Addendum to Final Permit Application

Notice of Intent
Intermountain Power Project
Proposed Unit 3

Prepared for

Intermountain Power Service Corporation

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Acronyms

°F	degrees Fahrenheit
$\mu g/m^3$	micrograms per cubic meter
acfm	actual cubic feet per minute
ACI	activated carbon injection
AO	approval order
AQIA	air quality impact analysis
AQRV	air quality-related values
BACT	best available control technology
Btu	British thermal unit
CAA	Clean Air Act
CAM	compliance assurance monitoring
CEMS	continuous emissions monitoring system
CFR	Code of Federal Regulations
CO	carbon monoxide
CO_2	Carbon Dioxide
COMS	continuous opacity monitoring system
CPM	condensable particulate matter
CSU	Colorado State University
CTG	composite theme grid
DAS	data acquisition system
DAT	deposition analysis thresholds
DEM	digital elevation model
EMCC	en masse chain conveyors
EPA	United States Environmental Protection Agency
ESP	electrostatic precipitator
ETF	emission threshold factor
ETV	emission threshold value
FGD	flue gas desulfurization
FLAG	Federal Land Manager's Air Quality-Related Values Workgroup
FLM	federal land manager
FR	Federal Register
ft^2	square feet
ft^3	cubic feet
g/m^3	grams per cubic meter
GEP	good engineering practices
gph	gallons per hour
H_2O	water
H_2SO_4	sulfuric acid mist
HAP	hazardous air pollutant
HCL	hydrochloric acid
HF	hydrogen fluoride
$HgCl_2$	mercuric chloride

HNO_3	nitric acid
IMPROVE	Interagency Monitoring of Protected Visual Environment
IPA	Intermountain Power Agency
IPP	Intermountain Power Project
IPSC	Intermountain Power Service Corporation
IWAQM	Interagency Workgroup on Air Quality Modeling
kg/ha/yr	kilograms per hectacre per year
km	kilometer
kW	kilowatt
kWh	kilowatt hour
LAER	lowest achievable emissions reduction
lb	pound
lb/hr	pound per hour
LNB	low NOx burner
LOI	loss on ignition (unburned carbon)
MACT	maximum achievable control technology
mg/m^3	milligrams per cubic meter
Mm^{-1}	inverse megameters
MM5	Mesoscale Model—Version 5
mmBtu	million British thermal units
mmBtu/hr	million British thermal units per hour
mmBtu/yr	million British thermal units per year
msl	mean sea level
MW	megawatt
MWH	megawatt hour
N	nitrogen
NAAQS	National Ambient Air Quality Standards
NCDC	National Climatic Data Center
NDIR	nondispersive infrared
NED	national elevation dataset
NESHAP	National Emissions Standards for Hazardous Air Pollutants
NH_3	ammonia gas
NO_2	nitrogen dioxide
NO_3	nitrate
NOI	notice of intent
NOx	nitrogen oxide
NP	National Park
NPS	National Park Service
NRA	National Recreation Area
NS	no standard
NSPS	New Source Performance Standards
NSR	New Source Review
NWS	National Weather Service
O_2	oxygen
PAH	poly aromatic hydrocarbons
Pb	lead
PC	pulverized coal

PCB	polychlorinated biphenyls
PCDD	polychlorinated dibenzo-p-dioxins
PCDF	polychlorinated dibenzo furans
PIC	product of incomplete combustion
PM	particulate matter
PM_{10}	particulate matter less than 10 microns in diameter
POM	polycyclic organic matter
PPA	pre-project actual
ppm	parts per million
ppmv	parts per million by volume
ppmvd	parts per million by volume dry
PPP	post-project potential
PSD	Prevention of Significant Deterioration
psig	pounds per square inch gauge
PTE	potential to emit
QA	quality assurance
QC	quality control
RBLC	RACT/BACT/LAER Clearinghouse
RCRA	Resource Conservation and Recovery Act
RMP	risk management plan
RSC	reduced sulfur compound
S	sulfur
SCR	selective catalytic reduction
SIC	standard industrial classification
SIP	state implementation plan
SNCR	selective noncatalytic reduction
SO_2	sulfur dioxide
SO_3	sulfur trioxide
SO_4	sulfate
SRDT	solar radiation/delta-T
TLV	threshold limit value
tph	tons per hour
tpy	tons per year
TRS	total reduced sulfur
UAC	Utah Administrative Code
UDAQ	Utah Division of Air Quality
UDEQ	Utah Department of Environmental Quality
USC	Utah Statutory Code
USGS	United States Geological Survey
UTM	universal transverse mercator
VOC	volatile organic compound

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Executive Summary

Intermountain Power Service Corporation (IPSC) currently operates the Intermountain Power Project (IPP) site located near the town of Delta in Millard County, Utah. The plant consists of two conventional Babcock & Wilcox, drum-type, pulverized coal (PC)-fired, generating units designated Unit 1 and Unit 2. Intermountain Power Agency (IPA) is proposing to expand the IPP facility by adding one additional nominal 950-gross MW unit designated as Unit 3.

The addition of Unit 3 at the IPP facility will result in additional power generating capacity to sustain current and future power demands in the State of Utah. This project will result in economic benefit through the creation of jobs: temporary jobs during facility construction, permanent jobs during startup and operation, and employment opportunities associated with facility support, fuel mining, and transportation functions.

This enhanced Notice of Intent (NOI) submitted on December 16, 2002, was intended to serve as an application for an Approval Order (AO) in accordance with Utah Administrative Code (UAC) R307-401. The December 16, 2002 NOI submittal was also a request for an amendment to the existing IPP Title V operating permit (Operating Permit #2700010001). A mark-up copy of the existing Title V permit to incorporate the operating provisions for Unit 3 will be provided after the renewed Title V permit for Units 1 and 2 has been issued.

Since the enhanced NOI was submitted to UDAQ on December 16, 2002, several meetings have been held with the staff of UDAQ where questions of clarification were raised about the submitted NOI. In order to capture the responses to all of these questions, at UDAQ's request IPA has chosen to prepare this red-line addendum to the NOI. This addendum is prepared with all of the answers to the questions embedded into the original text. In that way, the reader can read the supplementary material in context. The addition of Unit 3 is subject to Prevention of Significant Deterioration (PSD) regulations for carbon monoxide (CO), total particulate matter (PM), particulate matter less than 10 microns in diameter (PM_{10}), volatile organic compounds (VOCs), sulfur dioxide (SO_2), nitrogen oxide (NO_X), lead, sulfuric acid mist (H_2SO_4), hydrogen fluoride (HF), total reduced sulfur (TRS), and reduced sulfur compounds (RSCs). A complete Best Available Control Technology (BACT) analysis for all PSD pollutants has been performed.

The BACT analysis resulted in a Unit 3 design that will be one of the highest controlled PC-fired boilers ever constructed. The Unit 3 design includes the following add-on control devices: Low NO_x burners (LNBs) and a selective catalytic reduction (SCR) system to control NO_x emissions to an outlet concentration of 0.07 lb/mmBtu; a forced oxidation wet limestone flue gas desulfurization (FGD) system to control SO_2 to an outlet concentration of 0.10 pounds per million British thermal units (lb/mmBtu); and a fabric filter baghouse to control filterable PM to an outlet concentration of 0.020 lb/mmBtu and filterable PM_{10} emissions to an outlet concentration of 0.015 lb/mmBtu. IPP requests BACT emission limits based on a 30-day averaging period, consistent with EPA's NSR guidance and recent NSR enforcement Consent Decrees.

This addendum to the application includes a complete process description; a detailed regulatory review of all applicable state and federal air quality regulations; emissions estimates for all new sources and modified existing sources; the modeled impacts of these emissions on Class I and Class II areas; requested permit limits; a maximum achievable control technology (MACT) analysis for hazardous air pollutants (HAPs); monitoring information; and a compliance assurance monitoring (CAM) plan with appropriate certification.

1.0 Introduction

Intermountain Power Service Corporation (IPSC) currently operates the Intermountain Power Project (IPP) site located near the town of Delta in Millard County, Utah. The plant consists of two conventional Babcock & Wilcox, drum-type, pulverized coal (PC)-fired, generating units. These units are designated Unit 1 and Unit 2, and have a currently approved, combined gross generation capacity of 1,900 megawatts (MW). The IPP facility is a major stationary source of air emissions. The Intermountain Power Agency (IPA) is proposing to expand the IPP facility by adding one additional nominal 950-gross MW (nominal 900-net MW) unit designated as Unit 3. This enhanced Notice of Intent (NOI) is intended to serve as an application for an approval order (AO) in accordance with Utah Administrative Code (UAC) R307-401. This document also requests an amendment to the existing IPP Title V operating permit (Operating Permit #2700010001). The addition of Unit 3 to IPP will constitute a major modification of the existing major stationary source.

This application contains information for the proposed addition of Unit 3, including a process description, emissions information, a request for permit limits, regulatory review, a best available control technology (BACT) analysis, a maximum achievable control technology (MACT) analysis for applicable hazardous air pollutants (HAPs), results of Class I and Class II modeling, monitoring information, and a compliance plan. The required NOI and Title V application forms are provided in Appendices A and B of this application.

1.1 Project Overview

The addition of Unit 3 at the IPP facility will increase power generating capacity to sustain current and future power demands in the State of Utah. This project will result in economic benefit through the creation of jobs: temporary jobs during facility construction, permanent jobs during startup and operation, and employment opportunities associated with facility support, fuel mining, and transportation functions.

The IPP facility is located in an area of relatively low population density in the Sevier Desert of west central Utah. The IPP facility is situated in a broad valley that is favorable to plume dispersion. The nearest Class I area is located approximately 149 kilometers (km) southeast [Capitol Reef National Park (NP)]. State-of-the-art pollution controls are proposed for Unit 3 that will make the new unit one of the cleanest PC-fired power plants in the nation. Nitrogen oxide (NO_x) emissions will be controlled by low NO_x burners (LNBs), overfire air, and selective catalytic reduction (SCR) to an outlet concentration of 0.07 pound (lb)/million British thermal units (mmBtu). Sulfur dioxide (SO_2) emissions will be controlled by forced oxidation wet limestone flue gas desulfurization (FGD) to an outlet concentration of 0.10 lb/mmBtu. Particulate matter less than 10 microns in diameter (PM_{10}) emissions will be controlled by a reverse air fabric filter baghouse to an outlet concentration of 0.015 lb/mmBtu.

The atmospheric dispersion modeling aspects of the project are required to ensure that construction of Unit 3 will not result in adverse impacts to the many NPs and wilderness areas in Utah or to the area surrounding the plant. The air quality modeling that has been performed demonstrates that Unit 3 emissions will not adversely impact public health, public welfare, or air quality-related values (AQRVs). Early public involvement, by means of the air permitting process, will ensure that the Unit 3 project will be designed and constructed with adequate measures to protect public health and the environment.

1.2 Unit 3 Impact on IPP Emissions Levels

The addition of Unit 3 is subject to Prevention of Significant Deterioration (PSD) regulations for carbon monoxide (CO), total particulate matter (PM), PM_{10}, volatile organic compounds (VOCs), SO_2, NO_X, lead, sulfuric acid mist (H_2SO_4), hydrogen fluoride (HF), total reduced sulfur (TRS), and reduced sulfur compounds (RSCs).

IPP Units 1 and 2 were previously permitted (DAQE-049-02) as major stationary sources under state and federal PSD air quality regulations. The addition of Unit 3 is subject to separate additional PSD permitting because there is a significant increase in emissions of PSD-regulated pollutants associated with the proposed addition of Unit 3. Annual emissions from Unit 3 (including main boiler, cooling tower, and material handling operations) are estimated to be 3,964 tons per year (tpy) of SO_2, 2,775 tpy of NO_x, 5946 tpy of CO, 793 tpy of PM (filterable), 990 tpy of PM_{10} (filterable and condensable), 107 tpy of VOCs, 0.79 tpy of lead, 174 tpy of H_2SO_4, 20 tpy of HF, 29 tpy of TRS, 29 tons of RSCs, and 199 tpy of HAPs. All estimated outputs throughout this document and its appendices were based on highest feasible design values. Therefore, PSD New Source Review (NSR) requirements will apply to these pollutants for the addition of Unit 3.

The IPP is located in an attainment area for all criteria pollutants. The IPP will meet all primary and secondary National Ambient Air Quality Standards (NAAQS). IPP will also meet Class I increments in the NPs in southern Utah and Class II PSD increments in the vicinity of the plant. Unit 3 will also be required to meet the applicable New Source Performance Standards (NSPS) defined in federal regulations 40 Code of Federal Regulations (CFR) 60 Subpart Da.

1.3 NOI Application Organization

This application is organized into ten sections and seven appendices. They are summarized as follows:

- **Section 1.0 – Introduction.** This section provides an overview of the project and describes the report organization.
- **Section 2.0 – Process Description.** This section includes a process description for Unit 3.
- **Section 3.0 – Emissions–Related Information.** This section provides a summary of emissions-related information, including stack emissions and material handling emissions estimates.
- **Section 4.0 – Requested Permit Limits.** This section presents a discussion of requested permit limits consistent with assumptions made in the analysis of project-related emissions.

- Section 5.0 – Regulatory Applicability Review and Requirements. This section contains a detailed regulatory review of state and federal air regulations that may impact the permitting, construction, or operation of the proposed Unit 3.
- Section 6.0 – Control Technology Analysis. This section includes a control technology analysis for criteria pollutants (BACT analysis) and for HAPs (MACT analysis).
- Section 7.0 – Far-Field (CALPUFF) Air Quality Impact Analysis. This section presents a summary of the Class I modeling analysis.
- Section 8.0 – Near-Field Dispersion Modeling Analysis. This section presents the results of the Class II modeling analysis.
- Section 9.0 – Monitoring Information. This section presents monitoring-related information.
- Section 10.0 – Compliance Plan and Certification. This section presents the Title V compliance plan and certification.
- Appendix A – NOI Application Forms. This appendix provides the application forms necessary to obtain an NOI for Unit 3.
- Appendix B – Title V Application Forms. This appendix contains the completed forms necessary to obtain a Title V operating permit.
- Appendix C – Emissions Calculations. This appendix provides the calculations that were used to determine the emissions for this permit application.
- Appendix D – Regulatory Compliance Checklist. The regulatory compliance checklist lists all applicable regulations and their applicability to Unit 3.
- Appendix E – Air Quality Analysis. This appendix provides support for the air quality analysis.
- Appendix F – RBLC Database Tables. This appendix provides the RACT/BACT/LAER Clearinghouse (RBLC) database tables used for the BACT analysis, which is described in Section 6.0.
- Appendix G – BACT Cost Analysis. This appendix contains the full analysis of costs for each alternative reviewed in the BACT analysis.
- Appendix H – BACT Supporting Information. This appendix contains a review of all potential control technologies by applicable BACT pollutant.
- Appendix I – Technology Discussions. This appendix contains supplemental white papers prepared in response to specific UDAQ comments received during the technical review of the NOI.

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2.0 Process Description

2.1 General Process Description

The IPP facility is located in Millard County, Utah near the town of Delta. A site location map is provided in Figure 2-1. The plant currently consists of two PC-fired, electric generating units designated as Units 1 and 2. Their generating capacities are nominal 950-gross MW each (after completion of recently permitted upgrades). IPA is planning the addition of a third nominal 950-gross MW generating unit designated as Unit 3.

In the initial planning stages of this project it was necessary for IPA to define the type of electricity generating facility it would propose for IPA Unit 3. Several technical, financial, environmental, and practical considerations were reviewed in order to reach a conclusion as to the most appropriate design for IPA Unit 3. Items taken into consideration included: requisite generating capacity, reliability, availability, fuel availability, safety factors, operating training, redundancy/compatibility with existing IPP Units 1 and 2, and potential environmental impacts. Some of the more important project design criteria are listed below:

- Unit 3 should be capable of generating a nominal 900-MW net output.
- Unit 3 would be a baseload unit, and therefore the unit must be designed with technologies capable of achieving a capacity factor of 90 percent.
- As a baseload unit, Unit 3 must be very reliable and must be capable of maintaining a very low forced outage rate. Therefore, Unit 3 must be designed with a highly reliable boiler and turbine, reliable emission control technologies, and reliable ancillary equipment.
- Based on fuel availability, the Unit 3 boiler should be designed to fire Utah bituminous coal with an annual average maximum design coal sulfur content of 0.75 percent, and a design coal heating value of 11,193 Btu/lb.[1]
- To ensure flexibility in the fuel supply, the proposed boiler should be capable of burning a blend of Utah bituminous coal and western sub-bituminous coal.
- For safety considerations, operating training considerations, and O&M reliability, the boiler design and operation should be (to the extent practicable) compatible with the existing IPP coal-fired units.
- Unit 3 must be equipped with the best available emission control technologies, and controlled emissions from the proposed unit must not cause or contribute to a violation of the applicable NAAQS or applicable PSD increment.

[1] A detailed discussion of the proposed design fuel is provided in a paper titled "*Intermountain Power Project Unit 3 Coal Supply.*" This paper is included in Appendix I-1 of this NOI Addendum.

Various electricity generating technologies were reviewed to identify the technologies capable of meeting all of the project specifications. It was concluded that the most appropriate electricity generating technology, and, in fact, the only technically feasible and commercially available technology capable of meeting all the project specifications, was a large single-boiler pulverized coal-fired unit equipped with the best available emission control technologies. Project criteria critical to feasibility of the IPA project exclude Integrated Gasification Coal Combustion (IGCC), Circulating Fluidized Bed combustion (CFB), natural gas-fired combined cycle combustion, and other alternative electricity generating technologies from consideration. These alternative electricity generating technologies were not selected for various reasons, including size limitations, reliability and availability problems, fuel requirements, and safety considerations. To meet all critical project criteria, IPA is proposing a nominal 950-MW gross PC-fired boiler.

The IPP facility generates electric power for sale to the customers of the IPA; IPSC is the operating contractor of IPP. The generating plant produces electricity by combusting coal to produce heat, which is then used to convert water (H_2O) to steam. The steam-powered turbines are attached to electric generators. Generators convert mechanical energy supplied by a turbine into electrical energy that is delivered to customers via high voltage electric transmission lines. Each boiler/generator/turbine combination is referred to as a “unit.” Figure 2-2 contains a simplified diagram of a steam electric power plant.

A fossil fuel generating plant, consists of the following components:

- Boiler
- Turbine
- Generator
- Various Configurations of Auxiliary Equipment
- Fuel Handling
- Emissions Control Equipment
- Ash and Combustion By-Product Collection, Transport, and Disposal
- Limestone Handling

In a typical fossil fuel boiler, water-containing tubes line the inside of the furnace walls. Fuel is ignited and burned as it enters the furnace. The burning fuel releases thermal energy, which is absorbed by the water in the tubes. As the temperature of the water rises, the water begins to boil and steam is produced. The steam is piped from the boiler to the steam turbine.

