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Emissions from Additional Fuel Combustion	**SO_2**	**NO_X**	**CO**	**VOC**	**PM10**
Emission Factor (lb/10^6 ft^3)	0.6	140	84	5.5	7.6
RTO Emissions (ton/yr)	0.1	13.4	8.0	0.5	0.7
RCO Emissions (ton/yr)	0.0	0.0	0.0	0.0	0.0

CO Summary:

Unit	Uncontrolled Emissions (tpy)	Control Efficiency (%)	Tons Removed (tpy)	Total Annual Cost	Cost-Effectiveness ($/ton)
RTO	86	95%	82	$3,174,362	$38,673
RCO	78	96%	75	$1,632,013	$21,725

VOC Summary:

Unit	Uncontrolled Emissions (tpy)	Control Efficiency (%)	Tons Removed (tpy)	Total Annual Cost	Cost-Effectiveness ($/ton)
RTO	3.8	95%	3.6	$3,174,362	$885,364
RCO	3.2	30%	1.0	$1,632,013	$1,674,890

Combined Summary:

Unit	Uncontrolled Emissions (tpy)	Control Efficiency (%)	Tons Removed (tpy)	Total Annual Cost	Cost-Effectiveness ($/ton)
RTO	90.2	95%	85.7	$3,174,362	$37,054
RCO	81.6	93%	76.1	$1,632,013	$21,447

References

1. Bureau of Labor and Statistics, Producers Price Index
2. OAQPS, 6th Ed, Section 3.2
3. *Thermodynamics an Engineering Approach* , Cengel/Boles, 4th Edition
4. *Estimating Costs of Air Pollution Controls* , 1990
5. Capital costs from vendor quote, Vogt Power International
6. Data from "EmissionsINFO-Rev3.xls" from Stanley Consultants
7. Data from "LM6000PF Max Emissions.xls"
8. Capital costs from vendor and engineer quote, Thermal Engineering International and Stanley Consultants
9. Data from Stanley Consultants

Southern Montana Electric Generation and Transmission Cooperative
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CO BACT Economic Analysis
Case S4 - Combined Cycle

Background Calculations

Assumed Hours of Operation	8760
Capacity Factor of Plant	0.9

Source	Uncontrolled Emissions CO (lb/hr)	CO (tpy)	VOC (lb/hr)	VOC (tpy)	Q (acfm)	T_i (°F)	
LM6000PF	48.96	193.0	2.03	8.0	581,959	1046	Reference 6
Duct Burners	8.69	34.3	0.57	2.2			

Heat rate of Duct Burners	103.50	MMBtu/hr max	Reference 6
Assumed fuel Heat Content	1000.00	btu/scf	
Duct Burner CO Emission Factor	84.00	lb/MMscf	Reference 8
Duct Burner VOC Emission Factor	5.50	lb/MMscf	Reference 8

			Reference
Q =	200,708	scfm	Reference 7
T_i =	1506	°R	
	836	K	
PPI 1988 =	112.6		Reference 1, Other industrial machinery - PCU33329-33329-
PPI Jan 2009 =	166.4		Reference 1, Other industrial machinery (Preliminary) - PCU33329-33329-
PPI Adjustment Factor =	1.48		

RCO Calculations:

Combined cycle

CO Catalyst Cost =	$340,000	(Reference 5)
SCR Cost =	$590,000	(Reference 5)
Duct Plenum Costs =	$275,000	(Reference 9)
Dump Condenser Costs =	$1,099,924	(Reference 8)
RCO Equipment Cost =	$1,714,924	(Mar 2009 $, Actual)

T_{reqd} =	800	°F	(catalyst inlet air)
Cp_i =	7.63	Btu/lb-mole*°F	(Reference 3, Table A-2E)
Cp_{reqd} =	7.44	Btu/lb-mole*°F	(Reference 3, Table A-2E)

$\Delta H^{\wedge} = (Cp_{reqd})(T_{reqd}-T_{base}) - (Cp_i)(T_i - T_{base})$

= -2,016 Btu/lb-mole

ΔH^ is negative, no additional fuel required to heat process stream

Fuel to Raise Temp = 0 Mscf/yr Natural Gas

RTO Calculations:

RTO Equipment Cost = $2.204 \times 10^5 + 11.57\,Q$ (Reference 2, Eq. 2.33)
(Valid for 10,000 < Q < 100,000)

RTO Equipment Cost[1] = [(383,000 + 15.3 * Q) + (464,000 + 19.1 * Q)]/2

RTO Equipment Cost = $3,643,910 (1988 $, Calculated)
RTO Equipment Cost = $5,384,961 (Jan 2009 $, Calculated)

T_{reqd} =	1600	°F	(catalyst inlet air)
Cp_i =	7.63	Btu/lb-mole*°F	(Reference 3, Table A-2E)
Cp_{reqd} =	8.05	Btu/lb-mole*°F	(Reference 3, Table A-2E)

$\Delta H^{\wedge} = (Cp_{reqd})(T_{reqd}-T_{base}) - (Cp_i)(T_i - T_{base})$

=	4,861	Btu/lb-mole
n_{air} = PV/RT =	529	lb-mole/min
Q = DH = n DH^ =	2,572,393	Btu/min
Q = DH = n DH^ =	154,343,605	Btu/hr
Q = DH = n DH^ =	154.34	MMBtu/hr
Required Energy Input =	154.34	MMBtu/hr
Energy Recovery =	90%	
Fuel to Raise Temp =	**128,767**	**Mscf/yr Natural Gas**

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Case S4 - Combined Cycle

[1] Because Q is outside bounds of OAQPS Eqn 2.33, alternative cost calculations were sought.
Equations 6.13 (85%) and 6.14 (95%) of Reference 4 were averaged to obtain an estimate for 90% energy recovery

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Simple Cycle Turbines
CO BACT Economic Analysis
Case S4 - Combined Cycle

Total Capital Costs for Oxidation Catalyst

Cost Item	Factor	Cost
DIRECT COSTS		
Purchased equipment costs		
Catalyst + auxiliary equipment	A	$1,714,924
Instrumentation	0.10 A	$171,492
Sales taxes	0.00 A	$0
Freight	0.05 A	$85,746
Purchased equipment cost, PEC	B = 1.15 A	**$1,972,162**
Direct installation costs		
Foundations & supports	0.08 B	$157,773
Handling & erection	0.14 B	$276,103
Electrical	0.04 B	$78,886
Piping	0.02 B	$39,443
Insulation for ductwork	0.01 B	$19,722
Painting	0.01 B	$19,722
Direct installation cost	0.30 B	**$591,649**
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
Total Direct Cost, DC	1.30 B + SP + Bldg.	**$2,563,811**
INDIRECT COSTS (Installation)		
Engineering	0.10 B	$197,216
Construction and field expenses	0.05 B	$98,608
Contractor fees	0.10 B	$197,216
Start-up	0.02 B	$39,443
Performance test	0.01 B	$19,722
Contingencies	0.03 B	$59,165
Total Indirect Cost, IC	0.31 B	**$611,370**
TOTAL CAPITAL INVESTMENT (TCI) = DC + IC	1.61 B + SP + Bldg.	**$3,175,181**

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Simple Cycle Turbines
CO BACT Economic Analysis
Case S4 - Combined Cycle

Total Annual Costs for Oxidation Catalyst

Cost Item					Cost
DIRECT ANNUAL COSTS					
Operating Labor					
Operator		0.5 hrs/shift	30.00 $/hr		$16,200
Supervisor		15% of operator			$2,430
Operating Materials					
Catalyst Replacement (90% of total direct cost, 3 yr life)					$769,143
Maintenance					
Labor		0.5 hrs/shift	30.00 $/hr		$16,200
Material		100% of maint. labor			$16,200
Utilities					
Natural Gas	0	(kft/yr)	5.60 $/kft3		$118,947
Electricity	1,207,175	(kWh/yr)	0.042 $/kWh		$50,701
INDIRECT COSTS (Installation)					
Overhead		60% of sum of operating labor and materials and maintenance labor and materials.			$30,618
Administrative Charges			2% of TCI		$63,504
Property Taxes			1% of TCI		$31,752
Insurance			1% of TCI		$31,752
Capital Recovery Factor (Annualized Capital Cost, 10 yrs at 10%)					$516,746
TOTAL ANNUAL COST					**$1,664,193**

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Simple Cycle Turbines
CO BACT Economic Analysis
Case S4 - Combined Cycle

Total Capital Costs for Regenerative Thermal Oxidizer (RTO)

Cost Item	Factor	Cost
DIRECT COSTS		
Purchased equipment costs		
RTO + auxiliary equipment	A	$5,384,961
Instrumentation	0.10 A	$538,496
Sales taxes	0.00 A	$0
Freight	0.05 A	$269,248
Purchased equipment cost, PEC	B = 1.15 A	**$6,192,705**
Direct installation costs		
Foundations & supports	0.08 B	$495,416
Handling & erection	0.14 B	$866,979
Electrical	0.04 B	$247,708
Piping	0.02 B	$123,854
Insulation for ductwork	0.01 B	$61,927
Painting	0.01 B	$61,927
Direct installation cost	0.30 B	**$1,857,811**
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
Total Direct Cost, DC	1.30 B + SP + Bldg.	**$8,050,516**
INDIRECT COSTS (Installation)		
Engineering	0.10 B	$619,270
Construction and field expenses	0.05 B	$309,635
Contractor fees	0.10 B	$619,270
Start-up	0.02 B	$123,854
Performance test	0.01 B	$61,927
Contingencies	0.03 B	$185,781
Total Indirect Cost, IC	0.31 B	**$1,919,738**
TOTAL CAPITAL INVESTMENT (TCI) = DC + IC	1.61 B + SP + Bldg.	**$9,970,254**

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Simple Cycle Turbines
CO BACT Economic Analysis
Case S4 - Combined Cycle

Total Annual Costs for Regenerative Thermal Oxidizer (RTO)

Cost Item							Cost
DIRECT ANNUAL COSTS							
Operating Labor							
Operator		0.5	hrs/shift		30.00	$/hr	$16,200
Supervisor		15%	of operator				$2,430
Operating Materials							-
Maintenance							
Labor		0.5	hrs/shift		30.00	$/hr	$16,200
Material		100%	of maint. labor				$16,200
Utilities							
Natural Gas	128,767	(kft3/yr)		$5.60	$/kft3		$721,093
Electricity	0	(kWh/yr)		$0.042	$/kWh		$0
INDIRECT ANNUAL COSTS, IC							
Overhead	60% of sum of operating labor and materials and maintenance labor and materials.						$30,618
Administrative Charges				2%	of TCI		$199,405
Property Taxes				1%	of TCI		$99,703
Insurance				1%	of TCI		$99,703
Capital Recovery Factor (Annualized Capital Cost, 10 yrs at 10%)							$1,622,613
TOTAL ANNUAL COST							**$2,824,164**

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Highwood Generating Station
GE LM6000PF Simple Cycle Turbines
CO BACT Economic Analysis
Case S4 - Combined Cycle

Emissions from Additional Fuel Combustion	**SO_2**	**NO_X**	**CO**	**VOC**	**PM10**
Emission Factor (lb/10^6 ft^3)	0.6	140	84	5.5	7.6
RTO Emissions (ton/yr)	0.0	9.0	5.4	0.4	0.5
RCO Emissions (ton/yr)	0.0	0.0	0.0	0.0	0.0

CO Summary:

Unit	Uncontrolled Emissions (tpy)	Control Efficiency (%)	Tons Removed (tpy)	Total Annual Cost	Cost-Effectiveness ($/ton)
RTO	233	95%	221	$2,824,164	$12,776
RCO	227	96%	219	$1,664,193	$7,590

VOC Summary:

Unit	Uncontrolled Emissions (tpy)	Control Efficiency (%)	Tons Removed (tpy)	Total Annual Cost	Cost-Effectiveness ($/ton)
RTO	10.6	95%	10.1	$2,824,164	$280,444
RCO	10.2	30%	3.1	$1,664,193	$541,399

Combined Summary:

Unit	Uncontrolled Emissions (tpy)	Control Efficiency (%)	Tons Removed (tpy)	Total Annual Cost	Cost-Effectiveness ($/ton)
RTO	243.3	95%	231.1	$2,824,164	$12,220
RCO	237.5	94%	222.3	$1,664,193	$7,485

References
1. Bureau of Labor and Statistics, Producers Price Index
2. OAQPS, 6th Ed, Section 3.2
3. *Thermodynamics an Engineering Approach* , Cengel/Boles, 4th Edition
4. *Estimating Costs of Air Pollution Controls* , 1990
5. Capital costs from vendor quote, Vogt Power International
6. Data from "EmissionsINFO-Rev3.xls" from Stanley Consultants
7. Data from "LM6000PF Max Emissions.xls"
8. Capital costs from vendor and engineer quote, Thermal Engineering International and Stanley Consultants
9. Data from Stanley Consultants

Southern Montana Electric Generation and Transmission Cooperative
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NOX BACT Economic Evaluation
Cases T1, T2, S2 - Combined Cycle

SCR Economic Analysis
Based on methodology described in:
EPA Pollution Cost Control Manual, 6th Edition
January 2002
Section 4.2, Chapter 2

Input Values		Description	Reference
	369.7 MMBtu/hr	Heat input rate, max per turbine, -17.7 ℉, 100% Load	Reference 4
	103.5 MMBtu/hr	Heat input rate, max per duct burner, 91.5℉, 100% load	Reference 3
Q_B =	446.2 MMBtu/hr	Heat input rate, max per generating unit, 91.5℉, 100% load	Reference 3
$q_{flg, act}$ =	581,959 acfm	Exhaust gas flow rate	Reference 3
η_{NOX} =	91.9% Control efficiency		Reference 2
	25 ppmvd @ 15% O2	Inlet NOx concentration, turbine exhaust	Reference 4
	36.58 lb/hr	Inlet NOx rate as NO2, turbine only	Reference 4
	0.099 lb/MMBtu	Inlet NOx factor, turbine only	
	140 lb/MMscf	NOX emission factor, duct burners	Reference 7
	1000 Btu/scf	heat content, natural gas	
	14.5 lb/hr	Uncontrolled duct burner emissions	
	0.140 lb/MMBtu	Uncontrolled duct burner emissions	
$NO_{X,IN}$ =	0.114 lb/MMBtu	Combined Turbine and Duct Burner Emissions	
Slip =	10 ppm	Allowable slip	Stanley Consultants
S =	1.72E-05 wt fraction	Fuel S concentration	Calculated, See "Wt fract S in NG" tab
T =	750 ℉	Reactor Inlet gas temperature	Industry standard following tempering air
n_{empty} =	1	Empty catalyst layers for change-out	Bison Estimate
ASR =	1.05	Actual stoichiometric ratio = (NSR / SR_T)	Reference 1, Eqn 2.11
C_{SOL} =	19%	Concentration of aqueous ammonia solution by weight (assumed)	Reference 8
$Cost_{NH3}$ =	$ 0.220 $/lb (1998 $)	Cost of ammonia -- value per OAQPS example	Reference 9
Hours of Operation =	8760		
Assumed CF =	0.9		Reference 8
CF $_{PLANT}$ **=**	**0.90**	Capacity factor of plant	
CF_{SCR} =	1.0	Capacity factor of SCR when plant is operational	Bison Estimate
$Cost_{ELEC}$ =	0.05 $/kWh (1998 $)	Cost of electricity -- value per OAQPS example	Reference 1, Pg 2-50
i =	10%	Interest rate, assumed	
SCR Cost $_{LoT}$ =	$ 590,000 (2009 $)	Lower Temperature Combined Cycle SCR Cost	Reference 5
	$ 419,046 (1998 $)		
Plenum & Mat'l costs	$ 275,000 (2009 $)		
	$ 195,318 (1998 $)		
Ammonia Tank Costs	$ 248,884 (2006 $)		
	$ 194,036 (1998 $)		
CC_{new} =	$ 170,000 (2009 $)	Lower Temperature Combined Cycle SCR Catalyst Cost	Reference 5
	$ 120,742 (1998 $)		
CC_{new} =	$ 618 $\$/ft^3$ (1998 $)	Catalyst initial price -- value per OAQPS example	
$CC_{replace}$ =	$ 618 $\$/ft^3$ (1998 $)	Catalyst replacement price -- value per OAQPS example	
N =	20.0 yr	Expected lifetime of control system	Reference 1, Pg 2-48
CEPCI98 =	389.5	Chemical Engineering Plant Cost Index, 1998 annual	www.che.com
CEPCI06 =	499.6	Chemical Engineering Plant Cost Index, 2006 annual	www.che.com
CEPCI08 =	548.4	Chemical Engineering Plant Cost Index, 2008 (Sept 2008 preliminary)	www.che.com
$M_{reagent}$ =	17.03 g/mol	Molecular Weight of reagent (ammonia)	Reference 1, Pg 2-39
M_{NO2} =	46.01 g/mol	Molecular Weight of NO_2	Reference 1, Pg 2-39
ρ_{sol} =	56.0 lbs/ft^3	Density of aqueous reagent solution, @ 60 ℉	Referen ce 1, Pg 2-40
v_{sol} =	7.48 gal/ft^3	Specific Volume of aqueous reagent solution, @ 60 °F	Reference 1, Pg 2-40
ΔP_{duct} =	2.50 in H20	Pressure drop, additional ductwork	Reference 1, Pg 2-46
$\Delta P_{catalyst}$ =	0.85 in H20	Pressure drop, SCR	Reference 1, Pg 2-46

Design Values

CF_{TOTAL} = CF_{PLANT} * CF_{SCR} — Reference 1, Eqn 2.6
= 0.9

$Vol_{catalyst}$ = 2.81 * Q_B * [0.2869 + (1.058 * η_{NOX})] * [1.2835 - (0.0567 * *Slip*)] — Reference 1, Eqn 2.19, 2.20, 2.21, 2.22, 2.23, 2.24
* [0.08524 + (0.3208 * NO_{XIN})] * [0.9636 + (0.0455 * *S*)]
* [15.16 - (0.03937 * *T*) + (2.74E-05 * *T*^2)]
= 139 ft^3 (Catalyst volume)

$A_{catalyst}$ = $q_{fluegas}$ / 960 — Reference 1, Eqn 2.25
= 606 ft^2 (Catalyst area)

A_{SCR} = 1.15*$A_{catalyst}$ — Reference 1, Eqn 2.26
= 697 ft^2 (SCR area)

n_{LAYER} = $Vol_{catalyst}$/ (3.1 * $A_{catalyst}$) — Reference 1, Eqn 2.28
= 1 (Number of catalyst layers)

h_{layer} = [$Vol_{catalyst}$ / (n_{layer} * $A_{catalyst}$)] + 1 — Reference 1, Eqn 2.29
= 1.23 ft (Height of each layer)

n_{total} = n_{layer} + n_{empty} — Reference 1, Eqn 2.30
= 2 (Total number of layers)

h_{SCR} = n_{total} * (7 + h_{layer}) + 9 — Reference 1, Eqn 2.31
= 25.5 ft (Height of SCR)

$m_{sol} = [(NO_{X,IN} * Q_B * ASR * \eta_{NOx} * (M_{reagent} / M_{NOx})] / C_{SOL})$ — Reference 1, Eqn 2.32, 2.33

= 95.95 lb/hr — (Mass flow rate of aqueous ammonia)

$q_{sol} = m_{sol} * \rho_{sol} / v_{sol}$ — Reference 1, Eqn 2.34

= 12.82 gal/hr — (Volume flow rate of aqueous ammonia)

$Tank\ Volume = q_{sol} * 14 * 24$ — Reference 1, Eqn 2.35

= 4307 gal — (Ammonia tank volume assuming 14 day capacity)

Direct Capital Costs

DCC = $808,401 — Direct capital cost (1998 $)

Indirect Capital Costs

$IIC = DCC * (0.05 + 0.10 + 0.05)$ — Reference 1, Table 2.5

= $161,700 — Indirect installation cost for General Facilities, Engineering and Home Office Fees, Process Contingency (1998 $)

$CONT = (DCC + IIC) * 0.15$ — Reference 1, Table 2.5

= $145,500 — Contingency cost (1998 $)

$TPC = DCC + IIC + CONT$ — Reference 1, Table 2.5

= $1,115,600 — Total plant cost (1998 $)

$PPC = TPC * 0.02$ — Reference 1, Table 2.5

= $22,300 — Preproduction cost (1998 $)

$IC = TankVolume * Cost_{NH3}$ — Reference 1, Table 2.5

= $7,100 — Inventory capital cost (1998 $)

Total Capital Investment

$TCI = TPC + PPC + IC$ — Reference 1, Table 2.5

= $1,145,000 — Total capital investment (1998 $)

Direct Annual Costs

$AMC = 0.015 * TCI$ — Reference 1, Eqn 2.46

= $17,180 — Annual Maintenance Cost (1998 $)

$ARC = m_{sol} * Cost_{NH3} * CF_{TOTAL} * 8760$ — Reference 1, Eqn 2.47

= $166,600 /yr — Reagent consumption cost (1998 $)

PWR = 131 kW — Power usage rate, Lower temperature SCR — Reference 6

$PC = PWR * CF_{TOTAL} * 8760 * COST_{ELEC}$ — Reference 1, Eqn 2.49

= $51,700 /yr — Cost of electricity (1998 $)

Y = 3.0 yr — Future worth factor years, catalyst guaranteed 3-yr life

$FWF = i * 1 / [(1 + i)^{(Y)} - 1]$ — Reference 1, Eqn 2.52

= 0.30 — Future worth factor

$ACRC = FWF * Vol_{catalyst} * CC_{replace} / n_{LAYER}$ — Reference 1, Eqn 2.50, 2.51

= $25,900 /yr — Annual catalyst replacement cost (1998 $)

$DAC = MC + RC + PC + ACRC$ — Reference 1, Eqn 2.45

= $261,380 /yr — Direct annual costs (1998 $)

Indirect Annual Costs

$CRF = i / (1 - (1 + i)^{-n})$ — Reference 1, Eqn 2.55

= 0.117 — Capital recovery factor

$IDAC = CRF * TCI$

= $134,500 /yr — Indirect annual costs (1998 $) — Reference 1, Eqn 2.54

Total Annual Costs

$TAC = DAC + IDAC$ — Reference 1, Eqn 2.56

= $395,880 /yr — Total annual cost (1998 $/yr)

Cost Effectiveness

$NO_X\ Removed = NO_{X,IN} * Q_B * 8760 * CF_{TOTAL} * \eta_{NOX} / 2000$ — Reference 1, Eqn 2.57

= 185 tons/yr — NOx removed (tons/yr)

$CE = TAC / NO_X\ Removed$ — Reference 1, Eqn 2.58

= $2,140 /ton — Cost per ton of NOx removed (1998 $)

$IACE = CE * (CEPCI08 / CEPCI98)$

= **$3,013 /ton** — Inflation adjusted cost per ton of NOx removed (Dec 2008 $)

References

1. EPA/452/B-02-001, Sixth Edition, Section 4.2, Ch 2
2. "PTE Emissions Summary - V3.xls" from Bison Engineering
3. "EmissionsINFO-Rev3.xls" from Stanley Consultants
4. "LM6000PF Max Emissions.xls" from Stanley Consultants
5. Vendor Quote, Vogt Power International
6. Vendor Quote, Braden Manufacturing
7. AP-42 Table 1.4-1
8. Data from Stanley Consultants
9. Terra Industries, Inc. representative via 1/4/08 telephone call.

S_{con} =	0.5	gr/100 scf	sulfur content of pipeline quality natural gas	As defined in CFR (acid rain)
Ts =	68	°F	Standard temperature	Standard engineering calculat ion
Ts =	528	R	Standard temperature	Standard engineering calculation
Ps =	1	atm	Standard pressure	
R =	0.7302	$(ft^3 * atm)/(lb\text{-}mol\ {}^*R)$	Ideal gas law constant	
M_{NG} =	16	lb/lb-mol	Ammonia molecular weight	
$CF_{gr\text{-}lb}$ =	7000	gr/lb	Conversion factor	

n_{NG} = Ps * Vol / (R * Ts)
= 0.259 (moles CH4 in 100 scf)

wt_{CH4} = $n_{CH4} * M_{CH4}$
= 4.144 (wt of CH4 in 100 scf, lb)

S = $S_{con} / wt_{NH3} / CF_{gr\text{-}lb}$
= 1.724E-05 (fuel S concentration, weight fraction)

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000 Simple Cycle Turbines
SCR BACT Economic Evaluation
Cases T2, T3, T4 - Simple Cycle

SCR Economic Analysis
Based on methodology described in:
EPA Pollution Cost Control Manual, 6th Edition
January 2002
Section 4.2, Chapter 2

Input Values

Input Values			Description	Reference
Q_B =	369.7	MMBtu/hr	Heat input rate, per turbine	Reference 2
$q_{flg, act}$ =	581,959	acfm	Exhaust gas flow rate	Reference 3
η_{NOX} =	89%	Control efficiency		Reference 2
$NO_{X,IN}$ =	25	ppmvd @ 15% O2	Inlet NOx concentration, post DLE	Reference 4
	36.58	lb/hr	Inlet NOx rate as NO2	Reference 4
	0.099	lb/MMBtu	Inlet NOx factor	Calculated
Slip =	10	ppm	Allowable slip	Stanley Consultants
S =	1.72E-05	wt fraction	Fuel S concentration	Calculated, See "Wt fract S in NG" tab
T =	750	℉	Reactor Inlet gas temperature	Industry standard following tempering air
n_{empty} =	1		Empty catalyst layers for change-out	Bison Estimate
ASR =	1.05		Actual stoichiometric ratio = (NSR / SR_T)	Reference 1, Eqn 2.11
C_{SOL} =	19%		Concentration of aqueous ammonia solution by weight (assumed)	Bison Assumption
$Cost_{NH3}$ =	$ 0.220	$/lb (1998 $)	Cost of ammonia -- value per OAQPS example	Reference 9
Hours of Operation =	3200			
Assumed CF =	0.9			Bison Estimate
***CF_{PLANT}* =**	**0.33**		Capacity factor of plant	Bison Estimate
CF_{SCR} =	1.0		Capacity factor of SCR when plant is operational	Bison Estimate
$Cost_{ELEC}$ =	0.050	$/kWh (1998 $)	Cost of electricity -- value per OAQPS example	Reference 1, Pg 2-50
i =	10%		Interest rate, assumed	Bison Estimate
CSC1 =	$ 4,200,000	(2009 $)	Control System Cost, high temperature	Reference 6
CSC2 =	$ 2,300,000	(2009 $)	Control System Cost, high temperature	Reference 7
CSC_{AVE} =	$ 3,250,000	(2009 $)	Control System Cost, high temperature, average	
CSC_{each} =	$ 1,625,000	(2009 $)	Control System Cost, high temperature, each turbine	
$CC_{new,LoT}$ =	$ 170,000	(2009 $)	Lower Temperature Combined Cycle SCR Catalyst Cost	Reference 5
$SCR\ Cost_{LoT}$ =	$ 590,000	(2009 $)	Lower Temperature Combined Cycle SCR Cost	Reference 5
$CO\ Catalyst\ Cost_{LoT}$	$ 340,000	(2009 $)	Lower Temperature Combined Cycle CO Catalyst Cost	Reference 5
SCR Cost % of total	63.4%		SCR portion of Control System Cost	
SCR Cat % of total	18.3%		SCR Catalyst portion of Control System Cost	
$SCR\ Cost_{HiT}$	$ 1,030,914	(2009 $)	High Temperature SCR Costs	
	$ 732,205	(1998 $)		
$CC_{new,HiT}$ =	$ 297,043	(2009 $)	High Temperature SCR Catalyst Costs	
	$ 210,974	(1998 $)		
Plenum & Mat'l costs	$ 275,000	(2009 $)		Reference 8
	$ 195,318	(1998 $)		
Ammonia Tank Costs	$ 248,884	(2006 $)		Reference 8
	$ 194,036	(1998 $)		
CC_{new} =	$ 1,396	$/ft^3 (1998 $)	Catalyst initial price	
$CC_{replace}$ =	$ 1,396	$/ft^3 (1998 $)	Catalyst replacement price	
N =	20.0	yr	Expected lifetime of control system	Reference 1, Pg 2-48
CEPCI98 =	389.5		Chemical Engineering Plant Cost Index, 1998 annual	www.che.com
CEPCI06 =	499.6		Chemical Engineering Plant Cost Index, 2006 annual	www.che.com
CEPCI08 =	548.4		Chemical Engineering Plant Cost Index, 2008 (Dec 2008 preliminary)	www.che.com
$M_{reagent}$ =	17.03	g/mol	Molecular Weight of reagent (ammonia)	Reference 1, Pg 2-39
M_{NO2} =	46.01	g/mol	Molecular Weight of NO_2	Reference 1, Pg 2-39
ρ_{sol} =	56.0	lbs/ft^3	Density of aqueous reagent solution, @ 60 ℉	Referen ce 1, Pg 2-40
v_{sol} =	7.48	gal/ft^3	Specific Volume of aqueous reagent solution, @ 60 °F	Reference 1, Pg 2-40
ΔP_{duct} =	2.50	in H20	Pressure drop, additional ductwork	Reference 1, Pg 2-46
$\Delta P_{catalyst}$ =	0.85	in H20	Pressure drop, SCR	Reference 1, Pg 2-46

Design Values

$CF_{TOTAL} = CF_{PLANT} * CF_{SCR}$ — Reference 1, Eqn 2.6

= 0.328767123

$Vol_{catalyst}$ = 2.81 * Q_B * [0.2869 + (1.058 * η_{NOX})] * [1.2835 - (0.0567 * *Slip*)] * [0.08524 + (0.3208 * NO_{XIN})] * [0.9636 + (0.0455 * *S*)] * [15.16 - (0.03937 * *T*) + (2.74E-05 * *T*^2)] — Reference 1, Eqn 2.19, 2.20, 2.21, 2.22, 2.23, 2.24

= 107 ft^3 (Catalyst volume)

$A_{catalyst} = q_{fluegas}$ / 960 — Reference 1, Eqn 2.25

= 606 ft^2 (Catalyst area)

$A_{SCR} = 1.15 * A_{catalyst}$ — Reference 1, Eqn 2.26

= 697 ft^2 (SCR area)

$n_{LAYER} = Vol_{catalyst} / (3.1 * A_{catalyst})$ — Reference 1, Eqn 2.28

= 1 (Number of catalyst layers)

$h_{layer} = [Vol_{catalyst} / (n_{layer} * A_{catalyst})] + 1$ — Reference 1, Eqn 2.29

= 1.18 ft (Height of each layer)

$n_{total} = n_{layer} + n_{empty}$ — Reference 1, Eqn 2.30

= 2 (Total number of layers)

$h_{SCR} = n_{total} * (7 + h_{layer}) + 9$ — Reference 1, Eqn 2.31

= 25.4 ft (Height of SCR)

$m_{sol} = [(NO_{X,IN} * Q_B * ASR * \eta_{NOx} * (M_{reagent} / M_{NOx}))] / C_{SOL})$ Reference 1, Eqn 2.32, 2.33
= 66.31 lb/hr (Mass flow rate of aqueous ammonia)

$q_{sol} = m_{sol} * \rho_{sol} / v_{sol}$ Reference 1, Eqn 2.34
= 8.86 gal/hr (Volume flow rate of aqueous ammonia)

$Tank\ Volume = q_{sol} * 14 * 24$ Reference 1, Eqn 2.35
= 2977 gal (Ammonia tank volume assuming 14 day capacity)

Direct Capital Costs

DCC = $1,121,559 Direct capital cost (1998 $)

Indirect Capital Costs

IIC = *DCC* * (0.05 + 0.10 + 0.05) Reference 1, Table 2.5
= $224,300 Indirect installation cost for General Facilities, Engineering and Home Office Fees, Process Contingency (1998 $)

CONT = (*DCC* + *IIC*) * 0.15 Reference 1, Table 2.5
= $201,900 Contingency cost (1998 $)

TPC = *DCC* + *IIC* + *CONT* Reference 1, Table 2.5
= $1,547,800 Total plant cost (1998 $)

PPC = *TPC* * 0.02 Reference 1, Table 2.5
= $31,000 Preproduction cost (1998 $)

$IC = TankVolume * Cost_{NH3}$ Reference 1, Table 2.5
= $4,900 Inventory capital cost (1998 $)

Total Capital Investment

TCI = *TPC* + *PPC* + *IC* Reference 1, Table 2.5
= $1,583,700 Total capital investment (1998 $)

Direct Annual Costs

AMC = 0.015 * TCI Reference 1, Eqn 2.46
= $23,760 Annual Maintenance Cost (1998 $)

$ARC = m_{sol} * Cost_{NH3} * CF_{TOTAL} * 8760$ Reference 1, Eqn 2.47
= $42,100 /yr Reagent consumption cost (1998 $)

PWR = 318 kW Power usage rate Reference 6

$= PWR * CF_{TOTAL} * 8760 * COST_{ELEC}$ Reference 1, Eqn 2.49
= $45,700 /yr Cost of electricity (1998 $)
= $118,947 /yr Cost of natural gas (2009 $), due to add'l back-pressure of simple cycle c Reference 8
= $84,482 /yr Cost of natural gas (1998 $)
PC = $130,182 /yr Total Cost of Fuels (1998 $)

Y = 3.0 yr Future worth factor years, catalyst guaranteed 3-yr life

FWF = *i* * 1 / [(1 + *i*)^(*Y*) - 1] Reference 1, Eqn 2.52
= 0.30 Future worth factor

$ACRC = FWF * Vol_{catalyst} * CC_{replace} / n_{LAYER}$ Reference 1, Eqn 2.50, 2.51
= $45,300 /yr Annual catalyst replacement cost (1998 $)

DAC = *MC* + *RC* + *PC* + *ACRC* Reference 1, Eqn 2.45
= $241,342 /yr Direct annual costs (1998 $)

Indirect Annual Costs
$CRF = i / (1 - (1 + i)^{-n})$ Reference 1, Eqn 2.55
= 0.117 Capital recovery factor

IDAC = *CRF* * *TCI*
= $186,000 /yr Indirect annual costs (1998 $) Reference 1, Eqn 2.54

Total Annual Costs
TAC = *DAC* + *IDAC* Reference 1, Eqn 2.56
= $427,342 /yr Total annual cost (1998 $/yr)

Cost Effectiveness
$NO_X\ Removed = NO_{X,IN} * Q_B * 8760 * CF_{TOTAL} * \eta_{NOX} / 2000$ Reference 1, Eqn 2.57
= 47 tons/yr NOx removed (tons/yr)

$CE = TAC / NO_X\ Removed$ Reference 1, Eqn 2.58
= $9,090 /ton Cost per ton of NOx removed (1998 $)

IACE = *CE* * (*CEPCI08* / *CEPCI98*)
= **$12,798 /ton** Inflation adjusted cost per ton of NOx removed (Dec-2008 $)

References
1. EPA/452/B-02-001, Sixth Edition, Section 4.2, Ch 2
2. "PTE Emissions Summary - V3.xls" from Bison Engineering
3. "EmissionsINFO-Rev3.xls" from Stanley Consultants
4. "LM6000PF Max Emissions.xls" from Stanley Consultants
5. Vendor Quote, Vogt Power International
6. Vendor Quote, Braden Manufacturing, LLC.
7. Vendor Quote, Turner Envirologic
8. Data from Stanley Consultants
9. Terra Industries, Inc. representative via 1/4/08 telephone call.

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GE LM6000 Simple Cycle Turbines
NOX BACT Economic Evaluation
Case T3 - Combined Cycle

SCR Economic Analysis
Based on methodology described in:
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January 2002
Section 4.2, Chapter 2

Input Values		Description	Reference
	369.7 MMBtu/hr	Heat input rate, max per turbine, -17.7 ℉, 100% Load	Reference 4
	103.5 MMBtu/hr	Heat input rate, max per duct burner, 91.5℉, 100% load	Reference 3
Q_B =	446.2 MMBtu/hr	Heat input rate, max per generating unit, 91.5℉, 100% load	Reference 3
$q_{flg, act}$ =	312,899 acfm	Exhaust gas flow rate	Reference 3
η_{NOX} =	91.9% Control efficiency	Only applies to turbine emissions, this case	Reference 2
$NO_{X,IN}$ =	25 ppmvd @ 15% O2	Inlet NOx concentration, post DLE, turbine only	Reference 4
	36.58 lb/hr	Inlet NOx rate as NO2, turbine only	Reference 4
	140 lb/MMscf	NOX emission factor, duct burners	AP-42 Table 1.4-1
	1000 Btu/scf	heat content, natural gas	
	14.5 lb/hr	Uncontrolled duct burner emissions	
	0.114 lb/MMBtu	Combined turbine and duct burner emissions	
$Slip$ =	10 ppm	Allowable slip	Stanley Consultants
S =	1.72E-05 wt fraction	Fuel S concentration	Calculated, See "Wt fract S in NG" tab
T =	750 ℉	Reactor Inlet gas temperature	Industry standard following tempering air
n_{empty} =	1	Empty catalyst layers for change-out	Bison Estimate
ASR =	1.05	Actual stoichiometric ratio = (NSR / SR_T)	Reference 1, Eqn 2.11
C_{SOL} =	19%	Concentration of aqueous ammonia solution by weight (assumed)	Bison Assumption
$Cost_{NH3}$ =	$ 0.220 $/lb (1998 $)	Cost of ammonia -- value per OAQPS example	Reference 9
Hours of Operation =	8760		
Assumed CF =	0.9		Reference 8
CF_{PLANT} =	0.90	Capacity factor of plant	
CF_{SCR} =	1.0	Capacity factor of SCR when plant is operational	Bison Estimate
$Cost_{ELEC}$ =	0.05 $/kWh (1998 $)	Cost of electricity -- value per OAQPS example	Reference 1, Pg 2-50
i =	10%	Interest rate, assumed	
CSC1 =	$ 4,200,000 (2009 $)	Control System Cost, simple cycle	Reference 6
CSC2 =	$ 2,300,000 (2009 $)	Control System Cost, simple cycle	Reference 7
CSC_{AVE} =	$ 3,250,000 (2009 $)	Control System Cost, simple cycle, each turbine	
CSC_{each} =	$ 1,625,000 (2009 $)	Control System Cost, simple cycle, Average	
$CC_{new,CC}$ =	$ 170,000 (2009 $)	Lower Temperature Combined Cycle SCR Catalyst Cost	Reference 5
$SCR\ Cost_{CC}$ =	$ 590,000 (2009 $)	Lower Temperature Combined Cycle SCR Cost	Reference 5
$CO\ Catalyst\ Cost_{CC}$	$ 340,000 (2009 $)	Lower Temperature Combined Cycle CO Catalyst Cost	Reference 5
SCR Cost % of total	63.4%		
SCR Cat % of total	18.3%		
SCR Cost SC	$ 1,030,914 (2009 $)		
	$ 732,205 (1998 $)		
CCnew,SC =	$ 297,043 (2009 $)		Reference 5
	$ 210,974 (1998 $)		
Plenum & Mat'l costs	$ 275,000 (2009 $)		Reference 8
	$ 195,318 (1998 $)		
Ammonia Tank Costs	$ 248,884 (2006 $)		Reference 8
	$ 194,036 (1998 $)		
CC_{new} =	$ 1,302 $/ft^3 (1998 $)	Catalyst initial price -- value per OAQPS example	
$CC_{replace}$ =	$ 1,302 $/ft^3 (1998 $)	Catalyst replacement price -- value per OAQPS example	
N =	20.0 yr	Expected lifetime of control system	Reference 1, Pg 2-48
CEPCI98 =	389.5	Chemical Engineering Plant Cost Index, 1998 annual	www.che.com
CEPCI06 =	499.6	Chemical Engineering Plant Cost Index, 2006 annual	www.che.com
CEPCI08 =	548.4	Chemical Engineering Plant Cost Index, 2008 (Sept 2008 preliminary)	www.che.com
$M_{reagent}$ =	17.03 g/mol	Molecular Weight of reagent (ammonia)	Reference 1, Pg 2-39
M_{NO2} =	46.01 g/mol	Molecular Weight of NO_2	Reference 1, Pg 2-39
ρ_{sol} =	56.0 lbs/ft^3	Density of aqueous reagent solution, @ 60 ℉	Referen ce 1, Pg 2-40
v_{sol} =	7.48 gal/ft^3	Specific Volume of aqueous reagent solution, @ 60 °F	Reference 1, Pg 2-40
ΔP_{duct} =	2.50 in H20	Pressure drop, additional ductwork	Reference 1, Pg 2-46
$\Delta P_{catalyst}$ =	0.85 in H20	Pressure drop, SCR	Reference 1, Pg 2-46

Design Values

CF_{TOTAL} = CF_{PLANT} * CF_{SCR} — Reference 1, Eqn 2.6
= 0.9

$Vol_{catalyst}$ = 2.81 * Q_B * [0.2869 + (1.058 * η_{NOX})] * [1.2835 - (0.0567 * $Slip$)] — Reference 1, Eqn 2.19, 2.20, 2.21, 2.22, 2.23, 2.24
* [0.08524 + (0.3208 * NO_{XIN})] * [0.9636 + (0.0455 * S)]
* [15.16 - (0.03937 * T) + (2.74E-05 * T^2)]
= 115 ft^3 (Catalyst volume)

$A_{catalyst}$ = $q_{fluegas}$ / 960 — Reference 1, Eqn 2.25
= 326 ft^2 (Catalyst area)

A_{SCR} = 1.15*$A_{catalyst}$ — Reference 1, Eqn 2.26
= 375 ft^2 (SCR area)

n_{LAYER} = $Vol_{catalyst}$/ (3.1 * $A_{catalyst}$) — Reference 1, Eqn 2.28
= 1 (Number of catalyst layers)

h_{layer} = [$Vol_{catalyst}$ / (n_{layer} * $A_{catalyst}$)] + 1 — Reference 1, Eqn 2.29
= 1.35 ft (Height of each layer)

n_{total} = n_{layer} + n_{empty} — Reference 1, Eqn 2.30
= 2 (Total number of layers)

h_{SCR} = n_{total} * (7 + h_{layer}) + 9 — Reference 1, Eqn 2.31

=	25.7 ft	(Height of SCR)	
m_{sol} =	$[(NO_{X,IN} * Q_B * ASR * \eta_{NOx} * (M_{reagent} / M_{NOx})] / C_{SOL})$		Reference 1, Eqn 2.32, 2.33
=	79.50 lb/hr	(Mass flow rate of aqueous ammonia)	
q_{sol} =	$m_{sol} * \rho_{sol} / v_{sol}$		Reference 1, Eqn 2.34
=	10.62 gal/hr	(Volume flow rate of aqueous ammonia)	
Tank Volume =	q_{sol} * 14 * 24		Reference 1, Eqn 2.35
=	3569 gal	(Ammonia tank volume assuming 14 day capacity)	

<u>Direct Capital Costs</u>

DCC =	$1,121,559	Direct capital cost (1998 $)	

<u>Indirect Capital Costs</u>

IIC =	*DCC* * (0.05 + 0.10 + 0.05)		Reference 1, Table 2.5
=	$224,300	Indirect installation cost for General Facilities, Engineering and Home Office Fees, Process Contingency (1998 $)	
CONT =	(*DCC* + *IIC*) * 0.15		Reference 1, Table 2.5
=	$201,900	Contingency cost (1998 $)	
TPC =	*DCC* + *IIC* + *CONT*		Reference 1, Table 2.5
=	$1,547,800	Total plant cost (1998 $)	
PPC =	*TPC* * 0.02		Reference 1, Table 2.5
=	$31,000	Preproduction cost (1998 $)	
IC =	*TankVolume* * $Cost_{NH3}$		Reference 1, Table 2.5
=	$5,900	Inventory capital cost (1998 $)	

<u>Total Capital Investment</u>

TCI =	*TPC* + *PPC* + *IC*		Reference 1, Table 2.5
=	$1,584,700	Total capital investment (1998 $)	

<u>Direct Annual Costs</u>

AMC =	0.015 * TCI		Reference 1, Eqn 2.46
=	$23,770	Annual Maintenance Cost (1998 $)	
ARC =	$m_{sol} * Cost_{NH3} * CF_{TOTAL}$ * 8760		Reference 1, Eqn 2.47
=	$138,000 /yr	Reagent consumption cost (1998 $)	
PWR =	318 kW	Power usage rate	Reference 6
=	$PWR * CF_{TOTAL} * 8760 * COST_{ELEC}$		Reference 1, Eqn 2.49
=	$125,200 /yr	Cost of electricity (1998 $)	
=	$118,947 /yr	Cost of natural gas (2009 $), due to add'l back-pressure of simple cycle (	Reference 8
=	$84,482 /yr	Cost of natural gas (1998 $)	
PC =	$209,682 /yr	Total Cost of Fuels (1998 $)	
Y =	3.0 yr	Future worth factor years, catalyst guaranteed 3-yr life	
FWF =	*i* * 1 / [(1 + *i*)^(*Y*) - 1]		Reference 1, Eqn 2.52
=	0.30	Future worth factor	
ACRC =	$FWF * Vol_{catalyst} * CC_{replace} / n_{LAYER}$		Reference 1, Eqn 2.50, 2.51
=	$45,300 /yr	Annual catalyst replacement cost (1998 $)	
DAC =	*MC* + *RC* + *PC* + *ACRC*		Reference 1, Eqn 2.45
=	$332,270 /yr	Direct annual costs (1998 $)	

<u>Indirect Annual Costs</u>

CRF =	$i / (1 - (1 + i)^{-n})$		Reference 1, Eqn 2.55
=	0.117	Capital recovery factor	
IDAC =	*CRF* * *TCI*		
=	$186,100 /yr	Indirect annual costs (1998 $)	Reference 1, Eqn 2.54

<u>Total Annual Costs</u>

TAC =	*DAC* + *IDAC*		Reference 1, Eqn 2.56
=	$518,370 /yr	Total annual cost (1998 $/yr)	

<u>Cost Effectiveness</u>

NO_X *Removed* =	$NO_{X,IN} * Q_B * 8760 * CF_{TOTAL} * \eta_{NOX} / 2000$		Reference 1, Eqn 2.57
=	153 tons/yr	NOx removed (tons/yr)	
CE =	*TAC* / NO_X *Removed*		Reference 1, Eqn 2.58
=	$3,390 /ton	Cost per ton of NOx removed (1998 $)	
IACE =	*CE* * (*CEPCI08* / *CEPCI98*)		
=	**$4,773 /ton**	Inflation adjusted cost per ton of NOx removed (Sept-2008 $)	
Effective Control Efficiency =	71.6%	Due to uncontrolled duct burner emissions	

<u>References</u>

1. EPA/452/B-02-001, Sixth Edition, Section 4.2, Ch 2
2. "PTE Emissions Summary - V3.xls" from Bison Engineering
3. "EmissionsINFO-Rev3.xls" from Stanley Consultants
4. "LM6000PF Max Emissions.xls" from Stanley Consultants
5. Vendor Quote, Vogt Power International
6. Vendor Quote, Braden Manufacturing, LLC.
7. Vendor Quote, Turner Envirologic
8. Data from Stanley Consultants
9. Terra Industries, Inc. representative via 1/4/08 telephone call.

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GE LM6000 Simple Cycle Turbines
NOX BACT Economic Evaluation
Case T4 - Combined Cycle

SCR Economic Analysis
Based on methodology described in:
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January 2002
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Input Values			Description	Reference
	369.7	MMBtu/hr	Heat input rate, max per turbine, -17.7 ℉, 100% Load	Reference 4
	103.5	MMBtu/hr	Heat input rate, max per duct burner, 91.5℉, 100% load	Reference 3
Q_B =	446.2	MMBtu/hr	Heat input rate, max per generating unit, 91.5℉, 100% load	Reference 3
$q_{flg,\ act}$ =	581,959	acfm	Exhaust gas flow rate	Reference 3
η_{NOX} =	91.85%	Control efficiency		Reference 2
	25	ppmvd @ 15% O2	Inlet NOx concentration, post water injection	Reference 4
	36.58	lb/hr	Inlet NOx rate as NO2	Reference 4
	140	lb/MMscf	NOX emission factor, duct burners	Reference 7
	1000	Btu/scf	heat content, natural gas	
	14.5	lb/hr	Uncontrolled duct burner emissions	
$NO_{X,IN}$ =	0.114	lb/MMBtu	Combined Turbine and Duct Burner Emissions	
Slip =	10	ppm	Allowable slip	Reference 8
S =	1.72E-05	wt fraction	Fuel S concentration	Calculated, See "Wt fract S in NG" tab
T =	750	℉	Reactor Inlet gas temperature	Industry standard following tempering air
n_{empty} =	1		Empty catalyst layers for change-out	Bison Estimate
ASR =	1.05		Actual stoichiometric ratio = (NSR / SR_T)	Reference 1, Eqn 2.11
C_{SOL} =	19%		Concentration of aqueous ammonia solution by weight (assumed)	Reference 8
$Cost_{NH3}$ =	$ 0.220	$/lb (1998 $)	Cost of ammonia -- value per OAQPS example	Reference 9
Hours of Operation =	8760			
Assumed CF =	0.9			Bison Estimate
CF_{PLANT} =	**0.90**		Capacity factor of plant	Bison Estimate
CF_{SCR} =	1.0		Capacity factor of SCR when plant is operational	Bison Estimate
$Cost_{ELEC}$ =	0.05	$/kWh (1998 $)	Cost of electricity -- value per OAQPS example	Reference 1, Pg 2-50
i =	10%		Interest rate, assumed	Bison Estimate
CSC1 =	$ 3,480,000	(2009 $)	Control System Cost, simple cycle	Reference 6
CSC2 =	$ 1,580,000	(2009 $)	Control System Cost, simple cycle	Reference 7
CSC_{AVE} =	$ 2,530,000	(2009 $)	Control System Cost, simple cycle, average	
CSC_{each} =	$ 1,265,000	(2009 $)	Control System Cost, simple cycle, each turbine	
$CC_{new,CC}$ =	$ 170,000	(2009 $)	Lower Temperature Combined Cycle SCR Catalyst Cost	Reference 5
	$ 120,742	(1998 $)		
$SCR\ Cost_{CC}$ =	$ 590,000	(2009 $)	Lower Temperature Combined Cycle SCR Cost	Reference 5
	$ 419,046	(1998 $)		
$CO\ Catalyst\ Cost_{CC}$ =	$ 340,000	(2009 $)	Lower Temperature Combined Cycle CO Catalyst Cost	Reference 5
SCR Cost % of total =	63.4%			
SCR Cat % of total =	12.6%			
SCR Cost SC =	$ 802,527	(2009 $)		
	$ 569,993	(1998 $)		
CCnew,SC =	$ 159,409	(2009 $)		Reference 5
	$ 113,220	(1998 $)		
Plenum & Mat'l costs =	$ 550,000	(2009 $)		Reference 8
	$ 390,636	(1998 $)		
Ammonia Tank Costs =	$ 248,884	(2006 $)		Reference 8
	$ 194,036	(1998 $)		
ID Fan Costs =	$ 500,000	(2009 $)		
	$ 355,124	(1998 $)		
CC_{new} =	$ 1,197	$/ft^3 (1998 $)	Catalyst initial price -- value per OAQPS example	
$CC_{replace}$ =	$ 1,197	$/ft^3 (1998 $)	Catalyst replacement price -- value per OAQPS example	
N =	20.0	yr	Expected lifetime of control system	Reference 1, Pg 2-48
CEPCI98 =	389.5		Chemical Engineering Plant Cost Index, 1998 annual	www.che.com
CEPCI06 =	499.6		Chemical Engineering Plant Cost Index, 2006 annual	www.che.com
CEPCI08 =	548.4		Chemical Engineering Plant Cost Index, 2008 (Sept 2008 preliminary)	www.che.com
$M_{reagent}$ =	17.03	g/mol	Molecular Weight of reagent (ammonia)	Reference 1, Pg 2-39
M_{NO2} =	46.01	g/mol	Molecular Weight of NO_2	Reference 1, Pg 2-39
ρ_{sol} =	56.0	lbs/ft^3	Density of aqueous reagent solution, @ 60 ℉	Referen ce 1, Pg 2-40
v_{sol} =	7.48	gal/ft^3	Specific Volume of aqueous reagent solution, @ 60 °F	Reference 1, Pg 2-40
ΔP_{duct} =	2.50	in H20	Pressure drop, additional ductwork	Reference 1, Pg 2-46
$\Delta P_{catalyst}$ =	0.85	in H20	Pressure drop, SCR	Reference 1, Pg 2-46

Design Values

$CF_{TOTAL} = CF_{PLANT} * CF_{SCR}$ — Reference 1, Eqn 2.6

$= 0.9$

$Vol_{catalyst} = 2.81 * Q_B * [0.2869 + (1.058 * \eta_{NOX})] * [1.2835 - (0.0567 * Slip)] * [0.08524 + (0.3208 * NO_{XIN})] * [0.9636 + (0.0455 * S)] * [15.16 - (0.03937 * T) + (2.74E-05 * T\hat{}2)]$ — Reference 1, Eqn 2.19, 2.20, 2.21, 2.22, 2.23, 2.24

$= 139\ ft^3$ (Catalyst volume)

$A_{catalyst} = q_{fluegas} / 960$ — Reference 1, Eqn 2.25

$= 606\ ft^2$ (Catalyst area)

$A_{SCR} = 1.15 * A_{catalyst}$ — Reference 1, Eqn 2.26

$= 697\ ft^2$ (SCR area)

$n_{LAYER} = Vol_{catalyst} / (3.1 * A_{catalyst})$ — Reference 1, Eqn 2.28

$= 1$ (Number of catalyst layers)

$h_{layer} = [Vol_{catalyst} / (n_{layer} * A_{catalyst})] + 1$ — Reference 1, Eqn 2.29

$= 1.23$ ft (Height of each layer)

$n_{total} = n_{layer} + n_{empty}$ — Reference 1, Eqn 2.30

= 2 (Total number of layers)

$h_{SCR} = n_{total} * (7 + h_{layer}) + 9$ Reference 1, Eqn 2.31
= 25.5 ft (Height of SCR)

$m_{sol} = [(NO_{X,IN} * Q_B * ASR * \eta_{NOx} * (M_{reagent} / M_{NOx})] / C_{SOL})$ Reference 1, Eqn 2.32, 2.33
= 95.95 lb/hr (Mass flow rate of aqueous ammonia)

$q_{sol} = m_{sol} * \rho_{sol} / v_{sol}$ Reference 1, Eqn 2.34
= 12.82 gal/hr (Volume flow rate of aqueous ammonia)

$Tank\ Volume = q_{sol} * 14 * 24$ Reference 1, Eqn 2.35
= 4307 gal (Ammonia tank volume assuming 14 day capacity)

Direct Capital Costs

DCC = $1,928,836 Direct capital cost (1998 $)

Indirect Capital Costs

$IIC = DCC * (0.05 + 0.10 + 0.05)$ Reference 1, Table 2.5
= $385,800 Indirect installation cost for General Facilities, Engineering and Home Office Fees, Process Contingency (1998 $)

$CONT = (DCC + IIC) * 0.15$ Reference 1, Table 2.5
= $347,200 Contingency cost (1998 $)

$TPC = DCC + IIC + CONT$ Reference 1, Table 2.5
= $2,661,800 Total plant cost (1998 $)

$PPC = TPC * 0.02$ Reference 1, Table 2.5
= $53,200 Preproduction cost (1998 $)

$IC = TankVolume * Cost_{NH3}$ Reference 1, Table 2.5
= $7,100 Inventory capital cost (1998 $)

Total Capital Investment

$TCI = TPC + PPC + IC$ Reference 1, Table 2.5
= $2,722,100 Total capital investment (1998 $)

Direct Annual Costs

$AMC = 0.015 * TCI$ Reference 1, Eqn 2.46
= $40,830 Annual Maintenance Cost (1998 $)

$ARC = m_{sol} * Cost_{NH3} * CF_{TOTAL} * 8760$ Reference 1, Eqn 2.47
= $166,600 /yr Reagent consumption cost (1998 $)

PWR = Power High Temp SCR + Power Low Temp SCR + $0.105 * Q_B * [0.5 * (\Delta P_{duct} + n_{total} * \Delta P_{SCR})]$ Reference 1, Eqn 2.48
= 547 kW Power usage rate, high temp SCR, low temp SCR and ID Fan

$PC = PWR * CF_{TOTAL} * 8760 * COST_{ELEC}$ Reference 1, Eqn 2.49
= $215,600 /yr Cost of electricity (1998 $)
= $118,947 /yr Cost of natural gas (2009 $), due to add'l back-pressure of simple cycle cor Reference 8
= $84,482 /yr Cost of natural gas (1998 $)
PC = $300,082 /yr Total Cost of Fuels (1998 $)

Y = 3.0 yr Future worth factor years, catalyst guaranteed 3-yr life

$FWF = i * 1 / [(1 + i)^(Y) - 1]$ Reference 1, Eqn 2.52
= 0.30 Future worth factor

$ACRC = FWF * Vol_{catalyst} * CC_{replace} / n_{LAYER}$ Reference 1, Eqn 2.50, 2.51
= $50,200 /yr Annual catalyst replacement cost (1998 $)

$DAC = MC + RC + PC + ACRC$ Reference 1, Eqn 2.45
= $473,230 /yr Direct annual costs (1998 $)

Indirect Annual Costs

$CRF = i / (1 - (1 + i)^{-n})$ Reference 1, Eqn 2.55
= 0.117 Capital recovery factor

$IDAC = CRF * TCI$
= $319,700 /yr Indirect annual costs (1998 $) Reference 1, Eqn 2.54

Total Annual Costs

$TAC = DAC + IDAC$ Reference 1, Eqn 2.56
= $792,930 /yr Total annual cost (1998 $/yr)

Cost Effectiveness

$NO_X\ Removed = NO_{X,IN} * Q_B * 8760 * CF_{TOTAL} * \eta_{NOX} / 2000$ Reference 1, Eqn 2.57
= 185 tons/yr NOx removed (tons/yr)

$CE = TAC / NO_X\ Removed$ Reference 1, Eqn 2.58
= $4,290 /ton Cost per ton of NOx removed (1998 $)

$IACE = CE * (CEPCI08 / CEPCI98)$
= **$6,040 /ton** Inflation adjusted cost per ton of NOx removed (Dec-2008 $)

References

1. EPA/452/B-02-001, Sixth Edition, Section 4.2, Ch 2
2. "PTE Emissions Summary - V3.xls" from Bison Engineering
3. "EmissionsINFO-Rev3.xls" from Stanley Consultants
4. "LM6000PF Max Emissions.xls" from Stanley Consultants
5. Vendor Quote, Vogt Power International
6. Vendor Quote, Braden Manufacturing
7. AP-42 Table 1.4-1
8. Data from Stanley Consultants
9. Terra Industries, Inc. representative via 1/4/08 telephone call.

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Simple Cycle Turbines
SCR Cost Effectiveness Estimation
Case S2 - Simple Cycle

SCR Economic Analysis
Based on methodology described in:
EPA Pollution Cost Control Manual, 6th Edition
January 2002
Section 4.2, Chapter 2

Input Values			Description	Reference
Q_B =	369.7	MMBtu/hr	Heat input rate, per turbine	Reference 2
$q_{flg,\ act}$ =	581,959	acfm	Exhaust gas flow rate	Reference 3
η_{NOX} =	89%	Control efficiency		Reference 2
	25	ppmvd @ 15% O2	Inlet NOx concentration, post water injection	Reference 4
	36.58	lb/hr	Inlet NOx rate as NO2	Reference 4
$NO_{X,IN}$ =	0.099	lb/MMBtu	Inlet NOx factor	Calculated
$Slip$ =	10	ppm	Allowable slip	Reference 8
S =	1.72E-05	wt fraction	Fuel S concentration	Calculated, See "Wt fract S in NG" tab
T =	750	°F	Reactor Inlet gas temperature	Industry standard following tempering air
n_{empty} =	1		Empty catalyst layers for change-out	Bison Estimate
ASR =	1.05		Actual stoichiometric ratio = (NSR / SR_T)	Reference 1, Eqn 2.11
C_{SOL} =	19%		Concentration of aqueous ammonia solution by weight (assumed)	Reference 8
$Cost_{NH3}$ =	$ 0.220	$/lb (1998 $)	Cost of ammonia -- value per OAQPS example	Reference 9
Hours of Operation =	3200			
Assumed CF =	0.9			Reference 8
***CF**$_{PLANT}$* =	**0.33**		Capacity factor of plant	
CF_{SCR} =	1.0		Capacity factor of SCR when plant is operational	Bison Estimate
$Cost_{ELEC}$ =	0.05	$/kWh (1998 $)	Cost of electricity -- value per OAQPS example	Reference 1, Pg 2-50
i =	10%		Interest rate, assumed	
CSC1 =	$ 4,200,000	(2009 $)	Control System Cost, high temperature catalyst	Reference 6
CSC2 =	$ 2,300,000	(2009 $)	Control System Cost, high temperature catalyst	Reference 7
CSC_{AVE} =	$ 3,250,000	(2009 $)	Control System Cost, high temperature catalyst, average	
CSC_{each} =	$ 1,625,000	(2009 $)	Control System Cost, high temperature catalyst, each turbine	
$CC_{new,CC}$ =	$ 170,000	(2009 $)	Lower Temperature Combined Cycle SCR Catalyst Cost	Reference 5
SCR Cost$_{CC}$ =	$ 590,000	(2009 $)	Lower Temperature Combined Cycle SCR Cost	Reference 5
CO Catalyst Cost$_{CC}$ =	$ 340,000	(2009 $)	Lower Temperature Combined Cycle CO Catalyst Cost	Reference 5
SCR Cost % of total =	63.4%			
SCR Cat % of total =	18.3%			
SCR Cost SC =	$1,030,914	(2009 $)	SCR cost portion of CSC_{each}	
	$732,205	(1998 $)		
CCnew,SC =	$297,043	(2009 $)	SCR Catalyst costs from CSC_{each}	
	$210,974	(1998 $)		
Plenum & Mat'l costs =	$275,000	(2009 $)		Reference 8
	$195,318	(1998 $)		
Ammonia Tank Costs =	$248,884	(2009 $)		Reference 8
	$194,036	(1998 $)		
OTSG Incr Costs =	$8,921,727	(2009 $)	Incremental cost increase of OTSG vs. HRSG	Reference 10
	$6,336,638	(1998 $)		
CC_{new} =	$ 1,965	$/ft^3 (1998 $)	Catalyst initial price -- value per OAQPS example	
$CC_{replace}$ =	$ 1,965	$/ft^3 (1998 $)	Catalyst replacement price -- value per OAQPS example	
N =	20.0	yr	Expected lifetime of control system	Reference 1, Pg 2-48
CEPCI98 =	389.5		Chemical Engineering Plant Cost Index, 1998 annual	www.che.com
CEPCI06 =	499.6		Chemical Engineering Plant Cost Index, 2006 annual	www.che.com
CEPCI08 =	548.4		Chemical Engineering Plant Cost Index, 2008 (Dec 2008 preliminary)	www.che.com
$M_{reagent}$ =	17.03	g/mol	Molecular Weight of reagent (ammonia)	Reference 1, Pg 2-39
M_{NO2} =	46.01	g/mol	Molecular Weight of NO_2	Reference 1, Pg 2-39
ρ_{sol} =	56.0	lbs/ft^3	Density of aqueous reagent solution, @ 60 °F	Referen ce 1, Pg 2-40
v_{sol} =	7.48	gal/ft^3	Specific Volume of aqueous reagent solution, @ 60 °F	Reference 1, Pg 2-40
ΔP_{duct} =	2.50	in H20	Pressure drop, additional ductwork	Reference 1, Pg 2-46
$\Delta P_{catalyst}$ =	0.85	in H20	Pressure drop, SCR	Reference 1, Pg 2-46

Design Values

CF_{TOTAL} = $CF_{PLANT} * CF_{SCR}$ — Reference 1, Eqn 2.6
= 0.328767123

$Vol_{catalyst}$ = 2.81 * Q_B * [0.2869 + (1.058 * η_{NOX})] * [1.2835 - (0.0567 * $Slip$)] * [0.08524 + (0.3208 * NO_{XIN})] * [0.9636 + (0.0455 * S)] * [15.16 - (0.03937 * T) + (2.74E-05 * T^2)] — Reference 1, Eqn 2.19, 2.20, 2.21, 2.22, 2.23, 2.24
= 107 ft^3 (Catalyst volume)

$A_{catalyst}$ = $q_{fluegas}$ / 960 — Reference 1, Eqn 2.25
= 606 ft^2 (Catalyst area)

A_{SCR} = 1.15*$A_{catalyst}$ — Reference 1, Eqn 2.26
= 697 ft^2 (SCR area)

n_{LAYER} = $Vol_{catalyst}$/ (3.1 * $A_{catalyst}$) — Reference 1, Eqn 2.28
= 1 (Number of catalyst layers)

h_{layer} = [$Vol_{catalyst}$ / (n_{layer} * $A_{catalyst}$)] + 1 — Reference 1, Eqn 2.29
= 1.18 ft (Height of each layer)

n_{total} = n_{layer} + n_{empty} — Reference 1, Eqn 2.30
= 2 (Total number of layers)

$h_{SCR} = n_{total} * (7 + h_{layer}) + 9$			Reference 1, Eqn 2.31
=	25.4 ft	(Height of SCR)	
$m_{sol} = [(NO_{X,IN} * Q_B * ASR * \eta_{NOx} * (M_{reagent} / M_{NOx})] / C_{SOL})$			Reference 1, Eqn 2.32, 2.33
=	66.31 lb/hr	(Mass flow rate of aqueous ammonia)	
$q_{sol} = m_{sol} * \rho_{sol} / v_{sol}$			Reference 1, Eqn 2.34
=	8.86 gal/hr	(Volume flow rate of aqueous ammonia)	
$Tank\ Volume = q_{sol} * 14 * 24$			Reference 1, Eqn 2.35
=	2977 gal	(Ammonia tank volume assuming 14 day capacity)	

Direct Capital Costs

DCC =	$7,458,197	Direct capital cost (1998 $)	

Indirect Capital Costs

$IIC = DCC * (0.05 + 0.10 + 0.05)$			Reference 1, Table 2.5
=	$1,491,600	Indirect installation cost for General Facilities, Engineering and Home Office Fees, Process Contingency (1998 $)	
$CONT = (DCC + IIC) * 0.15$			Reference 1, Table 2.5
=	$1,342,500	Contingency cost (1998 $)	
$TPC = DCC + IIC + CONT$			Reference 1, Table 2.5
=	$10,292,300	Total plant cost (1998 $)	
$PPC = TPC * 0.02$			Reference 1, Table 2.5
=	$205,800	Preproduction cost (1998 $)	
$IC = TankVolume * Cost_{NH3}$			Reference 1, Table 2.5
=	$4,900	Inventory capital cost (1998 $)	

Total Capital Investment

$TCI = TPC + PPC + IC$			Reference 1, Table 2.5
=	$10,503,000	Total capital investment (1998 $)	

Direct Annual Costs

$AMC = 0.015 * TCI$			Reference 1, Eqn 2.46
=	$157,550	Annual Maintenance Cost (1998 $)	
$ARC = m_{sol} * Cost_{NH3} * CF_{TOTAL} * 8760$			Reference 1, Eqn 2.47
=	$42,100 /yr	Reagent consumption cost (1998 $)	
PWR =	318 kW	Power usage rate, high temperature SCR	Reference 6
$PC = PWR * CF_{TOTAL} * 8760 * COST_{ELEC}$			Reference 1, Eqn 2.49
=	$45,700 /yr	Cost of electricity (1998 $)	
=	$118,947 /yr	Cost of natural gas (2009 $), due to add'l back-pressure of high temp. ca	Reference 8
=	$84,482 /yr	Cost of natural gas (1998 $)	
PC =	$143,082 /yr	Total Cost of Fuels (1998 $)	
Y =	3.0 yr	Future worth factor years, catalyst guaranteed 3-yr life	
$FWF = i * 1 / [(1 + i)^(Y) - 1]$			Reference 1, Eqn 2.52
=	0.30	Future worth factor	
$ACRC = FWF * Vol_{catalyst} * CC_{replace} / n_{LAYER}$			Reference 1, Eqn 2.50, 2.51
=	$63,700 /yr	Annual catalyst replacement cost (1998 $)	
$DAC = MC + RC + PC + ACRC$			Reference 1, Eqn 2.45
=	$406,432 /yr	Direct annual costs (1998 $)	

Indirect Annual Costs

$CRF = i / (1 - (1 + i)^{-n})$			Reference 1, Eqn 2.55
=	0.117	Capital recovery factor	
$IDAC = CRF * TCI$			Reference 1, Eqn 2.54
=	$1,233,700 /yr	Indirect annual costs (1998 $)	Reference 1, Eqn 2.54

Total Annual Costs

$TAC = DAC + IDAC$			Reference 1, Eqn 2.56
=	$1,640,132 /yr	Total annual cost (1998 $/yr)	

Cost Effectiveness

$NO_X\ Removed = NO_{X,IN} * Q_B * 8760 * CF_{TOTAL} * \eta_{NOX} / 2000$			Reference 1, Eqn 2.57
=	47 tons/yr	NOx removed (tons/yr)	
$CE = TAC / NO_X\ Removed$			Reference 1, Eqn 2.58
=	$34,900 /ton	Cost per ton of NOx removed (1998 $)	
$IACE = CE * (CEPCI08 / CEPCI98)$			
=	**$49,138 /ton**	Inflation adjusted cost per ton of NOx removed (Dec-2008 $)	

References

1. EPA/452/B-02-001, Sixth Edition, Section 4.2, Ch 2
2. "PTE Emissions Summary - V3.xls" from Bison Engineering
3. "EmissionsINFO-Rev3.xls" from Stanley Consultants
4. "LM6000PF Max Emissions.xls" from Stanley Consultants
5. Vendor Quote, Vogt Power International
6. Vendor Quote from Braden Manufacturing, LLC.
7. Vendor Quote from Turner Envirologic
8. Data from Stanley Consultants
9. Terra Industries, Inc. representative via 1/4/08 telephone call.
10. Data from Stanley Consultants for similar project

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Simple Cycle Turbines
NOX BACT Economic Evaluation
Case S2 - Combined Cycle

SCR Economic Analysis
Based on methodology described in:
EPA Pollution Cost Control Manual, 6th Edition
January 2002
Section 4.2, Chapter 2

Input Values			Description	Reference
	369.7	MMBtu/hr	Heat input rate, max per turbine, -17.7 ℉, 100% Load	Reference 4
	103.5	MMBtu/hr	Heat input rate, max per duct burner, 91.5℉, 100% load	Reference 3
Q_B =	446.2	MMBtu/hr	Heat input rate, max per generating unit, 91.5℉, 100% load	Reference 3
$q_{flg, act}$ =	581,959	acfm	Exhaust gas flow rate	Reference 3
η_{NOX} =	91.9%	Control efficiency		Reference 2
	25	ppmvd @ 15% O2	Inlet NOx concentration, post water injection	Reference 4
	36.58	lb/hr	Inlet NOx rate as NO2	Reference 4
	140	lb/MMscf	NOX emission factor, duct burners	Reference 9
	1000	Btu/scf	heat content, natural gas	
	14.5	lb/hr	Uncontrolled duct burner emissions	
$NO_{X,IN}$ =	0.114	lb/MMBtu	turbine and duct burner combined	
Slip =	10	ppm	Allowable slip	Reference 8
S =	1.72E-05	wt fraction	Fuel S concentration	Calculated, See "Wt fract S in NG" tab
T =	750	℉	Reactor Inlet gas temperature	Industry standard following tempering air
n_{empty} =	1		Empty catalyst layers for change-out	Bison Estimate
ASR =	1.05		Actual stoichiometric ratio = (NSR / SR_T)	Reference 1, Eqn 2.11
C_{SOL} =	19%		Concentration of aqueous ammonia solution by weight (assumed)	Reference 8
$Cost_{NH3}$ =	$ 0.220	$/lb (1998 $)	Cost of ammonia -- value per OAQPS example	Reference 10
Hours of Operation =	8760			
Assumed CF =	0.9			Reference 8
CF_{PLANT} =	0.90		Capacity factor of plant	
CF_{SCR} =	1.0		Capacity factor of SCR when plant is operational	Bison Estimate
$Cost_{ELEC}$ =	0.05	$/kWh (1998 $)	Cost of electricity -- value per OAQPS example	Reference 1, Pg 2-50
i =	10%		Interest rate, assumed	
CSC1 =	$ 3,480,000	(2009 $)	Control System Cost, high temperature catalyst	Reference 6
CSC2 =	$ 1,580,000	(2009 $)	Control System Cost, high temperature catalyst	Reference 7
CSC_{AVE} =	$ 2,530,000	(2009 $)	Control System Cost, high temperature catalyst, average	
CSC_{each} =	$ 1,265,000	(2009 $)	Control System Cost, high temperature catalyst, each turbine	
$CC_{new,LoT}$ =	$ 170,000	(2009 $)	Lower Temperature Combined Cycle SCR Catalyst Cost	Reference 5
SCR Cost $_{LoT}$ =	$ 590,000	(2009 $)	Lower Temperature Combined Cycle SCR Cost	Reference 5
CO Catalyst Cost $_{LoT}$ =	$ 340,000	(2009 $)	Lower Temperature Combined Cycle CO Catalyst Cost	Reference 5
SCR Cost % of total =	63.4%			
SCR Cat % of total =	18.3%			
SCR Cost $_{HiT}$ =	$802,527	(2009 $)	SCR system cost portion of CSC_{each}, High Temperature Catalyst	
	$569,993	(1998 $)		
CCnew $_{HiT}$ =	$231,237	(2009 $)	SCR Catalyst costs from CSC_{each}, High Temperature Catalyst	
	$164,235	(1998 $)		
Plenum & Mat'l costs =	$275,000	(2009 $)		Reference 8
	$195,318	(1998 $)		
Ammonia Tank Costs =	$ 248,884	(2009 $)		Reference 8
	$194,036	(1998 $)		
OTSG Incr Costs =	$8,921,727	(2009 $)	Incremental cost increase of OTSG vs. HRSG	Reference 10
	$6,336,638	(1998 $)		
CC_{new} =	$ 1,183	$/ft^3 (1998 $)	Catalyst initial price -- value per OAQPS example	
$CC_{replace}$ =	$ 1,183	$/ft^3 (1998 $)	Catalyst replacement price -- value per OAQPS example	
N =	20.0	yr	Expected lifetime of control system	Reference 1, Pg 2-48
CEPCI98 =	389.5		Chemical Engineering Plant Cost Index, 1998 annual	www.che.com
CEPCI06 =	499.6		Chemical Engineering Plant Cost Index, 2006 annual	www.che.com
CEPCI08 =	548.4		Chemical Engineering Plant Cost Index, 2008 (Dec 2008 preliminary)	www.che.com
$M_{reagent}$ =	17.03	g/mol	Molecular Weight of reagent (ammonia)	Reference 1, Pg 2-39
M_{NO2} =	46.01	g/mol	Molecular Weight of NO_2	Reference 1, Pg 2-39
ρ_{sol} =	56.0	lbs/ft^3	Density of aqueous reagent solution, @ 60 ℉	Referen ce 1, Pg 2-40
v_{sol} =	7.48	gal/ft^3	Specific Volume of aqueous reagent solution, @ 60 °F	Reference 1, Pg 2-40
ΔP_{duct} =	2.50	in H20	Pressure drop, additional ductwork	Reference 1, Pg 2-46
$\Delta P_{catalyst}$ =	0.85	in H20	Pressure drop, SCR	Reference 1, Pg 2-46

Design Values

$CF_{TOTAL} = CF_{PLANT} * CF_{SCR}$ — Reference 1, Eqn 2.6
= 0.9

$Vol_{catalyst} = 2.81 * Q_B * [0.2869 + (1.058 * \eta_{NOX})] * [1.2835 - (0.0567 * Slip)]$
$* [0.08524 + (0.3208 * NO_{XIN})] * [0.9636 + (0.0455 * S)]$
$* [15.16 - (0.03937 * T) + (2.74E\text{-}05 * T\text{^}2)]$ — Reference 1, Eqn 2.19, 2.20, 2.21, 2.22, 2.23, 2.24
= 139 ft^3 (Catalyst volume)

$A_{catalyst} = q_{fluegas} / 960$ — Reference 1, Eqn 2.25
= 606 ft^2 (Catalyst area)

$A_{SCR} = 1.15 * A_{catalyst}$ — Reference 1, Eqn 2.26
= 697 ft^2 (SCR area)

$n_{LAYER} = Vol_{catalyst} / (3.1 * A_{catalyst})$ — Reference 1, Eqn 2.28
= 1 (Number of catalyst layers)

$h_{layer} = [Vol_{catalyst} / (n_{layer} * A_{catalyst})] + 1$ — Reference 1, Eqn 2.29
= 1.23 ft (Height of each layer)

$n_{total} = n_{layer} + n_{empty}$ — Reference 1, Eqn 2.30
= 2 (Total number of layers)

$h_{SCR} = n_{total} * (7 + h_{layer}) + 9$ — Reference 1, Eqn 2.31
= 25.5 ft (Height of SCR)

$m_{sol} = [(NO_{X,IN} * Q_B * ASR * \eta_{NOx} * (M_{reagent} / M_{NOx})] / C_{SOL})$ — Reference 1, Eqn 2.32, 2.33
= 95.95 lb/hr (Mass flow rate of aqueous ammonia)

$q_{sol} = m_{sol} * \rho_{sol} / v_{sol}$ — Reference 1, Eqn 2.34

= 12.82 gal/hr	(Volume flow rate of aqueous ammonia)	
Tank Volume = q_{sol} * 14 * 24		Reference 1, Eqn 2.35
= 4307 gal	(Ammonia tank volume assuming 14 day capacity)	

Direct Capital Costs

$f(h_{SCR})$ = (\$6.12/ft * h_{SCR}) - \$187.9		Reference 1, Eqn 2.37
= -32.10 \$/(MMBtu/hr)	(Adjustment factor, SCR height)	
$f(NH_3\,rate)$ = [(\$411/(lb/hr)) * (m_{sol} / Q_B)] - \$47.3		Reference 1, Eqn 2.38
= 41.08 \$/(MMBtu/hr)	Adjustment factor, ammonia mass flow rate	
f(new) = -728 \$/(MMBtu/hr)	Adjustment factor, new installation	Reference 1, Eqn 2.40
f(*bypass*) = 127 \$/(MMBtu/hr)	Adjustment factor, SCR bypass system	Reference 1, Eqn 2.41
$f(Vol_{catalyst})$ = ($Vol_{catalyst}$) * CC_{new}		Reference 1, Eqn 2.43
= \$164,235	Adjustment factor, catalyst volume	
DCC = \$7,295,986	Direct capital cost (1998 \$)	

Indirect Capital Costs

IIC = *DCC* * (0.05 + 0.10 + 0.05)		Reference 1, Table 2.5
= \$1,459,200	Indirect installation cost for General Facilities, Engineering and Home Office Fees, Process Contingency (1998 \$)	
CONT = (*DCC* + *IIC*) * 0.15		Reference 1, Table 2.5
= \$1,313,300	Contingency cost (1998 \$)	
TPC = *DCC* + *IIC* + *CONT*		Reference 1, Table 2.5
= \$10,068,500	Total plant cost (1998 \$)	
PPC = *TPC* * 0.02		Reference 1, Table 2.5
= \$201,400	Preproduction cost (1998 \$)	
IC = *TankVolume* * $Cost_{NH3}$		Reference 1, Table 2.5
= \$7,100	Inventory capital cost (1998 \$)	

Total Capital Investment

TCI = *TPC* + *PPC* + *IC*		Reference 1, Table 2.5
= \$10,277,000	Total capital investment (1998 \$)	

Direct Annual Costs

AMC = 0.015 * TCI		Reference 1, Eqn 2.46
= \$154,160	Annual Maintenance Cost (1998 \$)	
ARC = m_{sol} * $Cost_{NH3}$ * CF_{TOTAL} * 8760		Reference 1, Eqn 2.47
= \$166,600 /yr	Reagent consumption cost (1998 \$)	
PWR = 318 kW	Power usage rate, high temperature SCR	Reference 6
PC = *PWR* * CF_{TOTAL} * 8760 * $COST_{ELEC}$		Reference 1, Eqn 2.49
= \$125,200 /yr	Cost of electricity (1998 \$)	
= \$118,947 /yr	Cost of natural gas (2009 \$), due to add'l back-pressure of simple cycle c	Reference 8
= \$84,482 /yr	Cost of natural gas (1998 \$)	
PC = \$209,682 /yr	Total Cost of Fuels (1998 \$)	
Y = 3.0 yr	Future worth factor years, catalyst guaranteed 3-yr life	
FWF = *i* * 1 / [(1 + *i*)^(*Y*) - 1]		Reference 1, Eqn 2.52
= 0.30	Future worth factor	
ACRC = *FWF* * $Vol_{catalyst}$ * $CC_{replace}$ / n_{LAYER}		Reference 1, Eqn 2.50, 2.51
= \$49,600 /yr	Annual catalyst replacement cost (1998 \$)	
DAC = *MC* + *RC* + *PC* + *ACRC*		Reference 1, Eqn 2.45
= \$495,560 /yr	Direct annual costs (1998 \$)	

Indirect Annual Costs

CRF = i / (1 - (1 + i)$^{-n}$)		Reference 1, Eqn 2.55
= 0.117	Capital recovery factor	
IDAC = *CRF* * *TCI*		
= \$1,207,100 /yr	Indirect annual costs (1998 \$)	Reference 1, Eqn 2.54

Total Annual Costs

TAC = *DAC* + *IDAC*		Reference 1, Eqn 2.56
= \$1,702,660 /yr	Total annual cost (1998 \$/yr)	

Cost Effectiveness

NO_X *Removed* = $NO_{X,IN}$ * Q_B * 8760 * CF_{TOTAL} * η_{NOX} / 2000		Reference 1, Eqn 2.57
= 185 tons/yr	NOx removed (tons/yr)	
CE = *TAC* / NO_X *Removed*		Reference 1, Eqn 2.58
= \$9,200 /ton	Cost per ton of NOx removed (1998 \$)	
IACE = *CE* * (*CEPCI08* / *CEPCI98)*		
= **\$12,953 /ton**	Inflation adjusted cost per ton of NOx removed (Sept-2008 \$)	

References
1. EPA/452/B-02-001, Sixth Edition, Section 4.2, Ch 2
2. "PTE Emissions Summary - V3.xls" from Bison Engineering
3. "EmissionsINFO-Rev3.xls" from Stanley Consultants
4. "LM6000PF Max Emissions.xls" from Stanley Consultants
5. Vendor Quote, Vogt Power International
6. Vendor Quote, Braden Manufacturing
7. Vendor Quote, Turner Envirologic
8. Data from Stanley Consultants
9. AP-42 Table 1.4-1
10. Terra Industries, Inc. representative via 1/4/08 telephone call.