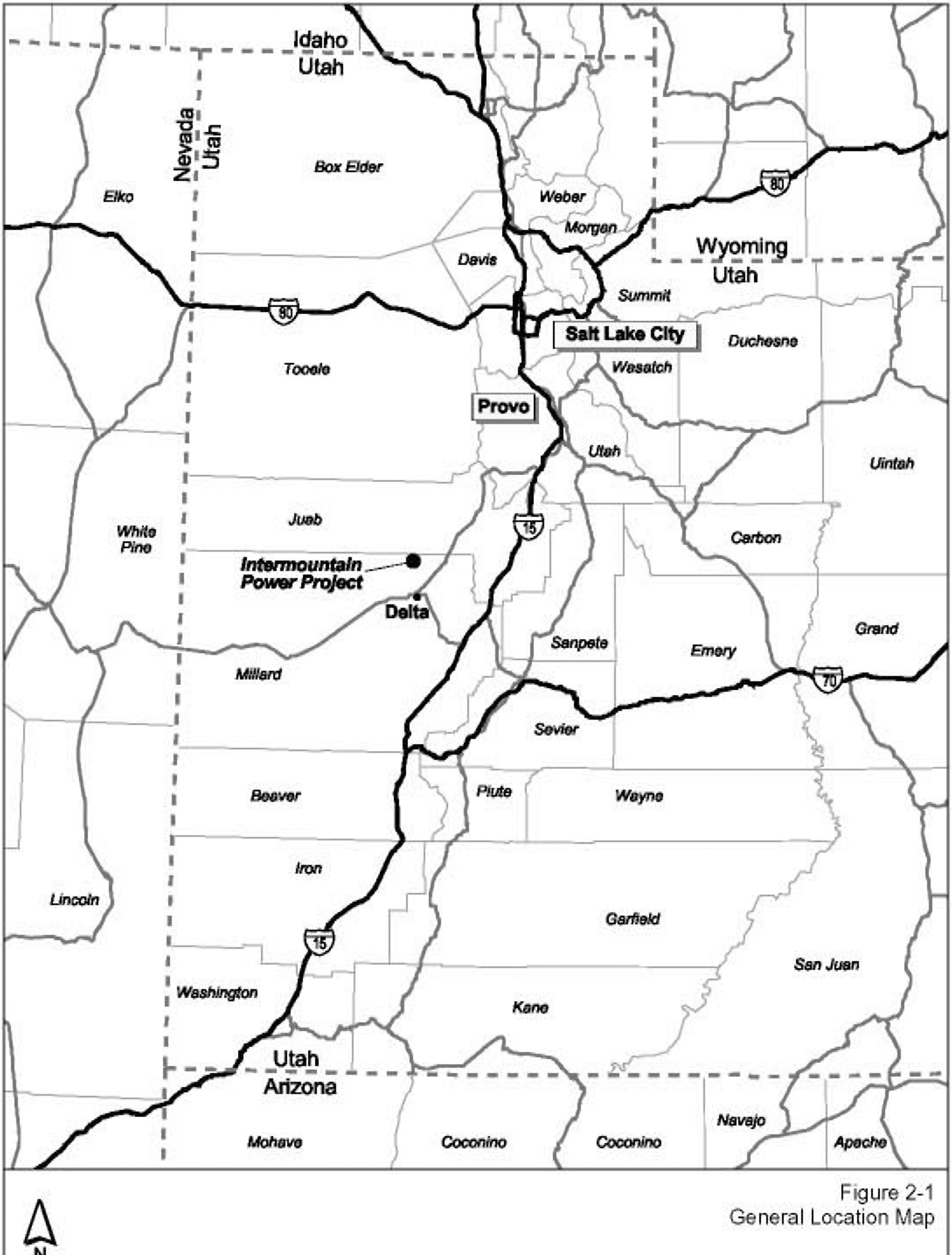

Figure 2-1
General Location Map

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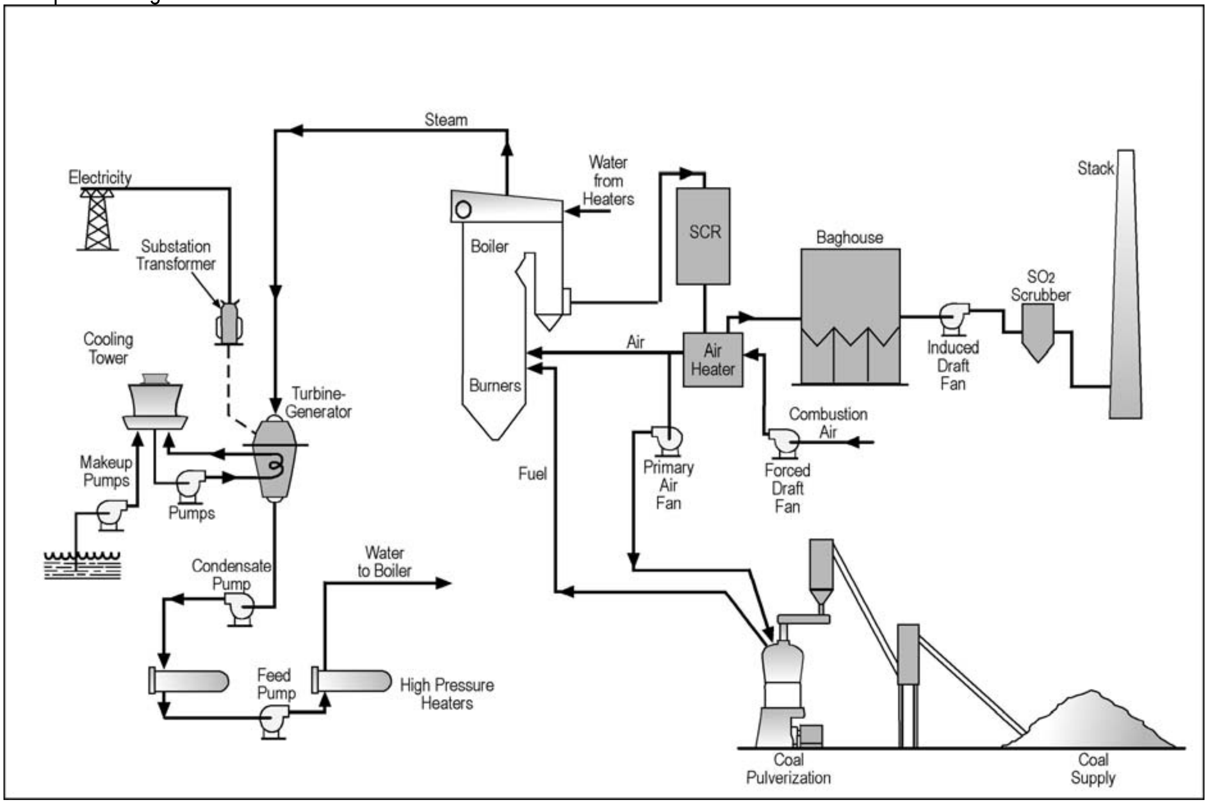
FIGURE 2-2
Simplified Diagram of a Steam Electric Power Plant



The steam turbine is comprised of blades attached to a rotating shaft. Steam turbines have both stationary and rotating blades. As the high-pressure steam passes through the turbine blades, the pressure and thermal energy of the steam is converted to mechanical energy. The mechanical energy causes the rotating set of blades to move, thus rotating the shaft of the turbine. The steam turbine shaft is coupled to the shaft of the electrical generator. The generator converts mechanical energy into electric energy.

As the steam passes through the turbine, it flows into the condenser. In the condenser, the steam is cooled and condensed back into water. The water is then pumped back to the boiler through a series of low-pressure condensate heaters, a deaerator, and several high-pressure feedwater heaters. Then the cycle begins again.

The complete loop from the boiler, through the turbine, into the condenser, through the condensate and feedwater systems, and back to the boiler is called the condensate-feedwater-steam cycle. All of the components and systems involved in the condensate-feedwater-steam cycle are generally referred to as one generating unit.

Each generating unit is comprised of several component systems that are either specific to that individual generating unit or shared across multiple units. The major component systems and sub-systems of the existing IPP Generating Station are as follows:

- Steam Generating Units
  - Boiler
  - Steam Turbine

  - Boiler Feedwater System
  - Process Cooling Water System
- Pollution Control Equipment
  - FGD System (SO_2 Scrubber)
  - Baghouse
- Fuel Handling
  - Coal Handling
  - Fuel Oil System
- Limestone, Lime, and Soda Ash Handling
- Ash and Combustion By-Products Collection, Transport, and Disposal

The new unit shall consist of the same sub-systems. Unit 3 will also have an SCR control system as part of the emissions control equipment. The remainder of this section includes a description of those systems which contain or affect this facility's air emissions. Systems that do not contain or impact air emissions, or those systems with air emissions deemed insignificant by the Utah Division of Air Quality (UDAQ), are not included in this process description.

2.2 Steam Generating Units

2.2.1 Proposed Unit 3 Process Description

The proposed primary fuel will be a western bituminous coal. Coal will be primarily delivered to the plant by rail and alternately in trucks. The coal will be delivered to the coal shed and transferred to the plant by means of covered conveyors. Unit 3 coal heat input at full load is estimated at 9,050 million British thermal units per hour (mmBtu/hr) or 7.93E+7 million British thermal units per year (mmBtu/yr) at 100-percent capacity factor. No. 2 fuel oil will be used for light off, startup, and flame stabilization. No. 2 fuel oil is stored in the existing aboveground tanks, which are located on the plant site and currently serve Units 1 and 2. No additional oil storage is planned for Unit 3. The total amount of oil used per year will be approximately 50,000 barrels per year for the auxiliary boilers permitted under Unit 1 and 2 permit. Coal and oil burner configurations and combustion control systems will be designed to provide high combustion efficiency and to control the production of NO_x, CO, and VOCs in the flue gas.

The SO_2 emissions will be controlled with a forced oxidation wet limestone FGD scrubbing system. NO_x emissions will be controlled with LNBs, overfire air, and SCR. PM and PM_{10} emissions will be controlled by a reverse air baghouse.

The clean flue gas will go from the induced-draft fans through the FGD and will be exhausted through a stack to the atmosphere. The stack will consist of a concrete outer shell and a fiber glass flue. A continuous emissions monitoring system (CEMS) will be provided to monitor emissions.

2.2.2 Proposed Boiler Process Description

The proposed Unit 3 boiler will be an indoor-type, subcritical, PC-fired boiler designed for base load operation. The unit will have a maximum gross heat input of approximately

9,050 mmBtu/hr and a plant electrical output of approximately 950-gross MW. Unit 3 will generate a main steam turbine throttle pressure of 2,520 pounds per square inch gauge (psig) at 1,050°F. The primary fuel for Unit 3 will be western bituminous coal. However, the unit will be designed to burn blends of western bituminous and sub-bituminous coal. No. 2 fuel oil will be used as the startup fuel. The design fuel characteristics for the proposed western bituminous coal are shown in Table 2-1.

TABLE 2-1
Western Bituminous Worst-Case Design Coal Characteristics

Parameter	Units	Worst-Case Design Coal[a]
Gross (Higher) Heating Value	Btu/lb	11,193
Moisture	wt percent	8.26
Volatile Matter	wt percent	37.0
Fixed Carbon	wt percent	43.0
Average Maximum[b] Sulfur Content	wt percent	0.75
Average Maximum[b] Ash Content	wt percent	12.0
Average Maximum[b] Uncontrolled SO_2 Emission Rate	lb/mmBtu	1.34

[a]*Worst-case design coal* will generate the highest pollutant emission rates, refer to coal supply white paper in Appendix I.

[b]*Average maximum* is defined as the maximum coal characteristic value based on an average of sample results collected over a calendar year.

It is anticipated that the Unit 3 boiler will be a dry-bottom, tangentially-fired or wall-fired (front and rear) boiler with LNBs and overfire air ports. Specifications for the proposed boiler are included in Table 2-2. Flue gas from Unit 3 will pass through a series of post-combustion emissions control devices (described in Section 2.2.1 of this permit application) before going to the ambient air through a single 712-foot stack.

- Low NO_X Burners, overfire air, and Selective Catalytic Reduction
- Fabric Filter
- Wet limestone Flue Gas Desulfurization system

TABLE 2-2
Boiler Design Parameters

Plant Parameter[a]	Units	Design Parameters
Nominal Gross Plant Output	Gross-kilowatt (kW)	950,000
Steam Temperature	^{o}F	1,050
Main Steam Pressure	Psig	2,520
Gross Plant Heat Rate - HHV	Btu/gross-kilowatt hour (kWh)	9,072
Net Plant Heat Rate - HHV	Btu/net-kWh	9,790

Full Load Heat Input to Boiler - HHV	mmBtu/hr	9,050
Coal Feed Rate	tph	404
Maximum Fuel Oil Feed Rate[b]	gph	10,000

[a] The numbers in this table are preliminary design estimates.

[b] 15 percent of full load heat input

The boiler area will be a totally enclosed design. Burners will be located at various levels either in the four corners or in the front and back furnace walls. The principal components of the boiler will be:

- Membrane Wall Furnace
- Superheater
- Reheater
- Economizer
- Convection Pass
- Coal Pulverizers
- LNBs, Fans, and Air Heater
- Flues and Ducts
- Piping and Valves

2.2.3 Proposed Boiler Coal Description

IPP Unit 3 will primarily utilize Utah-produced coal with an average maximum sulfur content of 0.75 percent by weight and a heat content of 11,193 BTU/lb. This represents the worst-case design coal, or coal that will generate the highest pollutant emission rates. As noted in Table 2-1, average maximum is defined as the maximum coal characteristic value based on an average of sample results collected over a calendar year.

Since fuel costs represent over 40 percent of the cost of power generation, it is important to evaluate the delivered fuel cost, including the cost of transporting fuels over long distances. Based on this, Utah coals are economic for the proposed IPP Unit 3. In accordance with the Utah Legislature's intent to support the economic viability of the Utah coal market, as well as the Governor's desire for IPP Unit 3 to use Utah coal as much as practical, IPA has designed Unit 3 to burn primarily Utah coals. If availability of Utah coals is limited in the future, it may be economical and necessary to burn out-of-state coals. Therefore, IPA must allow for fuel flexibility in developing the design for Unit 3.

Utah coals have some of the highest heat content and lowest sulfur content in the country. Power River Basin (PRB) coals are also considered to be low sulfur coals. PRB coals however have a lower heat content compared to Utah coals. The higher heat content of Utah coals has a significant effect on post-combustion SO_2 concentration. The post-combustion concentration of SO_2 for a typical Utah coal is comparable to a typical PRB fuel. With the uncontrolled SO_2 emission rates essentially the same for both coal types, IPP Unit 3 will be permitted with a worst-case design coal sulfur content, 0.75 percent in Utah coal.

Additional discussion relating to the Utah coal supply and use of Utah Coal for Unit 3 is provided in Appendix I-1 in the supplemental white paper entitled *Intermountain Power Plant Unit 3 Coal Supply*.

2.3 Pollution Control Equipment

2.3.1 FGD System

The Unit 3 boiler will be equipped with a wet limestone FGD system. The FGD system, located downstream from the fabric filter, will be designed to remove SO_2 from the flue gas stream through limestone slurry absorption system. Emissions of other sulfur compounds will also be controlled with the use of the FGD system.

The FGD system is composed of the following five subsystems:

- The absorption system, which consists of a spray tower, reaction tank, agitators, air sparger, air compressor, and spray tower recycle pumps.
- The limestone slurry preparation system, which consists of the limestone ball mills, slurry tanks, and slurry pumps.
- Limestone handling and storage system, which consists of a rail/truck unloading facility, conveyors, storage area, and transfer conveyors.
- The primary and secondary dewatering system, which consists of a hydroclone or thickeners, filter feed tank, vacuum/belt filters, conveyors, and temporary storage area.
- The flue gas system, which consists of inlet and outlet ducts, induced draft fans, and inlet/outlet dampers.

The FGD system for Unit 3 starts at the gas outlet flanges of the fabric filter system and includes the outlet ducts and induced draft fans, each with inlet and outlet dampers. The fans are connected in parallel and provide draft to pull the gas through the boiler, SCR system, and fabric filters. The fans then force the gas through the spray tower absorbers and into the stack. All boiler exhaust gases from Unit 3 will pass through the FGD system. The FGD system will be designed with two scrubber modules. Each absorber vessel is being designed to treat a nominal 67 percent of the gas flow under normal operating conditions. The scrubbers will be designed to control SO_2 emissions from a western bituminous coal based on coal parameters in Table 2-1.

Ground limestone in the scrubbing slurry reacts with SO_2 in the flue gas to form calcium sulfite and some calcium sulfate. Slurry from the spray tower flows to the bottom of the scrubber to a reaction tank. The reaction tank will be designed with blowers to oxidize the calcium sulfite to calcium sulfate (i.e., gypsum). The gypsum slurry will be drawn off the reaction tank and sent to a sludge conditioning system. It is anticipated that the gypsum slurry will be treated in a series of hydroclones located in the scrubber building. Reclaimed water from the hydroclones will be sent back for reuse in the scrubber system, and gypsum solids will be sent to a vacuum filtration system. Gypsum solids from the vacuum filter system can be washed to remove contaminants and loaded into railcars or trucks for shipment as a product. If necessary, the contaminants washed off the gypsum solids will be mixed with fly ash and conveyed to the landfill using the facility's existing conveyor system.

The FGD system will be designed to consistently achieve a controlled SO_2 emission rate of 0.10 lb/mmBtu. Based upon the coal characteristics in Table 2-1, the FGD system will be designed to reduce SO_2 emissions by approximately 90 percent. Anticipated design and operating parameters for the FGD system include flue gas flow rate [in actual cubic feet per minute (acfm)] as shown in Table 2-3. Additional technical discussion relating to the proposed control technology for SO_2 is provided in Appendix I-5 in the supplemental white paper entitled *Sulfur Dioxide Control – Flue Gas Desulfurization and Control Efficiency*.

TABLE 2-3
FGD Operating Parameters

Parameter	Units	Estimated Design Value	Notes
General Description		Wet Limestone FGD	
Number of Scrubber Modules		Two ~67 percent Modules	
Flue Gas Flow Rate	acfm	3,617,117 @ 275 – 300 °F	At 100-percent load
Flue Gas Temperature (inlet)	^oF	275 – 300	
Pressure Drop Through Scrubber	in. H_2O	8 (typical)	
Inlet SO_2 Concentration	lb/mmBtu	1.34	Design coal
Outlet SO_2 Concentration	lb/mmBtu	0.10	Maximum SO_2 emission rate
SO_2 Removal Efficiency	percent	90+	Based on worst-case design
HCl Removal Efficiency	percent	90	
HF Removal Efficiency	percent	90	
Calcium to Sulfur Molar Ratio		1.03	
Limestone Feed Rate	lb/hr	20,072	At 100-percent load
Sorbent Analysis		$CaCO_3$ 90 percent $MgCO_3$ 3 percent CaO 0 percent Ash 6.5 percent Moisture 0.5 percent	Typical limestone sorbent analysis
Scrubber Sludge Generation Rate	lb/hr	32,429	At 100-percent load

The wet limestone FGD system will also be used to control emissions of sulfuric acid from IPP Unit 3. Based on source test information obtained from IPP Unit 1, it is anticipated that the overall H_2SO_4 removal efficiency across the baghouse and the wet limestone FGD system will be approximately 90 percent. Technical discussion relating to the baghouse is provided in Section 2.3.3. Additional technical discussion relating to the H_2SO_4 emissions reduction capacity of the wet limestone FGD system is provided in Appendix I-4 in Section II of the supplemental white paper entitled *Evaluation of Wet Electrostatic Precipitation to Control Sulfuric Acid Mist Emissions*.

2.3.2 NO_x Control Technologies

IPP Unit 3 will be equipped with LNBs and an over fire air (OFA) system as combustion control for NO_x and with a SCR unit for post combustion control of NO_x emissions.

Low NOx burners limit NOx formation by controlling both the stoichiometric and temperature profiles of the combustion flame in each burner flame envelope. This control is achieved with design features that regulate the aerodynamic distribution and mixing of the fuel and air, yielding reduced oxygen (O2) in the primary combustion zone, reduced flame temperature, and reduced residence time at peak combustion temperatures.

In the OFA process, the injection of air into the firing chamber is staged into zones. The staging of the combustion air reduces NO_x formation by two mechanisms. The staged combustion results in a cooler flame, and the staged combustion results in less oxygen reacting with fuel molecules. However, the degree of staging is limited by operational problems. Excessive staging can result in incomplete combustion conditions and increased CO and VOC emissions. The combination of these two combustion control techniques produces lower NO_x emissions during the combustion process.

SCR is the state-of-the-art technology for the reduction of NO_x from flue gas streams. The proposed SCR is designed for high dust loading applications, and will be located external from the boiler. The SCR system uses a catalyst and a reactant [ammonia gas (NH_3)] to dissociate NO_x into nitrogen gas and water vapor. Since NO_x is a combination of NO_x and nitrogen dioxide (NO_2), there are two different chemical reactions that take place. The catalytic process reactions for this NO_x removal are as follows:

$$4NO + 4NH_3 + \text{oxygen } (O_2) \rightarrow 4N_2 + 6\ H_2O \text{ and}$$

$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O$$

The optimum temperature window for this catalytic reaction is between approximately 575 degrees Fahrenheit (°F) and 750°F. Therefore, the SCR reaction chamber will be located between the boiler economizer outlet and air heater flue-gas inlet. The system will be designed to use anhydrous ammonia as the reducing agent. Ammonia injection pipes, nozzles, and a mixing grid will be located upstream of the reaction chamber. A diluted mixture of NH_3 in air will be dispersed through injection nozzles into the flue-gas stream. The ammonia/flue-gas mixture then enters the reactor where the catalytic reactions occur.

SCR systems have been designed with a variety of catalysts and catalyst support substrate designs. Catalyst composition and geometry cannot be determined until detailed design of the SCR system is complete. Typically, the catalyst will be supported on a stainless steel or corrugated fiberglass substrate. The substrate will be designed to minimize abrasion of the catalyst surface while providing contact between the catalyst and flue gas.

The catalyst composition typically used in PC-fired plants consists of vanadium pentoxide (active catalyst) and titanium (used to disperse and support the vanadium mixture). An important design variable that may limit the SCR control efficiency is $SO_2 \rightarrow$ sulfur trioxide (SO_3) oxidation. Depending on the specific flue gas characteristics, catalyst manufacturers may have to control the $SO_2 \rightarrow SO_3$ oxidation rate by lowering the vanadium pentoxide content in the catalyst. Catalyst chemistry and design is a relatively new technology, and continues to evolve and improve. The final catalyst composition may consist of many active metals and support materials to meet the NO_x reduction requirements specified in the permit application.

Based on technical information provided by boiler vendors, it is anticipated that NO_x emissions from the boiler (prior to the SCR) can be controlled with LNBs and overfire air to 0.35 lb/mmBtu [approximately 250 parts per million by volume dry (ppmvd) at 3 percent O_2] while maintaining acceptable levels of CO and VOCs. Assuming a NO_x inlet concentration of 250 ppmvd at 3 percent O_2, the SCR will be designed to reduce the NO_x concentration to approximately 50 ppmvd at 3 percent O_2, or 0.07 lb/mmBtu. This represents a SCR removal efficiency of 80 percent.

Although a new SCR system may be able to achieve removal efficiencies greater than 80 percent, it is unlikely that a removal efficiency greater than 80 percent can be consistently achieved during long-term operation. Despite the fact that SCR is being used to control NO_x emissions from other pulverized coal-fired boilers, SCR is a relatively new control system and there is limited long-term operating experience. Furthermore, there is no actual operating experience demonstrating the affect that Utah bituminous coals may have on the SCR catalyst. Although Utah coals do not appear to exhibit qualities that will adversely impact SCR performance, without actual operating experience, the possibility exists that flue gas characteristics unique to Utah coals may cause unforeseen catalyst deterioration or deactivation.

Several factors influence the performance of an SCR system, including the catalyst age, abrasion of the catalyst surface, plugging, and flue gas characteristics that may be toxic to the catalyst (e.g., heavy metals in the fly ash). A catalyst that has been in service for a period of time will have decreased performance due to normal deactivation and deterioration. To prevent this decrease in performance, a catalyst maintenance plan will be developed to rotate and replace the catalyst modules as they become deactivated. Catalyst deterioration and deactivation is a function of several variables, including the flue gas characteristics, and it is not certain how flue gas generated from burning western bituminous coal will affect the SCR catalyst. The anticipated SCR operating parameters are summarized in Table 2-4.

Additional technical discussion relating to the proposed NO_x control technology is provided in Appendix I-2 in the supplemental white paper entitled *Nitrogen Oxide Emissions and Control*.

TABLE 2-4
SCR Operating Parameters

Parameter	Unit	Estimated Design Value
Catalytic Reaction Temperature	^{o}F	675 - 725
Inlet Gas Temperature	^{o}F	700 - 715
Inlet Gas Flow Rate	acfm	3,800,000 @ 700-715 °F
Reducing Agent		Anhydrous Ammonia
Maximum Ammonia Feed Rate	lb/hr	993
NO_x Inlet Concentration	ppmvd @ 3 percent O_2	250 (0.35 lb/mmBtu)
NO_x Outlet Concentration	ppmvd @ 3 percent O_2	50 (0.07 lb/mmBtu)
NO_x Control Efficiency	percent	80
Ammonia Slip	ppmvd @ 3 percent O_2	5
Catalyst Life	years	2 - 3

2.3.3 Baghouse

A fabric filter dust collector system (or "baghouse") will be provided for Unit 3 to remove PM and PM_{10} from the boiler flue gas stream. The fabric filter system will consist of a number of parallel banks of individual filter compartments located downstream of the air preheaters and upstream of the induced draft fans and the FGD system. Individual filter compartments consist of a bottom collection hopper and an upper bag compartment. A tube sheet separates the hopper from the bag compartment, and tube sheet thimbles direct gas flow through the tube sheet into the open bottom end of the filter bags. The closed upper end of the bag is attached to the top of the filter compartment.

Particulate-laden flue gas from the boiler enters the system compartments in the upper section of the hopper, just below the tube sheet. The flue gas stream travels up through the filter bags where particles collect on the inside of the bags. PM captured on the filter bags will form a filter cake. The filter cake increases both the filtration efficiency of the cloth and its resistance to gas flow.

Fabric filtration is a constant-emission process. Pressure drop across the filters, inlet particulate loading, or changes in gas volumes may change the rate of filter cake buildup, but will not change the final emission rate. Actual performance of a fabric-filter depends on specific items such as air/cloth ratio, permeability of the filter cake, the loading and nature of the particles (e.g., irregular-shaped or spherical), particle size distribution, and to some extent, the frequency of the cleaning cycle.

The filter bags must be routinely cleaned to remove accumulated filter cake. The cleaning frequency of the individual compartments will depend, in part, upon the inlet grain loading and the flow resistance of the filter cake formed. It is anticipated that the fabric filter system will be designed as a reverse-air system. In a reverse-air system, gas flow through an isolated compartment is reversed, causing the filter bag to collapse and fracture the filter cake. The filter cake then falls into the collection hopper for transport to the fly ash handling system.

Fabric filter system design involves inlet loading rates, fly ash characteristics, the selection of the cleaning mechanism, and selection of a suitable bag fabric and finish. Specific design parameters cannot be established until the actual fabric filter manufacturer is determined; however, the fabric filter system will be designed to achieve a maximum filterable PM_{10} emission rate of 0.015 lb/mmBtu.

Based on an average maximum fuel ash content, as shown in Table 2-1, and assuming that 80 percent of the total ash is emitted as fly ash, the maximum particulate loading to the fabric filter will be 6.58 lb/mmBtu heat input. At the maximum heat input of 9,050 mmBtu/hr, and an exhaust gas flow rate from the boiler of 3,628,000 acfm, particulate loading into the fabric filter system will be approximately 2.50 grains/acf (77,616 lb/hour). Controlling filterable PM_{10} emissions to a rate of 0.015 lb/mmBtu represents a control efficiency of 99.83 percent (based on the estimated inlet particulate loading of 8.58 lb/MMBtu). Anticipated fabric filter system parameters are summarized in Table 2-5.

Additional technical discussion relating to the proposed PM_{10} control technologies is provided in Appendix I-3 in the supplemental white paper *entitled PM_{10} Emissions and Fabric Filter Control Efficiency*.

TABLE 2-5
Anticipated Fabric Filter Design Parameters

Parameter	Units	Estimated Design Value
Flue Gas Flow Rate to Fabric Filter	acfm	3,617,117 @ 275 – 300 °F
Inlet Gas Temperature	°F	275 - 300
Inlet Particulate Loading	lb/hr	77,616 (8.58 lb/mmBtu)
Outlet Filterable PM_{10} Loading	lb/mmBtu	0.015
Outlet Filterable PM_{10} Loading	lb/hr	136
Collection Efficiency	%	99.83
Bag Material		Undetermined
Bag Diameter, Length, Number of Bags		Undetermined
Number of Modules and Compartments per Module		Undetermined
Air to Cloth Ratio	acf/ft^2	2
Pressure Drop Across Bags	in. H_2O	5 - 6 (typical)
Cleaning Mechanism and Cycle		Reverse Air

2.4 Fuel Handling

Figures 2-3 and 2-4 present a schematic flow diagram of the existing and modified coal handling system for Units 1, 2, and 3, and the emission points associated with the coal handling system.

In order to accommodate the increased burn rate due to the new steam generator for Unit 3, the existing coal reclaiming and silo fill systems will require modification.

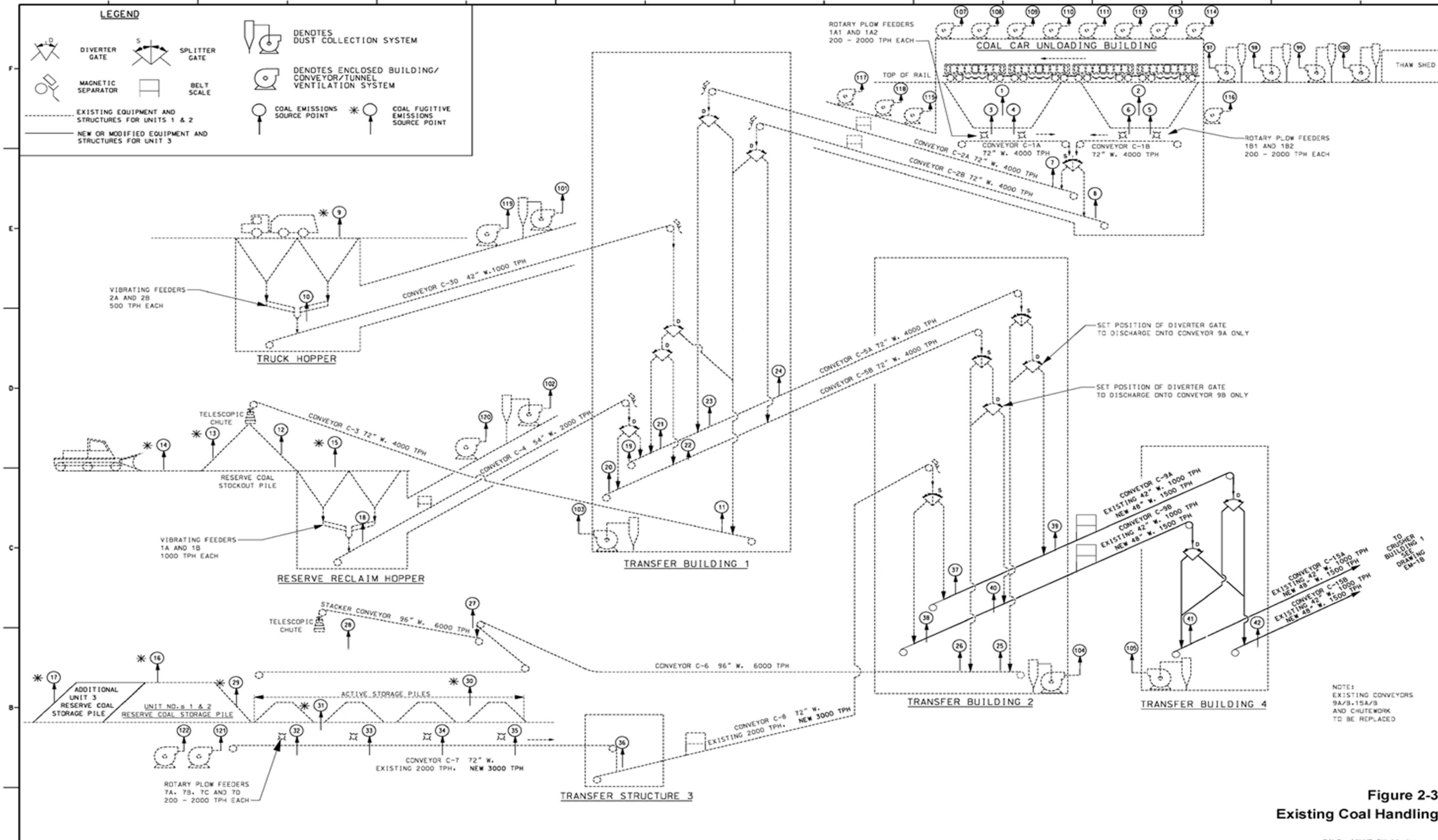


Figure 2-3
Existing Coal Handling

REV.	DATE REL'D.	PREPARED	REVIEWED	APPROVED	PURPOSE
0	4/15/2002	F.A.NORMAN	B.SHAH		ISSUED TO CH2M HILL FOR AIR MODELING

SCALE: NONE — PROJECT NUMBER: 11271-000

COAL HANDLING FACILITIES EMISSION DIAGRAM UNIT NO.s 1, 2, & 3
INTERMOUNTAIN POWER PROJECT
Sargent & Lundy
DRAWING NO. EM-1A — REV. 0

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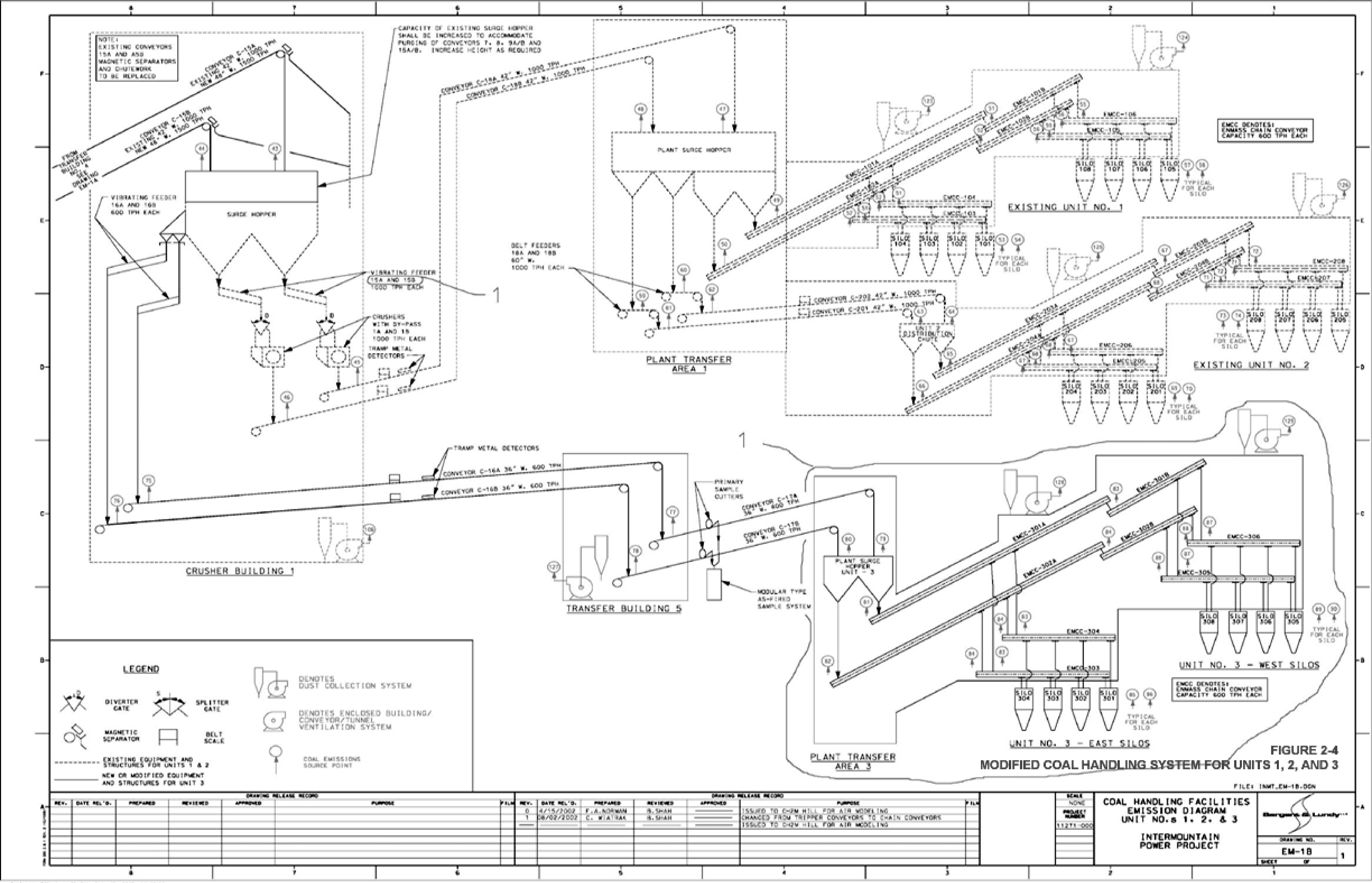

FIGURE 2-4
MODIFIED COAL HANDLING SYSTEM FOR UNITS 1, 2, AND 3

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2.4.1 Existing Coal Handling System

The existing coal handling conveyor system consists of the equipment listed in Table 2-6.

TABLE 2-6
Existing Coal Handling Conveyor System

Conveyor Designation	Belt Width	Capacity tons per hour (tph)
Conveyors 1A/1B	72"	4,000
Conveyors 2A/2B	72"	4,000
Conveyor 3	72"	4,000
Conveyor 4	54"	2,000
Conveyors 5A/5B	72"	4,000
Conveyor 6 with traveling stacker	96"	6,000
Conveyor 7	72"	2,000
Conveyor 8	72"	2,000
Conveyors 9A/9B	42"	1,000
Conveyors 15A/15B	42"	1,000
Conveyors 18A/18B	42"	1,000
Conveyor 30	42"	1,000
Conveyors 201/202	42"	1,000
En Masse Chain Conveyors	630mm	600

Coal is received from unit trains with bottom dump cars at the coal car unloading building and from rear or bottom dump trucks at the coal truck unloading hopper.

Unloading of the rapid discharge bottom dump rail cars is accomplished by moving the train over the track hopper and dumping the coal by remote control of the car doors. The coal is unloaded into both halves of the track hopper and two rotary plow feeders are used to reclaim coal from each half of the hopper and discharged onto Conveyors 1A, 1B, and Conveyor 30 respectively. The coal is transferred onto Conveyor(s) 2A and/or 2B by means of a splitter gate.

The coal truck unloading system is designed with two hopper sections. The hoppers receive the coal from bottom dump and rear dump trucks. Each hopper is equipped with a 500 tph variable rate vibrating feeder. Coal from the coal truck unloading hopper is conveyed to Transfer Building 1 via Conveyor 30. By means of diverter gates, coal is discharged onto either Conveyor 3, 5A, or 5B.

Coal from the coal car unloading building is transferred to Conveyors 2A and 2B which convey the coal to Transfer Building 1. Conveyor 2A diverts coal to either Conveyor 3 or Conveyor 5A by means of a diverter gate. Similarly, Conveyor 2B diverts coal to either Conveyor 3 or Conveyor 5B. Conveyors 5A and 5B convey the coal to Transfer Building 2.

Conveyor 3 conveys coal to the coal reserve stock outpile. Coal in the reserve stock outpile is transferred by mobile equipment to either the reserve coal storage pile or reclaim hopper when needed. The reclaim hopper is designed with two hopper sections. Each section is equipped with a 1,000 tph variable rate vibrating feeder. The coal from the hopper is discharged onto Conveyor 4 via feeders and is transported to Transfer Building 1 where it is transferred to either Conveyor 5A or 5B by means of a diverter gate.