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Simple Cycle Turbines
NOX BACT Economic Evaluation
Case S3 - Combined Cycle

SCR Economic Analysis
Based on methodology described in:
EPA Pollution Cost Control Manual, 6th Edition
January 2002
Section 4.2, Chapter 2

Input Values			Description	Reference
	369.7	MMBtu/hr	Heat input rate, max per turbine, -17.7 °F, 100% Load	Reference 4
	103.5	MMBtu/hr	Heat input rate, max per duct burner, 91.5°F, 100% load	Reference 3
Q_B =	446.2	MMBtu/hr	Heat input rate, max per generating unit, 91.5°F, 100% load	Reference 3
$q_{flg,\ act}$ =	581,959	acfm	Exhaust gas flow rate	Reference 3
η_{NOX} =	91.9%	Control efficiency		Reference 2
	25	ppmvd @ 15% O2	Inlet NOx concentration, post water injection	Reference 4
	36.58	lb/hr	Inlet NOx rate as NO2	Reference 4
	140	lb/MMscf	NOX emission factor, duct burners	Reference 9
	1000	Btu/scf	heat content, natural gas	
	14.5	lb/hr	Uncontrolled duct burner emissions	
$NO_{X,IN}$ =	0.114	lb/MMBtu	turbine and duct burner combined	
$Slip$ =	10	ppm	Allowable slip	Reference 8
S =	1.72E-05	wt fraction	Fuel S concentration	Calculated, See "Wt fract S in NG" tab
T =	750	°F	Reactor Inlet gas temperature	Industry standard following tempering air
n_{empty} =	1		Empty catalyst layers for change-out	Bison Estimate
ASR =	1.05		Actual stoichiometric ratio = (NSR / SR_T)	Reference 1, Eqn 2.11
C_{SOL} =	19%		Concentration of aqueous ammonia solution by weight (assumed)	Reference 8
$Cost_{NH3}$ =	$ 0.220	$/lb (1998 $)	Cost of ammonia -- value per OAQPS example	Reference 10
Hours of Operation =	8760			
Assumed CF =	0.9			Reference 8
CF_{PLANT} =	0.90		Capacity factor of plant	
CF_{SCR} =	1.0		Capacity factor of SCR when plant is operational	Bison Estimate
$Cost_{ELEC}$ =	0.05	$/kWh (1998 $)	Cost of electricity -- value per OAQPS example	Reference 1, Pg 2-50
i =	10%		Interest rate, assumed	
CSC1 =	$ 3,480,000	(2009 $)	Control System Cost, high temperature catalyst	Reference 6
CSC2 =	$ 1,580,000	(2009 $)	Control System Cost, high temperature catalyst	Reference 7
CSC_{AVE} =	$ 2,530,000	(2009 $)	Control System Cost, high temperature catalyst, average	
CSC_{each} =	$ 1,265,000	(2009 $)	Control System Cost, high temperature catalyst, each turbine	
$CC_{new,LoT}$ =	$ 170,000	(2009 $)	Lower Temperature Combined Cycle SCR Catalyst Cost	Reference 5
SCR Cost $_{LoT}$ =	$ 590,000	(2009 $)	Lower Temperature Combined Cycle SCR Cost	Reference 5
CO Catalyst Cost $_{LoT}$ =	$ 340,000	(2009 $)	Lower Temperature Combined Cycle CO Catalyst Cost	Reference 5
SCR Cost % of total =	63.4%			
SCR Cat % of total =	18.3%			
SCR Cost $_{HiT}$ =	$802,527	(2009 $)	SCR system cost portion of CSC_{each}, High Temperature Catalyst	
	$569,993	(1998 $)		
CCnew $_{HiT}$ =	$231,237	(2009 $)	SCR Catalyst costs from CSC_{each}, High Temperature Catalyst	
	$164,235	(1998 $)		
Plenum & Mat'l costs =	$275,000	(2009 $)		Reference 8
	$195,318	(1998 $)		
Ammonia Tank Costs =	$ 248,884	(2009 $)		Reference 8
	$194,036	(1998 $)		
OTSG Incr Costs =	$8,921,727	(2009 $)	Incremental cost increase of OTSG vs. HRSG	Reference 11
	$6,336,638	(1998 $)		
CC_{new} =	$ 1,183	$/ft³ (1998 $)	Catalyst initial price -- value per OAQPS example	
$CC_{replace}$ =	$ 1,183	$/ft³ (1998 $)	Catalyst replacement price -- value per OAQPS example	
N =	20.0	yr	Expected lifetime of control system	Reference 1, Pg 2-48
CEPCI98 =	389.5		Chemical Engineering Plant Cost Index, 1998 annual	www.che.com
CEPCI06 =	499.6		Chemical Engineering Plant Cost Index, 2006 annual	www.che.com
CEPCI08 =	548.4		Chemical Engineering Plant Cost Index, 2008 (Dec 2008 preliminary)	www.che.com
$M_{reagent}$ =	17.03	g/mol	Molecular Weight of reagent (ammonia)	Reference 1, Pg 2-39
M_{NO2} =	46.01	g/mol	Molecular Weight of NO_2	Reference 1, Pg 2-39
ρ_{sol} =	56.0	lbs/ft³	Density of aqueous reagent solution, @ 60 °F	Referen ce 1, Pg 2-40
v_{sol} =	7.48	gal/ft³	Specific Volume of aqueous reagent solution, @ 60 °F	Reference 1, Pg 2-40
ΔP_{duct} =	2.50	in H20	Pressure drop, additional ductwork	Reference 1, Pg 2-46
$\Delta P_{catalyst}$ =	0.85	in H20	Pressure drop, SCR	Reference 1, Pg 2-46

Design Values

$CF_{TOTAL} = CF_{PLANT} * CF_{SCR}$ — Reference 1, Eqn 2.6
$= 0.9$

$Vol_{catalyst} = 2.81 * Q_B * [0.2869 + (1.058 * \eta_{NOX})] * [1.2835 - (0.0567 * Slip)]$
$* [0.08524 + (0.3208 * NO_{XIN})] * [0.9636 + (0.0455 * S)]$
$* [15.16 - (0.03937 * T) + (2.74E\text{-}05 * T^2)]$ — Reference 1, Eqn 2.19, 2.20, 2.21, 2.22, 2.23, 2.24
= 139 ft³ (Catalyst volume)

$A_{catalyst} = q_{fluegas} / 960$ — Reference 1, Eqn 2.25
= 606 ft² (Catalyst area)

$A_{SCR} = 1.15 * A_{catalyst}$ — Reference 1, Eqn 2.26
= 697 ft² (SCR area)

$n_{LAYER} = Vol_{catalyst} / (3.1 * A_{catalyst})$ — Reference 1, Eqn 2.28
= 1 (Number of catalyst layers)

$h_{layer} = [Vol_{catalyst} / (n_{layer} * A_{catalyst})] + 1$ — Reference 1, Eqn 2.29
= 1.23 ft (Height of each layer)

$n_{total} = n_{layer} + n_{empty}$ — Reference 1, Eqn 2.30
= 2 (Total number of layers)

$h_{SCR} = n_{total} * (7 + h_{layer}) + 9$ — Reference 1, Eqn 2.31
= 25.5 ft (Height of SCR)

$m_{sol} = [(NO_{X,IN} * Q_B * ASR * \eta_{NOx} * (M_{reagent} / M_{NOx})] / C_{SOL})$ — Reference 1, Eqn 2.32, 2.33
= 95.95 lb/hr (Mass flow rate of aqueous ammonia)

$q_{sol} = m_{sol} * \rho_{sol} / v_{sol}$			Reference 1, Eqn 2.34
=	12.82 gal/hr	(Volume flow rate of aqueous ammonia)	
$Tank\ Volume = q_{sol} * 14 * 24$			Reference 1, Eqn 2.35
=	4307 gal	(Ammonia tank volume assuming 14 day capacity)	

Direct Capital Costs

$f(h_{SCR})$ = (\$6.12/ft * h_{SCR}) - \$187.9			Reference 1, Eqn 2.37
=	-32.10 \$/(MMBtu/hr)	(Adjustment factor, SCR height)	
$f(NH_3\ rate)$ = [(\$411/(lb/hr)) * (m_{sol} / Q_B)] - \$47.3			Reference 1, Eqn 2.38
=	41.08 \$/(MMBtu/hr)	Adjustment factor, ammonia mass flow rate	
f(new) =	-728 \$/(MMBtu/hr)	Adjustment factor, new installation	Reference 1, Eqn 2.40
$f(bypass)$ =	127 \$/(MMBtu/hr)	Adjustment factor, SCR bypass system	Reference 1, Eqn 2.41
$f(Vol_{catalyst}) = (Vol_{catalyst}) * CC_{new}$			Reference 1, Eqn 2.43
=	\$164,235	Adjustment factor, catalyst volume	
DCC =	\$959,347	Direct capital cost (1998 \$)	

Indirect Capital Costs

IIC = DCC * (0.05 + 0.10 + 0.05)			Reference 1, Table 2.5
=	\$191,900	Indirect installation cost for General Facilities, Engineering and Home Office Fees, Process Contingency (1998 \$)	
$CONT = (DCC + IIC) * 0.15$			Reference 1, Table 2.5
=	\$172,700	Contingency cost (1998 \$)	
$TPC = DCC + IIC + CONT$			Reference 1, Table 2.5
=	\$1,323,900	Total plant cost (1998 \$)	
$PPC = TPC * 0.02$			Reference 1, Table 2.5
=	\$26,500	Preproduction cost (1998 \$)	
$IC = TankVolume * Cost_{NH3}$			Reference 1, Table 2.5
=	\$7,100	Inventory capital cost (1998 \$)	

Total Capital Investment

$TCI = TPC + PPC + IC$			Reference 1, Table 2.5
=	\$1,357,500	Total capital investment (1998 \$)	

Direct Annual Costs

AMC = 0.015 * TCI			Reference 1, Eqn 2.46
=	\$20,360	Annual Maintenance Cost (1998 \$)	
$ARC = m_{sol} * Cost_{NH3} * CF_{TOTAL} * 8760$			Reference 1, Eqn 2.47
=	\$166,600 /yr	Reagent consumption cost (1998 \$)	
PWR =	318 kW	Power usage rate	Reference 6
$PC = PWR * CF_{TOTAL} * 8760 * COST_{ELEC}$			Reference 1, Eqn 2.49
=	\$125,200 /yr	Cost of electricity (1998 \$)	
=	\$118,947 /yr	Cost of natural gas (2009 \$), due to add'l back-pressure of simple cycle c	Reference 8
=	\$84,482 /yr	Cost of natural gas (1998 \$)	
PC =	\$209,682 /yr	Total Cost of Fuels (1998 \$)	
Y =	3.0 yr	Future worth factor years, catalyst guaranteed 3-yr life	
$FWF = i * 1 / [(1 + i)^{(Y)} - 1]$			Reference 1, Eqn 2.52
=	0.30	Future worth factor	
$ACRC = FWF * Vol_{catalyst} * CC_{replace} / n_{LAYER}$			Reference 1, Eqn 2.50, 2.51
=	\$49,600 /yr	Annual catalyst replacement cost (1998 \$)	
$DAC = MC + RC + PC + ACRC$			Reference 1, Eqn 2.45
=	\$361,760 /yr	Direct annual costs (1998 \$)	

Indirect Annual Costs

$CRF = i / (1 - (1 + i)^{-n})$			Reference 1, Eqn 2.55
=	0.117	Capital recovery factor	
$IDAC = CRF * TCI$			
=	\$159,500 /yr	Indirect annual costs (1998 \$)	Reference 1, Eqn 2.54

Total Annual Costs

$TAC = DAC + IDAC$			Reference 1, Eqn 2.56
=	\$521,260 /yr	Total annual cost (1998 \$/yr)	

Cost Effectiveness

$NO_X\ Removed = NO_{X,IN} * Q_B * 8760 * CF_{TOTAL} * \eta_{NOX} / 2000$			Reference 1, Eqn 2.57
=	185 tons/yr	NOx removed (tons/yr)	
$CE = TAC / NO_X\ Removed$			Reference 1, Eqn 2.58
=	\$2,820 /ton	Cost per ton of NOx removed (1998 \$)	
$IACE = CE * (CEPCI08 / CEPCI98)$			
=	**\$3,970 /ton**	Inflation adjusted cost per ton of NOx removed (Sept-2008 \$)	

References
1. EPA/452/B-02-001, Sixth Edition, Section 4.2, Ch 2
2. "PTE Emissions Summary - V3.xls" from Bison Engineering
3. "EmissionsINFO-Rev3.xls" from Stanley Consultants
4. "LM6000PF Max Emissions.xls" from Stanley Consultants
5. Vendor Quote, Vogt Power International
6. Vendor Quote, Braden Manufacturing
7. Vendor Quote, Turner Envirologic
8. Data from Stanley Consultants
9. AP-42 Table 1.4-1
10. Terra Industries, Inc. representative via 1/4/08 telephone call.
11. Data from Stanley Consultants for similar project

Southern Montana Electric Generation and Transmission Cooperative
Highwood Generating Station
GE LM6000PF Simple Cycle Turbines
SCR BACT Economic Evaluation
Case S4 - Simple Cycle

SCR Economic Analysis
Based on methodology described in:
EPA Pollution Cost Control Manual, 6th Edition
January 2002
Section 4.2, Chapter 2

Input Values			Description	Reference
Q_B =	369.7	MMBtu/hr	Heat input rate, per turbine	Reference 2
$q_{flg, act}$ =	581,959	acfm	Exhaust gas flow rate	Reference 3
η_{NOX} =	89%	Control efficiency		Reference 2
	25	ppmvd @ 15% O2	Inlet NOx concentration, post water injection	Reference 4
	36.58	lb/hr	Inlet NOx rate as NO2	Reference 4
$NO_{X,IN}$ =	0.099	lb/MMBtu	Inlet NOx factor	Calculated
$Slip$ =	10	ppm	Allowable slip	Reference 8
S =	1.72E-05	wt fraction	Fuel S concentration	Calculated, See "Wt fract S in NG" tab
T =	750	°F	Reactor Inlet gas temperature	Industry standard following tempering air
n_{empty} =	1		Empty catalyst layers for change-out	Bison Estimate
ASR =	1.05		Actual stoichiometric ratio = (NSR / SR_T)	Reference 1, Eqn 2.11
C_{SOL} =	19%		Concentration of aqueous ammonia solution by weight (assumed)	Reference 8
$Cost_{NH3}$ =	$ 0.220	$/lb (1998 $)	Cost of ammonia -- value per OAQPS example	Terra Industries, Inc. representative via 1/4/08 telephone call.
Hours of Operation =	3200			
Assumed CF =	0.9			Bison Estimate
***CF_{PLANT}* =**	**0.33**		Capacity factor of plant	Bison Estimate
CF_{SCR} =	1.0		Capacity factor of SCR when plant is operational	Bison Estimate
$Cost_{ELEC}$ =	0.05	$/kWh (1998 $)	Cost of electricity -- value per OAQPS example	Reference 1, Pg 2-50
i =	10%		Interest rate, assumed	Bison Estimate
$SCR\ Cost_{LoT}$ =	$ 590,000	(2009 $)	Lower Temperature Combined Cycle SCR Cost	Reference 5
	$ 419,046	(1998 $)		
CCnew =	$ 170,000	(2009 $)	SCR Catalyst Costs, Low Temperature Catalysts	
	$ 120,742	(1998 $)		
Plenum & Mat'l costs =	$ 275,000	(2009 $)		Reference 8
	$ 195,318	(1998 $)		
Ammonia Tank Costs =	$ 248,884	(2006 $)		Reference 8
	$ 194,036	(1998 $)		
Dump Condenser Costs =	$ 1,099,924	(2009 $)		Reference 7
	$ 781,219	(1998 $)		
CC_{new} =	$ 799	$/ft^3 (1998 $)	Catalyst initial price -- value per OAQPS example	
$CC_{replace}$ =	$ 799	$/ft^3 (1998 $)	Catalyst replacement price -- value per OAQPS example	
N =	20.0	yr	Expected lifetime of control system	Reference 1, Pg 2-48
CEPCI98 =	389.5		Chemical Engineering Plant Cost Index, 1998 annual	www.che.com
CEPCI06 =	499.6		Chemical Engineering Plant Cost Index, 2006 annual	www.che.com
CEPCI08 =	548.4		Chemical Engineering Plant Cost Index, 2008 (Dec 2008 preliminary)	www.che.com
$M_{reagent}$ =	17.03	g/mol	Molecular Weight of reagent (ammonia)	Reference 1, Pg 2-39
M_{NO2} =	46.01	g/mol	Molecular Weight of NO_2	Reference 1, Pg 2-39
ρ_{sol} =	56.0	lbs/ft^3	Density of aqueous reagent solution, @ 60 °F	Reference 1, Pg 2-40
v_{sol} =	7.48	gal/ft^3	Specific Volume of aqueous reagent solution, @ 60 °F	Reference 1, Pg 2-40
ΔP_{duct} =	2.50	in H20	Pressure drop, additional ductwork	Reference 1, Pg 2-46
$\Delta P_{catalyst}$ =	0.85	in H20	Pressure drop, SCR	Reference 1, Pg 2-46

Design Values

$CF_{TOTAL} = CF_{PLANT} * CF_{SCR}$ — Reference 1, Eqn 2.6
= 0.33

$Vol_{catalyst} = 2.81 * Q_B * [0.2869 + (1.058 * \eta_{NOX})] * [1.2835 - (0.0567 * Slip)]$ — Reference 1, Eqn 2.19, 2.20, 2.21, 2.22, 2.23, 2.24
$* [0.08524 + (0.3208 * NO_{XIN})] * [0.9636 + (0.0455 * S)]$
$* [15.16 - (0.03937 * T) + (2.74E-05 * T^2)]$
= 107 ft^3 (Catalyst volume)

$A_{catalyst} = q_{fluegas} / 960$ — Reference 1, Eqn 2.25
= 606 ft^2 (Catalyst area)

$A_{SCR} = 1.15 * A_{catalyst}$ — Reference 1, Eqn 2.26
= 697 ft^2 (SCR area)

$n_{LAYER} = Vol_{catalyst} / (3.1 * A_{catalyst})$ — Reference 1, Eqn 2.28
= 1 (Number of catalyst layers)

$h_{layer} = [Vol_{catalyst} / (n_{layer} * A_{catalyst})] + 1$ — Reference 1, Eqn 2.29
= 1.18 ft (Height of each layer)

$n_{total} = n_{layer} + n_{empty}$ — Reference 1, Eqn 2.30
= 2 (Total number of layers)

$h_{SCR} = n_{total} * (7 + h_{layer}) + 9$ — Reference 1, Eqn 2.31
= 25.4 ft (Height of SCR)

$m_{sol} = [(NO_{X,IN} * Q_B * ASR * \eta_{NOx} * (M_{reagent} / M_{NOx})] / C_{SOL})$ — Reference 1, Eqn 2.32, 2.33
= 66.29 lb/hr (Mass flow rate of aqueous ammonia)

$q_{sol} = m_{sol} * \rho_{sol} / v_{sol}$ — Reference 1, Eqn 2.34
= 8.86 gal/hr (Volume flow rate of aqueous ammonia)

$Tank\ Volume = q_{sol} * 14 * 24$ — Reference 1, Eqn 2.35
= 2976 gal (Ammonia tank volume assuming 14 day capacity)

Direct Capital Costs

$f(h_{SCR})$ =	(\$6.12/ft * h_{SCR}) - \$187.9		Reference 1, Eqn 2.37
=	-32.73 \$/(MMBtu/hr)	(Adjustment factor, SCR height)	
$f(NH_3\ rate)$ =	[(\$411/(lb/hr)) * (m_{sol} / Q_B)] - \$47.3		Reference 1, Eqn 2.38
=	26.40 \$/(MMBtu/hr)	Adjustment factor, ammonia mass flow rate	
f(new) =	-728 \$/(MMBtu/hr)	Adjustment factor, new installation	Reference 1, Eqn 2.40
$f(bypass)$ =	127 \$/(MMBtu/hr)	Adjustment factor, SCR bypass system	Reference 1, Eqn 2.41
$f(Vol_{catalyst})$ =	$(Vol_{catalyst}) * CC_{new}$		Reference 1, Eqn 2.43
=	\$85,757	Adjustment factor, catalyst volume	
DCC =	\$1,589,619	Direct capital cost (1998 \$)	

Indirect Capital Costs

IIC =	DCC * (0.05 + 0.10 + 0.05)		Reference 1, Table 2.5
=	\$317,900	Indirect installation cost for General Facilities, Engineering and Home Office Fees, Process Contingency (1998 \$)	
$CONT$ =	(DCC + IIC) * 0.15		Reference 1, Table 2.5
=	\$286,100	Contingency cost (1998 \$)	
TPC =	$DCC + IIC + CONT$		Reference 1, Table 2.5
=	\$2,193,600	Total plant cost (1998 \$)	
PPC =	TPC * 0.02		Reference 1, Table 2.5
=	\$43,900	Preproduction cost (1998 \$)	
IC =	$TankVolume * Cost_{NH3}$		Reference 1, Table 2.5
=	\$4,900	Inventory capital cost (1998 \$)	

Total Capital Investment

TCI =	$TPC + PPC + IC$		Reference 1, Table 2.5
=	\$2,242,400	Total capital investment (1998 \$)	

Direct Annual Costs

AMC =	0.015 * TCI		Reference 1, Eqn 2.46
=	\$33,640	Annual Maintenance Cost (1998 \$)	
ARC =	$m_{sol} * Cost_{NH3} * CF_{TOTAL}$ * 8760		Reference 1, Eqn 2.47
=	\$42,000 /yr	Reagent consumption cost (1998 \$)	
PWR =	269 kW	Power usage rate (includes condenser circ pump)	Reference 6
PC =	$PWR * CF_{TOTAL}$ * 8760 * $COST_{ELEC}$		Reference 1, Eqn 2.49
=	\$38,700 /yr	Cost of electricity (1998 \$)	
=	\$118,947 /yr	Cost of natural gas (2009 \$), due to add'l back-pressure of simple cycle	Reference 8
=	\$84,482 /yr	Cost of natural gas (1998 \$)	
PC =	\$123,182 /yr	Total Cost of Fuels (1998 \$)	
Y =	3.0 yr	Future worth factor years, catalyst guaranteed 3-yr life	
FWF =	i * 1 / [(1 + i)^(Y) - 1]		Reference 1, Eqn 2.52
=	0.30	Future worth factor	
$ACRC$ =	$FWF * Vol_{catalyst} * CC_{replace} / n_{LAYER}$		Reference 1, Eqn 2.50, 2.51
=	\$25,900 /yr	Annual catalyst replacement cost (1998 \$)	
DAC =	$MC + RC + PC + ACRC$		Reference 1, Eqn 2.45
=	\$224,722 /yr	Direct annual costs (1998 \$)	

Indirect Annual Costs

CRF =	$i / (1 - (1 + i)^{-n})$		Reference 1, Eqn 2.55
=	0.117	Capital recovery factor	
$IDAC$ =	$CRF * TCI$		
=	\$263,400 /yr	Indirect annual costs (1998 \$)	Reference 1, Eqn 2.54

Total Annual Costs

TAC =	$DAC + IDAC$		Reference 1, Eqn 2.56
=	\$488,122 /yr	Total annual cost (1998 \$/yr)	

Cost Effectiveness

NO_X $Removed$ =	$NO_{X,IN} * Q_B$ * 8760 * $CF_{TOTAL} * \eta_{NOX}$ / 2000		Reference 1, Eqn 2.57
=	46.7 tons/yr	NOx removed (tons/yr)	
CE =	TAC / NO_X $Removed$		Reference 1, Eqn 2.58
=	\$10,460 /ton	Cost per ton of NOx removed (1998 \$)	
$IACE$ =	CE * ($CEPCI08$ / $CEPCI98$)		
=	**\$14,727 /ton**	Inflation adjusted cost per ton of NOx removed (Sept-2008 \$)	

References

1. EPA/452/B-02-001, Sixth Edition, Section 4.2, Ch 2
2. "PTE Emissions Summary - V3.xls" from Bison Engineering
3. "EmissionsINFO-Rev3.xls" from Stanley Consultants
4. "LM6000PF Max Emissions.xls" from Stanley Consultants
5. Vendor Quote, Vogt Power International
6. Vendor Quote, Braden Manufacturing
7. Capital costs from vendor and engineer quote, Thermal Engineering International and Stanley Consultants
8. Data from Stanley Consultants

Southern Montana Electric Generation and Transmission Cooperative
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NOX BACT Economic Evaluation
Case S4 - Combined Cycle

SCR Economic Analysis
Based on methodology described in:
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January 2002
Section 4.2, Chapter 2

Input Values			Description	Reference
	369.7	MMBtu/hr	Heat input rate, max per turbine, -17.7 ℉, 100% Load	Reference 4
	103.5	MMBtu/hr	Heat input rate, max per duct burner, 91.5℉, 100% load	Reference 3
Q_B =	446.2	MMBtu/hr	Heat input rate, max per generating unit, 91.5℉, 100% load	Reference 3
$q_{flg, act}$ =	581,959	acfm	Exhaust gas flow rate	Reference 3
η_{NOX} =	91.9%	Control efficiency		Reference 2
	25	ppmvd @ 15% O2	Inlet NOx concentration, post water injection	Reference 4
	36.58	lb/hr	Inlet NOx rate as NO2	Reference 4
	140	lb/MMscf	NOX emission factor, duct burners	Reference 9
	1000	Btu/scf	heat content, natural gas	
	14.5	lb/hr	Uncontrolled duct burner emissions	
$NO_{X,IN}$ =	0.114	lb/MMBtu	turbine and duct burner combined	
Slip =	10	ppm	Allowable slip	Reference 8
S =	1.72E-05	wt fraction	Fuel S concentration	Calculated, See "Wt fract S in NG" tab
T =	750	℉	Reactor Inlet gas temperature	Industry standard following tempering air
n_{empty} =	1		Empty catalyst layers for change-out	Bison Estimate
ASR =	1.05		Actual stoichiometric ratio = (NSR / SR_T)	Reference 1, Eqn 2.11
C_{SOL} =	19%		Concentration of aqueous ammonia solution by weight (assumed)	Reference 8
$Cost_{NH3}$ =	$ 0.220	$/lb (1998 $)	Cost of ammonia	Reference 10
Hours of Operation =	8760			
Assumed CF =	0.9			Reference 8
CF_{PLANT} =	**0.90**		Capacity factor of plant	
CF_{SCR} =	1.0		Capacity factor of SCR when plant is operational	Bison Estimate
$Cost_{ELEC}$ =	0.05	$/kWh (1998 $)	Cost of electricity -- value per OAQPS example	Reference 1, Pg 2-50
i =	10%		Interest rate, assumed	
$CC_{new,LoT}$ =	$ 170,000	(2009 $)	Lower Temperature Combined Cycle SCR Catalyst Cost	Reference 5
$SCR\ Cost_{LoT}$ =	$ 590,000	(2009 $)	Lower Temperature Combined Cycle SCR Cost	Reference 5
Plenum & Mat'l costs =	$275,000	(2009 $)		Reference 8
	$195,318	(1998 $)		
Ammonia Tank Costs =	$ 248,884	(2006 $)		Reference 8
	$194,036	(1998 $)		
Dump Condenser Costs =	$1,099,924	(2009 $)		Reference 7
	$781,219	(1998 $)		
CC_{new} =	$ 869	$\$/ft^3$ (1998 $)	Catalyst initial price -- value per OAQPS example	
$CC_{replace}$ =	$ 869	$\$/ft^3$ (1998 $)	Catalyst replacement price -- value per OAQPS example	
N =	20.0	yr	Expected lifetime of control system	Reference 1, Pg 2-48
CEPCI98 =	389.5		Chemical Engineering Plant Cost Index, 1998 annual	www.che.com
CEPCI06 =	499.6		Chemical Engineering Plant Cost Index, 2006 annual	www.che.com
CEPCI08 =	548.4		Chemical Engineering Plant Cost Index, 2008 (Sept 2008 preliminary)	www.che.com
$M_{reagent}$ =	17.03	g/mol	Molecular Weight of reagent (ammonia)	Reference 1, Pg 2-39
M_{NO2} =	46.01	g/mol	Molecular Weight of NO_2	Reference 1, Pg 2-39
ρ_{sol} =	56.0	lbs/ft^3	Density of aqueous reagent solution, @ 60 ℉	Referen ce 1, Pg 2-40
v_{sol} =	7.48	gal/ft^3	Specific Volume of aqueous reagent solution, @ 60 °F	Reference 1, Pg 2-40
ΔP_{duct} =	2.50	in H20	Pressure drop, additional ductwork	Reference 1, Pg 2-46
$\Delta P_{catalyst}$ =	0.85	in H20	Pressure drop, SCR	Reference 1, Pg 2-46

Design Values

$CF_{TOTAL} = CF_{PLANT} * CF_{SCR}$ — Reference 1, Eqn 2.6
= 0.9

$Vol_{catalyst}$ = 2.81 * Q_B * [0.2869 + (1.058 * η_{NOX})] * [1.2835 - (0.0567 * *Slip*)] — Reference 1, Eqn 2.19, 2.20, 2.21, 2.22, 2.23, 2.24
* [0.08524 + (0.3208 * NO_{XIN})] * [0.9636 + (0.0455 * *S*)]
* [15.16 - (0.03937 * *T*) + (2.74E-05 * *T*^2)]
= 139 ft^3 (Catalyst volume)

$A_{catalyst}$ = $q_{fluegas}$ / 960 — Reference 1, Eqn 2.25
= 606 ft^2 (Catalyst area)

A_{SCR} = 1.15*$A_{catalyst}$ — Reference 1, Eqn 2.26
= 697 ft^2 (SCR area)

n_{LAYER} = $Vol_{catalyst}$/ (3.1 * $A_{catalyst}$) — Reference 1, Eqn 2.28
= 1 (Number of catalyst layers)

h_{layer} = [$Vol_{catalyst}$ / (n_{layer} * $A_{catalyst}$)] + 1 — Reference 1, Eqn 2.29
= 1.23 ft (Height of each layer)

n_{total} = n_{layer} + n_{empty} — Reference 1, Eqn 2.30
= 2 (Total number of layers)

h_{SCR} = n_{total} * (7 + h_{layer}) + 9 — Reference 1, Eqn 2.31
= 25.5 ft (Height of SCR)

m_{sol} = [($NO_{X,IN}$ * Q_B * *ASR* * η_{NOx} * ($M_{reagent}$ / M_{NOx})] / C_{SOL}) — Reference 1, Eqn 2.32, 2.33
= 95.95 lb/hr (Mass flow rate of aqueous ammonia)

$q_{sol} = m_{sol} * \rho_{sol} / v_{sol}$ — Reference 1, Eqn 2.34
= 12.82 gal/hr — (Volume flow rate of aqueous ammonia)

$Tank\ Volume = q_{sol} * 14 * 24$ — Reference 1, Eqn 2.35
= 4307 gal — (Ammonia tank volume assuming 14 day capacity)

Direct Capital Costs

DCC = $1,760,573 — Direct capital cost (1998 $)

Indirect Capital Costs

$IIC = DCC * (0.05 + 0.10 + 0.05)$ — Reference 1, Table 2.5
= $352,100 — Indirect installation cost for General Facilities, Engineering and Home Office Fees, Process Contingency (1998 $)

$CONT = (DCC + IIC) * 0.15$ — Reference 1, Table 2.5
= $316,900 — Contingency cost (1998 $)

$TPC = DCC + IIC + CONT$ — Reference 1, Table 2.5
= $2,429,600 — Total plant cost (1998 $)

$PPC = TPC * 0.02$ — Reference 1, Table 2.5
= $48,600 — Preproduction cost (1998 $)

$IC = TankVolume * Cost_{NH3}$ — Reference 1, Table 2.5
= $7,100 — Inventory capital cost (1998 $)

Total Capital Investment

$TCI = TPC + PPC + IC$ — Reference 1, Table 2.5
= $2,485,300 — Total capital investment (1998 $)

Direct Annual Costs

$AMC = 0.015 * TCI$ — Reference 1, Eqn 2.46
= $37,280 — Annual Maintenance Cost (1998 $)

$ARC = m_{sol} * Cost_{NH3} * CF_{TOTAL} * 8760$ — Reference 1, Eqn 2.47
= $166,600 /yr — Reagent consumption cost (1998 $)

PWR = 269 kW — Power usage rate (includes condenser circ water pump) — Reference 6

$PC = PWR * CF_{TOTAL} * 8760 * COST_{ELEC}$ — Reference 1, Eqn 2.49
= $106,000 /yr — Cost of electricity (1998 $)

Y = 3.0 yr — Future worth factor years, catalyst guaranteed 3-yr life

$FWF = i * 1 / [(1 + i)^(Y) - 1]$ — Reference 1, Eqn 2.52
= 0.30 — Future worth factor

$ACRC = FWF * Vol_{catalyst} * CC_{replace} / n_{LAYER}$ — Reference 1, Eqn 2.50, 2.51
= $36,500 /yr — Annual catalyst replacement cost (1998 $)

$DAC = MC + RC + PC + ACRC$ — Reference 1, Eqn 2.45
= $346,380 /yr — Direct annual costs (1998 $)

Indirect Annual Costs

$CRF = i / (1 - (1 + i)^{-n})$ — Reference 1, Eqn 2.55
= 0.117 — Capital recovery factor

$IDAC = CRF * TCI$
= $291,900 /yr — Indirect annual costs (1998 $) — Reference 1, Eqn 2.54

Total Annual Costs

$TAC = DAC + IDAC$ — Reference 1, Eqn 2.56
= $638,280 /yr — Total annual cost (1998 $/yr)

Cost Effectiveness

$NO_X\ Removed = NO_{X,IN} * Q_B * 8760 * CF_{TOTAL} * \eta_{NOX} / 2000$ — Reference 1, Eqn 2.57
= 185 tons/yr — NOx removed (tons/yr)

$CE = TAC / NO_X\ Removed$ — Reference 1, Eqn 2.58
= $3,450 /ton — Cost per ton of NOx removed (1998 $)

$IACE = CE * (CEPCI08 / CEPCI98)$
= **$4,857 /ton** — Inflation adjusted cost per ton of NOx removed (Dec-2008 $)

References

1. EPA/452/B-02-001, Sixth Edition, Section 4.2, Ch 2
2. "PTE Emissions Summary - V3.xls" from Bison Engineering
3. "EmissionsINFO-Rev3.xls" from Stanley Consultants
4. "LM6000PF Max Emissions.xls" from Stanley Consultants
5. Vendor Quote, Vogt Power International
6. Vendor Quote, Braden Manufacturing
7. Vendor Quote, Thermal Engineering International and Stanley Consultants
8. Data from Stanley Consultants
9. AP-42 Table 1.4-1
10. Terra Industries, Inc. representative via 1/4/08 telephone call.

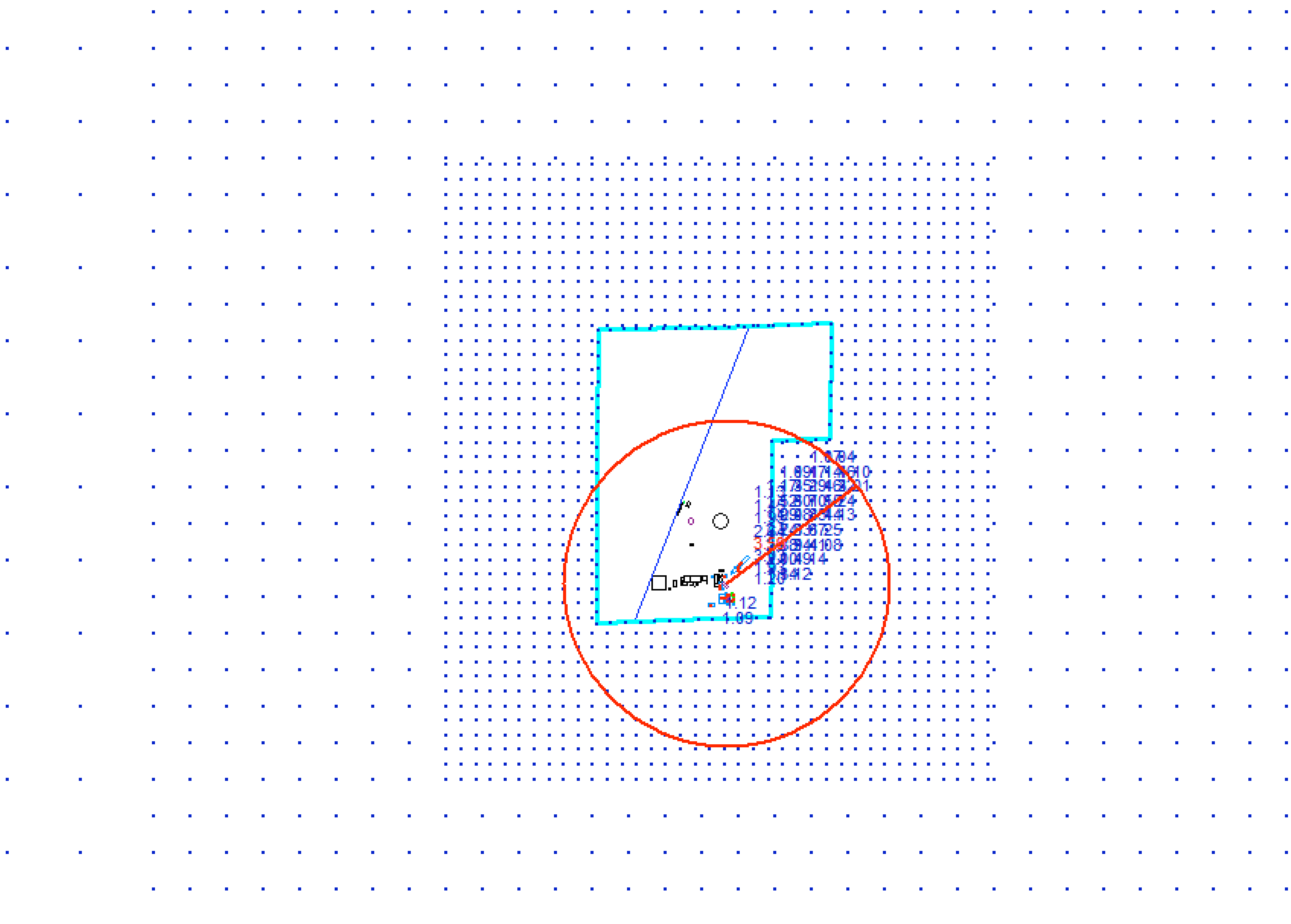
As defined in CFR (acid rain)
Standard engineering calculation
Standard engineering calculation

APPENDIX F: MODELING RESULTS SUMMARIES

1999 NOx ANN SIL 1ug/m^3 SIA=1.1km

Southern Montana Electric (SME)

G:\Models\SME209970\SIA\SIA FINAL\SIA_FINAL_1999_NOXANN.GRF



Scale: 1" = 1000.0 Meters

ANNUAL VALUES FOR GROUP: CC_SS

Max = 3.59274 (497721.6, 5266505)

1999 PM2.5 24-HR SIL 1.2ug/m^3 SIA=2.7km

Southern Montana Electric (SME)

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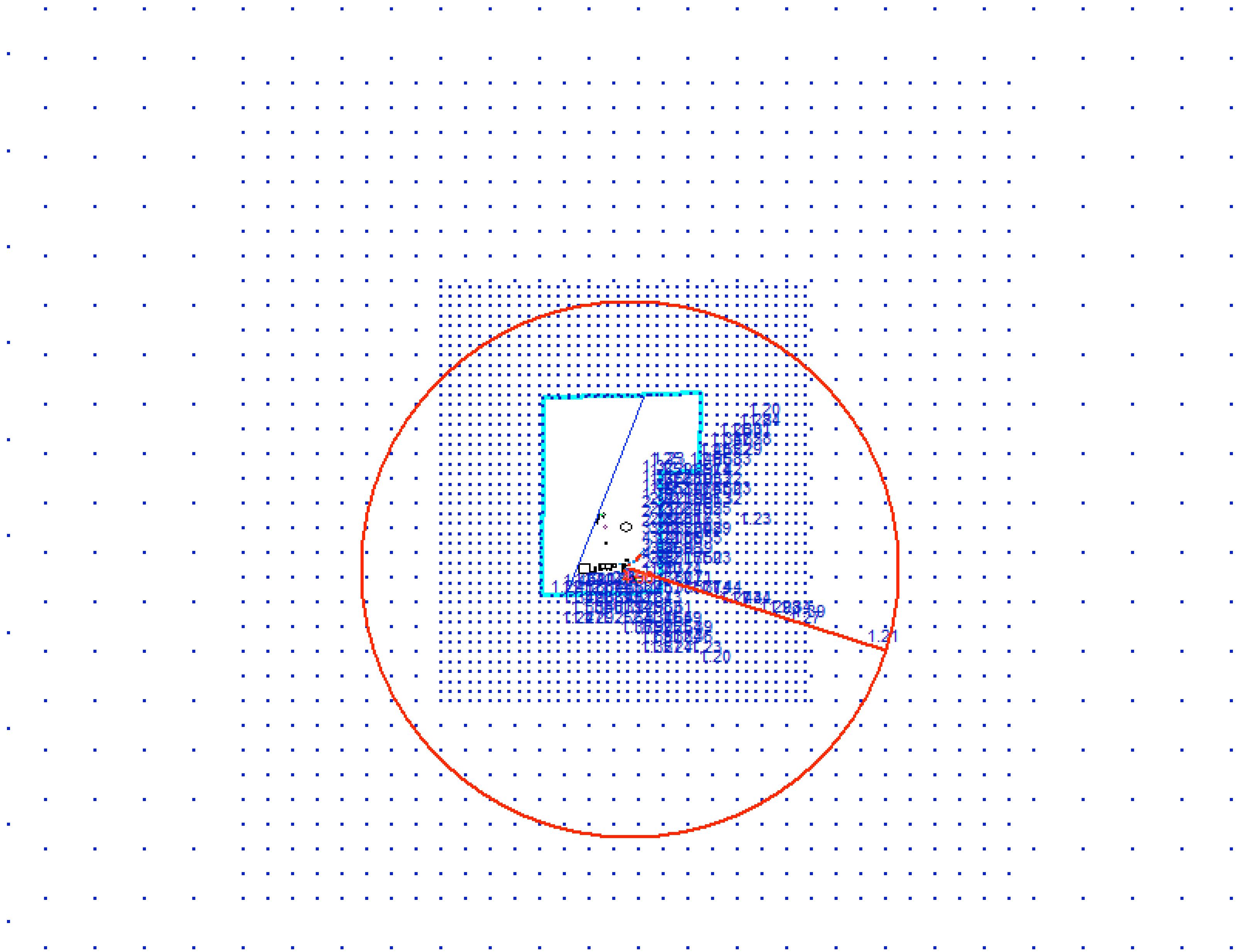

Scale: 1" = 1500.0 Meters

HIGH 1ST HIGH 24-HR VALUES FOR GROUP: CC_SS

Max = 4.95551 (497519.9, 5266097)

1999 PM2.5 ANN SIL 0.3ug/m^3 SIA=1.0km

Southern Montana Electric (SME)

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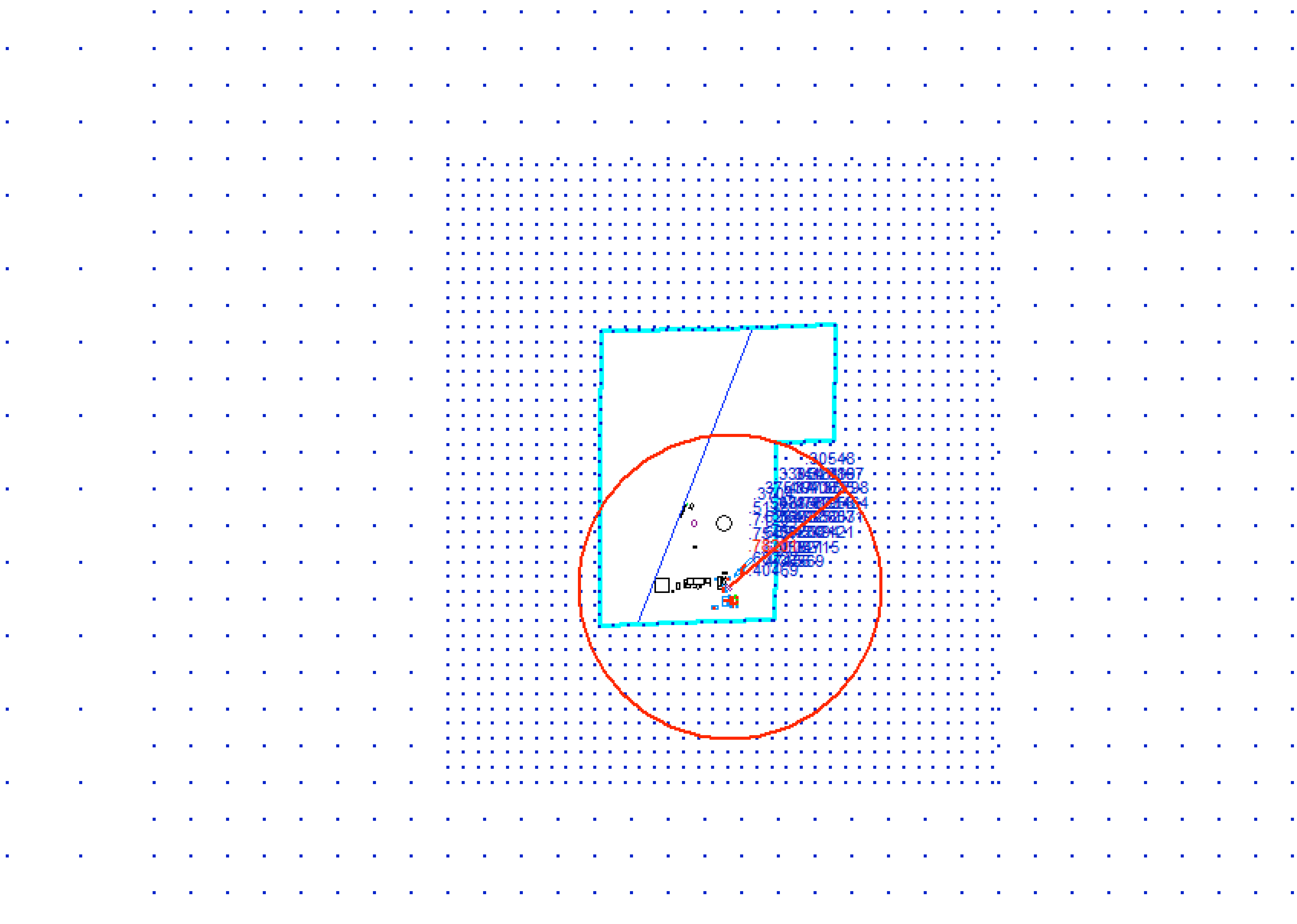

Scale: 1" = 1000.0 Meters

ANNUAL VALUES FOR GROUP: CC_SS

Max = 0.78201 (497721.6, 5266505)

2000 NOx ANN SIL 1ug/m^3 SIA=0.9km

Southern Montana Electric (SME)

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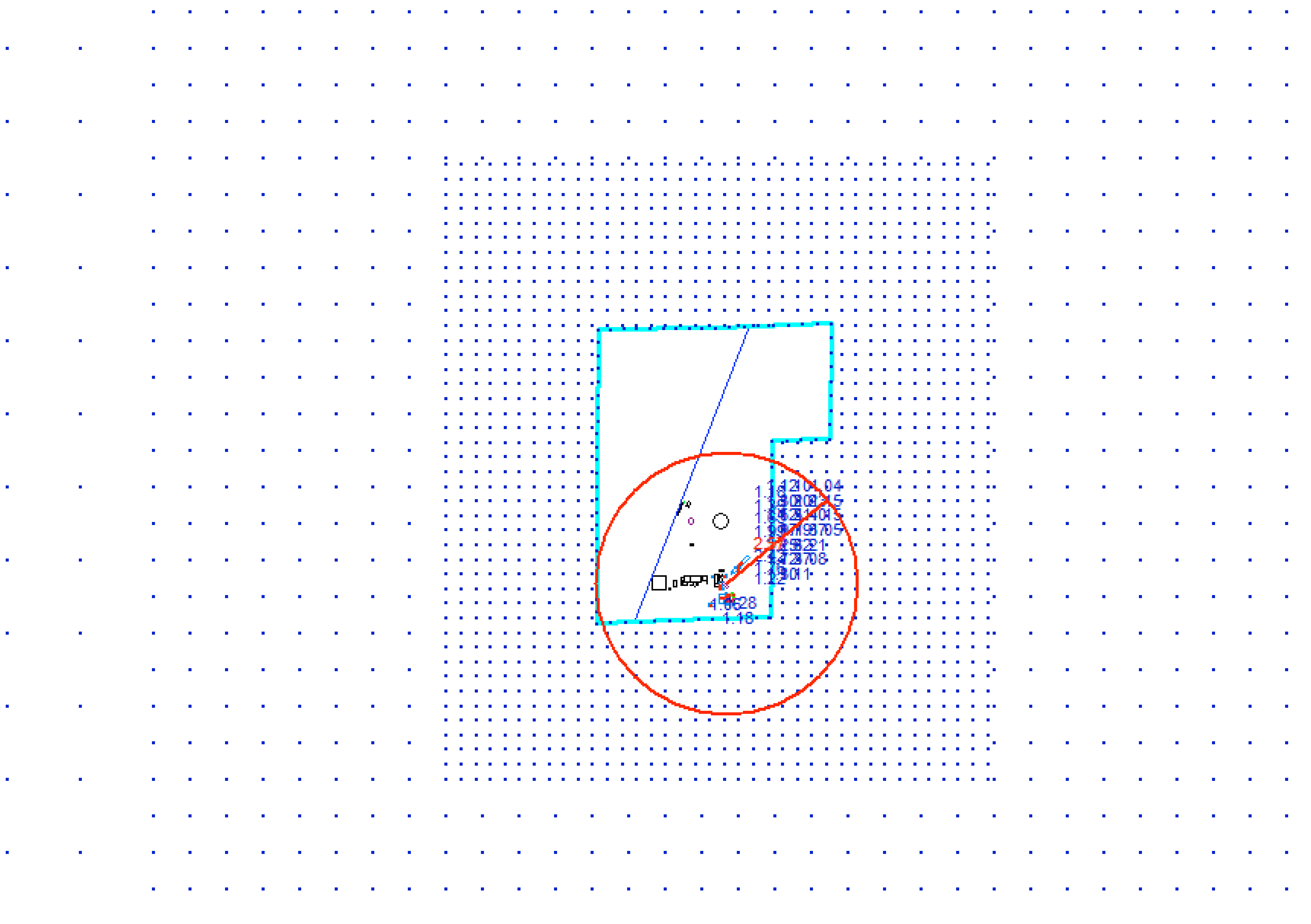

Scale: 1" = 1000.0 Meters

ANNUAL VALUES FOR GROUP: CC_SS

Max = 2.57355 (497721.6, 5266505)

2000 PM2.5 24-HR SIL 1.2ug/m^3 SIA=1.3km

Southern Montana Electric (SME)

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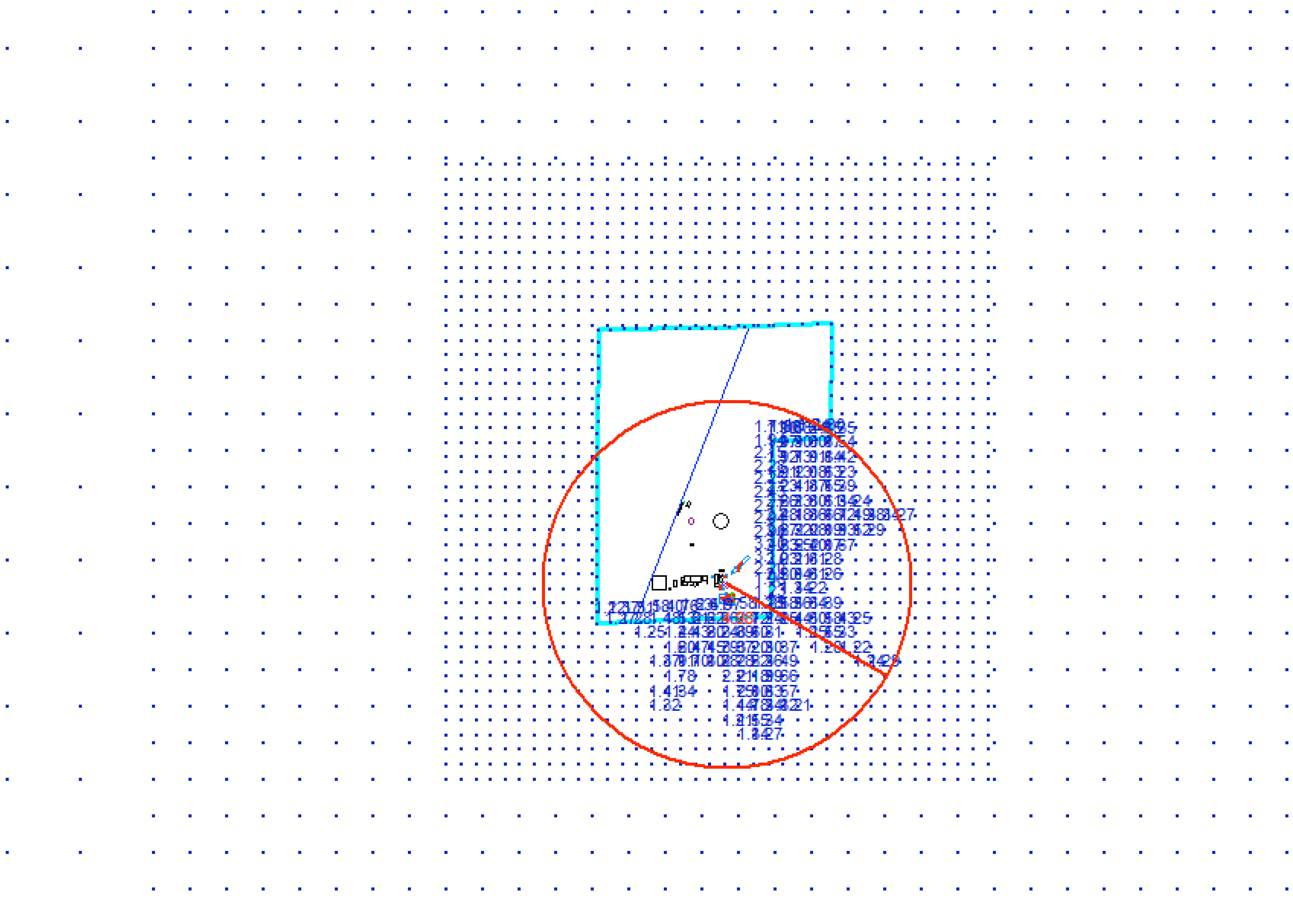

Scale: 1" = 1000.0 Meters

HIGH 1ST HIGH 24-HR VALUES FOR GROUP: CC_SS

Max = 4.976 (497500, 5266000)

2000 PM2.5 ANN SIL 0.3ug/m^3 SIA=0.8km

Southern Montana Electric (SME)

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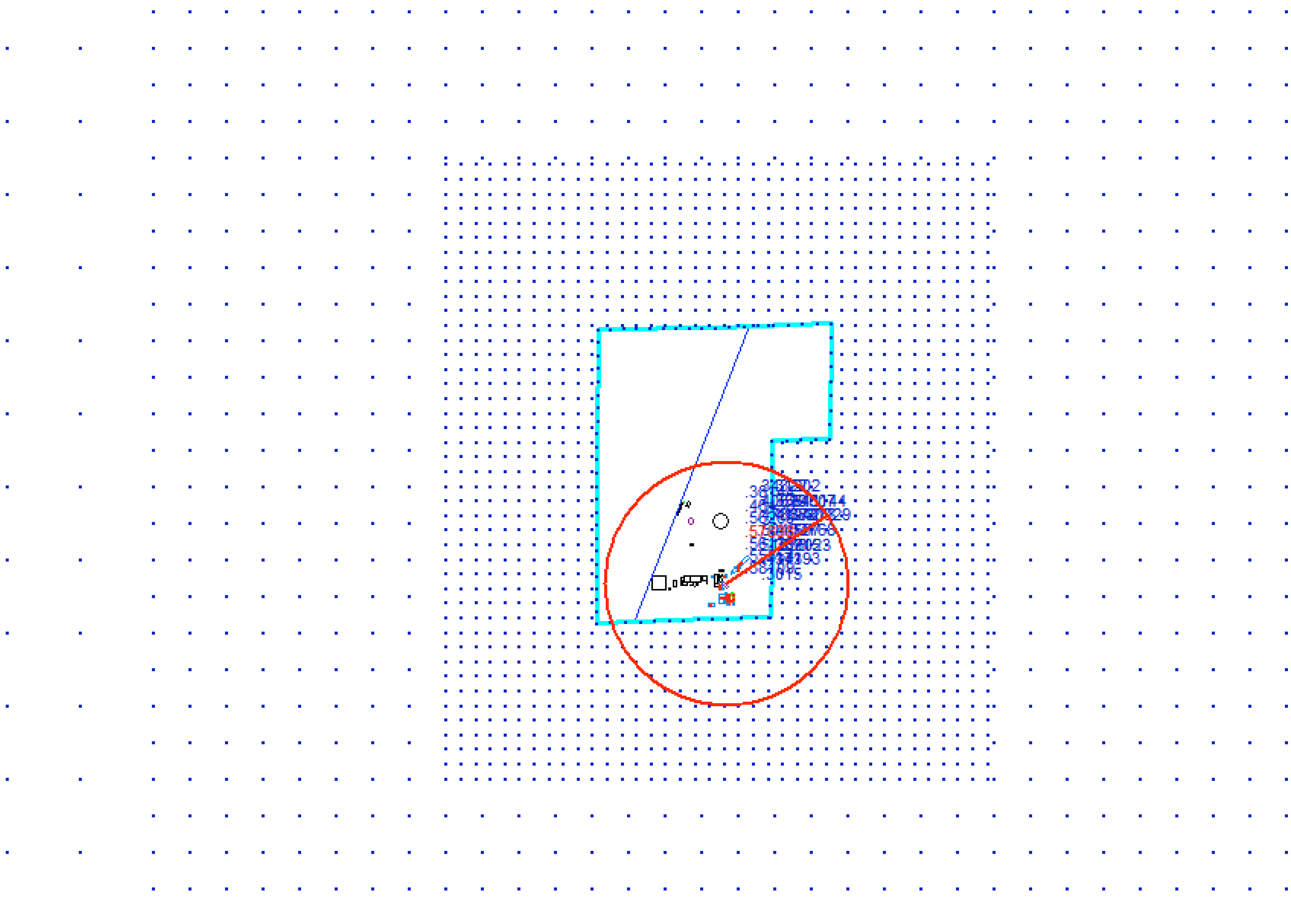

Scale: 1" = 1000.0 Meters

ANNUAL VALUES FOR GROUP: CC_SS

Max = 0.57838 (497721.9, 5266594)

2001 NOx ANN SIL 1ug/m^3 SIA=1.1km

Southern Montana Electric (SME)

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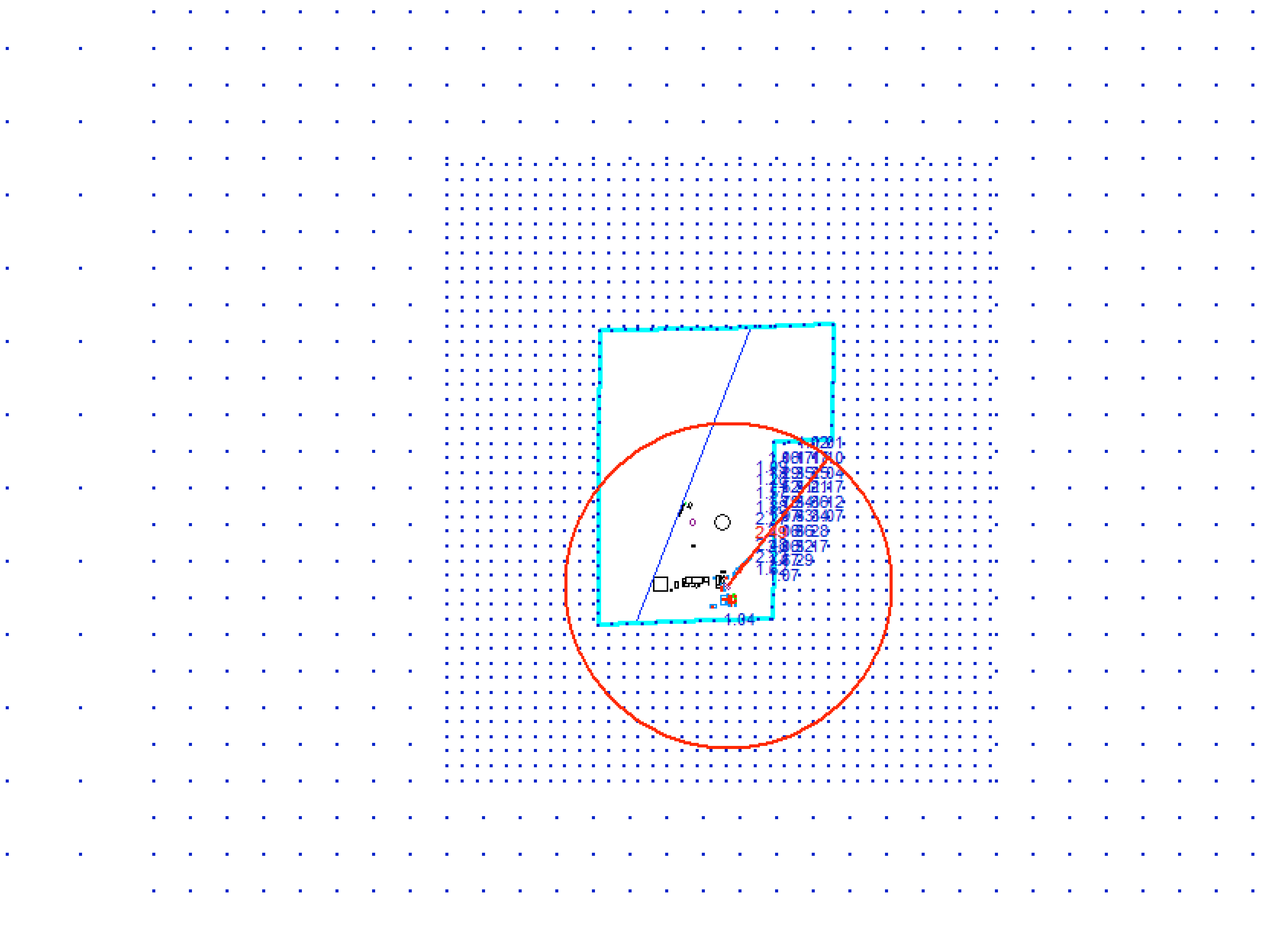

Scale: 1" = 1000.0 Meters

ANNUAL VALUES FOR GROUP: CC_SS

Max = 2.48525 (497721.9, 5266594)

2001 PM2.5 24-HR SIL 1.2ug/m^3 SIA=1.4km

Southern Montana Electric (SME)

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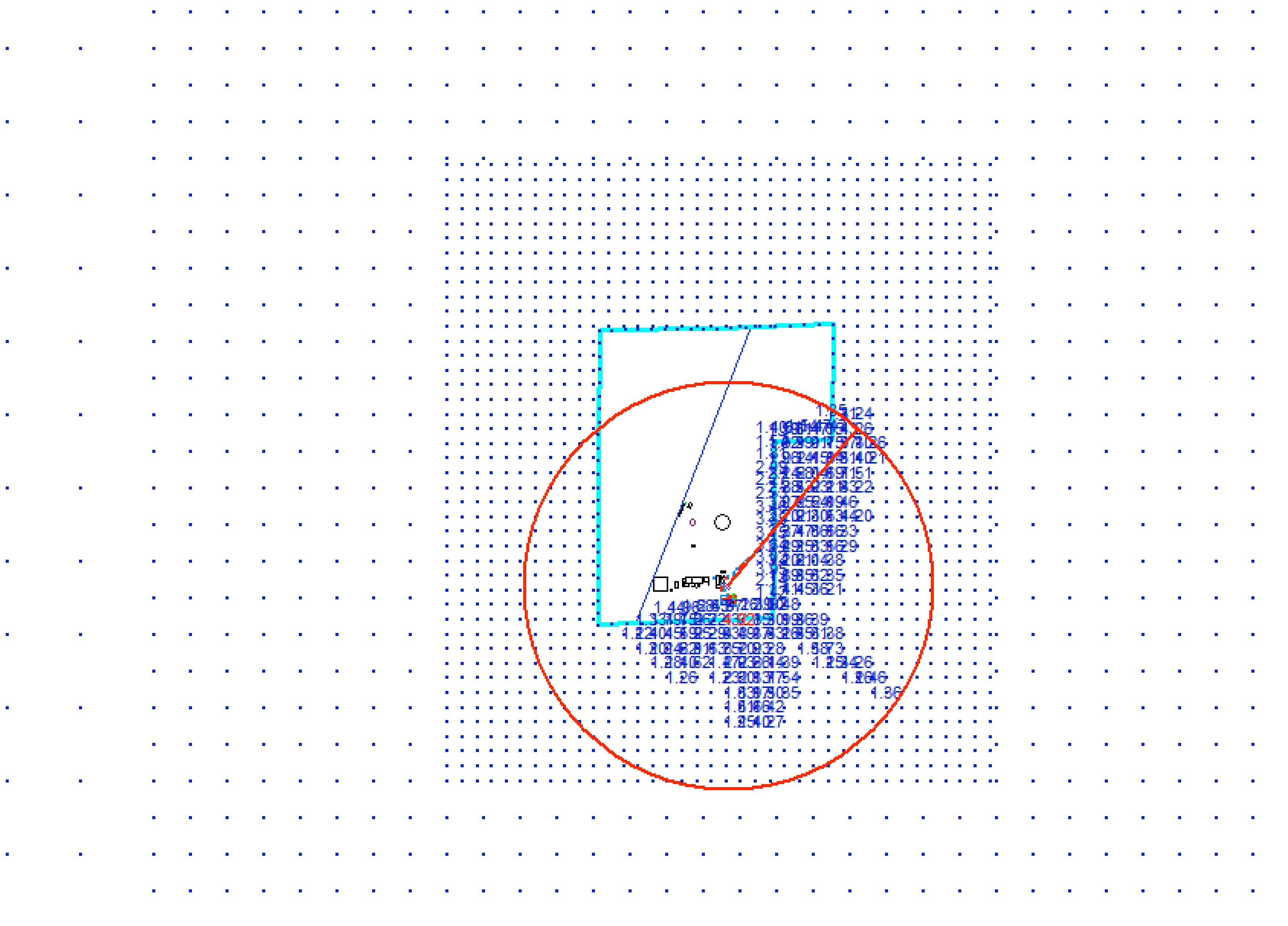

Scale: 1" = 1000.0 Meters

HIGH 1ST HIGH 24-HR VALUES FOR GROUP: CC_SS

Max = 4.91831 (497500, 5266000)

2001 PM2.5 ANN SIL 0.3ug/m^3 SIA=1.0km

Southern Montana Electric (SME)

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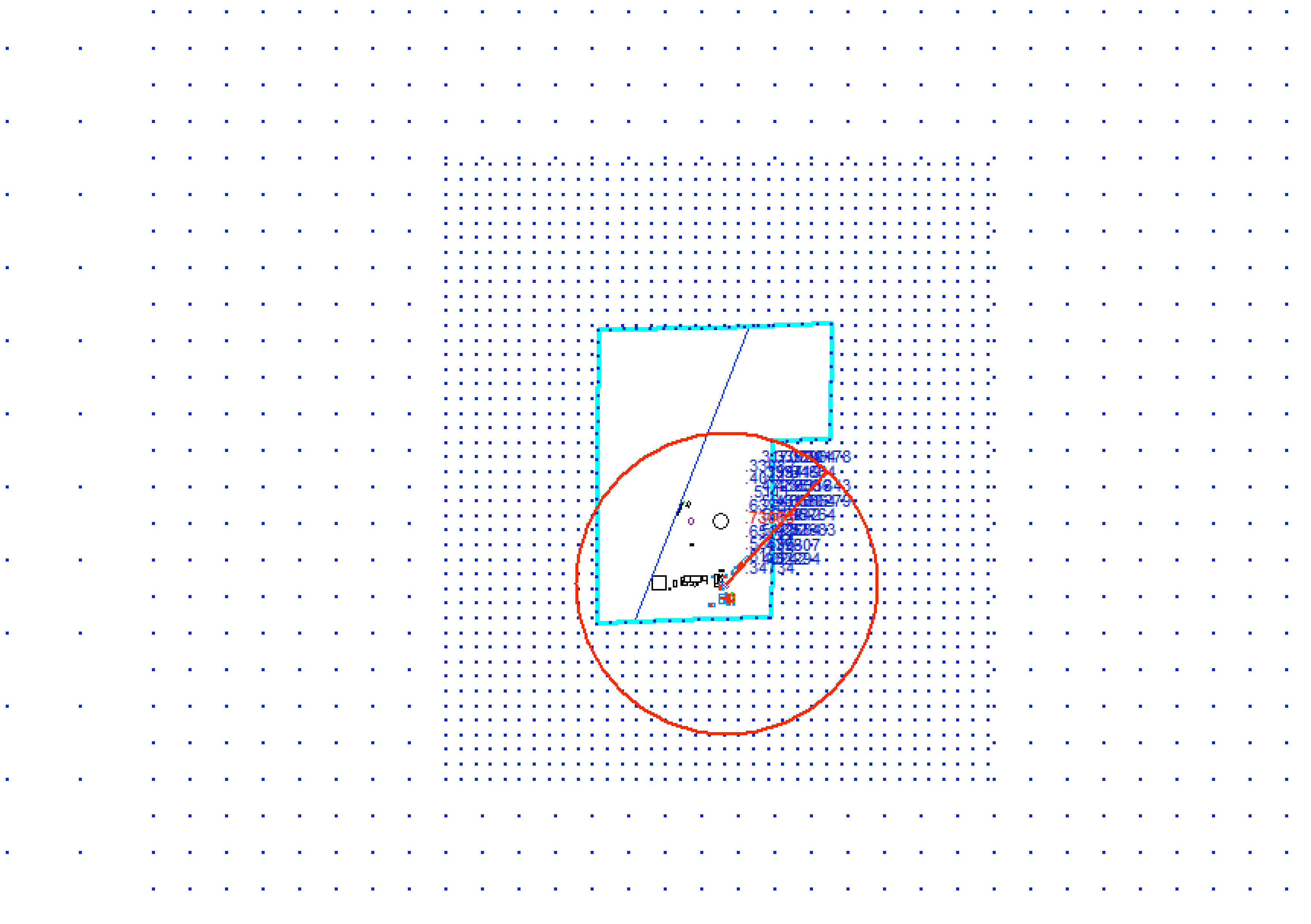

Scale: 1" = 1000.0 Meters

ANNUAL VALUES FOR GROUP: CC_SS

Max = 0.73063 (497722.2, 5266684)

2002 NOx ANN SIL 1ug/m^3 SIA=1km

Southern Montana Electric (SME)

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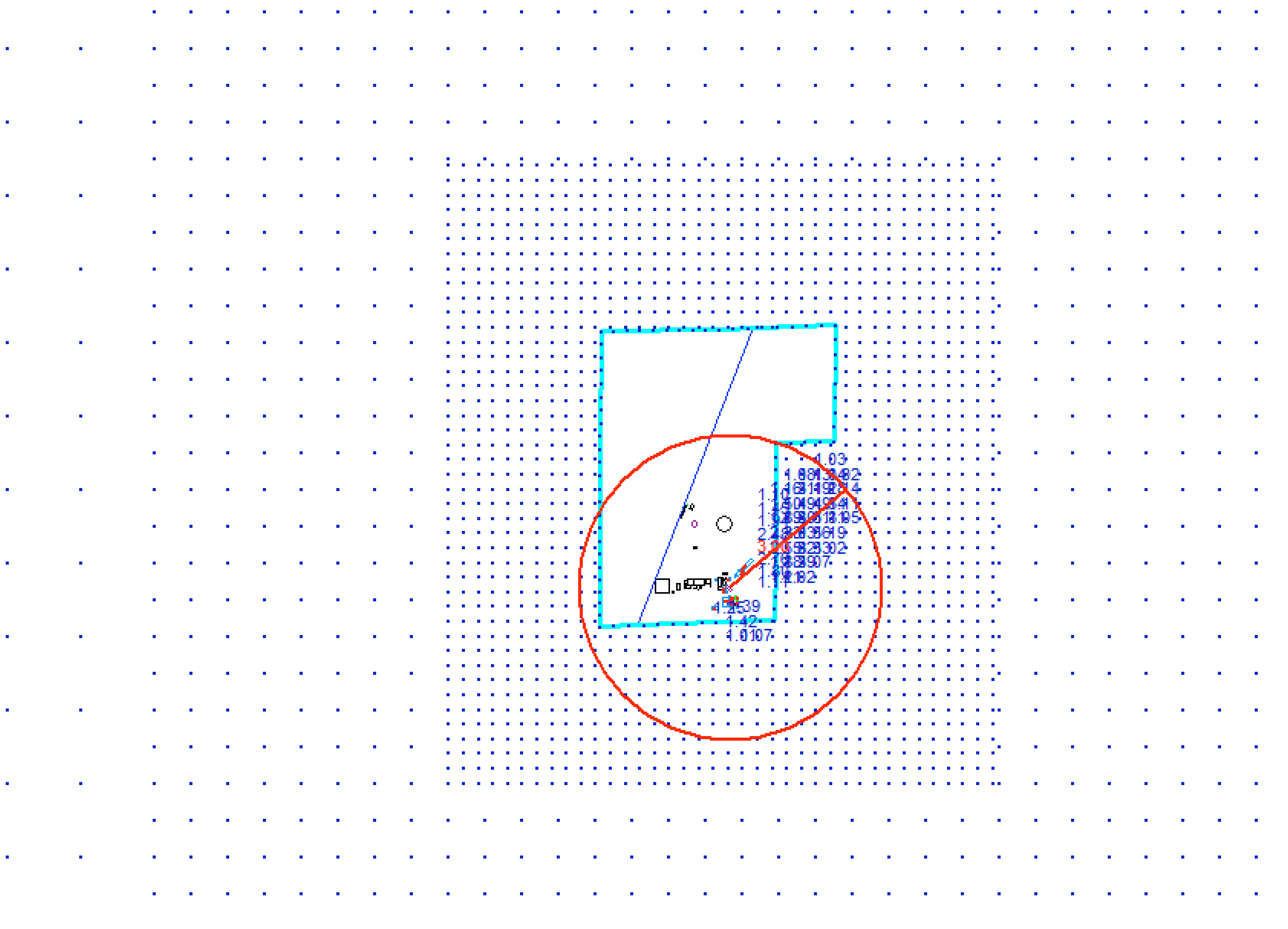

Scale: 1" = 1000.0 Meters

ANNUAL VALUES FOR GROUP: CC_SS

Max = 2.99722 (497721.6, 5266505)

2002 PM2.5 24-HR SIL 1.2ug/m^3 SIA=2.0km

Southern Montana Electric (SME)