In normal operation, due to an uneven split (2,000 and 1,000 tph) from Conveyor 5A to Conveyors 6 and 9A, and from Conveyor 5B to Conveyors 6 and 9B in Transfer Building 2, some of the coal unloaded at the coal car unloading building is diverted to an active storage pile via Conveyor 6. The rotary plow feeder(s) located under an active storage pile reclaims the coal from the storage pile and discharges it onto Conveyor 7. Coal is transferred from Conveyor 7 to Conveyor 8 in Transfer Structure 3 and conveyed to Transfer Building 2. Conveyors 9A and/or 9B receive coal from Conveyor 8 by means of a splitter gate and deposit into the surge hopper in Crusher Building 1 via Conveyors 15A and/or 15B. Alternatively, all of the coal unloaded at the car unloading building can be conveyed at a reduced rate (1,000 or 2,000 tph) to Units 1 and 2 silos directly.

Coal is removed at a controlled rate from the crusher surge hopper and discharged onto Conveyors 18A and/or 18B via crusher bypass chutes. The station currently receives sized coal so the crushers are being bypassed. Conveyors 18A and 18B convey coal to the plant surge hopper located in Plant Transfer Area 1. From the surge hopper, coal is transferred to the Unit 1 and 2 in-plant silos via conveyor systems.

There is some redundancy in the conveyor system. A dual conveyor system is provided from the coal car unloading building to the Unit 1 and 2 in-plant silos. Also a reserve stock out/reclaim system is provided in case an active storage/reclaim system is out of service. Capacity of the single conveyors of the dual reclaim/silo fill conveyor system is adequate to supply coal to Units 1 and 2.

2.4.2 Proposed Modifications and Additions to Existing Active Reclaim and Silo Fill Systems

This section describes the proposed modifications and additions to existing active reclaim and silo fill systems. These modifications and additions are necessary to accommodate the addition of proposed Unit 3. Table 2-7 lists the proposed modifications to the belt conveyor system.

TABLE 2-7
Modification to the Existing Coal Handling Conveyor System

Conveyor Designation	Belt Width		Capacity TPH		Remarks
	Exist	New	Exist	New	
Conveyor 7	72"	----	2,000	3,000	New drive components
Conveyor 8	72"	----	2,000	3,000	New drive components
Conveyors 9A/9B	42"	48"	1,000	1,500	New belting, idlers, pulleys, drive components, chute work, scrapers, and belt scales Existing bents, trusses, and conveyor support stringers

Conveyors 15A/15B	42"	48"	1,000	1,500	New belting, idlers, pulleys, drive components, chute work, scrapers, and magnetic separators Existing bents, trusses, and conveyor support stringers

Table 2-8 contains the proposed new coal handling conveyors with the addition of Unit 3.

TABLE 2-8
Proposed New Coal Handling Conveyors

Conveyor Designation	Belt Width	Capacity TPH	Belt (chain) Speed FPM	Remarks
Conveyors 16A/16B	36"	600	450	
Conveyors 17A/17B	36"	600	450	
En Mass Chain Conveyors 301A/B, 302 A/B, 303, 304, 305, and 306	24"	600	(135)	Totally enclosed conveyors

The capacity of the existing coal train unloading and stock out system is adequate to supply coal to Units 1, 2, and 3.

In normal operation, coal is delivered directly to the units from coal handling. Some may be diverted to the coal pile, if the unit silos are full. In worst case operation, due to an uneven split, all the coal received at the coal car unloading building will be transferred to an active storage pile via Conveyors 1A/B, 2A/B, 5A/B, and 6. Capacity of the existing reserve coal storage pile will be increased by approximately 624,000 tons to support Unit 3. This is based on a 65-day coal supply to operate Unit 3 at a burn rate of 400 tph.

Alternatively, when an active reclaim system is out of service and coal is being unloaded at the coal car unloading building, coal flow from Conveyor 5A will be split in half by means of a splitter gate located in the discharge chute. Conveyor 9A will receive a maximum of 1,500 tph and will supply coal to the Units 1, 2, and 3 in-plant silos. The balance of the coal from Conveyor 5A will be discharged onto Conveyor 6. Similarly, coal flow from Conveyor 5B can be split.

The capacity of existing Conveyors 7, 8, 9A/B, and 15A/B will be increased to support Unit 3. See Table 2-7 for the modification of existing Conveyors 7, 8, 9A/B, and 15A/B.

During reclaiming operation, the rotary plow feeder(s) will reclaim the coal from the active storage pile at a controlled rate, maximum 3,000 tph, and discharge onto Conveyor 7. Conveyor 8 will receive coal from Conveyor 7 and transfer to either Conveyor(s) 9A, 9B, or both via a splitter gate in Transfer Building 2. Conveyors 15A and 15B will receive coal from either Conveyor 9A or 9B via a diverter gate in Transfer Building 4 and deposit it into the surge hopper located in Crusher Building 1.

Modifications will be made to the surge hopper in Crusher Building 1 to increase the storage capacity and to provide two additional outlets for the installation of two new vibrating feeders that will feed coal to new Conveyors 16A and 16B. Conveyors 16A and 16B will discharge coal onto new Conveyors 17A and 17B respectively in Transfer Building 5 and transport to Plant Transfer Area 3. A new as-fired coal sampling system will be provided at Transfer Building 5.

At Plant Transfer Area 3, Conveyors 17A and 17B will discharge coal into the Plant Surge Hopper. Coal will then be transferred from the plant surge hopper to two 600 tph en masse chain conveyors (EMCCs) -301A and 302A.The silo fill system will consist of two EMCCs-301B and 302B across the back of the unit, two EMCCs-303 and 304 serving east silos and two EMCCS-305 and 306 serving west silos. Silo filling can be accomplished by several methods. The first method is to fill each silo, one at a time, by directing the flow of coal using the chain conveyor discharge gates. A high-level probe will determine when the silo is filled. Coal will then be directed to the next silo or any silo that needs to be filled by opening the discharge gate. This process will continue until all silos are filled. The second method of silo filling is to leave all the chain conveyor discharge gates feeding the silo row open. Coal will then fill the first silo in the row and then flow to the next silo in the row until they are completely filled. The third method would be a combination of the two preceding methods.

Refer to the Table 2-8 for the new conveyor's belt size and capacity. No modifications will be required for the existing silo fill system for Units 1 and 2. Redundancy in the system is supplied via a dual conveyor system from the existing crusher in Building 1 to Unit 3 plant silos. A single conveyor system will be used to supply coal to Unit 3.

The coal storage and handling system will have particulate controls to reduce fugitive dust emissions. Water sprays will be directed to coal unloaded at the coal car unloading building, for transfer out of storage. The inactive coal storage pile will be controlled by the application of a chemical binder. Enclosures with fabric filters will be used for the transfer points, silos, and crusher houses on the coal handling system.

2.5 Limestone Handling System

Figure 2-5 presents a schematic flow diagram of the existing and modified limestone handling system for Units 1, 2, and 3, and the emission points associated with the limestone handling system.

The capacity of existing limestone truck unloading and reclaiming system is adequate to supply limestone to Units 1, 2, and 3. Capacity of the existing 40,000 square feet (ft^2) limestone reserve storage pile will be increased by approximately 8,000 ft^2 to support Unit 3.

The total limestone usage for all three units will be approximately 200,000 tpy dependent on the specific coal and plant capacity factor. The maximum annual limestone usage for Unit 3 is approximately 88,000 tons. At maximum load, the Unit 3 FGD system will require 20,066 pounds of limestone per hour.

Table 2-9 shows the modifications and additions required to the existing limestone day bin fill and preparation systems as a result of the Unit 3 addition.

TABLE 2-9
Limestone Handling Modifications and Additions

Limestone Consumption	20,072 lbs/hr (10 tph)
Limestone Preparation System	New limestone slurry tank and associated pumps, valves, piping, and controls Add new structure to the existing building to enclose the new slurry tank and pumps

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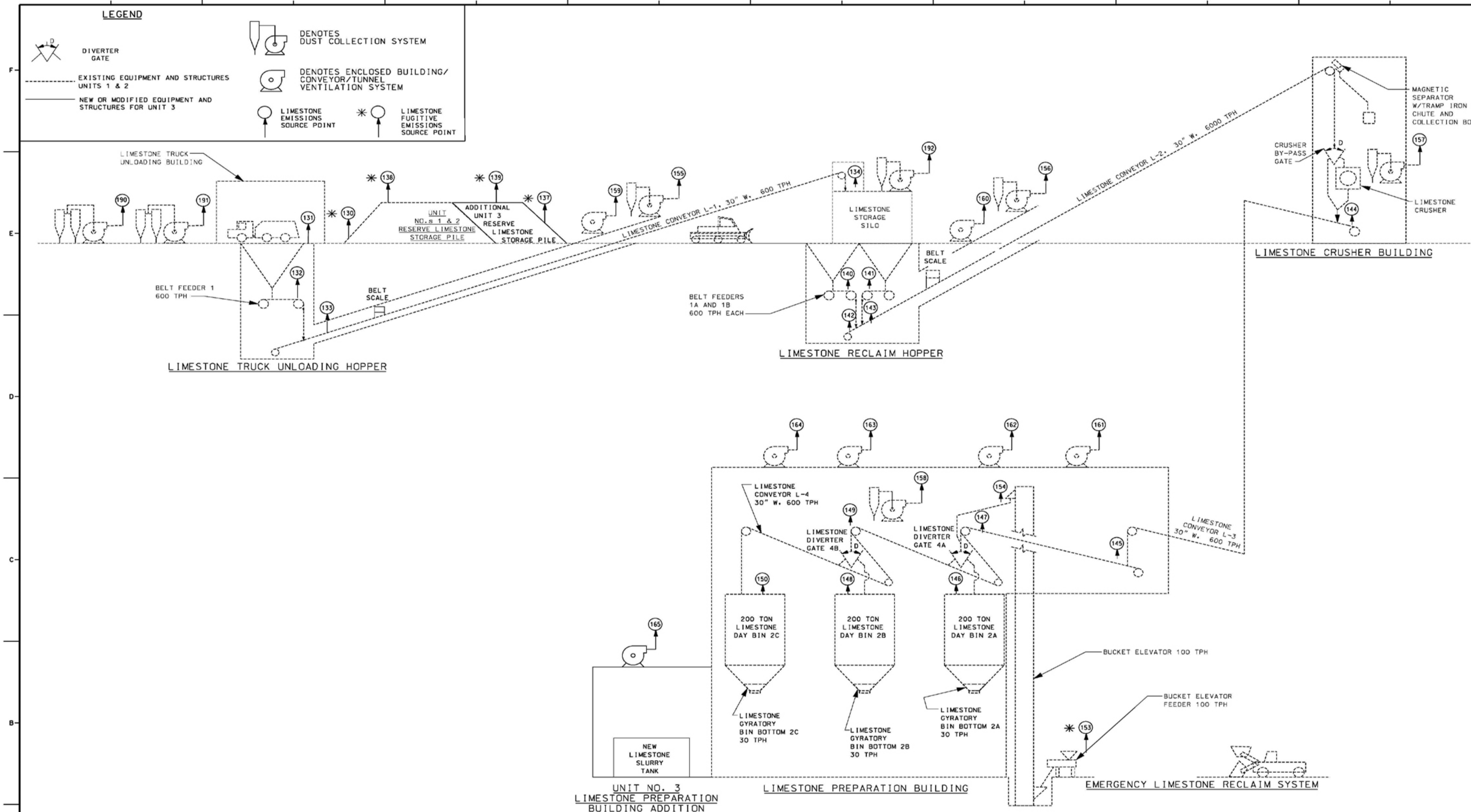

FIGURE 2-5
SCHEMATIC FLOW DIAGRAM OF LIMESTONE HANDLING SYSTEM

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DRAWING RELEASE RECORD

REV.	DATE REL'D.	PREPARED	REVIEWED	APPROVED	PURPOSE
0	4/15/2002	F.A.NORMAN	B.SHAH		ISSUED TO CH2M HILL FOR AIR MODELING
1	10/14/2002	B.HARRIGAN	B.SHAH		ISSUED TO CH2M HILL FOR AIR MODELING

SCALE: NONE
PROJECT NUMBER: 11271-000

LIMESTONE (SCRUBBER ADDITIVE) HANDLING FACILITIES EMISSIONS FLOW DIAGRAM UNITS NO.s 1, 2, & 3 INTERMOUNTAIN POWER PROJECT

Sargent & Lundy

DRAWING NO. EM-3 REV. 1

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2.6 Ash and Combustion By-Product Collection, Transport, and Disposal

2.6.1 Fly Ash Handling System Unit 3

Figure 2-6 presents a schematic flow diagram of the fly ash handling system for Unit 3, and the emission points associated with the fly ash handling system.

The pneumatic pressure type fly ash handling system for Unit 3 will convey the fly ash collected in the fabric filter and air heater hoppers to new Fly Ash Storage Silo 1C or existing Storage Silos 1A or 1B.

The fly ash handling system serving the fabric filter and air heater hoppers will be divided into two equally sized and independently operated pressure subsystems with a combined conveying capacity of 150 tph (75 tph per subsystem). One subsystem will serve three rows of fabric filter hoppers with eight outlets per row. The second subsystem will serve the other three rows of fabric filter hoppers with eight outlets per row and one row of air heater hoppers with four outlets. Cross-ties at the fabric filter will be provided in the transport piping so that all fly ash hoppers can be emptied using one of the subsystems. In addition, the transport piping at the silos will be cross-tied with the fly ash systems from Units 1 and 2 to permit fly ash from any unit to be conveyed to any silo.

The fly ash handling system will consist of air lock type pressure feeders, ash transport piping, branch isolation valves, crossover valves, mechanical blowers for conveying air, mechanical blowers for fluidizing air, fly ash storage silo with vent filter, and truck/rail car dry ash loading spout with vent filter.

The net storage capacity of the ash silo will be 50,000 cubic feet (ft^3). This will provide approximately 36 hours of storage for the fly ash. The silo vent filter will be equipped with a bag type vent filter system and designed to remove fly ash carryover from the air stream exiting the fly ash silo. The minimum efficiency of the vent filter will be 99.9 percent. The vent filter will be sized to accommodate the airflow resulting from the simultaneous discharge of four 70 tph conveying systems into the silo.

The fly ash storage silo will be equipped with a complete fluidizing air system including the porous fluidizing media, mechanical blowers, electric air heaters, and inlet filter silencers.

Fly ash destined for sale to outside markets will be loaded into totally enclosed trucks or railcars by a dry unloading system, which features a sealed loading spout with a vent system equipped with bag filters. Fly ash destined for disposal will be mixed with scrubber waste in a scrubber sludge/fly ash mixer as it is unloaded from the silo and conveyed via belt conveyors to the disposal area. This will minimize dusting during unloading.

The fly ash system will be provided with an automatic control system to empty the fabric filter and air heater hoppers and transport the ash to a fly ash silo(s). The control system will provide an automatic sequential operation of the branch isolation valves with provisions to bypass any one hopper or group of hoppers.

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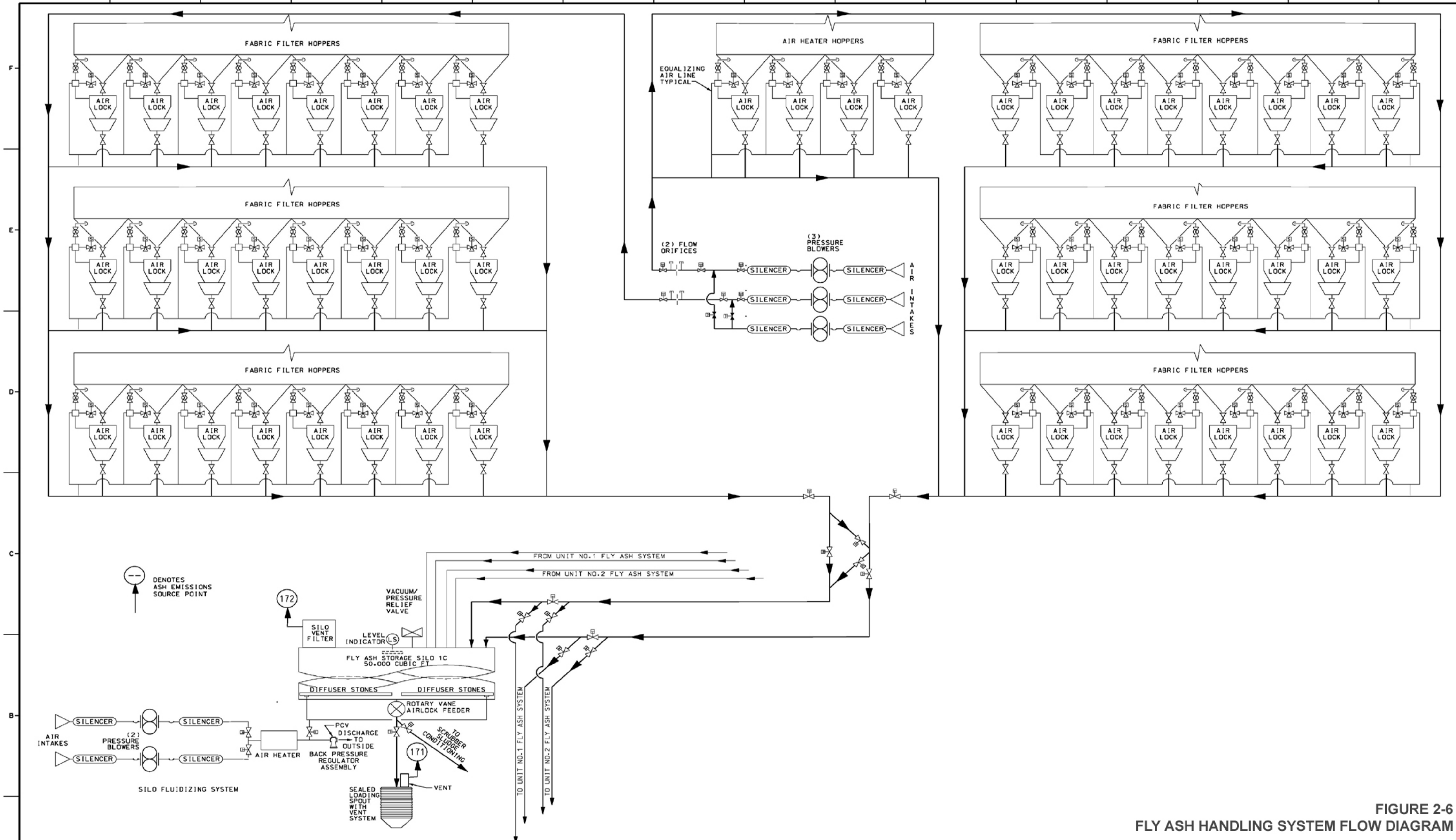

FIGURE 2-6
FLY ASH HANDLING SYSTEM FLOW DIAGRAM

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DRAWING RELEASE RECORD

REV.	DATE REL'D.	PREPARED	REVIEWED	APPROVED	PURPOSE	FILM
0	4/15/2002	F.A.NORMAN	B.SHAH		ISSUED TO CH2M HILL FOR AIR MODELING	

SCALE: NONE
PROJECT NUMBER: 11271-000

PRESSURE FLY ASH SYSTEM
FLOW DIAGRAM
UNIT NO. 3

INTERMOUNTAIN
POWER PROJECT

Sargent & Lundy

DRAWING NO.: EM-2
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Upon actuation of the system controls, each active pressure feeder located under the fabric filter and air heater hoppers will be vented to the associated fly ash hopper and the upper feed gate will be opened. Fly ash will flow into the pressure feeder assisted by the fluidizing air. After a predetermined time, the upper feed gate will be closed and the feeder pressurized slightly above the conveying header air pressure. The lower feed gate will then open allowing the fly ash to discharge into the conveying air stream. When the feeder is empty, the bottom gate will close and the cycle will be repeated until the hopper is empty. The fly ash will be conveyed through the transport pipe to a storage silo.

The fly ash storage and handling system will have particulate controls to reduce fugitive dust emissions. Enclosures with fabric filters will be used for the fly ash transfer points and storage silos.