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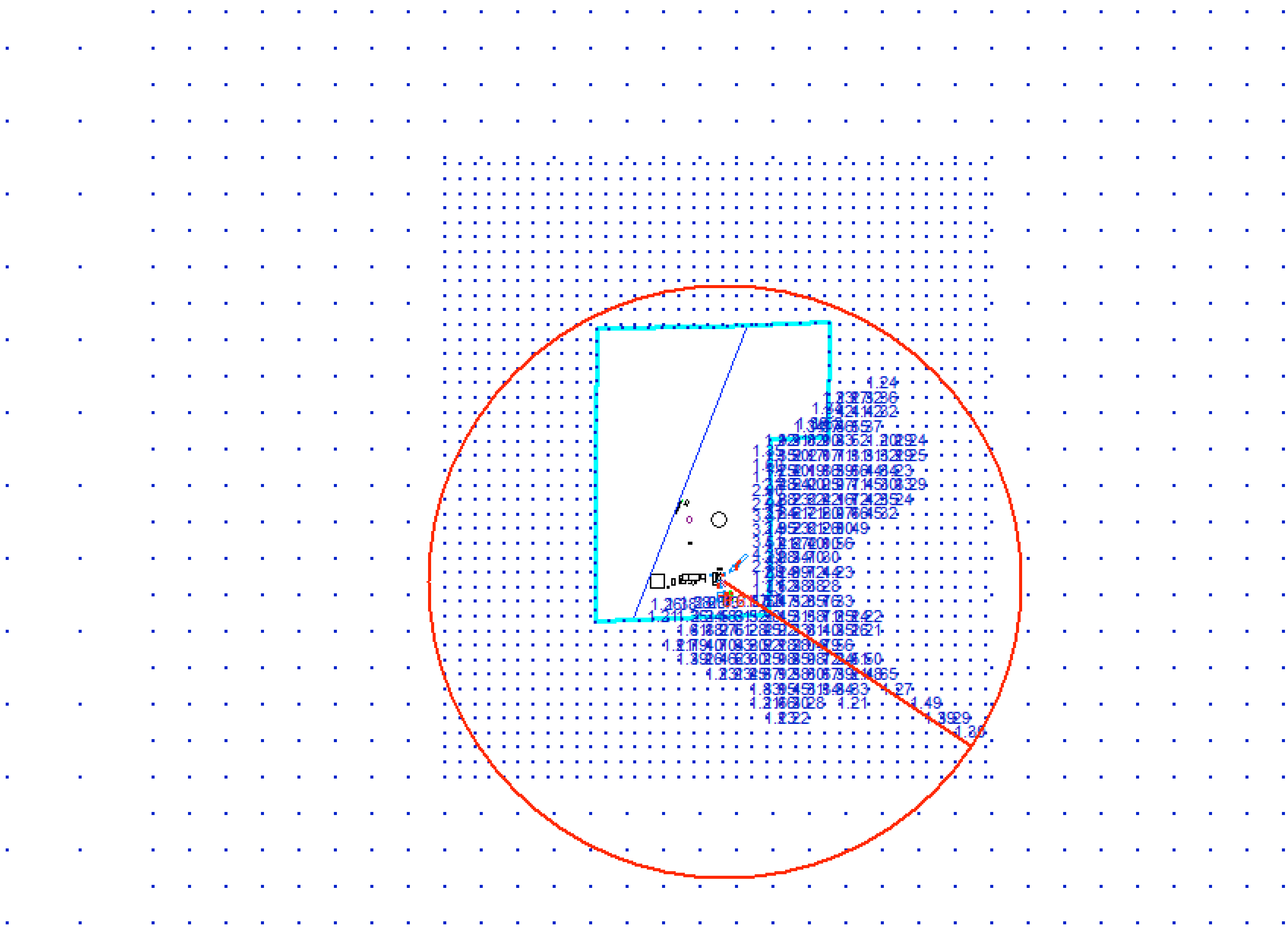


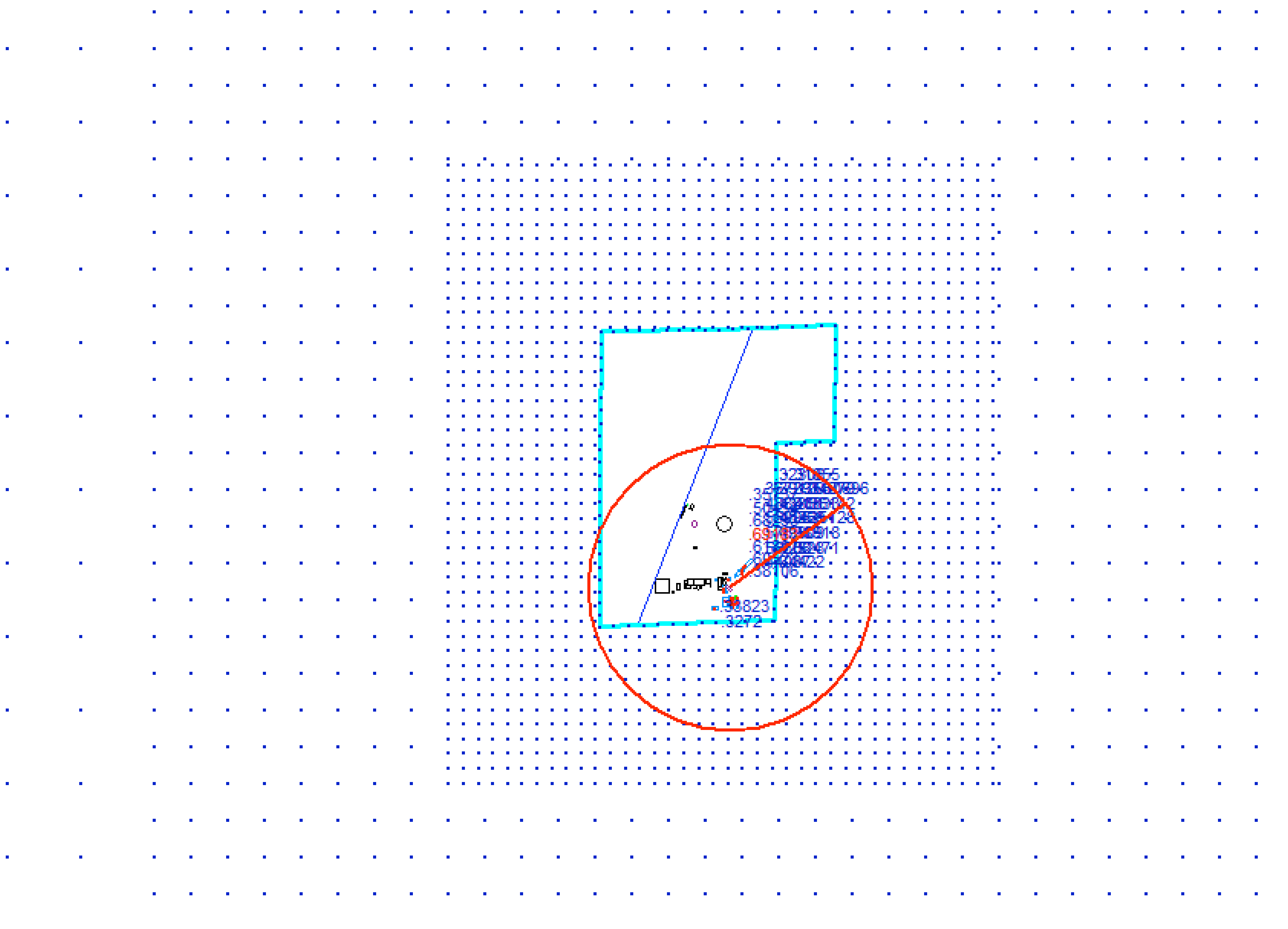
Scale: 1" = 1000.0 Meters

HIGH 1ST HIGH 24-HR VALUES FOR GROUP: CC_SS

Max = 6.60941 (497519.9, 5266097)

2002 PM2.5 ANN SIL 0.3ug/m^3 SIA=1.0km

Southern Montana Electric (SME) G:\Models\SME209970\SIA\SIA FINAL\SIA_FINAL_2002_PMANN.GRF



Scale: 1" = 1000.0 Meters ANNUAL VALUES FOR GROUP: CC_SS Max = 0.69183 (497721.9, 5266594)

2002 PM10 24-HR SIL 5ug/m^3 SIA=0.5km

Southern Montana Electric (SME)

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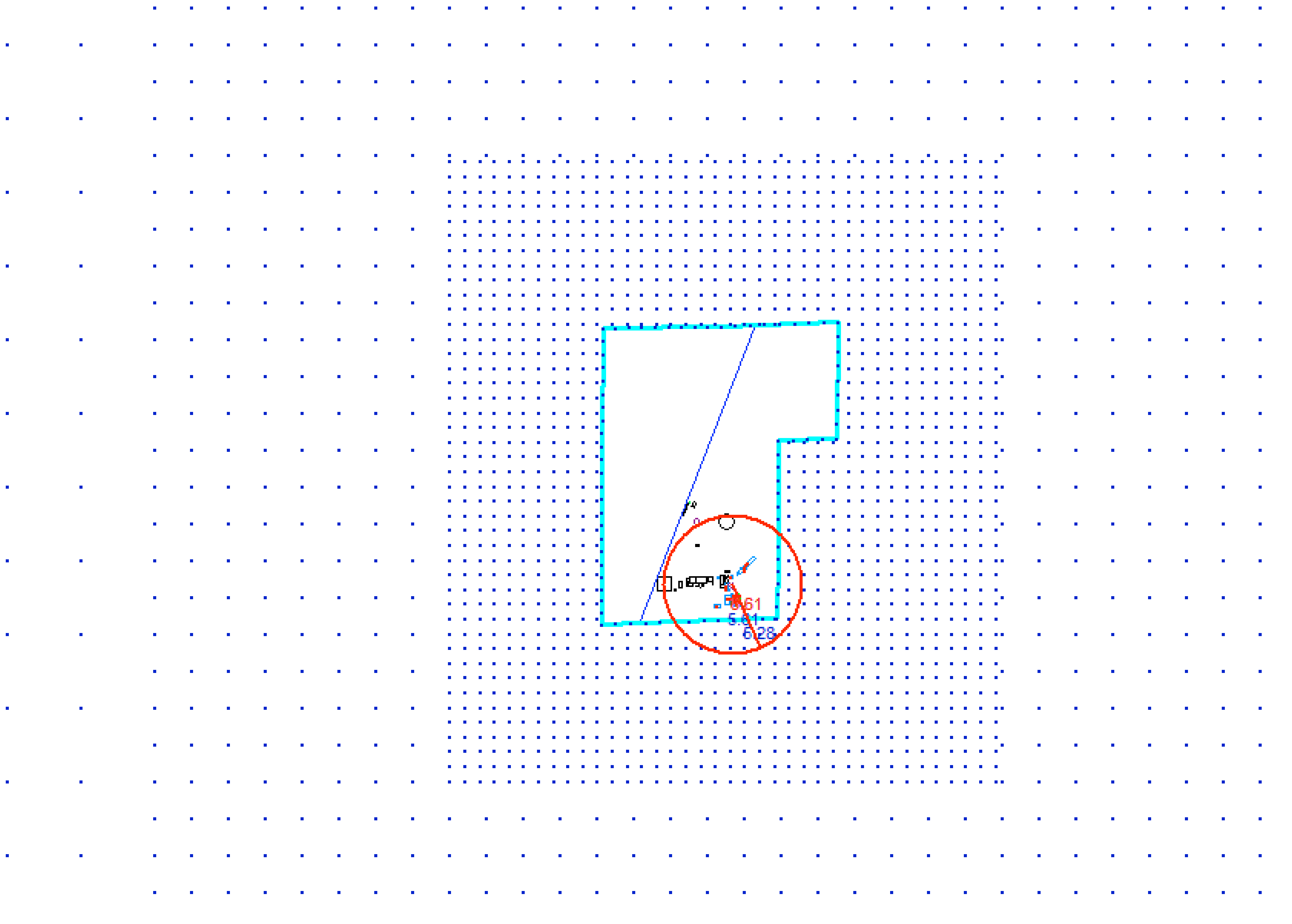

Scale: 1" = 1000.0 Meters

HIGH 1ST HIGH 24-HR VALUES FOR GROUP: CC_SS

Max = 6.60941 (497519.9, 5266097)

2003 NOx ANN SIL 1ug/m^3 SIA=0.6km

Southern Montana Electric (SME)

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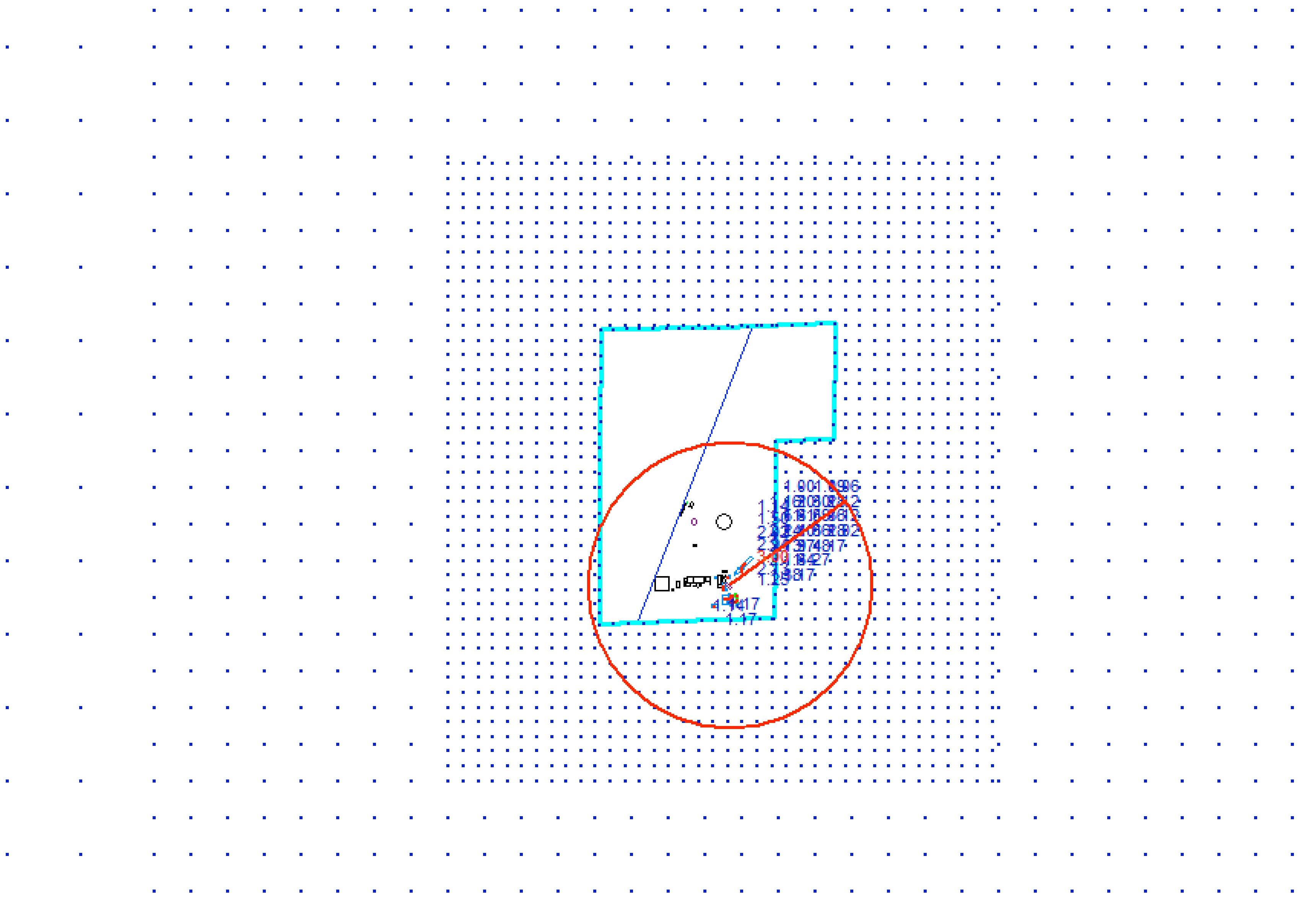

Scale: 1" = 1000.0 Meters

ANNUAL VALUES FOR GROUP: CC_SS

Max = 3.00269 (497721.1, 5266425)

2003 PM2.5 24-HR SIL 1.2ug/m^3 SIA=2.5km

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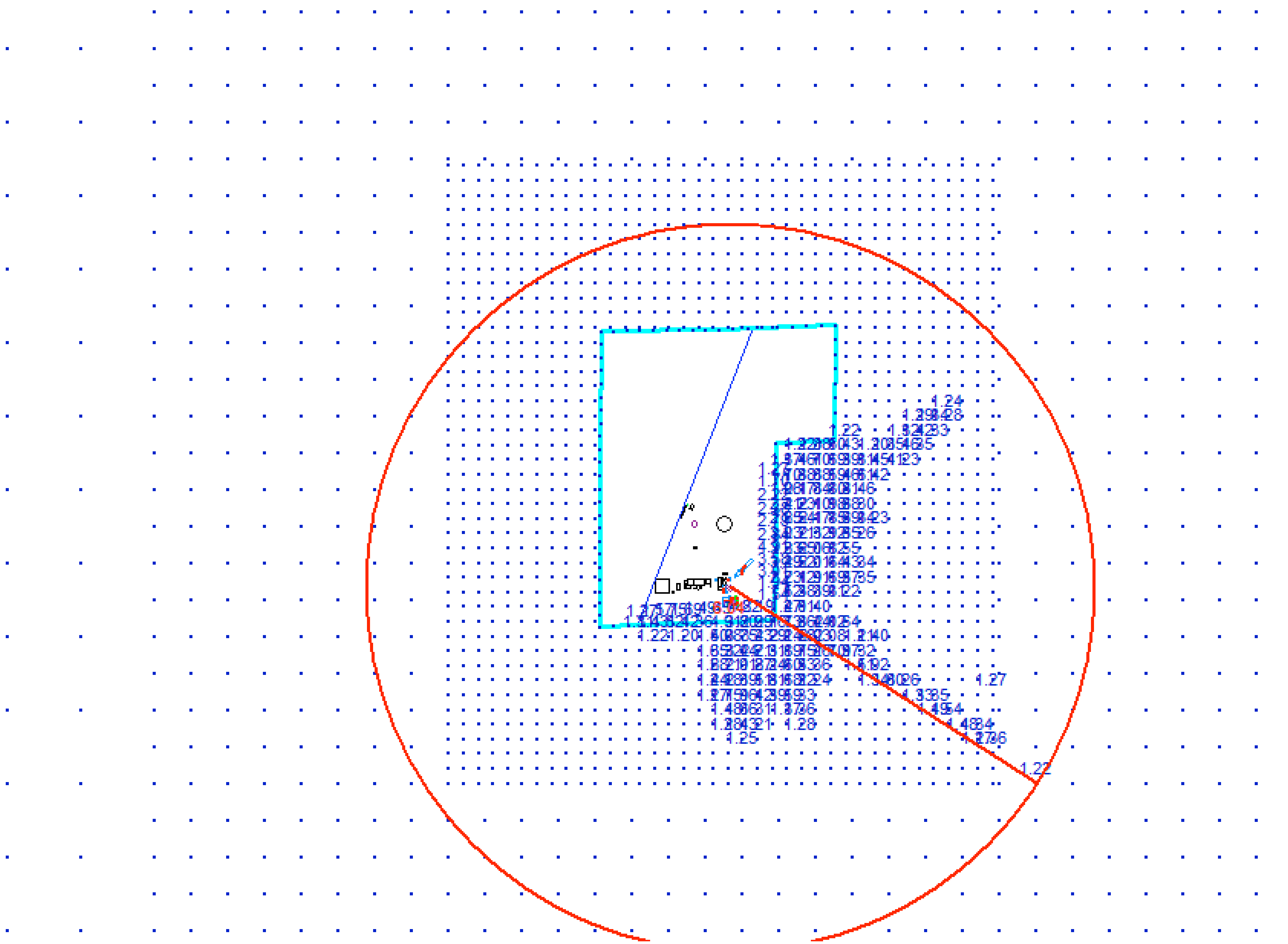
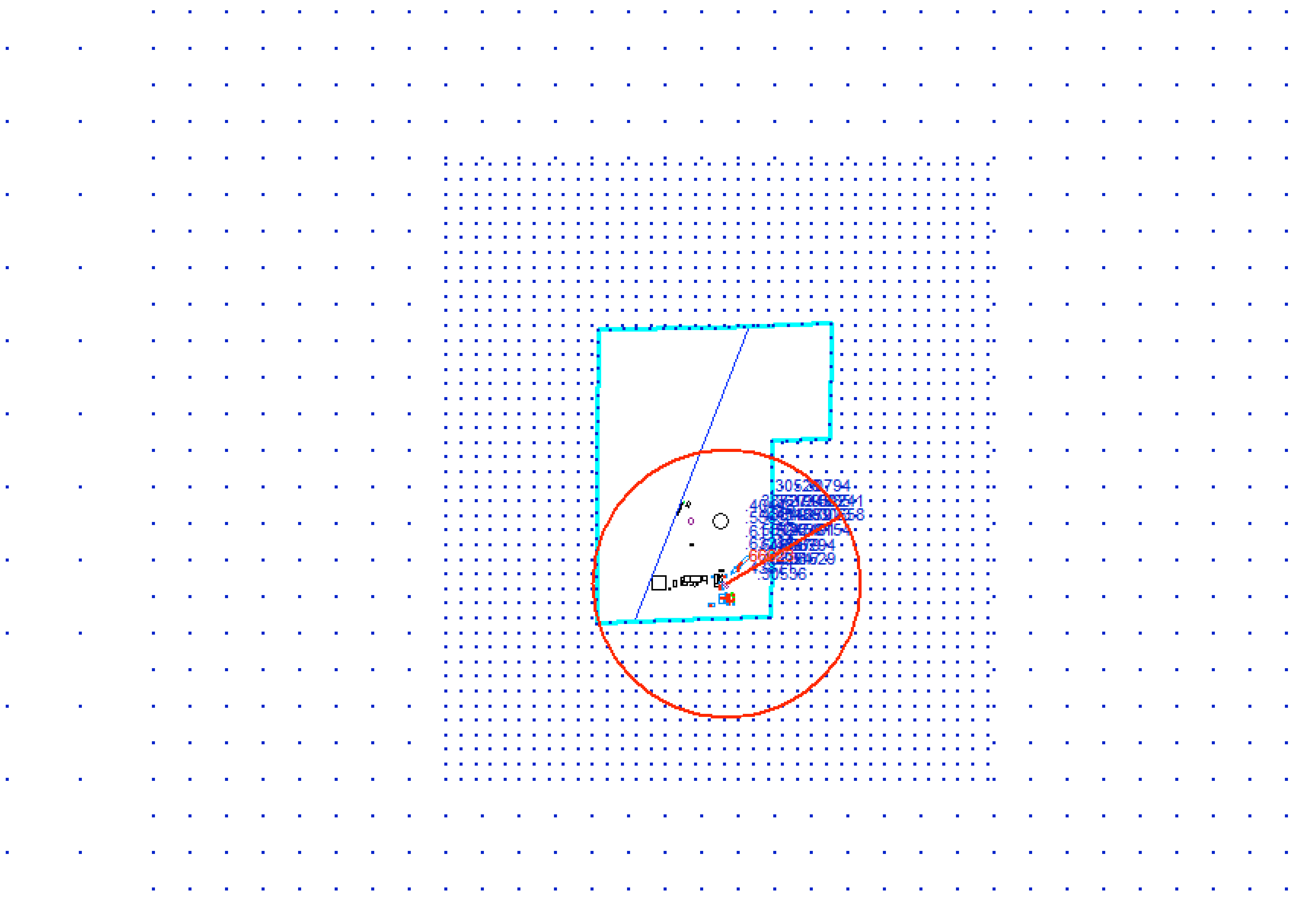


Scale: 1" = 1000.0 Meters HIGH 1ST HIGH 24-HR VALUES FOR GROUP: CC_SS Max = 6.03655 (497420.2, 5266093)

2003 PM2.5 ANN SIL 0.3ug/m^3 SIA=0.9km

Southern Montana Electric (SME) G:\Models\SME209970\SIA\SIA FINAL\SIA_FINAL_2003_PMANN.GRF



Scale: 1" = 1000.0 Meters ANNUAL VALUES FOR GROUP: CC_SS Max = 0.66623 (497721.1, 5266425)

2003 PM10 24-HR SIL 5ug/m^3 SIA=0.2km

Southern Montana Electric (SME)

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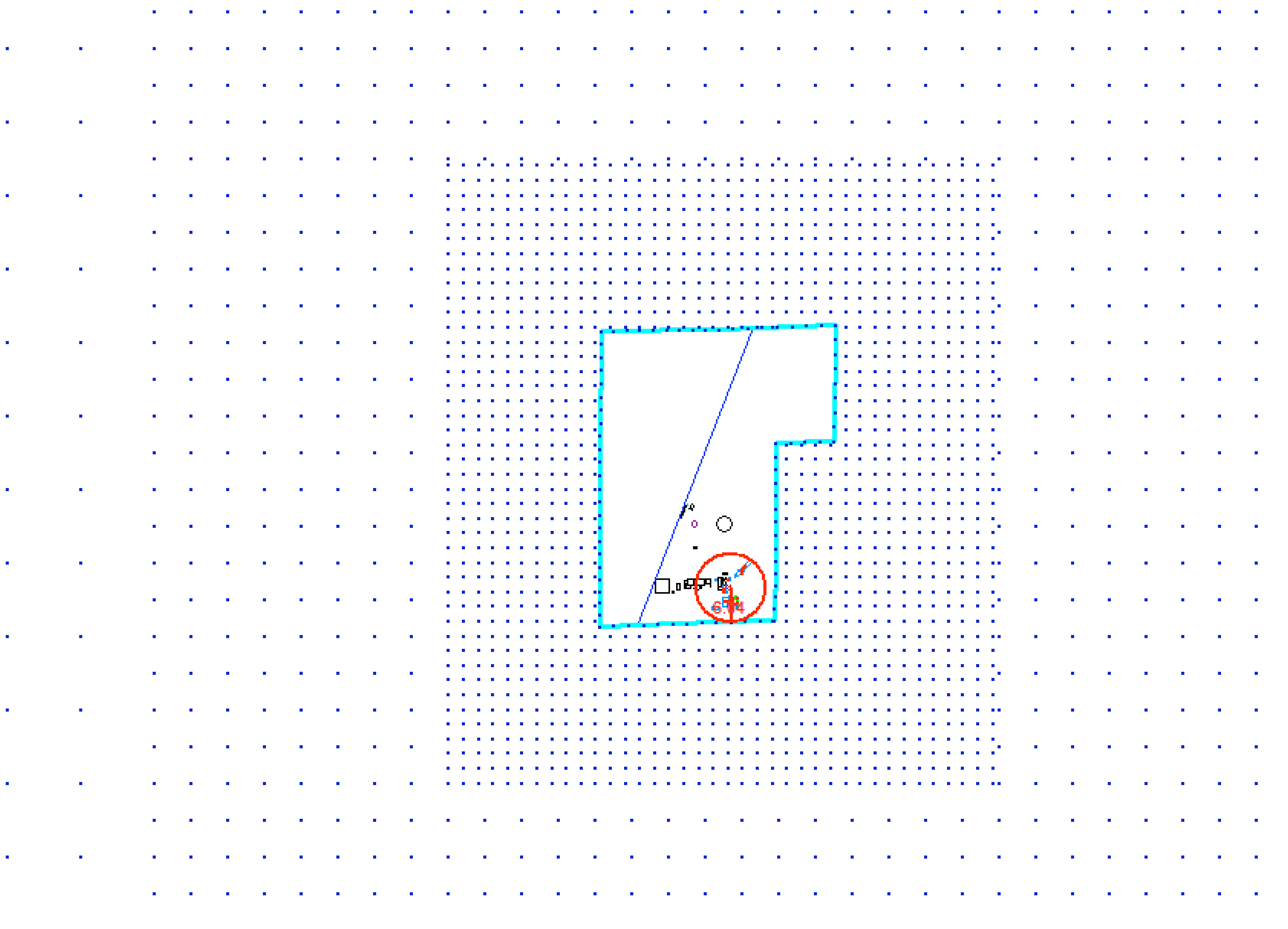

Scale: 1" = 1000.0 Meters

HIGH 1ST HIGH 24-HR VALUES FOR GROUP: 4SCE_CCW

Max = 6.03696 (497420.2, 5266093)

APPENDIX G: ENVIRONMENTAL ASSESSMENT

ENVIRONMENTAL ASSESSMENT FOR CONSTRUCTION OF THE HIGHWOOD GENERATING STATION NATURAL GAS PLANT

Great Falls, MT

Submitted by:

Southern Montana Electric
Generation and Transmission Cooperative
3521 Gabel Road, Suite 5
Billings, MT 59102

Prepared by:

Bison Engineering, Inc.
1400 11th Avenue
Helena, Montana 59601

April 24, 2009

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1.0 INTRODUCTION

Southern Montana Electric Generation and Transmission Cooperative, Inc. (Southern) is applying to revise Montana Air Quality Permit #3423-01 for the Highwood Generation Station. The revision would allow construction of a natural gas-fired power generation facility within the existing property boundary of the permitted coal-fired facility. Before issuing the modified permit, the Montana Department of Environmental Quality (MDEQ) is required to consider the environmental attributes of the project.[1] Southern has prepared this Environmental Assessment (EA) report to assist MDEQ in fulfilling its obligations under the Montana Environmental Policy Act (MCA 75-1-101, *et seq.* and ARM 17.4.601, *et seq.*).

1.1 Project Description

Southern proposes to build a 120-megawatt (MW) natural gas-fired power plant (the Project) at the Salem site near Great Falls, Montana. The Project would be located on property purchased for the Highwood Generating Station (HGS) approximately nine miles east-northeast of Great Falls. The property lies within Sections 24, 25 and 26, Township 21 North, Range 5 East, Cascade County, Montana. Generally referred to as the Project site, it lies adjacent to an aggregate surfaced county road named Salem Road. Figure 1-1 shows the general location of the Project site with respect to select roads (Stanley, 2009a).

The Project would initially include two natural gas-fired turbines, each powering dedicated electric generators. A second phase of the project would add a heat recovery steam generator following each natural gas turbine, and these steam generators would power an additional single electric steam turbine generator. Water and electric power transmission would be substantially as planned for the coal-fired facility. A new natural gas line would be installed to connect the Project to existing gas transmission pipelines north of the Missouri River. Ownership and the exact siting of the natural gas pipeline have not been established at this time. Southern is seeking an enforceable restriction in their Montana Air Quality Permit that would ensure the gas plant and the coal plant do not operate at the same time. Consequently, environmental impacts related to operation of the two portions of the facility would not be additive.

The natural gas-fired power plant is planned as an addition to a currently permitted coal-fired power plant. The proposed natural gas-fired facility would be located within the existing property boundary of the Highwood Generating Station (HGS). An air quality permit for the coal-fired facility was first issued in May 2007. Southern is seeking a modification to the air quality permit to add the natural gas facility. The modified permit would stipulate that the coal-fired generator and the natural gas-fired generators cannot operate simultaneously. As discussed further in the alternatives section below, Southern continues to evaluate the viability of the permitted coal-fired generation plant at HGS. Depending on this evaluation, Southern may consider requesting that MDEQ revoke the coal-fired power plant air quality permit.

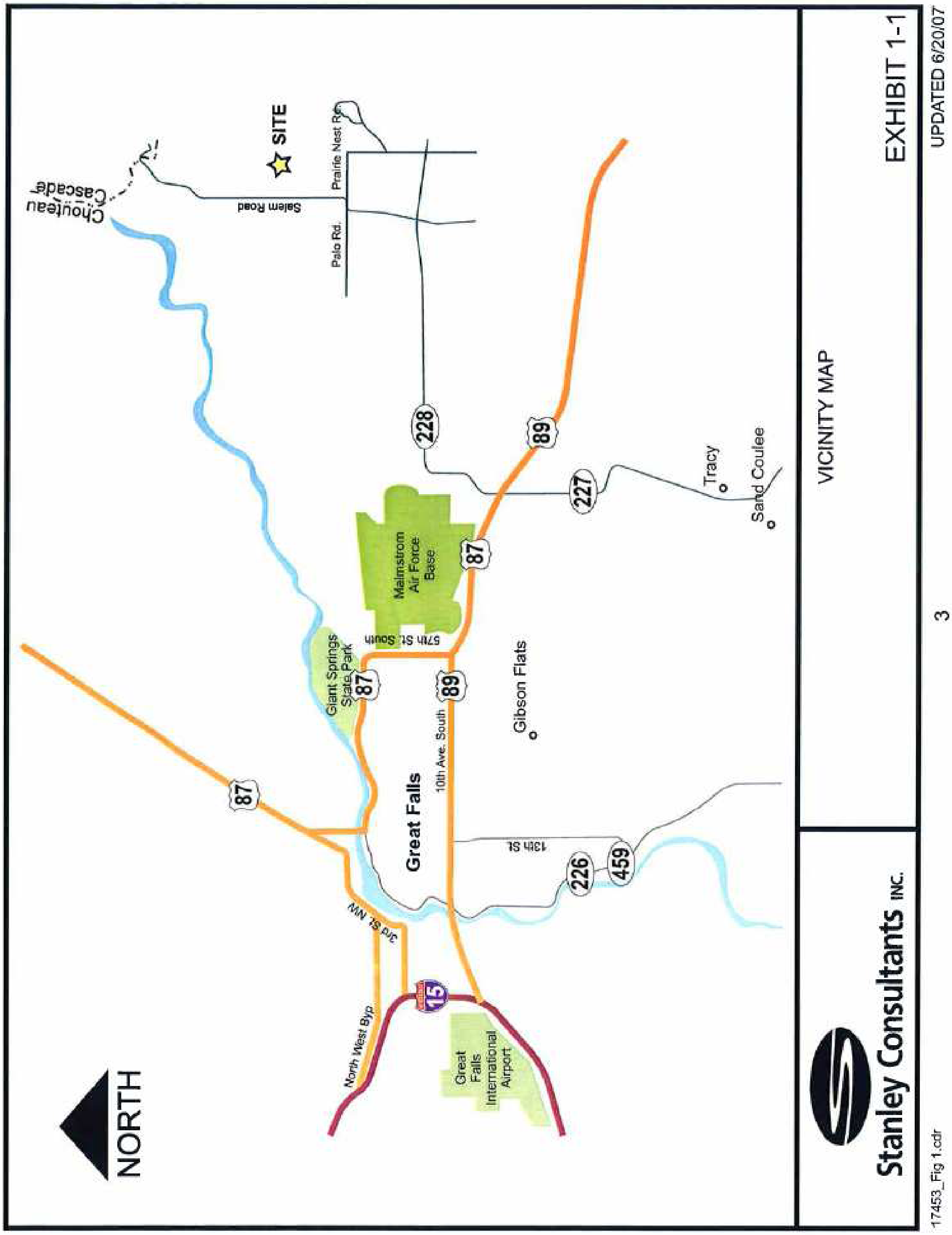
[1] See MCA 75-1-102(1).

Construction of the Project is estimated to require up to 320 construction workers over a period of 30 months. The number of workers on-site at any given time will vary throughout the course of construction. Operation of the facility would employ approximately 20 people full-time.

A final Environmental Impact Statement (RUS and MDEQ, 2007a) for the coal-fired facility was issued in January 2007 (referred to throughout this document as “the EIS”) and a Record of Decision (ROD) in May 2007 (RUS and MDEQ, 2007b). A copy of the EIS is available for review on the Montana Department of Environmental Quality (MDEQ) web site. The EIS was prepared by the Mangi Environmental Group, Inc. for the U.S. Department of Agriculture Rural Utilities Service (RUS) and MDEQ. At the time the EIS was being prepared, and through to its completion, RUS was considering a request to provide financial support to the coal-fired facility. Southern is no longer requesting funding from RUS, and RUS is not involved in the gas-fired power generation Project.

This EA will address marginal impacts to the human environment that could reasonably be expected to result from adding a natural gas-fired power plant to the coal-fired facility. The EA often references and draws liberally from information presented in the 2007 EIS when describing the affected environment for each affected resource. Any changes to the existing environment since 2007 are described in the EA.

Figure 1-1. Vicinity Map of Project Site



1.2 Purpose and Need

Southern is a non-profit, member-owned electric generation and transmission cooperative based in Billings, Montana. It provides wholesale electricity and related services to five electric distribution cooperatives and to the city of Great Falls, Montana. Under its charter, Southern is required to meet the electric power needs of its members who are located throughout 58,000 square miles of Montana and a small section of Wyoming.

Southern previously identified a need to replace a substantial portion of its electrical power generation portfolio when existing power purchase agreements expire. Southern commissioned an exhaustive study in 2004 of alternative options to meet this demand (SME, 2004a). The study concluded that construction and operation of a 250 MW coal-fired power plant would optimize power supply security and costs for cooperative members. A related study identified the location of the proposed gas plant as an optimum site for the coal-fired generation facility (SME, 2004b).

Over the last year, changing conditions in national and international economies and financial systems, in addition to projected new environmental regulations, have combined to make construction of coal-fired power generation facilities more difficult than when the power generation project was initially planned. Although generally considered to be more expensive to operate than a coal-fired plant, a natural gas-fired plant costs substantially less to build, takes less time to construct, and is easier to finance. Additionally, advocacy groups that strongly oppose coal combustion and are actively engaged in blocking approval of coal-fired generation projects have generally not challenged natural-gas power generation. These factors have led Southern to modify their earlier plans with respect to the coal plant and focus first on filling a portion of their power generation portfolio by using natural gas as a fuel.

1.3 Alternatives

As Southern worked through the process of performing an appropriate level of due diligence of its power supply alternatives under the guidance of RUS, Southern conducted an extensive review of wholesale power supply alternatives capable of meeting the current and forecasted demand for wholesale electric energy and related service needs of the distribution member systems it serves. The conclusion reached in this evaluation of viable power supply alternatives was that the construction of a new fossil fuel power generation facility at the HGS site represented the best long-term power supply alternative to meet the growing needs of Southern's member systems. In the context of this analysis, Southern evaluated alternative generation technologies and plant locations. Both studies are described in the EIS. Southern has continued to monitor the impact of ongoing changes in political, regulatory and financial environments on the conclusions reached in the alternative evaluation study.

Subsequent to the completion of the alternative evaluation study, there have been significant changes in the political, regulatory and financial environments. The net result of these changes appears to have materially impacted the viability of all proposed and existing coal-fired electric generation facilities. Based on this marked change in the external conditions impacting electric generation capacity development, Southern now believes that natural gas-fired generation, complemented with competitively priced power purchase agreements, represents the most reasonable near term solution to the power supply needs of Southern and the member systems it serves. Recognizing a need for a much higher level of power supply certainty, Southern decided to advance the development of the natural gas-fired generation facility while it continues to sort through the implications of the shift in national preference for base load electric generation capacity.

1.4 EA Organization

This EA will analyze impacts to several resources which the Project could be expected to affect. The resources considered are:

Soils

Water Resources

Air Quality

Biological Resources

Noise

Recreation

Cultural Resources

Visual Resources

Transportation

Farmland and Land Use

Human Health and Safety

Socioeconomic Resources

Environmental Justice and Protection of Children

Waste Management

Cumulative Impacts

For each resource, the EA will describe the current state of the resource (affected environment), describe potential impacts that could result from the Project, and identify and describe available measures to mitigate any potential adverse impacts. As appropriate, cumulative impacts resulting from construction and operation of both the coal-fired and natural gas-fired plants will be addressed.

2.0 SOILS, TOPOGRAPHY, AND GEOLOGY

2.1 Affected Environment

Great Falls is located within the Missouri Plateau region of the Great Plains physiographic area, which is characterized by several levels of rolling upland plains, small mountainous masses, and flat-topped buttes. The area is dissected by the Missouri River and its tributaries.

The regional topography in the Great Falls vicinity consists primarily of gently rolling northern Great Plains and prairie with little change in relief. Elevations in the area range from about 3,300 to 3,600 feet above mean sea level (MSL). Nearby mountain ranges partially encircle the Great Falls portion of the Missouri River valley. These include the Highwood and Little Belt Mountains, which are about 30 miles away to the east and south, respectively. The Big Belt Mountains are 40 miles distant to the southwest and the Front Range of the Rocky Mountains varies between 60 and 100 miles distance to the west and northwest.

The elevation at the planned facility location is approximately 3,310 feet above sea level. Site topography is gently sloping and undulating, sloping downward to the west and north toward the Missouri River.

A hydrogeologic report completed for this area in September, 2005 (PBSJ, 2005) identified the following strata of geologic formations below the Great Falls area: Madison limestone is the deepest, followed by the Swift Formation, then Morrison sandstone and shale beds, and finally the Kootenai Formation with an upper portion consisting mainly of mudstone and a lower portion consisting of sandstone and siltstone.

Unconsolidated sediments extend 125 to 150 feet below ground to the Kootenai Formation. These sediments consist of wind-blown deposits of silty sand, underlain by glacial lake bed and glacial till deposits.

Surface soils at the site consist entirely of Pendroy Clay soils with 2-8 percent slopes. The Pendroy Clay soils have a fine-grained inorganic clay content of 60-75 percent down to approximately 40 inches below the surface and a 50-65 percent clay content at depths between 40 to 70 inches. They exhibit very slow rates of water transmission and infiltration and a high degree of plasticity.

2.2 Environmental Consequences

Construction of the facility is expected to last approximately 30 months. The total footprint of the Project will be approximately six acres. Some surface disturbance will occur beyond the plant site with the construction of transmission lines and access roads. All or the majority of the site would be contoured to an even grade with soil removed from high areas used to fill low areas. Little or no soil stockpiling is expected.

Existing aggregate roadways currently leading to the site would be maintained for access during construction. These would be regraded and paved at the end of the construction period. A 1,800-foot long paved access road into the site would be constructed and maintained from the existing Salem Road.

Construction equipment to be used during site development would include bulldozers, backhoes, earth scrapers, motor graders, heavy haul trucks, large tractors, concrete trucks, asphalt pavers, concrete pavers, rollers, and compactors.

Some potential for soil contamination exists during construction and operation due to spills and leaks of fuels and chemicals. Construction equipment may compact soil, reducing its porosity and resulting in a slight increase in the amount of surface runoff in the immediate area. As noted above, the underlying soil in the area has a potential for high runoff and relatively high soil erosion potential. However, this potential is limited by the relatively gentle slopes in the immediate area of the plant site.

2.3 Mitigation and Monitoring

Southern would need to obtain permit coverage under a *General Permit for Storm Water Discharges Associated with Construction Activities* from MDEQ, and would have to develop a *Storm Water Pollution Prevention Plan* (SWPPP) for this Project. An existing Storm Water Construction Permit MTR103153 for the adjacent coal-fired generation facility would likely be modified to address or include the natural gas-fired generation facility. These documents would identify potential disturbances and the appropriate erosion and sediment control methods to be used to minimize effects. Measures such as limiting the area of disturbance and the use of silt-fences, straw mulch, temporary runoff diversions, sediment basins, temporary grading and other methods would limit short-term erosion. Long-term erosion would be effectively minimized by re-grading and re-vegetating as quickly as possible following disturbance. Regular inspections during and following construction would ensure proper implementation of erosion control techniques. Erosion would be naturally mitigated by the level nature of the Project site and much of the surrounding area.

Soil erosion on temporary and permanent roads would be minimized by proper drainage with dips, waterbars or other methods to prevent water from concentrating on roadways.

Soil compaction effects would be minimized by limiting vehicle use to established travel and construction routes. If any reclaim areas become compacted, they would be treated by ripping, plowing, disking or other appropriate methods prior to re-vegetating.

2.4 Impacts Summary

No significant direct, indirect, or cumulative adverse impacts to the soils, topography or geological resources of the Project area are anticipated as a result of the Project as proposed, including mitigation and monitoring measures. Construction or operation of the Project would not substantially alter the geography or topography of the area, would not result in soil erosion that could cause measurable sediment increases in surrounding surface water, and would not cause widespread soil compaction that would inhibit plant growth.

The no-action alternative would not affect this resource in any way.

3.0 WATER RESOURCES

3.1 Affected Environment

3.1.1 Surface Water

The Project site is located within the Upper Missouri River Basin and the Missouri-Sun-Smith River Sub-Basin. The Missouri-Sun-Smith River Sub-Basin consists of five watersheds that all drain into the Missouri River. The Project site is located in two of these watersheds. The western majority of the site is located within the Upper Missouri-Dearborn watershed while the eastern portion of the site is located within the northwesternmost tip of the Belt watershed.

Belt Creek is the primary drainage stream located within the Belt watershed, and it is a direct tributary to the Missouri. It joins the Missouri just downstream of the Project site, approximately 15 river miles northeast of Great Falls.

There are several intermittent streams in the vicinity of the Project site. To the east, drainage from the site would flow into Rogers Coulee, a drainage channel which connects with Belt Creek just northeast of the site. To the west of the site, and located immediately west of Salem Road, there are several unnamed drainage channels with intermittent flows to the Missouri River. Both Rogers Coulee and the drainages discussed above are dry the majority of the year and contain flowing water only during major overland runoff events. Box Elder Creek is the first named tributary of the river located to the west of the site. Surface water flows in a north to northeast direction throughout this area, into the Missouri River.

Wetlands within the project vicinity generally are limited to the incised drainage habitat and narrow fringes of the Missouri River and its tributaries (Westech, 2005). Though limited, these wetlands provide an invaluable resource for the filtration and adsorption of stream nutrients and contaminants, and for waterfowl and wildlife habitat. Five bird species on the State species of concern list have been documented in wetlands within ten miles of Great Falls: white-faced ibis, black-crowned night heron, Franklin's gull, common tern, and black tern (Westech, 2005).

Floodplains similarly follow the fringes of the perennial streams in the area. Along the Missouri River in the vicinity of the Project area, the floodplains do not extend over the river banks due to the fact that the river runs through a deeply incised channel with sides from sixty to over several hundred feet high (Nerud, 2006). The configuration and size of the channel, along with the area dams, prevent the Project site from receiving most flood waters.

3.1.2 Groundwater

The Great Falls area has ample groundwater resources, and the depth to water varies depending on the aquifer used as a source of water. The shallow alluvial aquifer contains water that is generally less than 100 feet. This aquifer does not appear to be present beneath the Project site based on geotechnical soil borings and local well logs.

The Kootenai Formation is the most commonly used aquifer in the area. The aquifer is used mostly for domestic purposes and public water supply, and is recharged by snow pack and runoff in streams. The thickness of the Kootenai Formation averages 200-250 feet. The upper portion of the Kootenai Formation consists primarily of mudstone with some claystone and siltstone. The lower portion of the Kootenai is characterized by sandstone and siltstone. The productive portion of the formation is normally found in these rocks. Estimated average hydraulic conductivity of this aquifer is 182 ft/day. The predominant groundwater flow within the aquifer is towards the Missouri River (PBSJ, 2006).

Below the Kootenai Formation is the Morrison Formation of Jurassic Age. It is about 100-200 feet thick. The Morrison sediments consist of intercalated sandstone and shale beds. It is the confining unit for the underlying Madison Formation. The Morrison is not a water-producing formation in the Great Falls area (PBSJ, 2006).

The second most commonly used aquifer in the area is the Madison limestone aquifer. This aquifer is used mostly for domestic purposes and public water supply, and, like the Kootenai Formation aquifer, is recharged by snowpack and runoff in streams. The Little Belt Mountains are the recharge area for the Madison limestone aquifer. The thickness of the Madison aquifer averages 500 feet. The Madison aquifer is a confined aquifer in the vicinity of Great Falls. Estimated average hydraulic conductivity of this aquifer is 321 ft/day. The predominant groundwater flow direction within the water table aquifer is towards the Missouri River; specifically, in the areas south of the river the direction of groundwater flow is to the north-northeast (PBSJ, 2006).

The quality of the groundwater is generally good in the Great Falls vicinity, with the exception of a few water quality parameters. Elevated concentrations of sulfate, manganese, and cadmium were measured in the alluvium, Kootenai, and Morrison formations. If the alluvial samples are ignored, then the data seem to indicate a logical progression and evolution of water quality with residence time and with depth/source rock type. Total dissolved solids (TDS), sulfate, hardness and bicarbonate/alkalinity increase from the shallow noncarbonate rocks (Kootenai) to the Morrison and then to the deeper carbonate rocks in the Madison. All of these waters are moderately to extremely hard (PBSJ, 2006).

3.2 Environmental Consequences

Construction of the Project is expected to last up to 30 months. General construction impacts could indirectly affect water resources by increased storm water runoff from the Project site carrying sediment and contamination loads into surface water, and by contamination from construction equipment and activities infiltrating area soils and percolating down into the groundwater. Direct impacts to water resources may result from construction activities including the construction of the water intake facility in, or wells adjacent to, the Morony Reservoir, and the installation of a transmission line and water and natural gas pipelines within the watershed of the Missouri River. The routes for the transmission lines and water pipelines are described in the EIS (RUS and MDEQ, 2007a). The route of a proposed natural gas pipeline is under consideration at this time, but would generally extend from the Project site to existing natural gas pipelines north of the Missouri River. As with almost any construction project involving the use of heavy equipment, there is some risk of an accidental fuel or chemical spill, which could adversely affect water quality if the spilled chemical were to percolate into groundwater or directly enter an adjacent surface water body.

The Project would obtain water required for its operation from a water intake in Morony Reservoir, or wells adjacent to Morony Reservoir, approximately 0.4 mile upstream of Morony Dam on the Missouri River. The plant would require an average of 458 gpm and a maximum of 1053 gpm of “make-up water” to be pumped from the reservoir or wells adjacent to the Morony Reservoir. As discussed in the EIS, withdrawal of this quantity of water from the Missouri River would have a minimal impact on river flows. The development of wells adjacent to the Morony Reservoir would pull surface water from Morony Reservoir and could potentially impact the groundwater resources in the area; however, those impacts are expected to be localized in the alluvial aquifer immediately adjacent to the reservoir.

The power plant would generate a maximum of 216 gpm of wastewater that must be treated and would consist of concentrated river water and trace amounts of cooling tower water and boiler water treatment chemicals (RUS and MDEQ, 2007a). The wastewater would be discharged back to the City of Great Falls for disposal at its existing wastewater treatment facility, or be treated on-site resulting in zero wastewater discharge from the Project site.

Since all process-related discharges from the facility would be sent to the Great Falls sanitary sewer or treated on-site, there would be no adverse impacts on water resources from operation of the facility. There would be storm water run-off from the Project site at times. This water would be channeled into plant storm ponds and managed in accordance with the facility Storm Water Permit.

3.3 Mitigation Measures

During construction, Best Management Practices (BMPs), such as silt fences, straw bales, and other temporary measures would be used to control erosion from storm run-off. Temporary sediment basins would be constructed and maintained until site vegetation is firmly established. These temporary sediment basins would be constructed before mass grading begins, so that they would be in place and working for the entire construction period. Disturbed areas would be revegetated. During operation, much of the storm run-off from the Project site would be contained in plant storm ponds, and the remainder would be managed in accordance with the facility Storm Water Permit.

To reduce the potential for water resource contamination, fuels would be stored and maintained in a designated equipment staging area, away from water bodies.

SME would need to obtain permit coverage under a *General Permit for Storm Water Discharges Associated with Construction Activities* from MDEQ, and would have to develop a *Storm Water Pollution Prevention Plan* (SWPPP) for this Project. An existing Storm Water Construction Permit MTR103153 for the adjacent coal-fired generation facility would likely be modified to address or include the natural gas-fired generation facility. Additional permits and authorizations that may be required for construction activities in or adjacent to water bodies include: Corps 404 and Section 10 Permits; Montana DEQ 401 Certification and 318 Authorization; and Cascade County 310 and Floodplain permits.

During operation, wastewater would be discharged back to the City of Great Falls for disposal at its existing wastewater treatment facility or treated on-site resulting in zero discharge from the site. The City of Great Falls wastewater treatment facility is licensed and permitted to treat and discharge up to 21 million gpd into the Missouri River (MPDES MT 0021920). An Industrial Wastewater Permit would be required from the City of Great Falls for these discharges. In addition, a wastewater pond would be constructed onsite in order to provide surge control and to contain steam cycle blowdown and sump discharges from turbine and transformer areas. The sump discharges would undergo treatment prior to entering the basin in a standard oil/water separator unit. No toxic organic compounds would be present in the discharged wastewater. Wastewater sampling and monitoring equipment would be installed and operated as required by the permitting authorities.

3.4 Impacts Summary

Construction of the facility for up to a 30-month period will have the potential to generate storm water runoff which could impact nearby water bodies. Storm water runoff will be managed in accordance with an MDEQ-approved Storm Water Permit and SWPPP for the project to mitigate this potential to the point of negligible impacts.

Water supply to the Project will have the potential to impact the Missouri River and possibly the nearby alluvial groundwater, depending on the choice for raw water supply. As described in the EIS, the withdrawals from the river will be minimal in comparison to historic flow records. Water withdrawals from alluvium immediately adjacent to the Morony Reservoir are expected to directly connect to surface water in the reservoir, and will have only a localized impact on alluvial groundwater. As outlined above, impacts of water use by the Project on water resources are anticipated to be minor.

Wastewater discharge from the Project will either be returned to the City of Great Falls sanitary sewer system, or will be treated on-site to the point of zero discharge of wastewater. Either case is anticipated to have minor impacts on water resources.

The No-Action Alternative will have no effect on the groundwater or surface water resources around the Project site.

4.0 AIR QUALITY

4.1 Affected Environment

The area in which the Project is located is classified as a Prevention of Significant Deterioration (PSD) Class II area (40 CFR 52.1382). The Project and surrounding areas are designated as attainment or unclassifiable in accordance with 42 USC 7407 (d)(1)(A)(ii) and (iii). Accordingly, these areas have been proven or presumed to comply with National Ambient Air Quality Standards (NAAQS) for all pollutants for which such standards have been promulgated.

The Project and surrounding areas are also considered to be in compliance with all Montana Ambient Air Quality Standards (MAAQS). A portion of the city of Great Falls near 10th Avenue South was a non-attainment area for carbon monoxide (CO) at one time. The area was re-designated into attainment/unclassifiable in May 2002.

The Clean Air Act (CAA) defines a PSD Class I area as national parks over 6,000 acres, national wilderness areas and national memorial parks over 5,000 acres, and international parks that were in existence as of August 7, 1977. In Montana, three Indian reservations have been redesignated as Class I areas, but are not considered mandatory Class I areas.

The PSD Class I area nearest the Project site is the Gates of the Mountains Wilderness located approximately 88 kilometers (km) from the facility. Five PSD mandatory Federal Class I areas are within 250 km of the facility and are listed below in Table 4.1.

Table 4.1: Class I Areas Within 250 km of the Project

Class I Area	Distance from Facility (km)
Gates of the Mountains Wilderness	86
Scapegoat Wilderness	118
Bob Marshall Wilderness	129
Glacier National Park	184
Mission Mountain Wilderness Area	199
UL Bend National Wildlife Refuge	215
Anaconda Pintler Wilderness Area	228

The Project area consists of active dryland farmland. Nearby existing sources of air pollutant emissions are primarily fugitive in nature and include farming related activities, windblown dust from tilled farmland, and road dust from traffic on unpaved county roads.

4.2 Environmental Consequences

This section assesses impacts that could result from the Project to ambient air quality. Significant adverse effects to ambient air quality could occur if air emissions result in ground-level pollutant concentrations that exceed national and/or state standards or if the combustion turbine plant operates in a manner that does not comply with air quality permit limits and conditions.

4.2.1 Emissions

<u>Criteria Pollutant Emissions</u>

Construction activity air emissions would consist primarily of fugitive particulate emissions resulting from surface grading and vehicular traffic. Temporary localized emissions of gaseous combustion pollutants would also result from construction-related traffic and miscellaneous activities. All construction-related air emissions would be intermittent, of limited duration, and of low quantities with respect to air emissions that normally occur in the area. Ongoing direct, indirect, and cumulative adverse impacts on background pollutant concentrations resulting from construction-related activities would be negligible.

Because the proposed facility would utilize natural gas fuel in the combustion turbines which would be transported by pipeline to the facility, and because the environmental controls proposed do not require large quantities of solid materials to function, vehicle and fugitive dust emissions are expected to be minimal during operation of the plant. Ongoing direct, indirect, and cumulative adverse impacts on background pollutant concentrations resulting from operation-related activities would be negligible.

The Project would be constructed in two phases. Phase I of construction would install two GE LM6000PF simple cycle combustion turbines, with all support equipment and structures, including the simple cycle stacks. Support equipment at the facility would include an emergency diesel generator, a firepump, and building heaters. Phase II construction would include the installation of two heat recovery steam generators (HRSGs), emissions control equipment, a steam turbine, and combined cycle exhaust stacks.

Southern proposes to permit the facility for continuous combined cycle operation of all generating units to service. During both the initial Phase I service period of simple cycle operation and the Phase II operation after steam plant installation, simple cycle hours of operation would be limited to 3,200 hours per year. Combined cycle operation hours would not be limited.

The natural gas-fired combustion turbines would be the largest sources of air emissions associated with the Project. The gas-fired turbines would have the potential to emit the following regulated pollutants: oxides of nitrogen (NO_X), carbon monoxide (CO), volatile organic compounds (VOC), particulate matter (PM), particulate matter with an aerodynamic diameter less than 10 microns (PM_{10}), particulate matter with an aerodynamic diameter less than 2.5 microns ($PM_{2.5}$), sulfur dioxide (SO_2), and lead (Pb). Other point sources of air pollutant emissions include the cooling tower and the emergency generator. Table 4.2 presents estimated potential annual emissions of criteria pollutants from the facility. These values represent worst-case operating conditions under both Phase I and Phase II operating scenarios.

Table 4.2: Facility Annual Potential to Emit Summary

Phase I Operations (Simple Cycle Only)								
Source	**NO_X (tpy)**	**CO (tpy)**	**VOC (tpy)**	**PM (tpy)**	**PM_{10} (tpy)**	**$PM_{2.5}$ (tpy)**	**SO_2 (tpy)**	**Pb (tpy)**
Turbines	117.06	367.03	12.48	15.36	15.36	15.36	1.82	---
Cooling Tower	---	---	---	1.14	1.14	1.14	---	---
Building Heaters	1.68	1.01	0.07	0.09	0.09	0.09	0.01	---
Emergency Gen	6.68	0.26	0.14	0.03	0.03	0.03	0.09	---
Fire-pump	0.92	0.21	0.03	0.04	0.04	0.04	0.02	---
Totals	123.34	368.52	12.72	16.66	16.66	16.66	1.94	---
Phase II Operations (Simple Cycle/Combined Cycle)								
Source	**NO_X (tpy)**	**CO (tpy)**	**VOC (tpy)**	**PM (tpy)**	**PM_{10} (tpy)**	**$PM_{2.5}$ (tpy)**	**SO_2 (tpy)**	**Pb (tpy)**
Turbines	162.18	378.30	20.11	63.10	63.10	63.10	6.05	---
Cooling Tower	---	---	---	1.14	1.14	1.14	----	
Building Heaters	1.68	1.01	0.07	0.09	0.09	0.09	0.01	---
Emergency Gen	6.68	0.26	0.14	0.03	0.03	0.03	0.09	---
Fire-pump	0.92	0.21	0.03	0.04	0.04	0.04	0.02	---
Totals	171.46	379.78	20.35	64.41	64.41	64.41	6.16	---

Note: Emissions are expressed to the nearest one hundredth unit for presentation and calculation purposes. Multiple digit accuracy should not be assumed.

Hazardous Air Pollutant Emissions

In addition to the criteria pollutants addressed above, the CAA specifically regulates a class of pollutants known as hazardous air pollutants (HAPs), which contains 189 individual compounds or groups of compounds. Table 4.3 presents a summary of combined potential HAP emissions from the gas turbines, emergency generator, and fire pump engine. The Project would be an area (or non-major) source of HAP emissions according to CAA definitions.

Table 4.3: Hazardous Air Pollutants Emission Inventory

Turbines, Black-start Generator and Emergency Fire Pump Hazardous Air Pollutant	CAS Number	Total Facility Emissions (tpy)
Organic HAPs		
1,3-Butadiene	106-99-0	0.002
Acetaldeyde	75-07-0	0.157
Acrolein	107-02-8	0.025
Benzene	71-43-2	0.050
Ethyl Benzene	100-41-4	0.125
Formaldehyde	50-00-0	2.813
Naphthalene	91-20-3	0.006
Polycyclical Aromatic Hydrocarbons (PAH)	PAH	0.010
Propylene Oxide	75-56-9	0.125
Toluene	108-88-3	0.511
Xylenes	1330-20-7	0.252
Total Organic HAPs		**4.08**
Inorganic HAPs		
Lead	7439-92-1	0.00
Total Inorganic HAPs		**0.00**
Total Calculated Maximum Potential HAP Emissions		**4.08**

Greenhouse Gas Emissions

Operating the facility will result in carbon dioxide (CO_2) emissions of roughly 250,000 tons per year.[1]

4.2.2 Air Quality Impacts

Estimated air quality impacts were determined for the area immediately surrounding the Project site, all of which is designated as a PSD Class II area, and at locations distant from the proposed site that are designated as PSD Class I areas (see Table 4.1 above). Air dispersion models were used to perform the analyses. These models use hourly meteorological data, terrain elevation data, and emission source data to calculate ground-level pollutant concentrations that would result in the Project's worst-case emissions at a set of defined locations. Conditions for both Phase I and Phase II operating scenarios were modeled. Primary thresholds to which the modeled impacts are compared are described in the Table 4.4.

[1] Estimate is made by assuming two General Electric LM-6000PF Dry Low Emissions combustion turbines in operation, 91.5°F, 100% load, 4,380 hours (approximately 50% of the year) and the duct burners running. The emission factor for the duct burners is from the US EPA publication AP-42, Table 1.4-2 and the emission factor for the turbines is from GE.

Table 4.4: Primary Air Quality Thresholds

Standard	Applicable PSD Area Classification	Description
Modeling significance thresholds	Class II and Class I areas (different requirements for each)	From MDEQ Modeling Guidelines (November, 2007, Draft) and 40 CFR 51, Appendix S.
National Air Quality Standards (NAAQS)	Class II and Class I areas (equivalent requirements for each)	Concentration limits based on human health and other effects. (ARM 17.8.201-230)
Montana Air Quality Standards (MAAQS)	Class II and Class I areas (equivalent requirements for each)	Concentration limits based on human health and other effects; identical to NAAQS in most cases. (ARM 17.8.201-230)
PSD increments	Class II and Class I areas (different requirements for each)	Apply to pollutants emitted in "significant" quantities from "major" sources. Designed to limit degradation of airsheds with ambient concentrations below the NAAQS. (ARM 17.8.804)
Contributions to regional haze	Class I areas	Evaluation methods and threshold values based on guidelines from an association of Federal Land Managers
Nitrogen and sulfur deposition	Class I areas	Evaluation methods and threshold values based on guidelines from an association of Federal Land Managers

Following are results and discussions of the analyses of Project impacts relative to each of the above standards.

Modeling Significance Thresholds

If emissions of a particular pollutant from a facility would result in a peak concentration over a specific averaging period that is below a related modeling significance threshold, then that source is considered incapable of contributing to a violation of an air quality standard or increment limit. In other words, the source's impacts on ambient concentrations of that pollutant for that averaging period are deemed to be "insignificant."

The Project's impacts to Class II area ambient concentrations of SO_2 and CO for all regulated averaging periods were shown to be insignificant, and no further analyses were performed for these pollutants. Further analyses of impacts to Class II area ambient concentrations of NO_x, PM_{10}, and $PM_{2.5}$ were conducted and the results are discussed below.

Unique Class I area impact limits are defined for NO_x and PM_{10} ambient concentrations. Modeling analyses demonstrated that the Project's NO_x and PM_{10} emissions would result in "insignificant" impacts to ambient concentrations in all surrounding Class I areas.

Impacts to ambient concentrations of VOC and lead were not evaluated for this project. As shown above, lead emissions are expected to be negligible. VOC emissions are considered to be insignificant based on regulatory thresholds and policy guidance.

Ambient Air Quality Standards (National and Montana)

Table 4.5 compares modeled peak concentrations of NO_x, PM_{10}, and $PM_{2.5}$ with the appropriate MAAQS and NAAQS. As shown, the Project would not result in a violation of any ambient air quality standards.

Table 4.5: Ambient Air Quality Analyses

Pollutant	Averaging Period	Concentration (µg/m^3)			Compliance with MAAQS/NAAQS
		Peak Modeled[a]	MAAQS	NAAQS	
PM_{10} (Phase I)	24-hr	34	150	150	Yes/Yes
	Annual	0	50	50	Yes/Yes
PM_{10} (Phase II)	24-hr	34	150	150	Yes/Yes
	Annual	0	50	50	Yes/Yes
$PM_{2.5}$ (Phase I)	24-hr	22	35	35	Yes/Yes
	Annual	7	15	15	Yes/Yes
$PM_{2.5}$ (Phase II)	24-hr	22	35	35	Yes/Yes
	Annual	7	15	15	Yes/Yes
NO_2 (Phase I)	1-hr [(c)]	393	564	--	Yes/NA
	Annual	8	94	100	Yes/Yes
NO_2 (Phase II)	1-hr [(c)]	393	564	--	Yes/NA
	Annual	8	94	100	Yes/Yes

[a] Values represent steady-state operation. Please see attached permit application for more detailed information.

Note that the modeled concentrations shown in the table above include default background concentrations and concentration impacts resulting from potential emissions of other permitted facilities in the region.

PSD Increments

The PSD permitting program establishes PSD increments which are maximum allowable increases in air contaminant concentrations in attainment or unclassified areas. The Project is required to demonstrate compliance with Class II increments for NO_x and PM_{10}. No increments have been established for $PM_{2.5}$.

Table 4.6 summarizes the peak PM_{10} and NO_2 Class II increment modeling results. No increments were exceeded in this modeling analysis.

Table 4.6: PM_{10} and NO_x Class II PSD Increment Modeling Results

Pollutant	Averaging Period	Concentration ($\mu g/m^3$)		Compliance?
		Peak Modeled[a]	Increment	
PM_{10} (Phase I)	24-hr	11	30	Yes
	Annual	0	17	Yes
PM_{10} (Phase II)	24-hr	11	30	Yes
	Annual	0	17	Yes
NO_x (Phase I)	Annual	2	25	Yes
NO_x (Phase II)	Annual	2	25	Yes

[a] Values represent steady-state operation. Please see attached permit application for more detailed information.

Note that peak modeled pollutant concentrations reported above include concentration impacts from appropriate permitted facilities in the region.

Contributions To Regional Haze

Impacts to natural background visibility, or regional haze, are expressed in terms of percentage change in background light extinction averaged over a 24-hour period. Federal Land Manager guidance suggests that a predicted change in extinction of less than 0.5 deciview, resulting from a single source, should generally be acceptable. A predicted change in extinction between 0.5 and 1.0 may warrant a cumulative analysis that includes impacts from certain other nearby sources.

Modeling analyses indicate that potential emissions from the Project would not result in a change in background extinction of 0.5 deciview or more.

Nitrogen And Sulfur Deposition

Federal Land Managers have provided guideline limits to rates of acid deposition within Class I areas resulting from a new or modified facility.

Following guideline analysis methods, Southern determined that acid deposition rates resulting from the Project's potential emissions would be far below the guideline threshold of 0.0050 kilogram per hectare per year in each of the surrounding Class I areas.

4.3 Mitigation and Monitoring

4.3.1 Fugitive Dust Control

Southern and its contractors would use best management practices to limit fugitive dust during construction and operation of the Project. These practices would include:

- Application of water and/or dust suppression chemicals to roadways and disturbed surfaces as needed.
- Observance of speed limits on access roads to limit road dust generation.
- Reseeding or other stabilization of disturbed areas.

4.3.2 Best Available Control Technology (BACT) for Combustion Turbine Emissions

Montana air quality regulations require that all permitted stationary sources of air pollutants use BACT to control emissions. By definition, BACT is determined on a case-by-case basis. Typically, MDEQ has applied this requirement to criteria pollutants ($PM/PM_{10}/PM_{2.5}$ NO_x, CO, SO_2, and VOC) and has used its discretion to apply the requirement to specific pollutants of concern. For this Project, Southern has determined the following controls are BACT for controlling emissions from the combustion turbine in simple cycle mode and combined cycle mode and from the emergency generator and emergency fire water pump.

Phase I (Simple Cycle Mode)

Pollutant	BACT
NO_x	Dry Low Emissions (DLE) and fuel selection. For simple cycle, NO_X control is cost-prohibitive above the baseline of fuel selection and DLE.
CO and VOC	Proper system design and operation. A catalytic oxidizer is not a cost-effective CO control technology for simple cycle operations.
SO_2	Use of low-sulfur, pipeline quality natural gas; proper maintenance and operation. Add-on controls are not cost-effective.
$PM/PM_{10}/PM_{2.5}$	Use of low-sulfur, pipeline quality natural gas; proper maintenance and operation. Add-on controls are not cost-effective.

Phase II (Combined Cycle Mode)

Pollutant	BACT
NO_x	DLE, Selective Catalytic Reduction, and fuel selection.
CO and VOC	Catalytic oxidation.
SO_2	Use of low-sulfur, pipeline quality natural gas; proper maintenance and operation. Add-on controls are not cost-effective.
$PM/PM_{10}/PM_{2.5}$	Use of low-sulfur, pipeline quality natural gas; proper maintenance and operation. Add-on controls are not cost-effective.

Emergency Generator and Emergency Fire Water Pump

Pollutant	BACT
NO_x	Operate only in emergencies and for required maintenance.
CO and VOC	
SO_2	
$PM/PM_{10}/PM_{2.5}$	

4.3.3 Emissions Monitoring

Compliance assurance monitoring (CAM) requirements are pollutant-specific and apply to certain emissions units at a facility that is required to obtain an air quality operating permit. The generation facility would be required to obtain an operating permit, but only the natural gas combustion turbines would meet the CAM applicability criteria. The criteria would only apply to NO_x and CO emissions. Southern will supply MDEQ with a formal CAM plan prior to the issuance of an operating permit as required. NO_x emissions would be monitored and recorded using a continuous emissions monitoring system.

4.4 Impacts Summary

In its air quality permit application for the natural gas plant, Southern has demonstrated compliance with all applicable ambient air quality regulatory and guideline limits including ambient standards, PSD increments, and regional haze. Southern would obtain required construction and operating permits and comply with all permit requirements including testing, monitoring, and reporting requirements. For these reasons, impacts to air quality from the Project would be insignificant.

The no-action alternative would not affect air quality in the Great Falls area. It is reasonable to assume, however, that choosing not to construct the Project could result in an increase in air emissions from other power generation facilities if expansion or new construction were required to supply the needs targeted by the Project.

5.0 BIOLOGICAL RESOURCES

5.1 Affected Environment

The area surrounding Great Falls is dominated by grassland and is primarily used for agricultural activities with isolated areas of urban, suburban, rural, and industrial development. The topography is mostly flat with some drainages created by creeks, rivers, and wind erosion. Shrubs and trees grow mostly in the drainages and canyon areas.

The Project site is currently privately owned farmland used for producing small grains, with approximately ten family residences within a two-mile radius. The natural gas generation facility would reside within the property boundary previously described for the coal-fired generation facility.

5.1.1 State Species of Concern

Westech Environmental Services, Inc. (WESTECH) conducted pre-field research of previously recorded wildlife sighting records within a ten mile radius of the Project site and areas surrounding the proposed transmission lines (WESTECH, 2005). The extensive pre-field research included interviews with landowners and with specialists from the Montana Department of Fish, Wildlife, and Parks (FWP). This research identified several State species of concern that have been observed in the Great Falls area. The identified species of concern are listed in Table 5-1.

Table 5-1. Montana Species of Concern Recorded Within Ten Miles of Great Falls

Species		Suitable Habitat
Common Name	**Scientific Name**	
Plants		
Roundleaf water hyssop	*Bacopa rotundifolia*	Muddy shores of ponds and streams; last recorded in 1891
Many-headed sedge	*Carex sychnocephala*	Moist meadows; lake shores; thickets at low elevations; last recorded in 1890
Chaffweed	*Centunculus minimus*	Drying vernal pools (seasonal wetlands); last recorded in 1891
	Entosthodon rubiginosus	Moss; last recorded in 1887
	Funaria americana	Moss; last recorded in 1902
Guadalupe water-nymph	*Najas guadalupensis*	Submerged in shallow fresh water of oxbow sloughs and ponds; drying vernal pools; last recorded in 1891
Dwarf woolly heads	*Psilocarphus brevissimus*	Drying vernal pools; last recorded in 1891
California waterwort	*Elatine californica*	Shallow waters and mudflats along the edges of wetlands; last recorded in 1891
Fish		
Blue sucker	*Cycleptus elongatus*	Missouri River below Morony Dam
Amphibians - none		
Reptiles		
Spiny softshell turtle	*Apalone spinifera*	Missouri River below Morony Dam
Mammals - none		
Birds		
Ferruginous hawk	*Buteo regalis*	Sagebrush steppe, grasslands with rolling to steep slopes
Bald eagle	*Haliaeetus leucocephalus*	Larger rivers, lakes and reservoirs
Burrowing owl	*Athene cunicularia*	Grasslands with rodent and badger burrows
White-faced ibis	*Plegadis chihi*	Wetlands
Black-crowned night heron	*Nycticorax nycticorax*	Wetlands
Franklin's gull	*Larus pipixcan*	Wetlands
Common tern	*Sterna hirundo*	Wetlands
Black tern	*Chlidonias niger*	Wetlands

[a] *Source:* MNHP, 2005 and USFWS letter dated May 12, 2005.

The blue sucker, sauger, and spiny softshell turtle are known to be present below Morony Dam (WESTECH, 2006a). The dams along the Missouri River have likely restricted the movement of these species (RUS and MDEQ, 2007a). Avian species of concern potentially in the Project area are ferruginous hawks, burrowing owls, white-faced ibis, black-crowned night heron, Franklin's gull, common tern, and black tern. Only the Franklin's gull was actually observed during the 2005 surveys (WESTECH, 2005).

5.1.2 Threatened or Endangered Species

According to the United States Fish and Wildlife Service (USFWS), two endangered or threatened species are known to reside in the Great Falls region: the bald eagle and Canada lynx.

A bald eagle nest is located near the confluence of the Missouri River and Belt Creek (Dubois, 2005; WESTECH, 2005). The site is approximately two miles from the generation facility site. The nest was active in 2005 and produced one fledgling (Taylor, 2005; WESTECH, 2005). No other bald eagle nests are known to be in the area (Taylor, 2005; WESTECH, 2005).

The area surrounding the Project site is not representative of typical Canada lynx habitat. Lynx prefer areas with fallen trees in and around dense lodgepole stands, and they primarily prey on snowshoe hare (Foresman, 2001). Lynx have not been reported within ten miles of the Project (RUS AND MDEQ, 2007a; WESTECH, 2005).

5.1.3 Game Animals

Mule deer, white tailed deer, and pronghorn are known to be present in the area. Of these, mule deer are the most abundant. Mule deer inhabit the surrounding areas year-round and frequent the area's many drainages and fields. White tailed deer primarily inhabit drainages with riparian habitat. The area is not conducive to large pronghorn populations, as most of the native vegetation has been converted to agriculture.

The Project site is just to the west of a 70 square-mile area which is surveyed for deer populations four times per year by FWP. Recent FWP counts of these species have shown populations of approximately 500 mule deer, 50 white tailed-deer, and 100 pronghorn in the surveyed area (RUS AND MDEQ, 2007a).

Other game potentially in this area include bobcat, coyote, gray partridge, mountain lion, red fox, and sharp tailed grouse.

5.1.4 Wetlands and Noxious Weeds

The amount of wetlands in the area surrounding the Project site is limited. Field surveys and reviews of aerial photographs revealed a few isolated wetlands along Box Elder Creek and the Missouri River (RUS AND MDEQ, 2007a). These areas would be avoided during construction.

Several species of noxious weeds are known to be present in the Great Falls area. These include Canada thistle, field bindweed, whitetop, leafy spurge, spotted knapweed, and dalmation toadflax. Only Canada thistle and spotted knapweed are common and widespread, while whitetop and leafy spurge are less abundant (WESTECH, 2006b). Dalmation toadflax and field bindweed were not observed near the Project area during biological resources field surveys.

5.2 Environmental Consequences

Adverse effects to flora and fauna may occur through construction or operation of the facility or infrastructure as described in the coal-fired generation facility EIS (RUS AND MDEQ, 2007a). Wildlife could experience mortality directly due to construction or operation of the facility or its infrastructure, or indirectly through habitat loss, fragmentation, or conversion. Vegetation can be directly affected by its removal as the ground surface on which it occurs is developed, or indirectly through changing populations of wildlife that feed on plants.

Construction, maintenance, and operation of facilities in an area that contains wildlife habitat could constitute an adverse effect on those habitats. An adverse effect is found when an undertaking or action alters, directly or indirectly, any of the characteristics of a habitat that provides for life history needs such as feeding, cover, travel, or breeding.

5.3 Mitigation and Monitoring

5.3.1 Threatened and Endangered Species

Activities conducted by construction contractors such as developing aggregate sources, gravel crushing, staging and stockpiling would be conducted well outside of areas requiring special protection for the nests of bald eagles along the Missouri River. The Montana Bald Eagle Management Plan places limitations on these high intensity activities and, if applicable, they would be followed. Any questions concerning the application of the regulations promulgated to protect this species would be directed to the USFWS and/or FWP.

5.3.2 State Species of Concern

Avoiding or minimizing disturbance of shrub, tree, and wetland habitats would reduce adverse effects on raptors and breeding bird species by the proposed Project. Disturbance of any such sites/habitats of importance to these species groups would be mitigated through the use of reasonable timing constraints during construction, reclamation and restoration of disturbed sites, and other appropriate measures.

5.3.3 Noxious Weeds

Southern would follow the requirements identified in the Cascade County Weed and Mosquito Management District's document, "Weed Management and Revegetation Requirements for Disturbed Areas in Cascade County, Montana." This document specifies the actions that need to be taken prior to disturbance, during operation, and upon reclamation, to prevent the spread of noxious weeds in the county.

5.4 Impacts Summary

Impacts to biological resources from constructing and operating the natural-gas fired plant at the Project site would be similar, but less than, those resulting from the coal-fired power plant. The incremental expansion of effects due to construction of the natural gas plant would be minor and limited to the area immediately adjacent to the coal power plant site. Incremental expansion of effects due to operation of the gas facility would be negligible. Similar to the analysis in the coal facility EIS (RUS AND MDEQ, 2007a), the biological impacts of the Project would be minor. Southern would continue to follow through with appropriate mitigation actions as previously described in the EIS and this EA.

The No Action Alternative would have no direct effects on biological resources at the Project site.

6.0 ACOUSTIC ENVIRONMENT

6.1 Affected Environment

For environmental noise studies, noise levels are typically described using A-weighted equivalent noise levels, L_{eq}, during a certain time period. The L_{eq} metric is useful because it uses a single number to describe the constantly fluctuating instantaneous ambient noise levels at a receptor location during a period of time, and accounts for all of the noises and quiet periods that occur during that time period.