2.6.2 Bottom Ash Handling System Unit 3

The bottom ash handling system for Unit 3 will include removal and disposal of bottom ash to the existing ash disposal ponds. Bottom ash is generated from the following:

- Bottom ash from the steam generator
- Boiler hopper ash
- Pulverizer rejects

The system will be similar to the existing bottom ash system for Units 1 and 2. Water supply and transport components will be sized to have 25 percent more capacity than the existing system. The new ash water tank for Unit 3 will have a capacity of 250,000 gallons and will be cross-tied to Units 1 and 2.

The 6-day bottom ash storage area is essentially a concrete floor with cinder block or concrete walls on three sides. Water liberated by the stored material will drain by gravity to the surge tank via a sump pump located at the storage area. From the open storage the combination ash material will be loaded into trucks and hauled to disposal.

2.6.3 FGD Sludge Handling System Unit 3

Scrubber sludge from the Unit 3 FGD system is sent to vacuum filters in the Sludge Conditioning Building for dewatering. The dry by-product filter cake is mixed with fly ash in pug mill mixers to create a conditioned FGD waste suitable for land disposal. The conditioned FGD sludge is transferred from the Sludge Conditioning Building to the landfill disposal area by a series of horizontal belt conveyors.

The paved ash haul and unpaved conditioned sludge haul roads will use water sprays and dust suppression chemicals for dust control.

3.0 Emission-Related Information

The Unit 3 emissions estimates include the Unit 3 boiler, the cooling towers, and material handling sources. Unit 3 has material handling operations for coal, fly ash, limestone preparation, FGD sludge and ash disposal, and water treatment. Detailed emissions estimates are provided in Appendix C, Emissions Calculations.

The major air emission sources and regulated air pollutants for Unit 3 are shown in Table 3-1. UDAQ Emission Source forms for Unit 3 are attached in Appendix A.

TABLE 3-1
Unit 3 Air Emission Sources and Regulated Air Pollutants

Source Number	Emission Point	Regulated Air Pollutants
Unit 3	Main Boiler – Unit 3 Stack	SO_2, NO_x, PM, PM_{10}, CO, VOC, Lead, H_2SO_4, HF, TRS, RSC, HAPs
3A and 3B	Unit 3 Cooling Towers	PM, PM_{10}
F-17	Unit 3 Coal Pile – Fugitives	PM, PM_{10}
EP-12, EP-27, EP-28, EP-32, EP-33, EP-34, EP-35, EP-36, EP-97, EP-98, EP-99, EP-100, F-101A, EP-101B, EP-102, EP-103, EP-104, EP-105, and EP-106a	Units 1, 2, and 3 Coal Handling System (Unit 3 portion only)	PM, PM_{10}
EP-106b, EP-127, EP-128 and EP-129	Unit 3 Coal Handling System	PM, PM_{10}
EP-171 and EP-172	Unit 3 Fly Ash Handling	PM, PM_{10}
F-130, F-153, EP-155, EP-156, EP-157, EP-158, EP-190, EP-191, and EP-192	Units 1, 2, and 3 Limestone Handling (Unit 3 portion only)	PM, PM_{10}
F-137 and F-139	Unit 3 Limestone Pile – Fugitives	PM, PM_{10}
EU-29, EU-30, EU-31, and EU-32	Units 1, 2, and 3 Water Treatment (Unit 3 portion only)	PM, PM_{10}
EU-35	Unit 3 FGD Sludge Handling – Fugitives	PM, PM_{10}
	Unit 3 Ash Hauling – Fugitives	PM, PM_{10}
	Unit 3 Conditioned Sludge Hauling - Fugitives	PM, PM_{10}

3.1 Unit 3 Boiler Criteria Emissions

The estimated hourly, daily, and annual controlled emission rates of criteria pollutants from the Unit 3 stack are shown in Table 3-2.

TABLE 3-2
Unit 3 Boiler Criteria Emissions

Pollutant	Hourly Emissions[a] (lbs/hr)	Daily Emissions[a] (lbs/day)	Annual Emissions[a b] (tpy)	PSD Significant Emission Levels (tpy)	Emission Factor Reference
SO_2	905.0	21,720.0	3964	40	Engineering Estimates
NO_X	633.5	15,204.0	2775	40	Engineering Estimates
Total PM	181.0	4,344.0	793	25	Engineering Estimates
PM_{10} (filterable)	135.7	3,256.8	595	15	Engineering Estimates
PM_{10} (filterable & condensable)[c]	220.9	5,301.6	968	15	Engineering Estimates
CO	1,357.5	32,580	5,946	100	Engineering Estimates
VOCs	24.3	583.2	107	40	AP-42 Table 1.1-19
Lead	0.181	4.34	0.79	0.6	AP-42 Table 1.1-18
Mercury	0.02	0.52	0.09	0.1	Analysis and Testing
H_2SO_4[d]	39.7	952.8	174	7	Engineering Estimates
Fluorides (as HF)	4.69	112.8	20.00	3	Engineering Estimates
TRS	6.7	160.8	29	10	AP-42 Table 1.1-3 (b)
RSCs	6.7	160.8	29	10	AP-42 Table 1.1-3 (b)

[a] Hourly, daily, and annual emissions are estimated at 100-percent operating capacity for Unit 3.

[b] Based on a 30-day rolling total.

[c] Condensable PM_{10} includes hydrochloric acid (HCl), HF, H_2SO_4 and $(NH_4)_2SO_4$.

[d] Engineering estimates for H_2SO_4 are based on stack test results from Unit 1 adjusted to account for increases resulting from SCR operation on Unit 3.

3.2 Unit 3 Boiler HAP Emissions

The estimated hourly and annual controlled emission rates of trace metal HAPs, organic HAPs, and acid gas HAPs are shown in Tables 3-3, 3-4, and 3-5 respectively. Section 6.3 provides additional information on emissions estimates and control levels for the Section 112 HAPs.

TABLE 3-3
Unit 3 Boiler Trace Metal HAPs

Pollutant	Controlled Emissions (lb/hr)	Controlled Emissions (tpy)	Emission Factor Reference
Antimony	0.01	0.02	AP-42 Table 1.1-16, (9/1998)
Arsenic	0.04	0.18	AP-42 Table 1.1-16, (9/1998)
Beryllium	0.00	0.00	AP-42 Table 1.1-16, (9/1998)
Cadmium	0.01	0.03	AP-42 Table 1.1-16, (9/1998)
Chromium	0.06	0.28	AP-42 Table 1.1-16, (9/1998)
Cobalt	0.01	0.03	AP-42 Table 1.1-16, (9/1998)
Lead	0.181	0.79	AP-42 Table 1.1-18
Manganese	0.03	0.15	AP-42 Table 1.1-16, (9/1998)
Mercury	0.02	0.09	Engineering calculations based on mercury stack test conducted at IPP Units 1 and 2.
Nickel	0.03	0.13	AP-42 Table 1.1-16, (9/1998)
Selenium	0.23	1.02	EPRI Coal HAP report

TABLE 3-4
Unit 3 Boiler Organic HAPs

Pollutant	Controlled Emissions (lb/hr)	Controlled Emissions (tpy)	Emission Factor Reference
Acenaphthene	0.00	0.00	AP-42 Table 1.1-13, (9/1998)
Acenaphthylene	0.00	0.00	AP-42 Table 1.1-13, (9/1998)
Acetaldehyde	0.23	1.01	AP-42 Table 1.1-14, (9/1998)
Acetophenone	0.01	0.03	AP-42 Table 1.1-14, (9/1998)
Acrolein	0.12	0.51	AP-42 Table 1.1-14, (9/1998)
Anthracene	0.00	0.00	AP-42 Table 1.1-13, (9/1998)
Benzene	0.03	0.15	EPRI Coal HAP Report
Benzo(a)anthracene	0.00	0.00	AP-42 Table 1.1-13, (9/1998)
Benzo(a)pyrene	0.00	0.00	AP-42 Table 1.1-13, (9/1998)
Benzo(b,j,k)fluoranthene	0.00	0.00	AP-42 Table 1.1-13, (9/1998)
Benzo(g,h,i)perylene	0.00	0.00	AP-42 Table 1.1-13, (9/1998)
Benzyl chloride	0.28	1.24	AP-42 Table 1.1-14, (9/1998)
Biphenyl	0.00	0.00	AP-42 Table 1.1-13, (9/1998)
Bis(2-ethylhexyl)phthalate (DEHP)	0.03	0.13	AP-42 Table 1.1-14, (9/1998)
Bromoform	0.02	0.07	AP-42 Table 1.1-14, (9/1998)

TABLE 3-4 (CONTINUED)
Unit 3 Boiler Organic HAPs

Pollutant	Controlled Emissions (lb/hr)	Controlled Emissions (tpy)	Emission Factor Reference
Carbon disulfide	0.05	0.23	AP-42 Table 1.1-14, (9/1998)
2-Chloroacetophenone	0.00	0.01	AP-42 Table 1.1-14, (9/1998)
Chlorobenzene	0.01	0.04	AP-42 Table 1.1-14, (9/1998)
Chloroform	0.02	0.10	AP-42 Table 1.1-14, (9/1998)
Chrysene	0.00	0.00	AP-42 Table 1.1-13, (9/1998)
Cumene	0.00	0.01	AP-42 Table 1.1-14, (9/1998)
2,4-Dinitrotoluene	0.00	0.00	AP-42 Table 1.1-14, (9/1998)
Dimethyl sulfate	0.02	0.08	AP-42 Table 1.1-14, (9/1998)
Ethyl benzene	0.04	0.17	AP-42 Table 1.1-14, (9/1998)
Ethyl chloride	0.02	0.07	AP-42 Table 1.1-14, (9/1998)
Ethylene dichloride	0.02	0.07	AP-42 Table 1.1-14, (9/1998)
Ethylene dibromide	0.00	0.00	AP-42 Table 1.1-14, (9/1998)
Fluoranthene	0.00	0.00	AP-42 Table 1.1-13, (9/1998)
Fluorene	0.00	0.00	AP-42 Table 1.1-13, (9/1998)
Formaldehyde	0.03	0.12	EPRI Coal HAP Report
Hexane	0.03	0.12	AP-42 Table 1.1-14, (9/1998)
Indeno(1,2,3-cd)pyrene	0.00	0.00	AP-42 Table 1.1-13, (9/1998)
Isophorone	0.23	1.03	AP-42 Table 1.1-14, (9/1998)
Methyl bromide	0.06	0.28	AP-42 Table 1.1-14, (9/1998)
Methyl chloride	0.21	0.94	AP-42 Table 1.1-14, (9/1998)
5-Methyl chrysene	0.00	0.00	AP-42 Table 1.1-13, (9/1998)
Methyl ethyl ketone	0.16	0.69	AP-42 Table 1.1-14, (9/1998)
Methyl hydrazine	0.07	0.30	AP-42 Table 1.1-14, (9/1998)
Methyl methacrylate	0.01	0.04	AP-42 Table 1.1-14, (9/1998)
Methyl tert butyl ether	0.01	0.06	AP-42 Table 1.1-14, (9/1998)
Methylene chloride	0.12	0.51	AP-42 Table 1.1-14, (9/1998)
Naphthalene	0.01	0.02	AP-42 Table 1.1-13, (9/1998)
Phenanthrene	0.00	0.00	AP-42 Table 1.1-13, (9/1998)
Phenol	0.01	0.03	AP-42 Table 1.1-14, (9/1998)
Propionaldehyde	0.15	0.67	AP-42 Table 1.1-14, (9/1998)
Pyrene	0.00	0.00	AP-42 Table 1.1-13, (9/1998)

TABLE 3-4 (CONTINUED)
Unit 3 Boiler Organic HAPs

Pollutant	Controlled Emissions (lb/hr)	Controlled Emissions (tpy)	Emission Factor Reference
Tetrachloroethylene	0.02	0.08	AP-42 Table 1.1-14, (9/1998)
Toluene	0.01	0.06	EPRI Coal HAP Report
1,1,1-Trichloroethane	0.01	0.04	AP-42 Table 1.1-14, (9/1998)
Styrene	0.01	0.04	AP-42 Table 1.1-14, (9/1998)
Xylenes	0.01	0.07	AP-42 Table 1.1-14, (9/1998)
Vinyl acetate	0.00	0.01	AP-42 Table 1.1-14, (9/1998)
Total PCDD[a]/PCDF[b]	0.00	0.00	EPRI Coal HAP Report

[a] PCDD – polychlorinated dibenzo-p-dioxins
[b] PCDF – polychlorinated dibenzo furans

TABLE 3-5
Unit 3 Boiler Acid Gas HAPs

Pollutant	Controlled Emissions (lb/hr)	Controlled Emissions (tpy)	Emission Factor Reference
Hydrogen Chloride	38.13	167.01	Engineering Estimates
Hydrogen Fluoride	4.7	20.00	Engineering Estimates

3.3 Unit 3 Cooling Towers

The estimated hourly, daily, and annual controlled particulate emission rates from the Unit 3 cooling towers are shown in Table 3-6.

TABLE 3-6
Unit 3 Cooling Tower Particulate Emissions

Pollutant	Hourly Emissions[a] (lbs/hr)	Daily Emissions[a] (lbs/day)	Annual Emissions[a] (tpy)	Emission Factor Reference
Total PM	14.1	339.0	61.9	Engineering Estimates
PM_{10}	0.7	16.9	3.1	Engineering Estimates

[a] Hourly, daily, and annual emissions are estimated at 100-percent operating capacity for Unit 3.
The emissions are the total from Towers 3A and 3B

3.4 Unit 3 Coal Handling

The estimated hourly, daily, and annual controlled particulate emission rates from the Unit 3 Coal Handling System are shown in Tables 3-7, 3-8, and 3-9. The tables summarize particulate emissions; details on each emission point can be found in Appendix C, Emissions Calculations. The emissions shown in Table 3-8 are for the estimated Unit 3 portion only. For common plant coal handling equipment, Unit 3 emissions were estimated to be 43.6 percent of the plant total based on the maximum coal burn rate for Unit 3.

TABLE 3-7
Unit 3 Coal Pile - Fugitives

Pollutant	Maximum Hourly Emissions (lbs/hr)	Maximum Daily Emissions (lbs/day)	Annual Emissions (tpy)	Emission Factor Reference
Total PM	0.01	0.24	0.04	AP-42 and Engineering Estimates
PM_{10}	0.005	0.12	0.02	AP-42 and Engineering Estimates

The emissions are the Unit 3 total from Emission Point F-17.

TABLE 3-8
Units 1, 2, and 3 Coal Handling System (Unit 3 portion only)

Pollutant	Maximum Hourly Emissions (lbs/hr)	Maximum Daily Emissions (lbs/day)	Annual Emissions (tpy)	Emission Factor Reference
Total PM	4.44	106.67	3.25	AP-42 and Engineering Estimates
PM_{10}	2.10	50.45	1.54	AP-42 and Engineering Estimates

Unit 3 estimated as 43.6 percent of the common coal handling transfer operations based on estimated coal received.
The emissions are the Unit 3 total from Emission Points EP-12, EP-27, EP-28, EP-32, EP-33, EP-34, EP-35, EP-36, EP-97, EP-98, EP-99, EP-100, F-101A, EP-101B, EP-102, EP-103, EP-104, EP-105, and EP-106a.

TABLE 3-9
Unit 3 Coal Handling System

Pollutant	Maximum Hourly Emissions (lbs/hr)	Maximum Daily Emissions (lbs/day)	Annual Emissions (tpy)	Emission Factor Reference
Total PM	0.09	2.18	0.10	AP-42 and Engineering Estimates
PM_{10}	0.04	1.06	0.04	AP-42 and Engineering Estimates

The emissions are the Unit 3 total from Emission Points EP-106b, EP-127, EP-128, and EP-129.

3.5 Unit 3 Fly Ash Handling

The estimated hourly, daily, and annual controlled particulate emission rates from the Unit 3 fly ash handling system are shown in Table 3-10. The table summarizes particulate emissions; details on each emission point can be found in Appendix C – Emissions Calculations.

TABLE 3-10
Unit 3 Fly Ash Handling System

Pollutant	Maximum Hourly Emissions (lbs/hr)	Maximum Daily Emissions (lbs/day)	Annual Emissions (tpy)	Emission Factor Reference
Total PM	0.60	14.40	0.68	AP-42 and Engineering Estimates
PM_{10}	0.30	7.20	0.34	AP-42 and Engineering Estimates

The emissions are the Unit 3 total from Emission Points EP-171 and EP-172.

3.6 Unit 3 Limestone Handling

The estimated hourly, daily, and annual controlled particulate emission rates from the Unit 3 limestone handling system are shown in Tables 3-11 and 3-12. The tables summarize particulate emissions; details on each emission point can be found in Appendix C, Emissions Calculations. The emissions shown in Table 3-11 are for the estimated Unit 3 portion only. For the common plant limestone handling system, Unit 3 emissions were estimated to be 57.6 percent of the plant total based on the maximum limestone use rate for Unit 3.

TABLE 3-11
Units 1, 2, and 3 Limestone Handling System (Unit 3 portion only)

Pollutant	Maximum Hourly Emissions (lbs/hr)	Maximum Daily Emissions (lbs/day)	Annual Emissions (tpy)	Emission Factor Reference
Total PM	1.88	45.07	0.27	AP-42 and Engineering Estimates
PM_{10}	0.89	21.30	0.13	AP-42 and Engineering Estimates

Unit 3 estimated as 57.6 percent of the common limestone handling operations based on estimated limestone received.
The emissions are the Unit 3 total from Emission Points F-130, F-153, EP-155, EP-156, EP-157, EP-158, EP-190, EP-191, and EP-192.

TABLE 3-12
Unit 3 Limestone Pile - Fugitives

Pollutant	Maximum Hourly Emissions (lbs/hr)	Maximum Daily Emissions (lbs/day)	Annual Emissions (tpy)	Emission Factor Reference
Total PM	0.11	2.66	0.20	AP-42 and Engineering Estimates
PM_{10}	0.10	2.30	0.16	AP-42 and Engineering Estimates

The emissions are the Unit 3 total from Emission Points F-137 and F-139.

3.7 Unit 3 Water Treatment System

The estimated hourly, daily, and annual controlled particulate emission rates from the Unit 3 water treatment system are shown in Table 3-13. The table summarizes particulate emissions; details on each emission point can be found in Appendix C, Emissions Calculations. The emissions shown in Table 3-13 are for the estimated Unit 3 portion only. For the common plant water treatment system, Unit 3 emissions were estimated to be 33.4 percent of the plant total.

TABLE 3-13
Units 1, 2, and 3 Water Treatment System (Unit 3 portion only)

Pollutant	Maximum Hourly Emissions (lbs/hr)	Maximum Daily Emissions (lbs/day)	Annual Emissions (tpy)	Emission Factor Reference
Total PM	0.000	0.005	0.000	AP-42 and Engineering Estimates
PM_{10}	0.000	0.004	0.000	AP-42 and Engineering Estimates

The emissions are the Unit 3 total from Emission Points EU-29, EU-30, EU-31, and EU-32.

3.8 Unit 3 Sludge/Ash Handling and Hauling

The estimated hourly, daily, and annual controlled particulate emission rates from the Unit 3 sludge/ash handling and hauling are shown in Tables 3-14, 3-15, and 3-16. The tables summarize particulate emissions; details on each emission point can be found in Appendix C – Emissions Calculations.

TABLE 3-14
Unit 3 FGD Sludge Handling - Fugitives

Pollutant	Maximum Hourly Emissions (lbs/hr)	Maximum Daily Emissions (lbs/day)	Annual Emissions (tpy)	Emission Factor Reference
Total PM	1.73	41.45	5.07	AP-42 and Engineering Estimates
PM_{10}	1.58	37.90	4.63	AP-42 and Engineering Estimates

The emissions are the Unit 3 total from Emission Point EU-35.

TABLE 3-15
Unit 3 Ash Hauling - Fugitives

Pollutant	Maximum Hourly Emissions (lbs/hr)	Maximum Daily Emissions (lbs/day)	Annual Emissions (tpy)	Emission Factor Reference
Total PM	1.05	25.20	4.59	AP-42 and Engineering Estimates
PM_{10}	0.20	4.80	0.89	AP-42 and Engineering Estimates

Based on paved ash haul road.

TABLE 3-16
Unit 3 Conditioned Sludge Hauling - Fugitives

Pollutant	Maximum Hourly Emissions (lbs/hr)	Maximum Daily Emissions (lbs/day)	Annual Emissions (tpy)	Emission Factor Reference
Total PM	13.61	326.64	43.46	AP-42 and Engineering Estimates
PM_{10}	3.54	84.96	11.30	AP-42 and Engineering Estimates

Based on unpaved sludge hauling road.

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4.0 Requested Permit Limits

This section presents the permit limits requested in this NOI application.

4.1 Pre-Project Actual Emissions

IPP was issued the original United States Environmental Protection Agency (EPA) PSD Permit to Construct (No. 8AH-A) for Units 1 and 2 on June 12, 1980. The original AO from the State of Utah for the construction of Units 1 and 2 was issued on October 17, 1983. On January 11, 2002 the State of Utah Department of Environmental Quality (UDEQ) issued the most recent AO (DAQE-049-02) for the modification to increase each unit's nominal gross generating capacity from 875 MW to 950 MW.

In determining pre-project actual (PPA) emissions values for Units 1 and 2, past actual emissions were established as the most recent two consecutive calendar years of 2000 and 2001. These 2 years were determined to be representative of normal operation and were used for establishing PPA emission values.

There have been no creditable emission increases or decreases during the period from 1999 through the projected construction commencement date of 2004 that have not otherwise been permitted with an AO.

Table 4-1 summarizes the PPA values used in determining the emission baseline requirement for the Unit 3 project. Past actual emissions are based on the average of actual emissions from 2000 and 2001. These 2 years are considered representative of normal operation. Additional information on Unit 1 and 2 actual emissions is contained in Appendix C.

TABLE 4-1
Unit 1 and 2 Total Actual Emissions 2000 and 2001

Pollutant	Unit 1 2000 Annual Emissions (tpy)	Unit 2 2000 Annual Emissions (tpy)	Unit 1 2001 Annual Emissions (tpy)	Unit 2 2001 Annual Emissions (tpy)	Units 1 and 2 2000/2001 Average Annual Emissions (tpy)
SO_2	1,855.1	1,619.2	1,914.1	2,286.2	3,837.3
NO_X	13,972.0	12,137.0	12,848.0	13,839.0	26,398.0
PM_{10}	223.4	100.5	83.0	74.3	240.6
CO	699.8	621.2	631.5	706.7	1,330.8
VOCs					12.7
Lead					0.09

4.2 Potential to Emit for Unit 3

Since Units 1 and 2 were previously permitted under a separate PSD permitting action and no creditable emissions increases or decreases are being relied on in this current permit application, the emissions increases for the Unit 3 project are based only on the potential to emit (PTE) of the new Unit 3.

This section describes the procedure used to evaluate the PTE of the proposed Unit 3 project.

4.2.1 Rationale for Determining Unit 3 PTE

The PTE values for Unit 3 were obtained using assumptions on what a newly constructed Unit 3 could achieve through the application of control technology required pursuant to applicable NSPS and BACT for each pollutant under consideration. This includes the following assumptions:

- Fuel and Unit Size

- A nominal unit size of 950-gross MW.
- A unit annual capacity factor of 105 percent
- An average maximum design coal sulfur content of 0.75 percent
- A design coal heating value of 11,193 Btu/lb

- SO_2

- The use of a forced oxidation wet limestone SO_2 scrubber system
- The SO_2 control system will be designed to meet 0.10 lb/mmBtu (30-day rolling average)

- NO_X

- The addition of LNBs, overfire air, and SCR control
- The NO_X control system will be designed to meet 0.07 lb/mmBtu (30-day rolling average)

- Total PM and PM_{10}

- The use of a fabric filter baghouse
- The boiler baghouse control system will be designed to meet a filterable PM_{10} emission limit of 0.015 lb/mmBtu
- The use of covered conveyors, dust suppression, and fabric filters
- Drift eliminators to control PM_{10} emissions from the proposed cooling towers

- CO

- The use of good combustion controls to limit CO emissions

- VOC
  - The use of good combustion controls to limit VOC emissions
- Lead
  - The use of a fabric filter baghouse
- H_2SO_4, HF, TRS, and RSC
  - The use of a forced oxidation wet limestone SO_2 scrubber system

4.2.2 Summary of Unit 3 PTE

A summary of the post-project potential (PPP) to emit for Unit 3 is shown in Table 4-2. These emission rates are the maximum expected emission rates based on continuous operation of the new unit. These maximum hourly emission rates were the basis for Unit 3 modeling and analysis of AQRVs.

TABLE 4-2
PTE Associated with the Addition of Unit 3

Pollutant	Hourly Emissions[a] (lbs/hr)	Daily Emissions[a] (lbs/day)	Annual Emissions[a] (tpy)	PSD Significance Levels (tpy)	Emission Factor Reference
CO	1,357.5	32,580	5,946	100	Engineering Estimates
Fluorides (as HF)	4.7	112.8	20	3	Engineering Estimates
Lead	0.181	4.34	0.79	0.6	AP-42 Table 1.1-18
Mercury	0.02	0.52	0.09	0.1	Analysis and Testing
NO_x	633.5	15,204.0	2,775	40	Engineering Estimates
PM_{10} (filterable & condensable)	220.9	5,301.6	968	15	Engineering Estimates
PM_{10} (filterable)			617.5	15	Engineering Estimates
RSCs	6.7	160.8	29	10	AP-42 Table 1.1-3 (b)
SO_2	905.0	21,720.0	3,964	40	Engineering Estimates
H_2SO_4[b]	39.7	952.8	174	7	Engineering Estimates
Total PM	181.0	4,344.0	793	25	Engineering Estimates
TRS	6.7	160.8	29	10	AP-42 Table 1.1-3 (b)
VOCs	24.3	583.2	107	40	AP-42 Table 1.1-19

[a] Hourly, daily, and annual emissions are estimated at 100-percent operating capacity for Unit 3.

[b] Engineering estimates for H_2SO_4 are based on stack test results from Unit 1 adjusted to account for increases resulting from SCR operation on Unit 3.

4.3 PSD Permitting Applicability

The addition of the proposed Unit 3 is a major modification to an existing major stationary source. The pollutants subject to the PSD program and their significance levels are listed in Table 4-2. As shown in Table 4-2, the PTE for all criteria pollutants exceed the applicable significance levels for the proposed Unit 3 addition. Thus, PSD review is applicable to all criteria pollutants. Section 5 provides detailed information on applicable regulations.

The basic PSD permitting requirements that must be met for a major modification include:

- Application of BACT
- Performance of an ambient air quality impacts analysis (dispersion modeling)
- Analysis of impacts to soils, vegetation, and visibility
- Analysis of Class I area impacts, including visibility and AQRVs

Section 6 of this application contains the BACT and MACT analysis. Section 7 contains the Class I visibility and other impacts analysis and Section 8 contains information on the Class II dispersion modeling results.

4.4 Requested Emission Limits

Based on the results of the BACT analysis, Class I visibility modeling and Class II dispersion modeling, IPP requests the following emission rate limits for the proposed Unit 3.

SO_2: 0.10 lb/mmBtu heat input based on a 30-day rolling average as determined by the arithmetic average of all hourly emission rates for the 30 successive boiler operating days, except during periods of startup, shutdown, maintenance/planned outage, or malfunction.

NO_x: 0.07 lb/mmBtu heat input based on a 30-day rolling average as determined by the arithmetic average of all hourly emission rates for the 30 successive boiler operating days, except during periods of startup, shutdown, maintenance/planned outage, or malfunction.

Total PM: 0.020 lb/mmBtu heat input based on a 3-hour rolling average, except during periods of startup, shutdown, maintenance/planned outage, or malfunction.

PM_{10} (filterable): 0.015 lb/mmBtu heat input based on a 3-hour rolling average, except during periods of startup, shutdown, maintenance/planned outage, or malfunction.

CO: 5,946 tpy on an annualized average based on an emission rate of 0.15 lb/mmBtu heat input, except during periods of startup, shutdown, maintenance/planned outage, or malfunction.

VOC: 107 tpy on an annualized average based on an emission rate of 0.0027 lb/mmBtu heat input, except during periods of startup, shutdown, maintenance/planned outage, or malfunction.

Lead: 0.79 tpy on an annualized average based on an emission rate of 0.00002 lb/mmBtu heat input, except during periods of startup, shutdown, maintenance/planned outage, or malfunction.

5.0 Regulatory Applicability Review and Requirements

This section provides a regulatory review of the applicability of state and federal air quality permitting requirements and air pollution control regulations for the new Unit 3 PC-fired generating unit proposed by IPA. The purpose of this section is to provide appropriate explanation and rationale regarding the applicability of these regulations to the IPP facility. The review is divided into two major sections. The first section addresses state and federal air permitting requirements, and the second section addresses other state and federal air pollution control regulations.

5.1 Air Permitting Requirements

The State of Utah has been delegated authority by EPA to implement and enforce the federal Clean Air Act (CAA) pursuant to the state implementation plan (SIP) review and approval process. Federal PSD air permitting requirements are embodied within the state rules. IPP is a major stationary source of air emissions, as defined within UAC R307 and 40 CFR 60. The UDAQ has previously issued permits and permit revisions to IPSC appropriate for existing IPP facilities.

5.1.1 State of Utah Air Permitting Requirements

The general requirements for permits and permit revisions are codified under the state environmental protection regulations at UAC R307.

5.1.1.1 NOI and AO (UAC R307-401)

The addition of Unit 3 will result in an increase of air pollutant emissions, necessitating the issuance of an AO pursuant to UAC R307-401, Permits. IPSC is required by UAC R307-401 to submit to UDAQ on behalf of IPA this NOI application and obtain a UDAQ-issued AO prior to initiation of construction activities associated with Unit 3. In addition, UAC R307-401 provides an outline of the required content information that is to be submitted with this NOI application. UAC R307-401 also includes the procedures to be implemented by UDAQ to review the NOI and issue the AO.

The following information, where applicable, is submitted within this NOI:

- A description of the nature of the processes involved; the nature, procedures for handling and quantities of raw materials; the type and quantity of fuels employed; and the nature and quantity of finished product.
- Expected composition and physical characteristics of effluent stream both before and after treatment by any control apparatus, including emission rates, volume, temperature, air contaminant types, and concentration of air contaminants.
- Size, type, and performance characteristics of any control apparatus.

- Location and elevation of the emission point and other factors relating to dispersion and diffusion of the air contaminant in relation to nearby structures and window openings, and other information necessary to appraise the possible effects of the effluent.
- The location of planned sampling points and the tests of the completed installation to be made by the owner or operator when necessary to ascertain compliance.
- The typical operating schedule.
- A schedule for construction.
- Any plans, specifications, and related information which are in final form at the time of submission of NOI.
- Any other information necessary to determine if the proposed source or modification will be in compliance with UAC R307-401-2.

5.1.1.2 Operating Permit Requirements (UAC R307-415)

The federal operating permits program (Title V) is implemented by regulations codified at 40 CFR Parts 70 and 71. The State of Utah has been granted authority to implement and enforce the federal Title V program through state regulations outlined under UAC R307-415. IPSC currently has a UDAQ-issued Title V operating permit (Permit No. 2700010001). Pursuant to UAC R307-415, the addition of Unit 3 will constitute a significant modification to the existing facility and will require a modification of the existing Title V permit.

An application for a Title V permit revision is required prior to commencing operation of the proposed Unit 3, as specified in UAC R307-415, Permits: Operating Permit Requirements. IPSC is submitting this enhanced NOI to serve as both an application for an AO and an application to modify the existing Title V operating permit to reflect the addition of Unit 3. Through this NOI application, IPSC is requesting that a revision to the existing Title V operating permit be issued in conjunction with issuance of the new AO for Unit 3. In accordance with UAC R307-415, this NOI application incorporates the following information:

- Company identifying information, including name, address, owner's name and agent, and telephone number and names of plant site manager or contact
- A description of the source's processes and products by Standard Industrial Classification (SIC) Code, including any associated with each alternate scenario identified by the source
- A description of the change, the emissions resulting from the change, and any new applicable requirements that will apply if the change occurs
- A description of the PTE all air pollutants for which the source is major, and the PTE of all regulated air pollutants and HAPs from any emissions unit, except for insignificant
- Identification and description of all points of emissions in sufficient detail to establish the basis for fees and the applicability of air quality regulatory requirements

- Emissions rates in tpy and in such terms as are necessary to establish compliance with applicable requirements consistent with the applicable standard reference test method
- The following information to the extent it is needed to determine or regulate emissions: fuels, fuel use, raw materials, production rates, and operating schedules
- Identification and description of air pollution control equipment and compliance monitoring devices or activities
- Limitations on source operation affecting emissions or any work practice standards, where applicable, for all regulated air pollutants and HAPs at the Part 70 source
- Calculations on which information is based
- Other information required by any applicable requirement, including information related to stack height limitations developed pursuant to Section 123 of the CAA
- Citation and description of all applicable pollution control requirements
- Description of, or reference to, any applicable test method for determining compliance with each applicable pollution control requirement
- The source's suggested draft permit
- Certification by a responsible official that the information in the document is complete, accurate, and truthful
- Completed forms for the executive secretary to use to notify EPA and affected states as required under UAC R307-415-8
- For applicable requirements with which the source is in compliance, a statement that the source will continue to comply with such requirements
- For applicable requirements that will become effective during the permit term, a statement that the source will meet such requirements on a timely basis
- For requirements for which the source is not in compliance at the time of permit issuance, a narrative description of how the source will achieve compliance with such requirements
- A statement that the source will meet in a timely manner applicable requirements that become effective during the permit term
- Other information as requested

5.1.1.3 NSR Significant Emission Increase Definition (UAC R307-101-2)

By themselves, PC-fired utility boilers of the size and capacity of the proposed unit at IPP typically are categorical sources whose emissions of SO_2, NO_x, CO, and PM traditionally exceed the major source threshold established within the federal NSR rules under 40 CFR 51. UDAQ has been delegated full authority from EPA for administering the federal NSR rules. Since the IPP is an existing major source, the construction of an additional generating unit with emissions greater than “significant” emission thresholds will trigger the NSR process. General provisions under UAC R307-101-2 define significant as: "A net emissions increase or the potential of a source to emit ....equal to or greater than.... CO 100 tpy; NO_x 40 tpy; SO_2 40 tpy; PM_{10} 15 tpy; PM 25 tpy; ozone 40 tpy (of VOCs); lead 0.6 tpy....H_2SO_4 7 tpy....." Since the net emissions increases attributable to Unit 3 for SO_2, NO_x, CO, PM, PM_{10}, VOCs, lead, H_2SO_4, HF, TRS, and RSCs are above the limits specified for significant net emissions increase and IPP is a major stationary source, the addition of Unit 3 is considered a major modification of an existing major stationary source and is subject to the NSR requirements for SO_2, NO_x, CO, VOCs, PM, PM_{10}, lead, H_2SO_4,, HF, TRS, and RSCs.

5.1.1.4 PSD (UAC R307-405)

Within the federal NSR regulations, a subset of rules, which apply to major sources and major modifications within attainment areas, are referred to as the PSD program. Since the new IPP unit will be located in an area classified as attainment for all criteria pollutants, the requirements of the federal PSD program will apply to the construction of Unit 3. The UDAQ has been delegated full authority from the EPA for administering the federal PSD rules; consequently, these requirements are codified within the state permitting rules at UAC R307-405.

The PSD program defines a major stationary source as:

1. Any source type belonging to one of 28 listed source categories that has PTE of 100 tpy or more of any conventional (or "criteria") pollutant regulated under the CAA or,

2. Any other (non-categorical) source type with a PTE of 250 tpy of any pollutant regulated under the CAA.

The IPP facility belongs to one of the 28 listed source categories (fossil fuel-fired steam electric plants of more than 250 mmBtu/hr heat input) and is considered an existing major stationary source because the PTE for SO_2, NO_x, CO, VOCs, PM, PM_{10}, lead, H_2SO_4, HF, TRS, and RSCs all exceed the limits listed in this section.

Modifications to an existing major stationary source are considered major and subject to PSD review if a net emissions increase is equal to or greater than the corresponding significant emissions increase threshold for each respective pollutant. A net emissions increase includes both of the following:

- The potential increase in emissions due to the modification itself

- Contemporaneous net emissions increases and decreases of regulated air pollutants, under the PSD program

An emissions increase is considered significant if emissions meet or exceed any of the following rates:

- CO, 100 tpy
- NO_x, 40 tpy
- SO_2, 40 tpy
- PM_{10}, 15 tpy
- PM, 25 tpy

- Ozone, 40 tpy of VOCs
- Lead, 0.6 tpy
- Asbestos, 0.007 tpy
- Beryllium, 0.0004 tpy
- Mercury, 0.1 tpy
- Vinyl chloride, 1 tpy
- Fluorides, 3 tpy
- H_2SO_4, 7 tpy
- Hydrogen sulfide, 10 tpy
- TRS (including H_2S), 10 tpy
- RSC (including H_2S), 10 tpy

The basic PSD permitting requirements that must be met for a major modification include:

- Application of BACT (presented in Section 6 of this NOI)
- Performance of an ambient air quality impacts analysis (dispersion modeling) (presented in Section 8 of this NOI)
- Analysis of impacts to soils, vegetation, and visibility (AQRVs) (presented in Section 7 of this NOI)
- Analysis of Class I area impacts (presented in Section 7 of this NOI)

These requirements apply to attainment pollutants for which the modification is major. As stated above, net emission increases of SO_2, NO_x, CO, VOCs, PM, PM_{10}, lead, H_2SO_4,, HF, TRS, and RSCs associated with the proposed Unit 3 exceed significant emission rate thresholds. Based on these emissions, the proposed addition of Unit 3 is a major modification (subject to the federal and state PSD program requirements) for SO_2, NO_x, CO, VOCs, PM, PM_{10}, lead, H_2SO_4,, HF, TRS, and RSCs.

IPP is located in a PSD area for all applicable pollutants and is subject to the provisions in UAC R307-405-6, PSD Areas - New Sources and Modifications. Pursuant to this section, IPSC must meet all applicable emissions requirements of UAC R307 and modifications must be reviewed by the executive secretary to determine the air quality impact of Unit 3. In addition, IPSC is required to include the following information with the NOI:

- An analysis of the air quality impact and a demonstration that increases will not contribute to a violation of any NAAQS or PSD increment
- An analysis of ambient air quality in the affected area for each pollutant that a new source would have the PTE in a significant amount
- An analysis of the air quality-related impact including an analysis of the impairment to visibility, soils, and vegetation and the projected air quality impact from general commercial, residential, industrial, and other growth associated with the source or modification
- Other information as requested by the executive secretary

5.1.1.5 Acid Rain Sources (UAC R307-417)

For purposes of implementing an acid rain program that meets the requirements of Title IV of the CAA, the provisions of 40 CFR Part 72 are incorporated into UAC R307-417 by reference. The State of Utah administers the acid rain program through adoption of 40 CFR 72 of the federal code. These requirements are discussed in Section 5.1.2.3 of this NOI.

5.1.1.6 New and Modified Sources in Nonattainment Areas and Maintenance Areas (UAC R307-405)

Described in this section are the requirements for proposed source permit approval. This rule requires the executive secretary to determine if a source will cause or contribute to a violation of the NAAQS as of the projected startup date. IPSC is located in an area classified as attainment; therefore, this rule does not apply.