The 90th percentile-exceeded noise level, L_{90}, is a metric that indicates the single noise level that is exceeded during 90 percent of a measurement period, although the actual instantaneous noise levels fluctuate continuously. The L_{90} noise level is typically considered the ambient noise level, and is often near the low end of the instantaneous noise levels during a measurement period. It typically does not include the influence of discrete noises of short duration, such as car doors closing, bird chirps, dog barks, car horns, wind gusts, etc.

The day-night average noise level, L_{dn}, is a single number descriptor that represents the constantly varying sound level during a continuous 24-hour period. The L_{dn} is typically calculated using 24 consecutive one-hour L_{eq} noise levels. The L_{dn} includes a 10 dBA penalty that is added to noises that occur during the nighttime hours between 10:00 p.m. and 7:00 a.m. to account for people's higher sensitivity to noise at night when the background noise level is typically low.

As a result of the Noise Control Act of 1972, the U.S. Environmental Protection Agency (EPA) developed acceptable noise levels under various conditions that would protect public health and welfare with an adequate margin of safety. The EPA identified outdoor L_{dn} noise levels less than or equal to 55 dBA as sufficient to protect public health and welfare in residential areas and other places where quiet is a basis for use (EPA, 1979). Although the EPA guideline is not an enforceable regulation, it is a commonly accepted target noise level for environmental noise studies.

The Project site is located in a rural area approximately eight miles (13 km) east of Great Falls in Cascade County. The surrounding land use is agricultural with scattered rural residences. Approximately eight residences are located within three miles of the Project site, and the closest residence is located about 0.5 mile (0.8 km) northwest of the Project site. Primary noise sources include traffic on county roads, noise generated by wind blowing through grass, water flowing in nearby creeks, wildlife, insects, birds, and aircraft flying overhead (BSA, 2007). These noise sources are characteristic of rural settings.

In late August and early September 2005, the acoustical consulting firm Big Sky Acoustics (BSA) conducted ambient (background) noise level measurements at the Project site in general accordance with the American Society for Testing and Materials (ASTM) E1014, *Standard Guide for Measurement of Outdoor A-weighted Sound Levels*

(ASTM, 2000). These measurements were taken to establish the typical ambient noise levels within approximately three miles of the Project site where the primary noise-sensitive receptors are located. Short-term measurements of 10-minute duration were conducted at a total of three Project site locations, and the L_{eq} and L_{90} for each 10-minute period were recorded. BSA completed two continuous 24-hour measurements, and the L_{eq} and L_{90} in 30- minute increments were also recorded (BSA, 2007).

Around the Project site, the L_{90} ambient short-term noise levels ranged from 20 to 47 dBA, and were influenced by chirping insects as seen in Table 6-1.

Table 6-1. Measured Short-term Ambient Noise Levels at the Project Site

Measurement Location	Date and Start Time (hours)	Measured Leq (dBA)	Measured L90 (dBA)	Dominant Noise Sources
1A	8/25/05 at 2151	29 dBA	25 dBA	Insects
	8/26/05 at 0837	34 dBA	31 dBA	Insects and wind in grass
	9/01/05 at 1814	48 dBA	47 dBA	Insects
1B	8/25/05 at 2211	22 dBA	20 dBA	Insects
	9/01/05 at 1832	46 dBA	45 dBA	Insects
1C	8/25/05 at 2241	28 dBA	23 dBA	Insects
	9/01/05 at 1843	47 dBA	38 dBA	Insects and birds

Source: BSA, 2007

BSA also conducted 24-hour measurements to determine the general existing ambient noise level trends versus time of day in the vicinity of the proposed Project site. The 30-minute L_{eq} data were used to calculate the L_{dn} levels at the measurement locations. The calculated noise levels based on the measurements were L_{dn} 47 dBA at the Project site (BSA, 2007). Since the measurements were completed in the summer months, insect noise appears to have influenced the measured L_{dn} values. Based on site observations and the 10-minute measurement results around the site (Table 6-2), the estimated L_{dn} values during quiet periods would be approximately L_{dn} 30 dBA at the Project site (BSA, 2007).

6.2 Environmental Consequences

As described in the Affected Environment Section above, approximately eight scattered rural residences are located within three miles of the Project site. The closest residence, which is uninhabited, is located approximately one mile northwest of the Project site. A Lewis and Clark Staging Area Interpretative Site which interprets the Great Falls Portage NHL, is located approximately two miles north of the Project site.

To analyze the effects of adding the proposed natural gas-fired plant to the Highwood Generating Station, Southern conducted an additional noise analysis in 2009 (BSA, 2009). The additional noise analysis adds a 120 MW natural gas-fired combined cycle (NGCC) power plant to the Project site. The 120 MW natural gas-fired plant would not operate simultaneously with the 250 MW coal-fired boiler described in the EIS.

Drawings of the revised Project site and updated equipment lists were provided to BSA (Stanley, 2009b), as well as noise level data for a gas turbine model under consideration (General Electric LM6000), a Deltak heat recovery steam generator (HRSG), and cooling tower for the NGCC plant (Stanley, 2009c). BSA also used noise data for typical equipment associated with other NGCC plant noise sources, such as the steam turbine, pumps, transformers, etc., for the analysis (EEI, 1984).

For the analysis, BSA assumed that all four wind turbines and the NGCC power plant were operating simultaneously and continuously during a 24-hour period. This should be considered conservative because the operation of the wind turbines will vary with the wind speed at the site.

The predicted noise levels for the NGCC and wind turbines are provided in Table 6-2.

Table 6-2: Predicted Noise Levels at Nearby Receptors-Natural Gas Power Plant and Wind Turbines

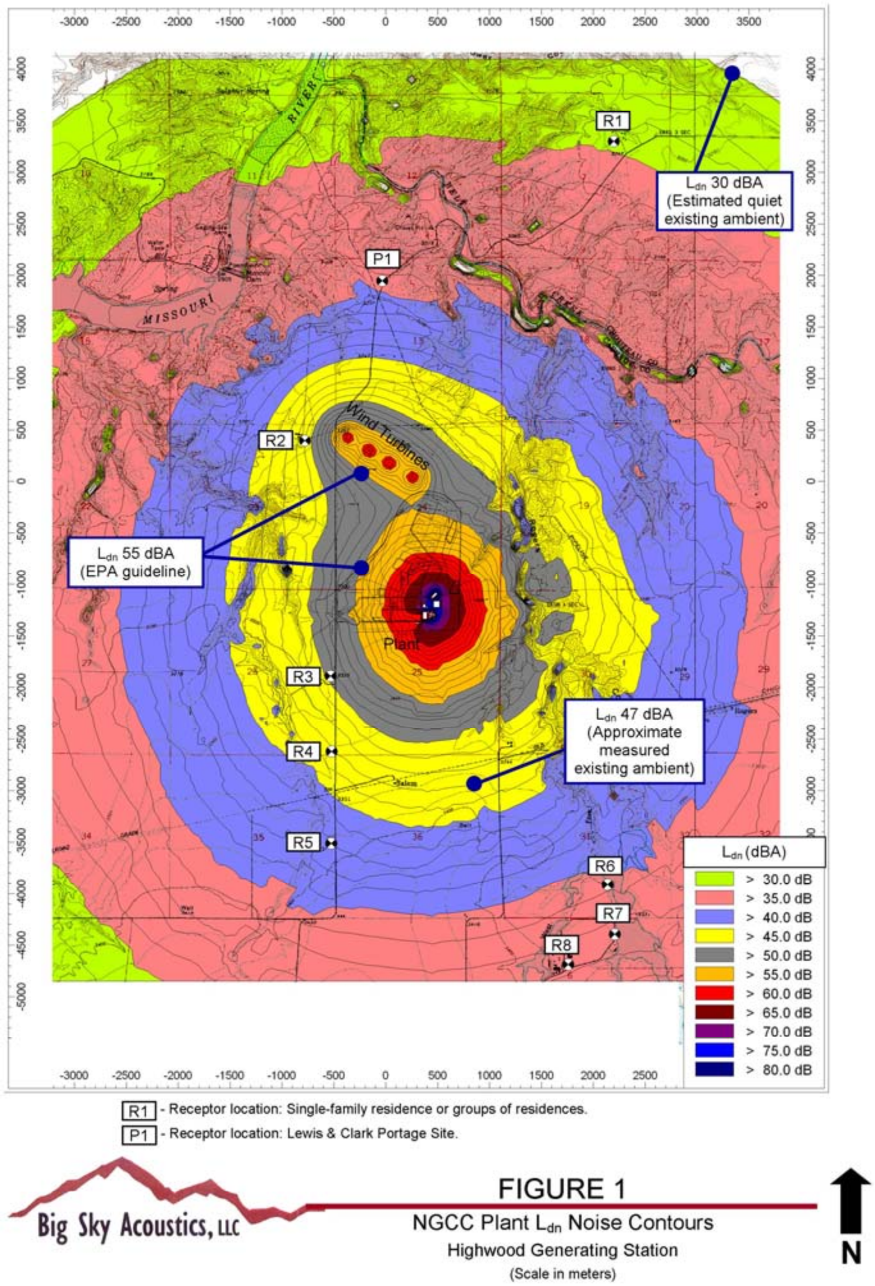
Receptor Locations	Type of Receptor	Noise Level L_{eq} (dBA)	Noise Level L_{dn} (dBA)
R1	Single-family residence	28	35
P1	Lewis and Clark Interpretive Site (i.e., Portage Staging Area)	33	39
R2	Single-family residence	43	50
R3	Single-family residence	44	51
R4	Single-family residence	40	47
R5	Single-family residence	37	43
R6	Single-family residence	33	39
R7	Three single-family residences	31	38
R8	Single-family residence	31	37

Source: BSA, 2009

Figure 6-1 shows the predicted L_{dn} noise level contours for the NGCC power plant and wind turbines overlaid on a USGS topographic map. As shown in the figure, the noise levels are not predicted to radiate equally in all directions.

As shown on Figure 6-1, the EPA L_{dn} 55 dBA guideline (EPA, 1979) is predicted to be met within 0.6 mile of the plant location and 0.1 mile of the wind turbines. The measured existing ambient noise level of L_{dn} 47 dBA (BSA, 2007) is predicted to be met within approximately 1.2 miles of the plant location and 0.5 mile of the wind turbines. The estimated quiet ambient noise level of L_{dn} 30 dBA without the influence of insect noise (BSA, 2007) is predicted to be met within approximately 3.7 miles (Figure 6-1).

Figure 6-1. Predicted Noise Levels Contours Surrounding HGS



Source: BSA, 2009

The predicted noise impacts of the gas-fired plant with turbines are similar to those from the analysis of the coal-fired power plant with turbines (BSA, 2007; BSA, 2009). The typical L_{dn} noise levels are predicted to be less than or equal to the L_{dn} 55 dBA EPA guideline at identified receptor locations (BSA, 2007; BSA, 2009).

6.3 Mitigation and Monitoring

Since no significant, adverse impacts are predicted at nearby residences and the Lewis and Clark Staging Area Interpretive Site, no mitigation measures are planned or proposed for the action alternative.

6.4 Impacts Summary

The typical L_{dn} noise levels are predicted to be less than or equal to the L_{dn} 55 dBA EPA guideline at all the receptor locations. The noise levels of typical daily plant operations are not predicted to exceed the EPA guideline of L_{dn} 55 dBA beyond 0.6 mile from the plant location and 0.1 mile from the wind turbines. The measured existing ambient L_{dn} level of 47 dBA is expected to be met at a distance of 1.2 miles from the plant location and 0.5 miles from the wind turbines. These levels can be met while the facility is utilizing either the coal-fired plant or the NGCC. As a result of these predicted noise levels, the Project is not expected to have a significant adverse impact on receptors where people live or will have access in the surrounding environment.

Under the No Action Alternative, sound levels would remain at their present levels and no impacts to noise levels are expected.

7.0 RECREATION

7.1 Affected Environment

Five designated wilderness areas are located within 150 miles of the Project site: Gates of the Mountains, Scapegoat, Bob Marshall, Mission Mountain, UL Bend, and Anaconda Pintler. In addition to these wilderness areas, four state parks are located within 50 miles of Great Falls: Giant Springs, Sluice Boxes, Tower Rock, and Ulm Pishkun. Also near the Project site is the Lewis and Clark Historic Trail Interpretive Center, 9 miles west of the Project site (FWP, no date).

No recreation takes place directly on the Project site. The nearest public access site is the Lewis and Clark Expedition staging area historic site about 0.8 mile away. This site provides educational and historical benefits but offers no recreational opportunities. Fishing opportunities in the nearby Morony Reservoir itself are reported to be non-existent because public access onto PPL-Montana property is prohibited (Urquhart, 2005). No other recreational facilities, parks, or opportunities are close to the Project site.

7.2 Environmental Consequences

Construction and operation of the HGS at the Project site would entail negligible to, at most, minor impacts on recreation in the immediate project vicinity and wider Great Falls area. There is one cultural/educational site in the immediate vicinity that could be impacted by the Project: the Lewis and Clark Staging Area Interpretive Viewpoint. It appears to receive relatively little visitation or public use at present. While the Project would not restrict access to it, during construction such access might be made more difficult because of heavy construction traffic. Other impacts to the interpretive viewpoint would include a possible degradation of the open view from the staging area, with the presence of the power plant 0.8 mile to south, as well as additional transmission lines. Neither the staging area interpretive viewpoint, nor access to it, would be significantly affected by the Project.

Potential impacts of the Project to the quality of distant recreation opportunities in national park and wilderness areas, as a result of its impacts on air quality and visibility, are discussed under air quality. Potential impacts on recreational fisheries as a result of incremental contributions to mercury deposition in the state, and subsequent bioaccumulation in sport fish (and the need to limit human consumption), would be negligible.

7.3 Mitigation and Monitoring

During construction, Southern would ensure ongoing access by motorists and visitors to the Lewis and Clark Staging Area Interpretive Viewpoint.

After construction has been completed, Southern would cooperate with the SHPO and local historic preservation interests to enhance the Lewis and Clark Staging Area Interpretive Viewpoint and the Great Falls Portage NHL experience, as discussed further in the Cultural Resources section. Such enhancements may include adding one or more kiosks, interpretive signs, parking, benches, or additional interpretive facilities closer to the confluence of Belt Creek and the Missouri River.

7.4 Impacts Summary

Construction and operation of the Project would entail negligible to, at most, minor impacts on recreation in the immediate project vicinity and wider Great Falls area.

The No Action Alternative would not result in any direct impacts on recreation facilities or opportunities at the Project site, though it would contribute indirectly to recreation impacts associated with those generating stations from which Southern would purchase electricity.

8.0 CULTURAL RESOURCES

8.1 Affected Environment

As part of the referenced EIS for the coal-fired facility, archaeologists conducted pre-field research for previously recorded cultural resource sites within the general vicinity of the Project site (Dickerson, 2005). The pre-field research encompassed a records search of the Montana State Historic Preservation Office (SHPO) records center and cultural resource site files at the Department of Anthropology, University of Montana, Missoula.

A professional archaeologist at Renewable Technologies, Inc. (RTI) completed a cultural resource inventory of the HGS site in 2005 (Dickerson, 2005). The inventory encompassed a total of 1,180 acres, covering the proposed HGS plant site and various infrastructure corridors. Since the natural gas plant footprint is materially smaller in magnitude and fits within the overall footprint of the proposed coal-fired HGS, pertinent inventories are carried forward into this assessment for the natural gas-fired facility.

Ten cultural properties were found to lie within the area of potential effect of Southern's HGS site. The ten cultural properties include five previously recorded sites, and five discovered and recorded as part of the project (Dickerson, 2005). Nine of the ten sites were fully recorded or amended. One newly discovered farmstead (field number RTI-05025-04) was identified but not fully documented due to lack of access to the property. Table 8-1 lists the ten sites documented within the Project area. Detailed descriptions and record forms for each site are contained in the RTI report (Dickerson, 2005).

Table 8-1. Cultural Sites Documented Within Southern's Project Area

Site Number	Description	Legal Location*	National Register Eligibility/Status
24CA238	Great Falls Portage National Historic Landmark	T20N, R5E, Secs 3-7; T21N, R5E, Secs 13-14, 23-27, 33-35	Listed, National Historic Landmark
24CA264	Chicago, Milwaukee, St. Paul & Pacific Railroad	T20N, R4E, Sec 1; T20N, R5E, Secs 5, 6; T21N, R5E, Secs 32-35	Eligible; portion lying within Southern's project area is a non-contributing element
24CA289 Feature 2	Morony Transmission Line	T21N, R4E, Secs 24-26	Contributing Element of an Eligible District
24CA291 Feature 34	Rainbow Transmission Line	T21N, R4E, Secs 24-26	Contributing Element of an Eligible District
24CA416	Rainbow-Ryan Road	T21N, R4E, Secs 25, 26; T21N, R5E, Sec 19	Eligible
24CA986	Historic Farmstead	T21N, R5E, Sec 23	Ineligible
24CA987	Historic Farmstead	T21N, R5E, Sec 26	Ineligible
24CA988	Historic Farmstead	T21N, R5E, Sec 26	Ineligible
24CA989	Cooper Siding	T20N, R5E, Sec 6	Ineligible
RTI-05025-4	Historic Farmstead	T21N, R5E, Sec 35	Unevaluated; presumed ineligible**

Source: Dickerson, 2005
* The legal locations listed above encompass only those portions of sites situated within Southern's project area.
** Property RTI-05025-4 was noted in the field, but not formally recorded or evaluated for National Register eligibility.

The Great Falls Portage National Historic Landmark (24CA238) is a historic landscape area associated with the portage of the Lewis and Clark Corps of Discovery around the Great Falls of the Missouri River in 1805. The site was first recorded in 1976, with revisions to the National Landmark nomination form in 1984 (Witherell, 1984). The Great Falls Portage National Historic Landmark (NHL) is an approximately one-mile wide discontinuous corridor spanning from the lower portage camp, located immediately north of the mouth of Belt Creek, to White Bear Island at the southern outskirts of Great Falls. RTI's 2005 inventory covered portions of the northern section of the NHL corridor extending northeast from the eastern boundary of Malmstrom Air Force Base. Within the inventory project area, RTI found no physical evidence of the Corps of Discovery's portage activities. No camp features, artifacts, or similar evidence were found on the surface.

On January 20, 2006, RUS sent letters to eight organizations in the Montana-Wyoming Tribal Leaders Council informing them of the HGS proposal and EIS process and inviting comment and participation. By way of this letter, RUS formally requested consultation with the tribes on Southern's proposal. RUS also asked tribal representatives to advise RUS if they have specific concerns regarding either of the proposed locations of the HGS, and in particular, for any information they may have on the possible presence of Traditional Cultural Properties (TCPs) or sacred sites at either of the proposed locations under study.

Two responses were received from tribes to this request for consultation. The Northern Cheyenne Tribe expressed concern about cumulative air quality impacts and asked to receive the Draft EIS. The Blackfeet Tribal Historic Preservation Office requested a site visit, which was held on March 24, 2006. To date, no TCPs have been identified at the Project site.

8.2 Environmental Consequences

As described above, ten cultural properties are in the vicinity of the Project. The ten include five previously recorded sites, and five discovered and recorded as part of investigations supporting the EIS. Of these ten properties (listed in Table 8-1), the EIS found that only one, the Great Falls Portage NHL (24CA238), would potentially be impacted by the proposed coal plant.

The NHL's integrity is based predominantly on visual landscape qualities that are reportedly similar to that which existed during the early 19th century when the Corps of Discovery traveled through the area. While portions of the visual landscape qualities of the Great Falls Portage NHL are similar to those which existed at the time of the Lewis and Clark expedition, other portions are not. In the vicinity of the NHL the visual landscape is quite changed, including damming of the great falls of the Missouri, development of the City of Great Falls, development of Malmstrom Air Force Base, development of numerous farmsteads and accompanying facilities, residential and commercial development, and installation of numerous transmission lines across the Missouri River.

The Draft EIS found a significant adverse effect to the NHL if Southern were to proceed with the development of a coal-fired generating station located on the NHL. As explained below, Southern proposed mitigation measures, including the shifting of the coal plant site off the NHL. The Final EIS also found an adverse effect, although noting the reduction of impacts from mitigation.

The construction and operation of a natural gas-fired generation facility at the Project site outside the boundaries of the NHL will not add significantly to this impact finding, and will not change the overall impact assessment for cultural resources in the HGS EIS.

8.3 Mitigation and Monitoring

Southern proposed and RUS agreed with proposed mitigation measures for the HGS coal-fired power plant and wind turbine project (listed below). Many of these proposals were completed or contemplated by Southern in designing the coal-fired project. In recognition of the change in focus to a natural gas-fired generation plant at the site, an update on each proposal as it applies to the natural gas plant is provided.

<u>On-Site Avoidance, Minimization, and Mitigation</u>:

- Shift the footprint of the coal plant outside of the NHL's designated boundaries. **The proposed natural gas facility will be located outside the boundary of the NHL.**
- Maximize the use of downward directional lighting where appropriate and safety measures allow. **This provision will be incorporated in the natural gas plant design.**
- Where feasible, use earth tone colors on any facilities. **This provision will be incorporated in the natural gas plant design.**
- Evaluate whether it is feasible to utilize landscaping around the facility. **A Landscaping Plan was developed for the coal-fired plant and approved by Cascade County; the landscape plan will be utilized with the natural gas plant even if the decision is made to cease further activity on the coal plant.**
- Construct HGS infrastructure using materials and techniques to lessen visual impacts on the NHL, such as use of self-weathering (Corten) steel transmission poles, burying pipelines and re-vegetating the disturbed area, and constructing new access roads in a manner similar to existing roads. **This provision will be followed for the natural gas plant and associated infrastructure.**

Off-Site Mitigation:

- The following proposals are designed to offset the visual impacts on the NHL by improving the viewshed of a number of Lewis and Clark interpretive sites and through the promotion of other related activities. Southern has already contributed to a number of these projects such as:
    - Acquire available properties (the property directly across from the Center and the former Wilhelm house) across the Missouri River from the Lewis and Clark Interpretative Center to create and preserve in perpetuity a more natural unencumbered landscape for an increased visitor experience. **Southern contributed to the purchase of the property across the river from the Interpretive Center.**
    - Attempt to acquire the property surrounding the staging area location and plant or allow the property to revert back to native vegetation. This will give visitors a sense of the conditions or setting present during the time of the portage. **This is under consideration by Southern.**
- Assist in funding the renovation of the Lewis and Clark Interpretative Center library and Lewis and Clark Trail Heritage Foundation Headquarters located in the Interpretative Center. **Southern is providing funding to the Interpretive Center that is being used in part for these programs.**
- Assist in and set up an annual contribution to enhance and maintain educational programs related to the Interpretative Center's activities. **Funding is being provided to the Interpretive Center for these programs.**
- Provide in-kind energy services to the Lewis and Clark Interpretive Center if they can be accepted. **This is under consideration by Southern**.

As recommended by the HGS EIS, Southern implemented an Archeological Monitoring Plan in conjunction with starting construction of HGS; this monitoring will be continued for further construction activities associated with the natural gas-fired generation facility.

8.4 Impacts Summary

Addition of a natural gas-fired facility to the site, located off the NHL and fitting within the overall footprint of the coal-fired facility, will not significantly add to the adverse visual impact from the coal-fired facility to the NHL. The much smaller profile of the natural gas-fired generation plant, located outside the boundary of the NHL, will not result in a significant impact to the NHL. It should be noted that the NHL is property held in fee simple by Southern and other neighboring landowners.

Since the completion of the EIS, there has been significant residential, industrial and commercial development within and contiguous to the NHL. The proposed natural gas-fired facility has a relatively small "footprint" in size and structure and is materially similar in scope to other activities that are taking place, and are planned to materialize, in and adjacent to the NHL at other locations.

The no-action alternative would not affect this resource. However, continuing residential, commercial, agricultural, or industrial development in the vicinity of Great Falls is likely to impact the NHL regardless of this potential action.

9.0 VISUAL RESOURCES

9.1 Affected Environment

The Project site is characterized by a gently sloping landscape ranging from about 3,260 ft. MSL to about 3,320 ft. MSL. Off-site, this plateau-like landscape is incised by steep-sided coulees or gullies (e.g., Rogers Coulee just to the east of the project site) that cut into the land surface and range from a few feet deep to 100-200 feet deep. The lands on the site itself and in the immediate vicinity are farmed (except for the coulees), with wheat being the dominant crop. The Highwood Mountains are prominently visible to the east at a distance of about 15 miles. Looking toward the south, the Little Belt Mountains that rise to over 9,000 ft. MSL also are visible about 30-40 miles away. Looking westward, the front range of the main Rocky Mountains also can be seen on clear days.

The EIS utilized the Visual Resource Management System (VRM) developed by the Bureau of Land Management (BLM) to assess the current visual resources in the vicinity of the Project site (BLM, no date). The VRM assigns a ranking system by rating the visual appeal of a tract of land, measuring public concern for scenic quality, and determining whether the tract of land is visible from travel routes or observation points. Classes I and II are the most valued, Class III represents a moderate value, and Class IV represents the least value. The VRM analysis of the Project site yielded a visual resource ranking of Class III; that is, as possessing moderate visual or scenic values (RUS and MDEQ, 2007a).

9.2 Environmental Consequences

The EIS determined that the visual impacts of the previously proposed coal-fired plant and transmission lines would be significant and adverse on the NHL (RUS and MDEQ, 2007a). Southern has analyzed the individual and incremental visual impacts from the natural gas plant from several different perspectives as described below.

The current view south from the Lewis and Clark Staging Area Interpretive Viewpoint is shown in Figure 9-1.

Figure 9-1. Looking South from Lewis and Clark Staging Area Interpretive Site, December 2005

Source: RUS and MDEQ, 2007

Because of its small profile, the natural gas-fired plant would not be visible from the Interpretive Viewpoint (Stanley, 2009d). The gas plant would be visible from various points along Salem Road. Mitigation measures described in the following section would reduce these impacts.

9.3 Mitigation and Monitoring

To address concerns from historic preservation parties over the potential impact of the coal plant on the aesthetics of the NHL, Southern agreed to relocate the power plant to a site approximately one-half mile south of the originally proposed location and outside the boundary of the NHL.

To further mitigate visual impacts, a landscaping design firm was contracted by Southern in 2008 to develop a comprehensive landscape plan for the Project site. Land Design, Inc. (Land Design) developed the landscape plan based on the findings of the EIS (Land Design, 2009). The plan includes creating earthen mounds around the HGS boundary planted with various trees, shrubs, and grasses. The proposed landscape plan has been approved by Cascade County as part of the location conformance permit required to construct an electrical generating facility at the Project site.

The artist renderings of the proposed landscape plan applied to the gas plant are presented in Figures 9-2 and 9-3. The application of the landscaping mitigation measures would substantially reduce visual impacts of the proposed natural gas facility from points of public access.

Figure 9-2. View of Entry to the Natural Gas Plant

Source: Stanley Consultants, 2009d

Figure 9-3. View South of the Natural Gas Plant From Salem Road

Source: Stanley Consultants, 2009d

To reduce visual impacts further, Southern agreed to use earth tone colors on buildings and transmission towers when designing the coal-fired facility. The design would also maximize the use of directional lighting to reduce the visual impacts at night. These mitigating actions (use of earth tone colors and maximizing directional lighting) would be implemented in the gas-fired plant's design, as well.

Other mitigating actions described in the EIS which could reduce visual impacts include:

1. Minimize the number of visible structures (e.g., utilize landscaping);
2. Minimize structure contrast (e.g., using earth-tone paints with low levels of reflectivity)
3. Redesign structures that do not blend/fit,
4. Minimize impact of utility crossings of roads,
5. Recognize the value and limitations of color.

9.4 Impacts Summary

Because the gas plant's footprint and profile are small relative to the adjacent coal-fired power plant, and because no additional transmission lines will be required, the gas-fired plant is not expected to incur any additional impacts to visual resources near the Project site. To mitigate visual impacts, several measures were identified in the EIS. These include relocating the Project outside of the NHL, landscaping around the property line, using earth tone colors on buildings, and maximizing directional lighting, among others.

By implementing these mitigating measures for the gas-fired plant, the overall impacts to visual resources are expected to be noticeably less.

The No-Action alternative will not impact visual resources and will not require mitigation and monitoring.

10.0 TRANSPORTATION

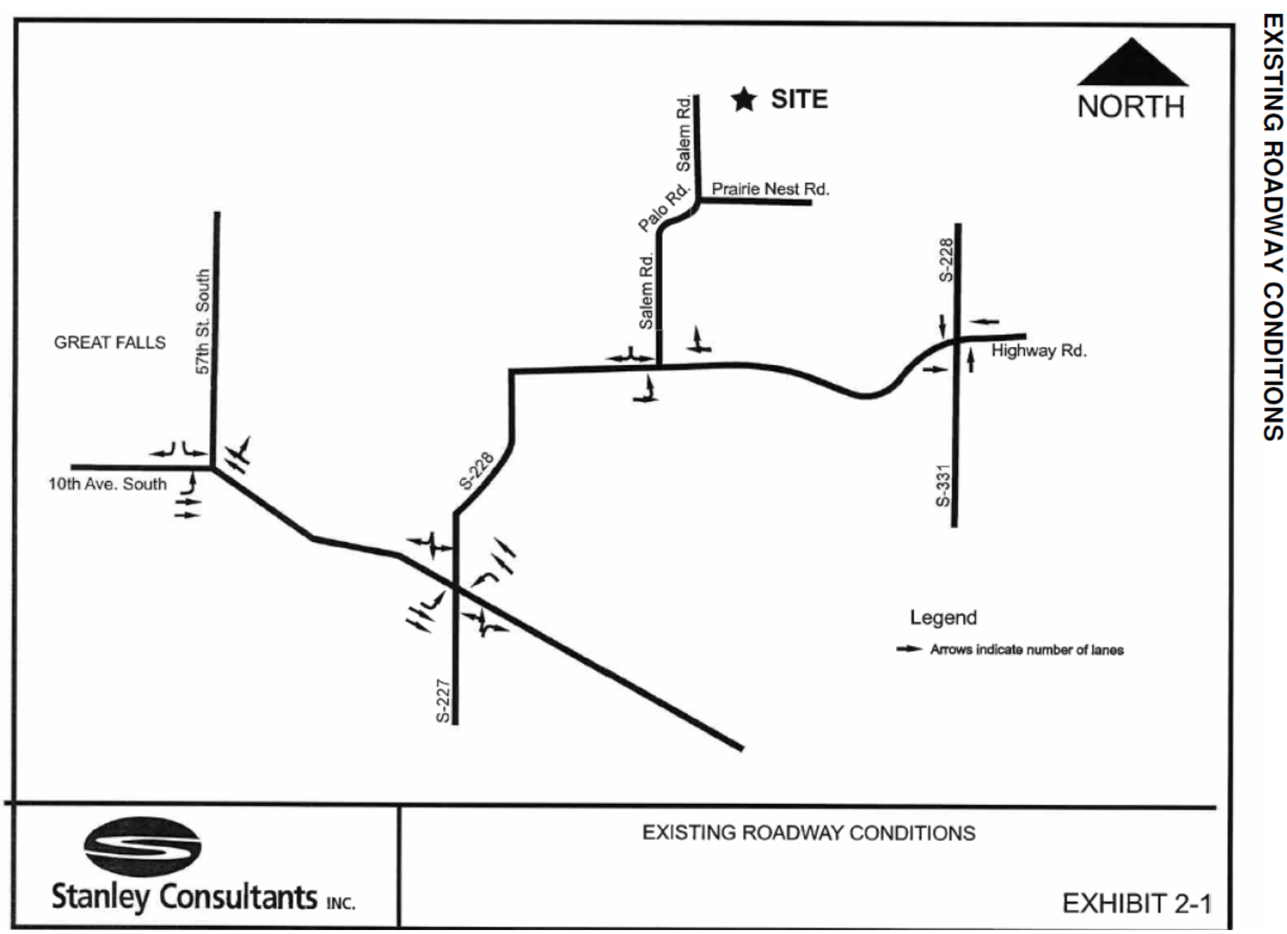
10.1 Affected Environment

The effects of construction, operation, and no action were evaluated as part of this Environmental Assessment. The transportation effects of the coal plant are described in detail in the prior EIS (RUS and MDEQ, 2007a). The following discussion will focus on the effects of the proposed gas-fired facility (the Project). The Project's transportation effects were considered for roads, traffic, airports, and railroads.

10.1.1 Roads and Traffic

The proposed Project site is located in a predominantly agricultural area approximately eight miles east of Great Falls. There are several roads surrounding the area, which can be seen in Figure 10-1 below.

Figure 10-1. Existing Roadway Conditions



Source: Stanley, 2009e

The HGS site is located beside the Salem Road, north of S-228 (Highwood Road), in the northwestern part of Cascade County. The portion of the county-maintained Salem Road (designated L07-204 by MDT) in Cascade County is 6.5 miles (10.5 km) long. On the east side of Belt Creek, it crosses into Chouteau County. It is an unpaved, graded, gravel road (MDT, 2001b). Salem Road is a lightly traveled, local, rural road used primarily by farmers and rural residents in the area. Based on a traffic study conducted in 2005, the average daily traffic (ADT) near Highwood Road is 36, while the ADT in the northern segment toward the HGS site is 21 (Peterson, 2005).

S-228 (Highwood Road) is a paved, two-lane, state secondary road on the Montana Secondary Highway System several miles south of the Project site that would be used to access it from Great Falls during both the construction and operation of the facility. S-228 continues east past the Salem Road intersection and intersects with S-331, a two-lane highway traveling north–south. The nearest ADT measurement taken by the Montana Department of Transportation (MDT) is approximately seven miles (11 km) from its intersection with the Salem Road. The combined (both directions) ADT in 2004 was 585 (Stanley, 2009e).

US-87/89 is a four-lane highway traveling southeast to northwest and intersects S-228 southeast of Great Falls. S-227 continues south from the S-228 and US-89 intersection. US 87/89 meets 57th Street South at an angle and forms a T-intersection before continuing west. US 87/89 is also known as 10th Avenue South/S-200 within city limits. Westbound US 87/89 has one through lane and one through right lane.

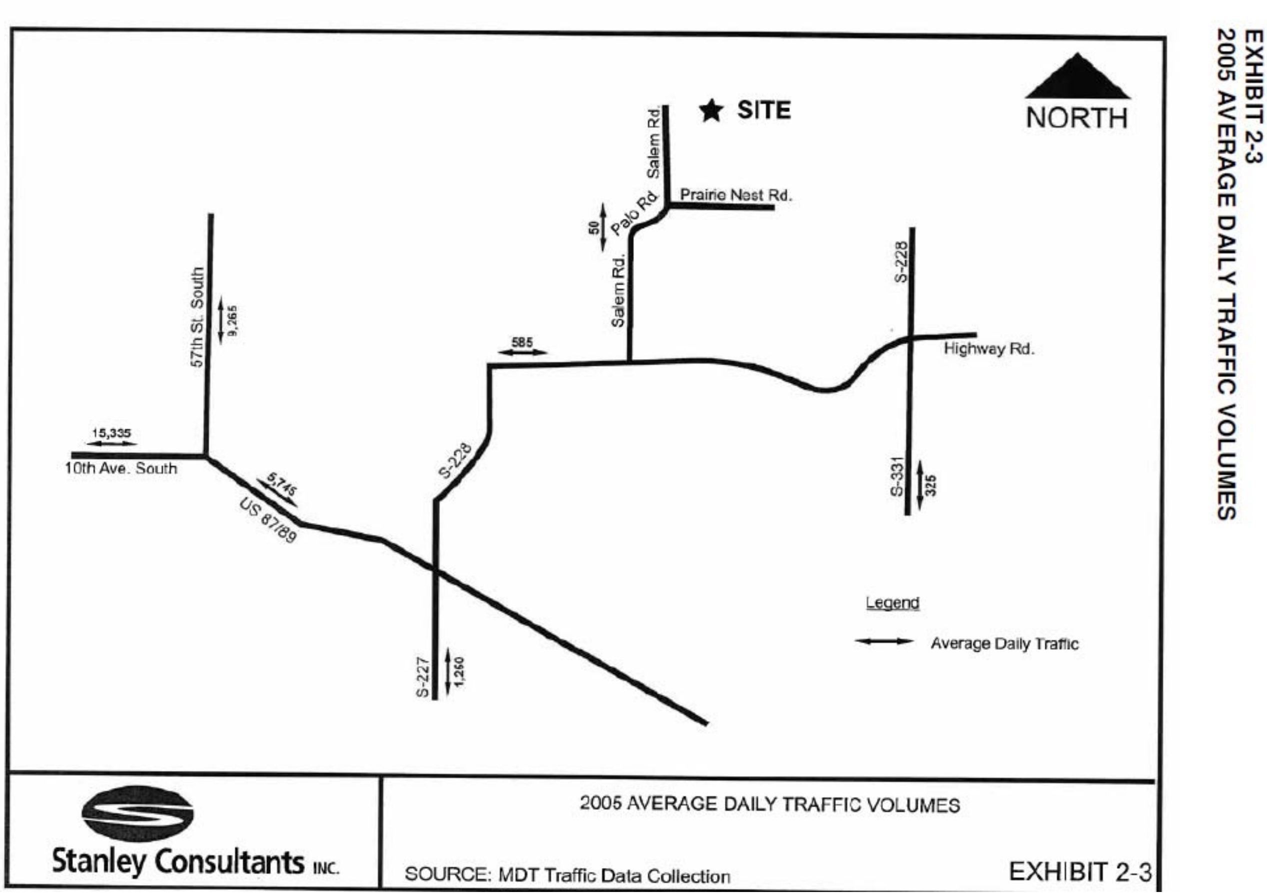
Traffic volumes from a 2005 survey of the affected areas are summarized in Table 10-1 and Figure 10-2 below.

Table 10-1: Traffic Volumes Near Project Site

Street/Road Name	Average Daily Traffic (vehicles per day)
57th Street South	9265
10th Avenue South	15335
US 87/89	5745
S-227	1250
S-228	585
S-331	325

Source: Stanley, 2009e

Figure 10-2. Existing Traffic Conditions



Source: Stanley, 2009e

10.1.2 Airports

Great Falls International Airport (GFIA) is located at an elevation of 3,677 ft. MSL, three miles southwest of downtown Great Falls and on the opposite side of the Missouri River (GFIAA, 2005). GFIA is located approximately 12-13 miles southwest of the Project site.

The airport averages 120 aircraft operations daily. Twenty-four percent of these operations are commercial, 24 percent transient general aviation, 23 percent air taxi, 15 percent local general aviation, and 14 percent military (GFIAA, 2005).

10.1.3 Rail

A Burlington Northern Santa Fe (BNSF) Railway line is located approximately six miles south of the Project site. BNSF is one of the largest freight railroad operators in the United States, with 38,000 employees operating 5,675 locomotives and an average of 220,000 freight cars on a 32,000-mile route system.