5.1.1.7 Visibility (UAC R307-406)

This section on visibility describes the requirements for the UDAQ review of any major source or major source modification proposed for the impact of its emissions on visibility in any mandatory Class I area. UDAQ is required to review emission impact analysis results to determine if the proposed major source modification will have an adverse impact on visibility. If the review determines that the impact will be adverse, pre- or post-construction monitoring may be required for the facility. Modeling results are provided in Section 7 of this NOI. This rule applies to the planned addition of Unit 3.

5.1.1.8 Emissions Impact Analysis (UAC R307-410)

This section provides the guidance used to develop modeling protocol established and conduct the emission impact analysis for the proposed projects. The modeling results for this project are provided in Section 8 of this NOI. This rule applies to the planned addition of Unit 3.

5.1.1.9 Exemptions and Special Provisions (UAC R307-413)

The conditions under which a source is exempt from submittal of an NOI and AO are described in this part. The IPP Unit 3 project does not meet the criteria to apply for exemptions or special provisions; therefore, this rule does not apply.

5.1.1.10 Fees for AOs (UAC R307-414)

Requirements for the payment of fees associated with review of NOIs are outlined in this section. This rule applies. UDAQ requires that a base fee of $,31,500 be submitted with the application for a major modification to an existing major source. If the standard allotted hours are exceeded at the state, an additional $70 per hour will be charged. UDAQ has already stated that the standard allotted hours will be exceeded and additional charges will apply to IPP.

5.1.2 Federal Air Permit Requirements

The general requirements for permits and permit revisions are codified under the CAA at 40 CFR 70. The EPA administers the federal Title V operating permit program.

5.1.2.1 Major Source NSR/PSD (40 CFR 51)

UDAQ has been delegated full authority from EPA for administering the federal PSD and NSR rules; therefore, these rules are summarized in Section 5.1.1.4 of this NOI.

5.1.2.2 Operating Permit Program (40 CFR Parts 70 and 71)

UDAQ has been delegated full authority from EPA for administering the federal Title V operating permit program rules; therefore, these rules are summarized in Section 5.1.1.2 of this NOI.

5.1.2.3 Acid Rain Program (40 CFR Parts 72, 73, 75, 76, and 77)

As a PC-fired electric utility boiler, Unit 3 will be subject to the SO_2 allowance allocation, NO_x emission limitations, and monitoring provisions of the federal acid rain program. The existing acid rain permit for IPP will be modified to incorporate the new unit. A CEMS will be designed, fabricated, installed, and certified on the new unit, in accordance with the requirements of Part 75. The State of Utah administers the acid rain program through UAC Title R307-417, which is an adoption of the federal code. See Appendix D, Table D-1 for further details with regard to the federal CEMS requirements.

5.2 Other State and Federal Air Quality Requirements

5.2.1 Overview of State Air Quality Regulations

The following comments all pertain to articles within UAC R307. Refer to Appendix D, Table D-1 for further details on the applicability of specific regulatory sections.

- The provisions of UAC R307-101 to UAC R307-135 are general in nature, and do not provide specific standards, limitations, or other requirements applicable to Unit 3. However, they do govern other provisions in other articles of this chapter that pertain specifically to Unit 3 now or possibly during future operations.
- The provisions of UAC R307-150 to UAC R307-170 pertain to emission inventories and emission monitoring; in general, these provisions apply to this facility.
- The provisions of UAC R307-201 to UAC R307-215 concern emission standards; in general, these provisions apply to this facility.
- The provisions of UAC R307-220 to UAC R307-223 pertain to specific facilities. Neither the IPP plant nor the planned Unit 3 is listed as one of these specific facilities; therefore these provisions do not apply.
- Since the IPP plant is in an attainment area, the provisions of UAC R307-301 to UAC R307-343 do not apply to this facility; these are requirements for nonattainment and maintenance areas only.
- The provisions of UAC R307-401 apply to NOIs and AOs. In general, these provisions apply to this facility; however, specific paragraphs do not apply to this facility (see Appendix D, Table D-1 for clarification).

- Since the IPP plant is in an attainment area, the provisions of UAC R307-403 do not apply to this facility; these are permit requirements for nonattainment and maintenance areas only.
- The provisions of UAC R307-405, PSD permit requirements, apply to this facility; however, specific paragraphs do not apply (see Appendix D, Table D-1 for clarification).
- The provisions of UAC R307-406 define visibility requirements for Class I areas and whether the facility will be required to monitor visibility impacts prior to and following construction apply to this facility.
- UAC R307-410 pertains to the emissions impact analysis and applies to this facility.
- UAC R307-413 pertains to exemptions and this facility does not meet the criteria to apply for exemptions or special provisions.
- UAC R307-414 pertains to the fees for AOs and applies to this facility; (see Section 5.1.1.10).
- UAC R307-415 applies to UDEQ's requirements for operating permits; these provisions apply to this facility.
- The provisions of UAC R307-417 pertain to acid rain sources; these provisions apply.
- The provisions of UAC R307-420 pertain to facilities in ozone nonattainment areas. Since IPP is not in an ozone nonattainment area, these provisions do not apply.
- The provisions of UAC R307-801 pertain to asbestos. Although the planned addition of Unit 3 is not an asbestos project, IPSC will take the appropriate precautions to ensure that asbestos-containing building materials present in the existing facility (if any) are not disturbed during construction of Unit 3. Precautions taken will conform to this rule and the National Emissions Standards for Hazardous Air Pollutants (NESHAP), Subpart M.
- The provisions of UAC R307-480 pertain to lead-based paint. Although the new Unit 3 will not contain lead-based paint, IPSC will take the appropriate precautions to ensure that lead-based paint within the existing facility (if any) is not disturbed, in accordance with this rule.
- The provisions of Utah Statutory Code (USC) Title 19, Chapter 2 apply primarily to the permit-issuing agency and are incorporated into UAC R307. The primary requirement in this section is that the facility owners and operators cooperate with the agency and supply necessary information. Since the provisions of USC Title 19, Chapter 2 are incorporated into UAC R307, these provisions were not included in Appendix D, Table D-1.
- In general, the SIP for nonattainment areas does not apply to this facility because it is located in an attainment area; therefore, these SIP requirements were not included in Appendix D, Table D-1.

5.2.1.1 Monitoring and Reporting

After an AO is received, IPSC will be required to conduct monitoring, submit emission reports, ensure that equipment meets certain specification, and other activities as UDAQ requests. Some of these requirements are enumerated, below:

- Meet the reporting requirements specified in UAC R307-107-2 in the event of an unavoidable breakdown (UAC R307-107)
- Submit and retain an annual HAP inventory and an annual air emission inventory (UAC R307-150 and R307-155)
- Conduct emissions testing in accordance with UAC R307-401 (UAC R307-165)
- Install CEMS and submit related reports to UDAQ (UAC R307-170)
- Conduct opacity observations in accordance with EPA Method 9 (UAC R307-201)
- Conduct air quality modeling (UAC R307-410)
- Ensure that the degree of emission limitation required reflects use of good engineering practices (GEP) in regard to stack height (UAC R307-410)

5.2.2 Other Federal Air Quality Regulations

5.2.2.1 NESHAPs (40 CFR Parts 61 and 63)

Requirements to receive authorization from the EPA (or designated states) before construction or modification of a source are provided in 40 CFR 61.01 through 61.08. This NOI is being submitted pursuant to these paragraphs. The reporting and monitoring requirements applicable to Unit 3 are provided in 40 CFR 61.09 through 61.15. Certain sections of NESHAP Subpart M, "National Emission Standard for Asbestos" may be applicable to the existing IPP facility. The remaining sections of 40 CFR 61 provide guidelines and requirements for specific sources that IPP does not operate; therefore, these sections do not apply to Unit 3 or IPP in general.

The EPA's regulations for case-by-case MACT, which were promulgated in 1996, are set out in 40 CFR Part 63, Subpart B. Those regulations require case-by-case determinations of MACT by the Title V permitting authority for each major source of HAPs which is constructed or reconstructed after the effective date of the Section 112(g) program. For electric utility steam generating units, the case-by-case provisions contain an exemption from applicability "unless and until such time as these units are added to the source category list." On December 14, 2000, the EPA announced that it was adding PC-fired power plants to the Section 112(c) list of sources [65 Federal Register (FR) 79825 published December 20, 2000]. Therefore, each PC-fired electric utility steam generating unit which is constructed or reconstructed is now subject to the case-by-case provisions of the Act until the EPA promulgates a nationally applicable MACT standard to address HAPs for this source category. The EPA expects to promulgate a final standard in December 2004.

Pursuant to 40 CFR Part 63, Subpart B, case-by-case MACT determination must be made by the permit applicant for each new unit that has emissions above the major source threshold for HAPs. Section 6.3 of this application contains the case-by-case MACT determination for the IPP Unit 3, as required for a new major source of HAPs.

5.2.2.2 Compliance Assurance Monitoring Program (40 CFR Part 64)

Since the existing facility and the proposed Unit 3 will be an "affected unit" subject to the federal acid rain program monitoring provisions, codified at 40 CFR Part 75, IPP is exempt from the federal compliance assurance monitoring (CAM) program requirements, codified at 40 CFR Part 64, for SO_2, and NO_x, pursuant to 40 CFR 64.2(b)(1)(iii). The PM_{10} CAM Plan for Unit 3 is contained in Section 10 of this NOI.

5.2.2.3 NSPS (40 CFR Part 60)

These rules establish emissions limitations for SO_2, NO_x, and PM and provide a variety of requirements for monitoring, recordkeeping, and reporting of emissions and other information. Any emissions unit subject to an NSPS subpart is also subject to the general provisions under Subpart A (codified at 40 CFR 60.1 through 60.19). IPP will also be subject to the provisions in Appendices B and F of this subpart which outline requirements and specifications for continuous opacity monitoring systems (COMS), CEMS, and the quality assurance (QA) and quality control (QC) plans required for these monitoring systems. The content of these sections is extremely detailed. Guidance regarding SIPs is given in sections 40 CFR 60.20 through 60.29 (Subpart B); these sections do not apply to IPP.

Sections 40 CFR 60.30 through 60.39 (Subpart C) are specific to waste combustion units, incinerators, solid waste landfills, and sulfuric acid production plants. IPP does not conduct any of these processes; therefore, the requirements in this section do not apply to the IPP facility.

The provisions of 40 CFR 60.40 through 60.49 (Subpart D) apply to fossil fuel-fired steam boilers having a heat input of 250 mmBtu per hour or more, and constructed since August 17, 1971. The IPP Unit 3 fits this definition; however, similar electric utility units constructed after September 18, 1978 are subject to the requirements of NSPS Subpart Da (see next paragraph) which, for such units, supercedes Subpart D.

The provisions of 40 CFR 60.40a through 60.49a (Subpart Da) apply to electric utility steam generating units having a heat input of 250 mmBtu per hour or more and constructed on or after September 18, 1978. The proposed Unit 3 will be a nominal 950-gross MW PC-fired electric utility steam boiler rated in excess of 9,050 mmBtu per hour heat input and is therefore subject to the requirements of 40 CFR Subpart Da. According to this subpart, all monitoring activities and reports of emissions should be documented and retained on file, and the following may not be exceeded:

- PM 0.03 lb/mmBtu (§ 60.42a) 30-day rolling average
- Opacity of 20 percent, except for one 6-minute period per hour (§ 60.42a)
- SO_2 1.2 lb/mmBtu (§ 60.43a) 30-day rolling average

- 90-percent SO_2 reduction (or 70-percent reduction if emissions are less than 0.60 lb/mmBtu) (§ 60.43a) 30-day rolling average for emission limit and 24-hour average for percent removal.
- NO_x 0.6 lb/mmBtu (§ 60.44a) 30-day rolling average
- NO_x 1.6 pounds per megawatt hour (MWH)(§ 60.44a d 1) 30-day rolling average

COMS and CEMS must be installed, calibrated, maintained, operated, and recorded in accordance with the requirements in 40 CFR 60.47a through 60.49a. Documentation is required to be maintained regarding performance tests and calibration and maintenance of equipment. These monitoring systems shall be certified in accordance with the performance specifications provided in Appendix B to Part 60, and maintained in accordance with the QA requirements provided in Appendix G to Part 60. Note that some of the criteria and certification test requirements within these NSPS appendices are, for acid rain sources, superceded by certain provisions within 40 CFR Part 75, which was promulgated later.

5.2.2.4 Risk Management Plan (40 CFR 68)

This regulation requires sources to develop a Risk Management Plan (RMP) for any chemicals stored onsite above threshold quantities defined in 40 CFR 68. Since this is an enhanced NOI intended to serve as both an application for an AO and a revision to the existing Title V permit, review of the current RMP submitted for the existing units will be required. If it is determined that additional chemicals above the RMP thresholds will be stored at the facility as a result of adding Unit 3, the existing RMP will be appropriately revised.

5.2.2.5 NO_x and Excess Emissions (40 CFR Parts 76 and 77)

Under 40 CFR 76, IPP Unit 3 is considered a Group I, Phase II boiler and shall not discharge emissions of NO_x in excess of 0.40 lb/mmBtu on an annual average basis for tangentially-fired boilers or 0.46 lb/mmBtu on an annual average basis for dry bottom wall-fired boilers.

5.2.3 Regulatory Applicability Summary Matrix

Appendix D contains a table that summarizes all requirements. The table is organized with the Utah rules first, followed by the federal regulations. The table identifies all requirements, denotes applicability, and provides an explanation. When necessary, Table D-1 defines the methods to be used to demonstrate compliance.

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6.0 Control Technology Analysis

This section describes the air pollution control equipment that will be utilized on the proposed IPP Unit 3, and includes the BACT and MACT analyses for applicable pollutants. Additional information relating to control technologies is contained in Appendix F, G, H, and I of this NOI addendum.

6.1 Design and Description of the Source

In the initial planning stages of this project it was necessary for IPA to define the type of electricity generating facility it would propose for IPA Unit 3. Several technical, financial, environmental, and practical considerations were reviewed in order to reach a conclusion as to the most appropriate design for IPA Unit 3. Items taken into consideration included: requisite generating capacity, reliability, availability, fuel availability, safety factors, operating training, redundancy/compatibility with existing IPP Units 1 and 2, and potential environmental impacts. Some of the more important project design criteria are listed below:

- Unit 3 should be capable of generating a nominal 900-MW net output.
- Unit 3 would be a baseload unit, and therefore the unit must be designed with technologies capable of achieving a capacity factor of 90 percent.
- As a baseload unit, Unit 3 must be very reliable and must be capable of maintaining a very low forced outage rate. Therefore, Unit 3 must be designed with a highly reliable boiler and turbine, reliable emission control technologies, and reliable ancillary equipment.
- Based on fuel availability, the Unit 3 boiler should be designed to fire Utah bituminous coal with an annual average maximum design coal sulfur content of 0.75 percent, and a design coal heating value of 11,193 Btu/lb.[1]
- To ensure flexibility in the fuel supply, the proposed boiler should be capable of burning a blend of Utah bituminous coal and western sub-bituminous coal.
- For safety considerations, operating training considerations, and O&M reliability, the boiler design and operation should be (to the extent practicable) compatible with the existing IPP coal-fired units.
- Unit 3 must be equipped with the best available emission control technologies, and controlled emissions from the proposed unit must not cause or contribute to a violation of the applicable NAAQS or applicable PSD increment.

Various electricity generating technologies were reviewed to identify the technologies capable of meeting all of the project specifications. It was concluded that the most

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[1] A detailed discussion of the proposed design fuel is provided in a paper titled "*Intermountain Power Project Unit 3 Coal Supply*" included in Appendix I-1 of this supplement.

appropriate electricity generating technology, and, in fact, the only technically feasible and commercially available technology capable of meeting all the project specifications, was a large single-boiler pulverized coal-fired unit equipped with the best available emission control technologies. Project criteria critical to the feasibility of the IPA project exclude Integrated Gasification Coal Combustion (IGCC), Circulating Fluidized Bed (CFB) combustion, natural gas-fired combined cycle combustion, and other alternative electricity generating technologies from consideration. These alternative electricity generating technologies were not selected for various reasons, including size limitations, reliability and availability problems, fuel requirements, and safety considerations. To meet all critical project criteria, IPA is proposing a nominal 950-MW gross pulverized coal-fired boiler.

Provided in Section 6.1 is a description of the pollution control systems proposed for Unit 3. Section 6.2 includes a detailed BACT analysis of control technologies available to control potential emissions from a large pulverized coal-fired boiler fired on Utah bituminous coal (i.e., the proposed source as defined by IPA). Section 6.2 does not include an evaluation of alternative electricity generating technologies. This approach is consistent with EPA guidance in the New Source Review Workshop Manual, which states that "Historically, EPA has not considered the BACT requirement as a means to redefine the design of the source when considering available control alternatives."[2] Section 6.3 includes a comprehensive case-by-case MACT determination for the control of potential emissions of hazardous air pollutants.

6.2 Pollution Controls

The proposed IPP Unit 3 will be equipped with pollution controls to limit the emissions of SO_2, TRS, RSCs, H_2SO_4, HCl, HF, NO_x, PM, PM_{10}, and lead.

6.2.1 SO_2 and Related Sulfur Compounds

Emissions of SO_2 and other sulfur compounds will be controlled on IPP Unit 3 with the use of a forced oxidation wet limestone FGD system. The FGD system will have a worst-case design SO_2 removal efficiency of 90 percent designed to achieve an outlet rate of 0.10 lb/mmBtu. The FGD system, located downstream from the fabric filter, will remove SO_2 from the flue gas stream by use of a limestone slurry absorption system.

The wet limestone FGD system will also have a similar removal efficiency (90 percent) for the control of TRS and RSCs.

The FGD system is basically composed of the following five subsystems:

- The absorption system, which consists of a spray tower, reaction tank, agitators, air sparger, air compressor, and spray tower recycle pumps.
- The limestone slurry preparation system, which consists of the limestone ball mills, slurry tanks, and slurry pumps.

[2] U.S. EPA, *New Source Review Workshop Manual*, Office of Air Quality Planning and Standards, Draft October 1990, page B.13.

- Limestone handling and storage system, which consists of a rail/truck unloading facility, conveyors, storage area, and transfer conveyors.
- The primary and secondary dewatering system, which consists of a hydroclone or thickeners, filter feed tank, vacuum/belt filters, conveyors, and temporary storage area.
- The flue gas system, which consists of inlet and outlet ducts, induced draft fans, and inlet/outlet dampers.

The FGD system for Unit 3 starts at the gas outlet flanges of the fabric filter system and includes the outlet ducts and induced draft fans, each with inlet and outlet dampers. The fans are connected in parallel and provide draft to pull the gas through the boiler, SCR system, and fabric filters, and then force the gas through the spray tower absorbers and into the stack. All boiler exhaust gases from Unit 3 will pass through the FGD system. The FGD system will be designed with two scrubber modules, each sized and designed to treat 67 percent of the maximum flue gas flow rate.

Ground limestone in the scrubbing slurry reacts with SO_2 in the flue gas to form calcium sulfites and some calcium sulfate. Slurry from the spray tower flows to the bottom of the scrubber to a reaction tank. The reaction tank will be designed with blowers to oxidize the calcium sulfite to calcium sulfate (i.e., gypsum). The gypsum slurry will be drawn off the reaction tank and sent to sludge conditioning. It is anticipated that the gypsum slurry will be treated in a series of hydroclones located in the scrubber building. Reclaimed water from the hydroclones will be sent back for reuse in the scrubber system, and gypsum solids will be sent to a vacuum filtration system. Gypsum solids from the vacuum filter system can be washed to remove contaminants and loaded into railcars or trucks for shipment as a product, or mixed with fly ash, if necessary, and conveyed to the landfill using the facility's existing conveyor system.