10.2 Environmental Consequences

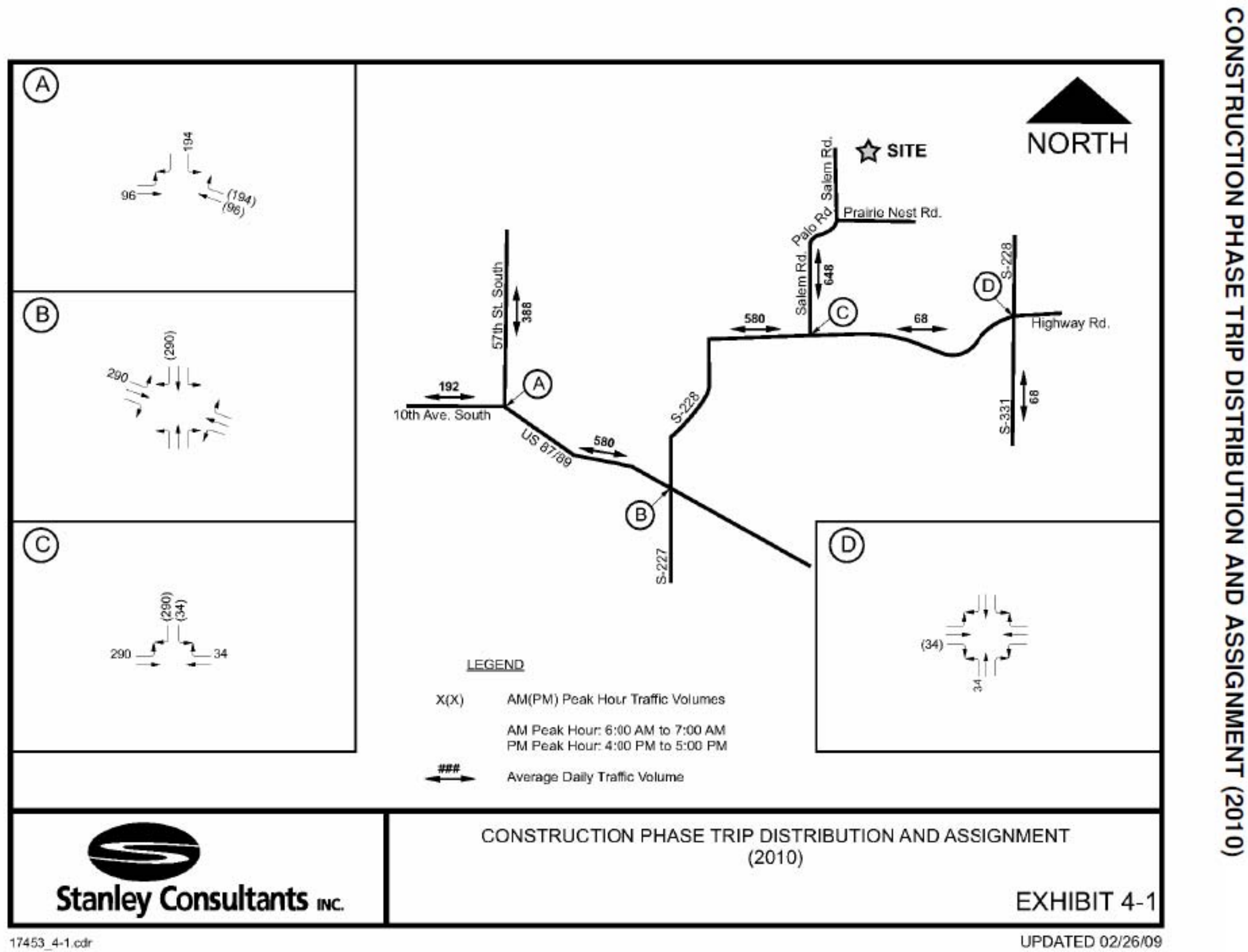
10.2.1 Construction

Stanley Consultants developed an updated Traffic Impacts Study in 2009 based on the revised inputs of the Project (Stanley, 2009e). The construction phase of the Project is expected to last approximately 30 months and employ up to 320 construction workers during the peak six months of the construction period (Stanley, 2009e). For comparison, the estimated coal-fired power plant construction workforce is estimated at 550 employees during the peak nine months of the 43-month construction period (Stanley, 2008). The Record of Decision for the coal plant EIS determined that the traffic impacts would be moderate and short-term during construction (RUS and DEQ, 2007b). Using this as a baseline, the traffic impacts of the Project are expected to be less due to the smaller construction workforce and shorter construction period.

From Great Falls, plant access would be from southbound U.S. Route 87/89 to eastbound S-228 to northbound Salem Road, thence to the site. During the peak of the construction phase, it is anticipated that the Project would generate 648 vehicle trips per day, including material delivery trips (Stanley,2009e). Most of the traffic would remain passenger cars, and the material delivery traffic would consist of heavy vehicles. Most of the traffic would occur early in the morning and mid- to late afternoon when workers are arriving and departing the construction site. At other times – most of the morning, mid-day, evening, and nighttime – traffic would be minimal.

Figure 10-3 below shows the estimated ADT impacts for the Project on the affected roadways and intersections during the construction phase.

Figure 10-3. Estimated Traffic Impacts During Construction Phase



Source: Stanley 2009

Stanley's 2009 Traffic Impact Study determined that increased traffic during the construction phase would result in the greatest potential impacts at two intersections: 1) the intersection of US 87/89 and S-228 (eastbound US 87/89 traffic turning left onto S-228 in the morning and westbound traffic turning right onto US 87/89 from S-228 in the afternoon) and, 2) the intersection of 10th Ave South and 57th Street (Stanley,2009e). Similar traffic volume increases (580 ADT) would be expected at both of these intersections. Mitigation measures for these impacts are discussed in the following Mitigation and Monitoring section.

The construction phase of the Project is not expected to have any adverse impacts to the Great Falls International Airport or the BNSF railway. Prior to project construction, FAA requirements potentially applying to the natural gas plant stack and other associated structures would need to be reviewed. If required, the gas turbine stacks may need the placement of lights for aviation safety.

10.2.2 Operation

The Project is expected to employ approximately 20 commuting workers during normal operation (Stanley,2009e). A maximum of 10 one-way material delivery trips per week are anticipated. During the long-term operation of the HGS, traffic impacts from 20 commuting workers and 10 delivery trips per week are expected to be minimal (Stanley,2009e).

10.3 Mitigation and Monitoring

Stanley consultants developed an updated Traffic Impacts Study in March of 2009 and submitted the study to MDT for review. In the updated traffic study, Stanley proposes monitoring the traffic impacts during the construction phase to determine if mitigating actions will be necessary. Southern would work with MDT to implement effective mitigating actions as required. As mentioned in the prior Environmental Impacts section, the greatest traffic impacts are likely to occur at two intersections during the construction phase: 1) the intersection of US 87/89 and S-228 and, 2) the intersection of 10^{th} Ave South and 57^{th} Street. Stanley evaluated three possible mitigation measures to address these impacts: 1) temporary or permanent traffic signals at one or more intersections, 2) using shuttle buses to deliver the construction workers, and 3) using a staggered start time for half of the Project workers to reduce traffic loads by 50 percent during the AM and PM peak hours.

The 2009 traffic study determined that using shuttle buses to deliver workers would have a minor beneficial impact on traffic congestion (Stanley,2009e). The use of traffic signals at both intersections and implementing a staggered start time for half of the construction workers during the peak of the construction phase was found to measurably reduce traffic impacts at these intersections. These recommendations have been submitted to MDT and will be implemented as needed and as directed.

Other mitigating actions would consist of standard measures used to minimize traffic congestion and damage to public roads during large construction projects. This would include appropriate signage to alert motorists approaching turnoffs to the construction site from both directions at distances of approximately 200 to 400 yards. If temporary detours and/or street closures would be necessary at any location, road crews and signs would safely and efficiently redirect oncoming traffic to the detour. Any material, such as aggregate or fill, falling from trucks would be removed promptly so as not to present a traffic hazard. Any damage to road surfaces from heavy equipment movement would also be repaired promptly.

Under the Proposed Action, Southern and its contractors would maintain existing aggregate roadways to be used for construction access. Roadway improvements to mitigate potential traffic problems would be constructed in advance of significant construction activity at the main plant site. Salem Road would be maintained throughout construction. At the end of the construction phase, Southern and its contractors would refurbish and pave Salem Road. This activity would mitigate any long-term effects of increased traffic on this road and represent a significant improvement to Salem Road's current conditions.

10.4 Impacts Summary

The Project is expected to employ up to 320 construction workers during the peak months (six) of the construction phase. The increased vehicle trips per day on Salem Road are estimated to be up to 648 during these six months. The entire duration of Project construction is estimated to be 30 months.

Southern proposes to work with MDT to monitor the traffic impacts on affected roadways during the construction phase of the Project. Southern has identified effective mitigating measures and would work with MDT to implement them as needed. These mitigating actions may include temporary or permanent traffic signals, implementing a staggered start and stop time of construction workers, or a combination of both. In addition, Salem Road would be maintained during construction and paved upon completion.

The construction phase of the project is not expected to have any adverse effects on the GFIA or the BNSF railway.

The small workforce at the plant is not expected to have any adverse effects on traffic or roadways in the Project's vicinity during the facility's operation. The operation of the facility is expected to have negligible effects on road, rail and air transportation in the Great Falls area.

The No Action Alternative would not contribute directly to transportation impacts at the Project site.

11.0 FARMLAND AND LAND USE

11.1 Affected Environment

In Cascade County, just over 80 percent of all land, or 1,388,530 acres, is farmland. Of this land, 507,107 acres is cropland, with 41,901 acres irrigated. The remaining farmland (881,423 acres) is rangeland and pasture. Nearly all the undeveloped land surrounding the proposed Project site is used for cultivation, with the primary agricultural crop being winter wheat, followed by spring wheat and barley (USDA, 2003).

The proposed Project site is located entirely on Pendroy Clay soils. Pendroy Clays typically are used for dryland crops as well as rangeland, and are not listed as prime or any other important farmlands in the Cascade County soil survey (NRCS, 2004). The land evaluation productivity index for Pendroy Clays for the state Land Evaluation and Site Assessment (LESA) system is 46 of 100 (NRCS, 2002). A rating under 50 generally means that the soil is of marginal quality for agricultural uses, and that approximately 73 percent of soils ranked have a higher quality (NRCS, 2002).

Pendroy Clay soils are in land capability class 4e, which consists of soils that have very severe limitations that restrict the choice of plants or require careful management, or both. The limitations of the Pendroy Clays primarily are due to their susceptibility to erosion (RUS and MDEQ, 2007a).

The Project site was previously unincorporated county land zoned A-2. A-2 is a broad classification which allows the property to have a variety of uses in addition to agriculture such as schools, hospitals, electrical substations, etc. (Zadick, 2009). Cascade County rezoned the property to heavy industrial on March 11, 2008, at the request of the former property owners to facilitate its use for electrical generating facilities (Zadick, 2009). The site is located east of the intersection between Salem Road and an abandoned railroad bed. The historical use of the area has been limited to agricultural and open space activities.

11.2 Environmental Consequences

The area of land that would be directly impacted and/or altered by the construction of the Project at the Project site includes the footprint of the power plant, roadways, and utility corridor zones required to make the plant operation-ready. Specifically, the Project would require the construction of the following elements:

- The power plant and associated facilities on a total footprint of approximately six acres;
- A 1,800-foot long paved access road from the existing Cascade County road (Salem Road) into the site;
- Two short segments of electrical transmission line with new 100-foot rights-of-way; the first line would be approximately 4.1 miles long and would extend from the

plant site to a new switchyard site proposed for a location south and west of the Project site, while the second line would be approximately 9.21 miles in length and would extend south and west from the plant site, across the Missouri River north and east of Cochrane Dam.

Raw water supply for the Project would be provided via one of two alternatives under consideration:

1. A raw water supply system which would include a collector well extending into the Morony Reservoir and associated water intake pipelines extending approximately two miles to the plant site; or
2. A groundwater pumping system which would pump water to a centralized basin and then directly to the plant.

Potable and waste water needs for the plant would be satisfied by one of two alternatives under consideration:

1. 55,000 feet of fresh potable water supply and waste water pipelines from the power plant to the City of Great Falls water and sewer lines; or
2. Construction of an evaporation pond to eliminate the need of the sewer line. Sanitary waste water would be routed to a septic leach field adjacent to the plant. Potable water would be transported to the facility from offsite.

No homesteads would be moved as a result of activities. The conversion of agricultural lands to an industrial plant with supporting facilities and infrastructure would be considered only a minor impact, though the impact would be permanent. Because the agricultural land that would be converted is not protected farmland and does not have a significant productivity rating, the conversion of this land in context to the amount and quality of farmland in other areas of Cascade County is not considered significant.

Construction of the facility is expected to last approximately 30 months. Construction activities could potentially cause some moderate indirect nuisance impacts to adjacent landowners. Impacts such as noise, dust, and increased traffic would likely be moderate, short-term, of small extent, and probable. While these nuisances could impact nearby residents, the impacts would not affect the actual uses of adjacent land.

The operation of the power plant would cause no additional direct impacts to land use or farmland. No additional amounts of land would be developed for the plant once the construction phase is completed.

11.3 Mitigation and Monitoring

Mitigation measures taken to minimize construction and operation impacts to resource areas (e.g., reduction in noise, visibility, and air quality impacts) would directly lessen the impacts to area residents. Best management practices would be utilized to minimize the ground areas disturbed by the Project’s infrastructure.

11.4 Impacts Summary

The Project would involve the direct conversion of agricultural lands to an industrialized facility with supporting infrastructure. No homesteads or residences would need to be moved under this alternative. In the context of the amount of quality farmland in other areas of Cascade County, the impacts of the actual conversion, or development, of the land required for the plant would be of minor magnitude, long-term duration, medium extent, and have a probable likelihood of occurring. The overall impacts on land use from the construction phase of the Project, after mitigation, would not be adverse.

The No Action Alternative would not adversely affect or alter existing land uses at or near the Project site.

12.0 HUMAN HEALTH AND SAFETY

12.1 Affected Environment

The Cascade City-County Health Department is responsible for the prevention of disease, promotion of good health practices and protection of the environment within Cascade County and the city of Great Falls. Between 1996-2000, the three leading causes of death in Cascade County were heart disease, cancer, and chronic lower respiratory disease (CLRD).

There are two National Priorities List (NPL) sites located within Cascade County: the Carpenter-Snow Creek and Barker-Hughesville sites (EPA, 2005). Both sites are areas of historical mining activity. The NPL is the list of national priorities among the known releases or threatened releases of hazardous substances, pollutants, or contaminants throughout the United States and its territories, and the sites listed in the NPL are also known as Superfund sites. In 2003, the Agency for Toxic Substances and Disease Registry (ATSDR) classified both sites as public health hazards.

On July 1, 2004, a Phase I Environmental Site Assessment (ESA) was completed on the Project site to identify recognized environmental conditions (SME, 2004c). A recognized environmental condition (REC) is defined as the presence or likely presence of any hazardous substances or petroleum products on a property under conditions that indicate an existing release, a past release, or a material threat of a release of any hazardous substances or petroleum products into structures on the property or into the ground, groundwater, or surface water of the property. The Phase I ESA was completed in general accordance with procedures outlined in American Society for Testing and Materials (ASTM) E1527-00, Standard Practice of Environmental Assessments: Phase I ESA Process.

The ESA included evaluation of individual properties adjacent to and within one mile (1.6 km) of the Project site. The evaluation included assessment of historical information pertaining to the area including historic aerial photographs, historic topographic mapping, available fire insurance mapping, a review of regulatory records for the areas, and visual evaluation of the assessment areas. Historically, activities conducted within the assessment areas have been for agricultural purposes, much as they are today. There were no recognized environmental conditions or concerns identified during the site assessment at the Project site.

12.2 Environmental Consequences

The environmental site assessment of the Project site identified no recognized environmental conditions or concerns within a one mile radius of the site. Additionally, the Project site is located a considerable distance away from the two NPL sites located within Cascade County. There are documented impacts from mining waste to soil, surface water and stream sediments in Belt Creek, which flows northeast of the site.

Belt Creek and the Missouri River north of the site are listed as impaired water bodies which do not support the beneficial uses of aquatic life, coldwater fishery, and drinking water. Because human activities associated with the power plant at the Project site would not conflict with any of these uses, the site itself is not considered to pose any risk to site workers and visitors.

Construction workers would be exposed to short-term health and safety risks typically faced in the construction industry, considered high-risk by the National Institute for Occupational Safety and Health (NIOSH). Additionally, traffic volumes and the presence of heavy construction equipment on site access roads could potentially cause a negligible to minor increase in vehicular accidents. Overall, impacts on human health and safety from the construction phase of the power plant would be non-significant.

Operation-related impacts on human health and safety for the Project site would be minimal. Occupational hazards attendant to working in an industrial electrical generation setting would be mitigated as described below. Air emissions from the Project are not expected to cause any health problems locally or regionally. Dispersion modeling analyses conducted for this EA and for the air quality permit indicate that concentrations of pollutants resulting from the Project would be well below standards set by EPA and MDEQ to protect public health and safety.

12.3 Mitigation Measures

Mitigation measures during operation of the power plant include installing and operating all BACT methods of reducing air pollutants. Implementation of proper waste management procedures and water pollution control would further reduce any impacts from the Project facility. Proper training, adherence to applicable safety regulations, and implementation of safety awareness programs would reduce occupational health and safety risks associated with construction and facility operation.

12.4 Impacts Summary

Construction- and operation-related impacts on human health and safety at the Project site would be insignificant and the potential for impacts could be mitigated.

The No Action alternative would cause no additional impacts to human health and safety from the current conditions around the Project site.

13.0 SOCIOECONOMICS

13.1 Affected Environment

The Project site is located in Cascade County, near the city of Great Falls. The city of Great Falls was settled around the Missouri River, which provided the city with its name as well as its reason for being. As the river traverses the city it drops over 500 feet in a series of rapids and five impressive waterfalls (CGF, no date).

Great Falls is by far the largest settlement in Cascade County, which is predominantly a rural, low population density, agricultural county. Table 13-1 presents recent demographic and economic data on Montana, Cascade County, and the city of Great Falls from the U.S. Census Bureau.

Table 13-1. Socioeconomic Characteristics of State of Montana, Cascade County, and City of Great Falls

Characteristic	Montana	Cascade County	City of Great Falls
Population, 2004 estimate[1]	917,621	79,849	56,155
Population, % change, 2000-2004[2]	2.7%	-0.6%	-1.0%
Population, 2000	902,195	80,357	56,690
Population, % change, 1990-2000	12.9%	3.4%	2.4%
Land Area, 2000 (square miles)	145,552	2,698	19
Persons per square mile (population density), 2000	6	30	2,909
White persons, %, 2000	91%	91%	90%
Non-Hispanic white persons, %, 2000	90%	90%	NA[3]
Black or African American persons, %, 2000	0.3%	1%	1%
American Indian persons, %, 2000	6%	4%	5%
Asian persons, %, 2000	0.5%	0.8%	0.9%
Persons of Latino or Hispanic origin, %, 2000	2%	2%	2%
Language other than English spoken at home, %, 2000	5%	5%	5%
Foreign born persons, %, 2000	2%	2%	2%

Characteristic	Montana	Cascade County	City of Great Falls
High school graduates, % of persons age 25+, 2000	87%	87%	87%
Bachelor's degree or higher, % of persons 25+, 2000	24%	22%	22%
Persons with a disability, age 5+, 2000	145,732	13,958	NA[3]
Median household income, 1999	$33,024	$32,971	$32,436
Per capita money income, 1999	$17,151	$17,566	$18,059
Persons below poverty, %, 1999	15%	14%	15%

Sources: USCB, 2005a; USCB, 2005b; USCB, 2005c
[1]2003 estimate for City of Great Falls
[2]2000-2003 for City of Great Falls
[3]Not Available

Because the economic impacts of the Proposed Action at the Project site extend beyond the political boundaries of Great Falls, the Great Falls Labor Market Area (LMA) provides a comprehensive look at the affected economic environment of the region. A labor market area is an economically integrated geographic area within which individuals can reside and find employment within a reasonable distance or can readily change employment without changing their place of residence (BLS, 2005). Normally, it is based on a 60-mile radius from some pre-set point, such as the county seat, 60 miles being about a one-hour drive. The Great Falls Development Authority estimates that approximately 14,900 workers are available to employers (GFDA, no date).

13.2 Socioeconomic Consequences

The construction phase of the Project could take up to 30 months. The Project's construction would employ up to 320 workers during the peak of activity. Wage rates for construction workers would vary from approximately $20/hr to close to $40/hr. Most of the construction and engineering jobs would be highly-skilled, specialized, well-paying positions. Due to the specialized expertise required, the construction workforce is expected to be primarily drawn from outside Cascade County. Most of the workers would live in the area temporarily and would not bring their families. A relatively small fraction of the workers associated with the construction of the plant would stay for the duration of the project and could potentially relocate their families, becoming permanent residents of the Great Falls area. In an area with a population of over 55,000, this increase would be expected to have a modest economic impact and little impact on public services such as public schools.

The construction activities could also create a number of jobs indirectly from project-related spending and the spending decisions of workers. This effect, known as the employment multiplier effect, takes the impacts from project-related spending into account to determine the number of indirect or induced jobs created in the local economy by an action. Using a PC based regional economic analysis system named IMPLAN®, the Montana Governor's Office of Economic Opportunity developed an employment multiplier of 1.5 (GOEO, 2005). Using this employment multiplier, the 320 jobs created during construction of the plant could potentially result in the creation of as many as 160 additional jobs in the community, for a total of 480 jobs created by the Project. Thus, the construction phase of the HGS at the Project site would have a primarily positive and beneficial effect on the socioeconomic environment of the local and regional area.

The operation of the Project would employ approximately 20 permanent employees with average salaries of $60,000 a year. The total annual payroll would be approximately $1.2 million. The positions would include plant operations, maintenance personnel, and engineering staff. The Project's addition of 20 well-paying, technical and professional jobs to the Great Falls region would create a minor, sustained, and beneficial economic impact on the region for the lifetime of the facility.

Another potential long-term benefit of the Project would be an increase in annual taxes to Cascade County. Based on the projected cost of the facility, annual taxes from the Project are estimated to be $3.1 million (Balzarini, 2009).

13.3 Mitigation and Monitoring

Due to the Project's expected beneficial socioeconomic effects and minimal downside, no mitigation measures are planned or proposed.

13.4 Impacts Summary

Overall, the construction of the Project would have a beneficial effect on the socioeconomic environment of the local and regional area, including increases in employment opportunities, total purchases of goods and services, and an increase in the tax base. During the lifespan of the facility, the Project would yield beneficial and potentially significant socioeconomic impacts on aggregate income, employment, and population in the city of Great Falls and Cascade County. It would also provide reliable electricity at potentially reduced rates for Southern's customer base.

Under the No Action Alternative, the Project would not be constructed at the proposed site. The direct and indirect economic benefits to the local economy from short-term (construction) and long-term (operation) job creation would be forgone under this alternative. These are not adverse impacts, but rather a lost opportunity to realize economic benefits to the local community from the Project.

Under this alternative, Southern's member cooperatives and consumers would be unprotected from possible future increases in the price of electricity on the open market. Given the volatility of this market, consumers could be paying substantially higher electric rates, although it is not possible to quantify precisely how much higher.

14.0 ENVIRONMENTAL JUSTICE/PROTECTION OF CHILDREN

14.1 Affected Environment

Executive Order 12898, *Federal Actions to Address Environmental Justice in Minority Populations and Low Income Populations*, directs federal agencies to identify and address any disproportionately high adverse human health or environmental effects of its projects on minority or low-income populations.

Cascade County does not have disproportionate numbers of minorities or a disproportionate level of poverty relative to the state of Montana. Its population is 1.1 percent black (compared to 0.3 percent for all of Montana), 4.2 percent American Indian (6.2 percent for Montana), 0.8 percent Asian (0.5 percent for Montana), and 2.4 percent Hispanic (2.0 percent for Montana). In Cascade County, 13.5 percent of persons lived below the poverty line in 1999, compared to 14.6 percent for the state as a whole (USCB, 2005b).

Historically, the Great Falls area was inhabited primarily by the Plains Indians and the Blackfeet Indian Nation. There are no Indian reservations or other tribal lands currently in the county, although the Little Shell Indian Tribe, made up of approximately 4,000 Chippewa Indians, considers Cascade County its homebase.

Executive Order 13045, *Protection of Children from Environmental Health Risks and Safety Risks*, directs federal agencies to "identify and address environmental health risks and safety risks that may disproportionately affect children." Order 13045 further directs federal agencies to "ensure that [their] policies, programs, activities, and standards address disproportionate risks to children that result" from these risks.

Generally, children are not present on the Project site or in its immediate vicinity, but may be presumed to live in and around the city limits of Great Falls.

An independent report on environmental justice in Cascade County was generated from Scorecard (Scorecard, 2005). Scorecard profiles environmental burdens in every community in the U.S., identifying which, if any, groups experience disproportionate toxic chemical releases, cancer risks from hazardous air pollutants, or proximity to Superfund sites and polluting facilities emitting smog and particulates. The report indicates that there is no disproportionate distribution of environmental burdens within Cascade County to groups based on race/ethnicity, education level, job classification, or home ownership status (Scorecard, 2005). Additionally, there is no disproportionate distribution within the county of chemical releases, cancer risks from hazardous air pollutants, or proximity to Superfund sites. However, there is some increased burden from existing facilities emitting criteria air pollutants near families and children below the poverty line when compared to families and children above the poverty line. Approximately 7.4 facilities emitting criteria air pollutants are located within one square mile of families and children below the poverty line within the county, compared to an average of 3.7 such facilities located within one square mile of families and children above the poverty line (Scorecard, 2005).

14.2 Environmental Consequences

The construction of the Project, and the installation of its infrastructure, would have a negligible effect on disproportionate numbers of minorities, persons living in poverty, or children, as these population groups are not generally present at or near the Project site.

There are eight scattered rural residences located within three miles of the site. Though there would be nuisances such as noise, dust, and traffic associated with construction activities, these impacts would not cause an environmental justice or protection of children concern due to the lack of these affected population groups in disproportionate numbers in the areas impacted by construction activities.

14.3 Mitigation and Monitoring

Since there are no significant, adverse impacts from the action alternatives anticipated on disproportionate numbers of minorities, persons living in poverty, or children, no mitigation measures specific to environmental justice issues are planned or proposed for the action alternative. Mitigation measures taken to minimize construction and operation impacts to other resource areas (e.g., reduction in noise, visibility, and air quality impacts) would also directly lessen the impacts to any sensitive or susceptible receptors in the impact areas, including children, minorities, or persons living below the poverty level.

14.4 Impacts Summary

The Project would have a negligible effect on children or persons living in poverty, as these population groups are not generally present at or near the Project site. The Project site and its adjacent land is low-density agricultural land, and though nuisances associated with construction and impacts from plant operations would affect areas within this land, there are no particularly susceptible population groups present in significant numbers within the area to cause concerns regarding environmental justice or protection of children.

There is not a disproportionate number of minorities in Cascade County, and neither the No Action Alternative nor the Proposed Action are expected to have an impact on a minority population group. Further, there is no evidence that the siting of the proposed Project has targeted areas with disproportionately high levels of racial minorities or impoverished populations. Moreover, there has been no regulatory discrimination of enforcement standards where the Project may affect those groups. Finally, there is no inequitable distribution of benefits, primarily economic, with the Project’s impacts such as increased pollution to those groups.

The No Action Alternative would involve no direct impact or effect from a power plant at the Project site on persons living in poverty or children. Insofar as Southern would need to meet energy supply needs in the service area by purchasing power from existing generation wholesale suppliers located elsewhere, Southern's member cooperatives and consumers would be unprotected from future increases in the price of electricity on the open market. This could lead to indirect economic effects on commercial and residential populations within Southern's service area, which could disproportionately affect low-income residential consumers.

15.0 WASTE MANAGEMENT

15.1 Affected Environment

As described in the EIS (RUS and DEQ, 2007a), the primary landfill in the Great Falls area is the High Plains Sanitary Landfill and Recycle Center (HPSL). This landfill is a licensed Class II landfill. Four other landfills exist in the area, but these are all privately owned and accept limited quantities of waste from outside sources. Non-exempt regulated hazardous waste must be delivered to a permitted hazardous waste destination, such as an incinerator or hazardous waste landfill, the nearest of which are located out of state in Oregon and Utah.

15.2 Environmental Consequences

15.2.1 Construction

The construction of the Project would generate construction debris waste, which would require proper disposal or reuse. Any non-hazardous construction debris that could not be reused or recycled would be disposed of at the HPSL. The construction contractor would be responsible for ensuring that the waste material generated was properly disposed. Portable restrooms for employee use during the construction period would be provided by a private contractor. Portable toilets would be serviced by a septic tank pumper licensed by MDEQ to perform these services.

15.2.2 Operation

The Project would generate relatively low volumes of non-hazardous wastes and possibly small quantities of hazardous wastes. These waste streams would consist primarily of boiler blowdown waste, cooler blowdown waste, demineralizer regenerant, and boiler chemical cleaning wastes. Southern would discharge aqueous wastes, including sanitary wastes, to the City of Great Falls wastewater treatment facility in accordance with conditions established by the City. Non-hazardous solid wastes would be disposed of at the HPSL.

The power plant would most likely be regulated as a "conditionally exempt small quantity generator" of hazardous waste. Conditionally exempt small generators must determine which of the wastes they generate are hazardous and keep records of any test results, waste analysis or other determinations used to characterize hazardous waste for at least three years from the date of final disposition of the waste. They may dispose of hazardous waste at a legitimate recycling facility, a permitted hazardous waste treatment, storage, or disposal facility, or a Class II municipal solid waste landfill. Either of the first two options would be used for disposing the Project's regulated hazardous wastes.

15.3 Mitigation and Monitoring

Southern would comply with conditions established for discharging wastes to its water treatment facility. They would also comply, as appropriate, with all rules applicable to conditionally exempt small quantity generators of hazardous waste.

15.4 Impacts Summary

Impacts from waste generation and disposal at the Project site would be typical of many industrial and commercial operations. Compliance with a variety of solid waste regulations and disposal of non-hazardous wastes to the HPSL and the City of Great Falls wastewater treatment facility would ensure that impacts to the environment from the Project's waste streams would be insignificant.

16.0 CUMULATIVE IMPACTS

16.1 Methodology

The effects of the coal-fired power plant with associated wind turbines, the gas-fired power plant, and the cumulative effects of both power plants were evaluated. This evaluation was based on information included in the coal-fired power plant EIS, the Record of Decision for the coal-fired power plant EIS, and this Environmental Assessment. Many of the impacts of the gas plant are compared or related to those from the coal plant.

16.2 Results

Table 16.1 below summarizes the evaluated impacts.

Table 16.1: Summary of Environmental Impacts

Resource/Issue	Coal-Fired Plant[a]	Natural Gas-Fired Plant	Combined
Soils and Topography	Moderate, short-term impacts due to construction; permanent increase in impermeable surface area; minor, long-term impacts due to waste monofill.	Minor impact during construction with smaller footprint; less permanent increase in impermeable surface area; no impacts from waste monofill (eliminated).	Moderate, short-term impacts due to construction; permanent increase in impermeable surface area; minor, long-term impacts due to waste monofill.
Water Resources	Negligible construction impacts to receiving water quality; minor impacts on Missouri River flows from water withdrawals.	Negligible construction impacts to receiving water quality; minor impacts on the Missouri River or groundwater from water withdrawals.	Negligible construction impacts to receiving water quality; minor impacts on Missouri River flows or groundwater from water withdrawals.
Air Quality	Short-term construction impacts; long-term minor to moderate impacts due to release of criteria pollutants, HAPs, GHGs, visual plume and haze.	Short-term construction impacts; minor operating impacts with reduced emissions due to change in fuel type and equipment.	Short-term construction impacts; long-term minor to moderate impacts due to release of criteria pollutants, HAPs, GHGs, visual plume and haze.
Biological Resources	Minor, short-term construction impacts to terrestrial and aquatic biota, vegetation; minor long-term impact from rail/traffic collisions.	Minor impacts – smaller footprint and impact area; much less activity during construction and operation.	Minor impacts. Moderate impacts could result from separate construction of both facilities.

Resource/Issue	Coal-Fired Plant[a]	Natural Gas-Fired Plant	Combined
Noise	Minor to moderate, short-term construction impacts; minor long-term impact from train traffic, plant operation; significant impacts to NHL.	Minor to moderate impacts. No train traffic due to change in fuel type.	Minor to moderate impacts. Both facilities will not operate simultaneously.
Recreation	Negligible to minor impacts.	Negligible.	Negligible to minor impacts.
Cultural Resources/ Historic Properties	Adverse effect to NHL; no impact to archeological resources.	Moderate impact due to smaller footprint and location off NHL.	Adverse effect to NHL; no impact to archeological resources.
Visual Resources	Significant impact/ adverse effect to NHL.	Moderate impact to NHL with mitigation.	Significant impact/ adverse effect to NHL.
Transportation	Short-term, moderate construction impacts.	Short-term, minor to moderate impacts; smaller construction force and shorter construction duration.	Short-term, moderate construction impacts.
Farmland and Land Use	Permanent loss of farmland; moderate, long-term impact on land use/property values.	Minor impacts on local farmland and local properties due to smaller footprint.	Permanent loss of farmland; moderate, long-term impact on land use/property values.
Waste Management	Minor, medium-term construction impacts; moderate, long-term operation impacts.	Negligible (no ash disposal required).	Minor, medium-term construction impacts; moderate, long-term operation impacts.
Human Health and Safety	Minor construction-related impacts; minor, long-term operation impacts	Minor construction-related impacts; minor, long-term operation impacts	Minor construction-related impacts; minor, long-term operation impacts
Socioeconomics	Minor to moderately beneficial impacts.	Minor to moderately beneficial impacts.	Minor to moderately beneficial impacts.
Environmental Justice	No impact.	No impact.	No impact.

[a] Source: RUS and MDEQ, 2007b

16.3 Summary

In summary, the impacts of the gas-fired power plant alone are less than or equal to the impacts of the coal-fired plant. Further, none of the gas plant impacts on environmental resources was found to be significant. The combined impacts of the coal plant and the natural gas plant are generally equal to the coal-fired power plant alone. When viewed cumulatively, the addition of the gas plant to the coal plant will not result in any additional significant impacts. For a more detailed discussion of these impacts, please refer to the representative sections of the EIS, Record of Decision, and this Environmental Assessment.

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APPENDIX H: ACID RAIN APPLICATION

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258

Acid Rain Permit Application

For more information, see instructions and 40 CFR 72.30 and 72.31.

This submission is: ☒ new ☐ revised ☐ for Acid Rain permit renewal

STEP 1

Identify the facility name, State, and plant (ORIS) code.

Highwood Generating Station Facility (Source) Name	**MT** State	**Pending** Plant Code

STEP 2

Enter the unit ID# for every affected unit at the affected source in column "a."

a	b
Unit ID#	Unit Will Hold Allowances in Accordance with 40 CFR 72.9(c)(1)
EU-01 General Electric LM6000PF Combustion Turbine	**Yes**
EU-02 General Electric LM6000PF Combustion Turbine	**Yes**

STEP 3

Read the standard requirements.

Permit Requirements

(1) The designated representative of each affected source and each affected unit at the source shall:

(i) Submit a complete Acid Rain permit application (including a compliance plan) under 40 CFR part 72 in accordance with the deadlines specified in 40 CFR 72.30; and

(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review an Acid Rain permit application and issue or deny an Acid Rain permit;

(2) The owners and operators of each affected source and each affected unit at the source shall:

(i) Operate the unit in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the permitting authority; and

(ii) Have an Acid Rain Permit.

Monitoring Requirements

(1) The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75.

(2) The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the source or unit, as appropriate, with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.

(3) The requirements of 40 CFR part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

Sulfur Dioxide Requirements

(1) The owners and operators of each source and each affected unit at the source shall:

(i) Hold allowances, as of the allowance transfer deadline, in the source's compliance account (after deductions under 40 CFR 73.34(c)), not less than the total annual emissions of sulfur dioxide for the previous calendar year from the affected units at the source; and

(ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.

(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.

(3) An affected unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:

(i) Starting January 1, 2000, an affected unit under 40 CFR 72.6(a)(2); or

(ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an affected unit under 40 CFR 72.6(a)(3).

Sulfur Dioxide Requirements, Cont'd.

STEP 3, Cont'd.

(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.
(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.
(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

Nitrogen Oxides Requirements

The owners and operators of the source and each affected unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

Excess Emissions Requirements

(1) The designated representative of an affected source that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77.
(2) The owners and operators of an affected source that has excess emissions in any calendar year shall:
  (i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR part 77; and
  (ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77.

Recordkeeping and Reporting Requirements

(1) Unless otherwise provided, the owners and operators of the source and each affected unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or permitting authority:
  (i) The certificate of representation for the designated representative for the source and each affected unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;

Recordkeeping and Reporting Requirements, Cont'd.

STEP 3, Cont'd.

(ii) All emissions monitoring information, in accordance with 40 CFR part 75, provided that to the extent that 40 CFR part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply.
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,
(iv) Copies of all documents used to complete an Acid Rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.

(2) The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR part 72 subpart I and 40 CFR part 75.

Liability

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
(4) Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.
(5) Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated representative of an affected source) shall also apply to the owners and operators of such source and of the affected units at the source.
(6) Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit.
(7) Each violation of a provision of 40 CFR parts 72, 73, 74, 75, 76, 77, and 78 by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

Effect on Other Authorities

No provision of the Acid Rain Program, an Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 shall be construed as:
(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an affected source or affected unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating

Highwood Generating Station
Facility (Source) Name (from STEP 1)

Effect on Other Authorities, Cont'd.

STEP 3, Cont'd.

to applicable National Ambient Air Quality Standards or State Implementation Plans;
(2) Limiting the number of allowances a source can hold; *provided,* that the number of allowances held by the source shall not affect the source's obligation to comply with any other provisions of the Act;
(3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law;
(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,
(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

Certification

STEP 4
Read the certification statement, sign, and date.

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name **Tim Gregori, Manager**	
Signature T R G	Date **04/24/2009**

Instructions for the Acid Rain Program Permit Application

The Acid Rain Program requires the designated representative to submit an Acid Rain permit application for each source with an affected unit. A complete Certificate of Representation must be received by EPA before the permit application is submitted to the title V permitting authority. A complete Acid Rain permit application, once submitted, is binding on the owners and operators of the affected source and is enforceable in the absence of a permit until the title V permitting authority either issues a permit to the source or disapproves the application.

Please type or print. If assistance is needed, contact the title V permitting authority.

STEP 1 A Plant Code is a 4 or 5 digit number assigned by the Department of Energy=s (DOE) Energy Information Administration (EIA) to facilities that generate electricity. For older facilities, "Plant Code" is synonymous with "ORISPL" and "Facility" codes. If the facility generates electricity but no Plant Code has been assigned, or if there is uncertainty regarding what the Plant Code is, contact EIA at (202) 586-4325 or (202) 586-2402.

STEP 2 In column "a," identify each unit at the facility by providing the appropriate unit identification number, consistent with the identifiers used in the Certificate of Representation and with submissions made to DOE and/or EIA. Do not list duct burners. For new units without identification numbers, owners and operators must assign identifiers consistent with EIA and DOE requirements. Each Acid Rain Program submission that includes the unit identification number(s) (e.g., Acid Rain permit applications, monitoring plans, quarterly reports, etc.) should reference those unit identification numbers in exactly the same way that they are referenced on the Certificate of Representation.

Submission Deadlines

For new units, an initial Acid Rain permit application must be submitted to the title V permitting authority 24 months before the date the unit commences operation. Acid Rain permit renewal applications must be submitted at least 6 months in advance of the expiration of the acid rain portion of a title V permit, or such longer time as provided for under the title V permitting authority=s operating permits regulation.

Submission Instructions

Submit this form to the appropriate title V permitting authority. If you have questions regarding this form, contact your local, State, or EPA Regional Acid Rain contact, or call EPA's Acid Rain Hotline at (202) 343-9620.

Paperwork Burden Estimate

The public reporting and record keeping burden for this collection of information is estimated to average 8 hours per response. Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number.

Send comments on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including through the use of automated collection techniques to the Director, Collection Strategies Division, U.S. Environmental Protection Agency (2822T), 1200 Pennsylvania Ave., NW., Washington, D.C. 20460. Include the OMB control number in any correspondence. **Do not send the completed form to this address.**

APPENDIX I: ELECTRONIC FILES