The FGD system will be designed to meet or exceed the SO_2 emission levels described in Section 4. Additional technical discussion relating to the proposed SO_2 control technologies is provided in Appendix I-5 in the supplemental white paper entitled *Sulfur Dioxide Control – Flue Gas Desulfurization and Control Efficiency.*

6.2.2 Sulfuric Acid

Emissions of sulfuric acid (H_2SO_4) will be controlled on IPP Unit 3 by the fabric filter system and the wet limestone FGD system. Selective Catalytic Reduction (SCR) will impact the formation and control of H_2SO_4. The SCR will approximately double the SO_3 concentration in the flue gas, and consequently double the potential emissions of H_2SO_4.

A portion of the SO_3 generated in the boiler and SCR will be captured in the fabric filter. Fly ash cake that accumulates on the filter bags acts as an alkaline filter through which the flue gas must pass. SO_3, which is very reactive, will readily react with alkaline components of the fly ash at temperatures below the H_2SO_4 dewpoint to form sulfate salts.

The flue gas desulfurization system will also provide some SO_3 control. In the FGD reaction vessel, SO_3 will react with alkaline components of the desulfurization scrubber slurry. However, in the case of wet FGD, some of the SO_3 entering the wet scrubber vessels may react with water and create micron-sized sulfuric acid droplets. Some of the micron-sized droplets may pass through the FGD spray levels and the mist eliminator, and be emitted as sulfuric acid mist.

Based on source test information obtained from Unit 1, it is anticipated that the overall H_2SO_4 removal efficiency across the baghouse and wet limestone FGD system will be approximately 90 percent. In the original NOI submission, a conservative estimate of 40 percent removal across the wet limestone FGD system was assumed, with anticipation of additional SO_3 removal across the fabric filters based on the alkalinity of the Utah Coal.

Additional technical discussion relating to the H_2SO_4 emission reduction capacity of the fabric filter and wet limestone FGD system is provided in Appendix I-4 in Section II of the supplemental white paper entitled *Evaluation of Wet Electrostatic Precipitation to Control Sulfuric Acid Mist Emissions.*

6.2.3 HCL and HF

The use of the wet limestone FGD system on IPP Unit 3 will reduce HCl and HF potential emissions by greater than 90 percent. Based on operating data at other coal-fired utilities that utilize fabric filters and wet limestone FGD systems, very high acid gas removal efficiencies have been demonstrated. Removal efficiencies up to 99 percent for HCl and 95 percent for HF have been reported. The level of control is also dependent on the coal properties.

6.2.4 NO_x

The emissions of NO_x from IPP Unit 3 will be controlled through the use of LNBs, over fire air (OFA), and SCR. Control methods for NO_x can be divided into two types of control technologies: post-combustion controls and combustion controls. Combustion controls (LNBs and OFA) reduce the amount of NO_x that is generated in the boiler. Post-combustion controls (SCR) remove NO_x from the boiler exhaust gas.

Low NO_x burners limit NO_x formation by controlling both the stoichiometric and temperature profiles of the combustion flame in each burner flame envelope. This control is achieved with design features that regulate the aerodynamic distribution and mixing of the fuel and air, yielding reduced oxygen (O_2) in the primary combustion zone, reduced flame temperature, and reduced residence time at peak combustion temperatures.

In the OFA process, the injection of air into the firing chamber is staged into two zones. The staging of the combustion air reduces NO_x formation by two mechanisms. The staged combustion results in a cooler flame, and the staged combustion results in less oxygen reacting with fuel molecules. However, the degree of staging is limited by operational problems. Excessive staging can result in incomplete combustion conditions and increased CO and VOC emissions.

The combination of these two combustion control techniques produces lower NO_x emissions during the combustion process. LNBs control the formation of NO_x by staging the combustion of the coal to keep the peak flame temperature below the threshold for NO_x formation. The burner initially introduces the coal into the boiler with less air than is needed for complete combustion. The flame is then directed toward an area where additional combustion air is introduced from overfire air ports allowing final combustion of the fuel.

An SCR unit will also be installed as a post-combustion control on IPP Unit 3 to further reduce the NO_x emissions. The proposed SCR is designed for high dust loading applications, and will be located external from the boiler. The SCR system uses a catalyst and a reactant (NH_3) to dissociate NO_x into nitrogen gas and water vapor. Since NO_x is a shorthand notation for the combination of NO and NO_2, NO_x reduction occurs in two separate reactions. The catalytic process reactions for this NO_x removal are as follows:

$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$ and

$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O$.

The optimum temperature window for this catalytic reaction is between approximately 575°F and 750ºF. Therefore, the SCR reaction chamber will be located between the economizer outlet and air heater flue-gas inlet. The system will be designed to use anhydrous ammonia as the reducing agent. Ammonia injection pipes, nozzles, and a mixing grid will be located upstream of the reaction chamber. A diluted mixture of NH_3 in air will be dispersed through injection nozzles into the flue-gas stream. The ammonia/flue-gas mixture then enters the reactor where the catalytic reaction occurs.

The SCR for IPP Unit 3 will have a design control efficiency of 80 percent. Although a new SCR system may be able to achieve removal efficiencies greater than 80 percent, it is unlikely that a removal efficiency greater than 80 percent can be consistently achieved during long-term operation. Despite the fact that SCR is being used to control NO_x emissions from other pulverized coal-fired boilers, SCR is a relatively new control system and there is limited long-term operating experience. Furthermore, there is no actual operating experience demonstrating the affect that Utah bituminous coals may have on the SCR catalyst. Although Utah coals do not appear to exhibit qualities that will adversely impact SCR performance, without actual operating experience the possibility exists that flue gas characteristics unique to Utah coals may cause unforeseen catalyst deterioration or deactivation.

Several factors influence the performance of an SCR system, including the catalyst age, abrasion to the catalyst surface, plugging, and flue gas characteristics that may deactivate the catalyst. Catalyst that has been in service for a period of time will have decreased performance due to normal deactivation and deterioration. Also, the NO_x removal efficiency is dependent on the ratio of ammonia to NO_x. Increasing the amount of ammonia injected increases the control efficiency but also increases the amount of unreacted ammonia (ammonia slip) that is emitted to the atmosphere. Ammonia emissions from a well-controlled SCR system can likely be limited to 5 parts per million by volume (ppmv) or less.

The LNB and SCR system for IPP Unit 3 will be designed to meet the NO_x emission levels described in Section 4. Additional technical discussion relating to the proposed NO_x control technologies is provided in Appendix I-2 in the supplemental white paper entitled *Nitrogen Oxide Emissions and Control.*

6.2.5 PM and PM_{10}

PM and PM_{10} will be controlled at IPP Unit 3 by a fabric filter dust collector. The fabric filters operate by passing the particle-laden flue gas through a series of felted fabric bags. The bags have an accumulated filter cake that removes the particles from the flue gas and the cleaned flue gas passes out of the fabric filter. The fabric filters will have a filterable particulate removal efficiency of 99.83 percent.

The fabric filter system will consist of a number of parallel banks of individual filter compartments located downstream of the air preheaters and upstream of the induced draft fans and the FGD system. Individual filter compartments consist of a bottom collection hopper and an upper bag compartment. A tube sheet separates the hopper from the bag compartment, and tube sheet thimbles direct gas flow through the tube sheet. The bottom, or open end, of the filter bag is attached to the tube-sheet thimble, while the upper end of the bag is attached to the top of the filter compartment.

Particulate-laden flue gas from the boiler enters the system compartments in the upper section of the hopper, just below the tube sheet. The flue gas stream travels up through the filter bags where particles collect on the inside of the bags. PM captured on the filter bags will form a cake. The filter cake increases both the filtration efficiency of the cloth and its resistance to gas flow.

Fabric filtration is a constant-emission device. Pressure drop across the filters, inlet particulate loading, or changes in gas volumes may change the rate of filter cake buildup, but will not change the final emission rate. Actual performance of a fabric-filter depends on specific items such as air/cloth ratio, permeability of the filter cake, the loading and nature of the particles (e.g., irregular-shaped or spherical), particle size distribution, and to some extent, the frequency of the cleaning cycle.

The filter bags must be routinely cleaned to remove accumulated filter cake. The cleaning frequency of the individual compartments will depend, in part, upon the inlet grain loading and the flow resistance of the filter cake formed. It is anticipated that the fabric filter system will be designed as a reverse-air type system. In a reverse-air system, gas flow through an isolated compartment is reversed, causing the filter bag to collapse and fracture the filter cake. Filter cake falls into the collection hopper for transport to the fly ash handling system.

Fabric filter system design involves inlet loading rates, fly ash characteristics, the selection of the cleaning mechanism, and selection of a suitable filter fabric and finish. Additional technical discussion relating to the proposed PM_{10} control technologies is provided in Appendix I-3 in the supplemental white paper entitled *PM_{10} Emissions and Fabric Filter Control Efficiency.*

6.2.6 Lead

The use of a fabric filter on IPP Unit 3 will reduce potential lead emissions by greater than 99 percent. Lead is emitted as a trace metal in the fly ash leaving the boiler. The removal of lead correlates with the collection efficiency of the particulate control device. Since the fabric filter will remove greater than 99 percent of the total PM, the removal efficiency for lead will be similar.

6.2.7 CO and VOCs

CO and non-methane VOCs are formed from the incomplete combustion of the coal in the boiler. The formation of CO and VOCs is limited by controlling the combustion of the fuel and providing adequate O_2 for complete combustion. Thus, good combustion controls will be used to limit CO and VOC emissions.

6.3 BACT Determination

This section presents the required BACT analyses.

6.3.1 Applicability

UAC R307-401-6 requires the degree of pollution control for emissions to be at least BACT, except as otherwise provided in UAC R307. The requirement to conduct a BACT analysis and determination is set forth in Section 164(a)(4) of the CAA and in federal regulations 40 CFR 52.21(j).

6.3.2 Top-Down BACT Process

EPA has developed a process for conducting BACT analyses. This method is referred to as the "top-down" method. The steps to conducting a "top-down" analysis are listed in EPA's *New Source Review Workshop Manual,* (EPA, 1990). The steps are:

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

Each of these steps has been conducted for SO_2, TRS, RSCs, H_2SO_4, NO_x, CO, VOC , PM, PM_{10}, lead, and fluoride and is described below. Emissions of mercury are less than the PSD significance level of 0.1 tpy.

Potential control technologies for each applicable pollutant were identified from a number of sources including the EPA RBLC database, EPA's NSR bulletin board, BACT guideline – South Coast Air Quality Management District, control technology vendors, technical journals and web sites, and other recently issued federal/state/local NSR permits. A summary of various technologies available for controlling SO_2, TRS, RSCs, H_2SO_4, NO_x, CO, VOC , PM, PM_{10}, lead, and fluoride, in addition to a brief technology description and applicability of each technology to coal-fired boilers, is presented as BACT supporting information in Appendix H.

6.3.3 SO_2 Analysis

The BACT analysis for SO_2 is presented below. The analysis is also applicable to the related compounds; TRS and RSCs.

6.3.3.1 Step 1 – Identify All Control Technologies

SO_2 will be emitted from the proposed IPP Unit 3 as a result of the combustion of coal that contains sulfur. The first step is to evaluate SO_2 controls determined to be BACT by permitting agencies across the United States. This information is available from the EPA RBLC database accessible on the Internet. The printout from the database for SO_2 is shown in Appendix F, Table F-8. Additional technology reviews from sources including EPA's NSR bulletin board, BACT guideline – South Coast Air Quality Management District, control technology vendors, technical journals and web sites, and other recently issued federal/state/local NSR permits are summarized in Appendix H.

The potential SO_2 emission reduction options applicable to coal-fired boilers are:

- Wet limestone scrubbing
- Wet lime scrubbing
- Lime spray dryer
- Circulating dry scrubber

The outlet concentrations range from 0.10 to 0.40 lb/mmbtu.

6.3.3.2 Step 2 – Eliminate Technically Infeasible Options

The first three of these options are technically feasible for use in reducing SO_2 emissions from IPP Unit 3. However, the use of a circulating dry scrubber requires the use of high calcium fly ash to provide the alkalinity needed to react with SO_2. The potential coals for IPP Unit 3 are not particularly high in calcium. In addition, control efficiencies for circulating dry scrubbers have not been demonstrated to be above 80 percent in the RBLC database. For these two reasons this technology was eliminated from further consideration.

6.3.3.3 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

EMISSION RATES FOR EACH OF THE REMAINING SO_2 REMOVAL TECHNOLOGIES ARE RANKED IN ORDER OF THEIR CONTROL EFFECTIVENESS. THESE EFFECTIVENESS VALUES ARE PROVIDED IN TABLE 6-1.

TABLE 6-1
SO_2 Control Technology Emission Rate Ranking

Control Technology	SO_2 Outlet Concentrations (lb/mmbtu)
Wet Limestone Scrubbing	0.10 – 0.40
Wet Lime Scrubbing	0.15 – 0.25
Lime Spray Dryer	0.10 – 0.32
NSPS Limit	0.60 [a]

[a] A removal efficiency of 70 percent is applicable when SO_2 emissions are less than 0.60 pounds per mmBtu.

6.3.3.4 The PSD NSR regulations require that BACT be no higher than emissions limits contained in the NSPS. Because there is an NSPS that applies to the boiler, the NSPS emission limit is also included in the ranking.Step 4 – Evaluate Most Effective Controls and Document Results

This step involves the consideration of energy, environmental, and economic impacts associated with each control technology. The top-down process requires that the evaluation begin with the most effective technology. For the new generating unit, the top technologies are wet limestone scrubbing, wet lime scrubbing, and dry lime scrubbing. All technologies can achieve high SO_2 removal efficiencies. On this project, IPP is proposing the installation of a forced oxidation wet limestone FGD system with a design SO_2 removal efficiency of 90 percent or greater.

Since wet limestone scrubbing is thought to represent the most effective SO_2 control technique that can be applied to PC-fired boilers, an economic evaluation is not required. However, a cost estimate for wet limestone FGD installation and operation has been prepared for this project and is provided in Appendix G. The effective cost of a wet limestone scrubber has been estimated at $801 per ton of SO_2 controlled. The use of wet limestone scrubbing for SO_2 control results in the production of a large quantity of by-product that must be disposed of in an environmentally responsible manner. The by-product will be blended with fly ash for landfill disposal on the IPP site. The energy, environmental, and economic impacts associated with wet limestone scrubbing are similar to the wet lime and spray dry systems. However, the costs of installing, running, and maintaining a lime-based system are potentially greater than for a wet limestone system. The use of a wet FGD system (limestone or lime) can also result in increased condensable PM_{10} emissions. Condensable PM_{10} includes emissions of HCl, HF, H_2SO_4, and $(NH_4)_2 SO_4$.

6.3.3.5 Step 5 – Select BACT

The final step in the top-down BACT analysis process is to select BACT. EPA's RBLC database and other recently issued permits were again consulted to assist in selecting BACT for this project. The SO_2 BACT limits from other recently issued PSD permits for PC-fired boilers are summarized in Table 6-2.

TABLE 6-2
Recently Issued PSD Permits – SO_2 Limits

Name	Type/Size	SO_2 Limit	Control Equipment
Hawthorne Unit 5 Missouri	Pulverized Coal 570 MW	0.12 lb/mmbtu (30 day rolling avg) 0.13 lb/mmbtu (3 hour avg)	Dry Lime FGD
Springerville Units 3 and 4 Arizona	Pulverized Coal 450 MW each	8,448 lb/hr Units 1-4 (3 hour rolling avg) 10,800 tpy Units 1-4	Dry Lime FGD Netted with Units 1 and 2 – no increase in facility SO_2 emissions
Holcomb Unit 2 Kansas	Pulverized Coal 660 MW	0.12 lb/mmbtu (30 day rolling avg)	Dry Lime FGD
Thoroughbred Units 1 and 2 Kentucky	Pulverized Coal 750 MW each	0.167 lb/mmbtu (30 day rolling avg) 0.41 lb/mmbtu (24 hour avg)	Wet Limestone FGD
Wygen Unit 2 Wyoming	Pulverized Coal 500 MW	0.10 lb/mmbtu (30 day rolling avg) 0.15 lb/mmbtu (3 hour block avg)	Dry Lime FGD
Bull Mountain Roundup Unit 1 Montana	Pulverized Coal 780 MW	0.12 lb/mmbtu (24 hour avg) 0.15 lb/mmbtu (1 hour avg)	Dry Lime FGD
Plum Point Energy Station Units 1 and 2 Arkansas	Pulverized Coal 550 – 800 MW each	0.16 lb/mmbtu (3 hour rolling avg)	Dry Lime FGD
Rocky Mountain Power, Hardin Unit 1 Montana	Pulverized Coal 113 MW	0.15 lb/mmbtu (30 day rolling avg)	Wet Lime FGD

All the permits above exempt startup, shutdown, and malfunction in the short term (1 hour, 3 hour, 24 hour, and 30 day) emission limits. Plum Point is a draft permit.

Both wet lime scrubbing and wet limestone scrubbing have been demonstrated at removal efficiencies of 90 percent or greater. The installation of a wet limestone scrubber on IPP Unit 3 will result in an SO_2 removal efficiency of 90 percent or greater. The highest collection efficiency shown in the RBLC database is 95 percent on Santee Cooper Cross Unit No. 1. This unit burns high sulfur coal and has an emission limit of 0.34 lb/mmBtu. The design SO_2 emission rate on IPP Unit 3 is 0.10 lb/mmBtu which is as low as any of the applicable units in the RBLC database including the recently issued PSD permits summarized in Table 6-2. The only known unit with a lower emission rate is Deseret at 0.0976 lb/mmBtu; however, this unit has an annual average emission rate limit. Therefore, wet limestone scrubbing is selected as BACT for this project with an SO_2 emission limit of 0.10 lb/mmBtu based on a 30-day rolling average. Additional technical discussion relating to the proposed SO_2 control technologies and proposed BACT Limits is provided in Appendix I-5 in the supplemental white paper entitled *Sulfur Dioxide Control – Flue Gas Desulfurization and Control Efficiency.*

6.3.4 H_2SO_4 Analysis

The BACT analysis for H_2SO_4 is presented below.

6.3.4.1 Step 1 – Identify All Control Technologies

Sulfuric acid mist (H_2SO_4) is generated in a coal-fired boiler when sulfur trioxide (SO_3) in the flue gas reacts with water to form sulfuric acid. A small portion of the sulfur dioxide (SO_2) generated in the boiler will oxidize to SO_3 during the combustion process, and some additional SO_2 to SO_3 oxidation will occur across the SCR. Based on operating information from existing coal-fired boilers, and information available from equipment vendors, it is estimated that approximately 1.0% of the flue gas SO_2 will oxidize to SO_3 in the boiler, and that an additional 1.2% of the flue gas SO_2 will convert to SO_3 across the SCR. SO_3 is hygroscopic and will absorb moisture to form H_2SO_4 at gas temperatures below the sulfuric acid dewpoint. A more detailed description of the generation of SO_3 and H_2SO_4 in a coal fired boiler is included in a white paper included in Appendix I-4 entitled *"Evaluation of Wet Electrostatic Precipitation to Control Sulfuric Acid Mist Emissions."*

The first step in the BACT evaluation is to identify H_2SO_4 control technologies available to control H_2SO_4 emissions. One source of information available to identify potential control technologies is the EPA RBLC database accessible on the Internet. A printout from the database for H_2SO_4 is shown in Appendix F, Table F-10. Additional potential control technologies were identified based on a review of several information sources including EPA's NSR bulletin board, BACT guideline – South Coast Air Quality Management District, control technology vendors, technical journals and web sites, and other recently issued federal/state/local NSR permits. Technologies reviewed are summarized in Appendix H.

H_2SO_4, and the precursor to H_2SO_4 (SO_3) will be captured in emission control technologies designed to control SO_2. Therefore, the same potential control technologies evaluated for SO_3 control were also evaluated for H_2SO_4 control. In addition, SO_3 generated in the boiler and SCR may be captured in the unit's fabric filter, therefore fabric filtration was included in the control technology evaluation. One additional post-FGD control technology, wet electrostatic precipitation (WESP), was also identified as a potential H_2SO_4control technology. H_2SO_4 control technologies evaluated included:

- Wet limestone scrubbing
- Wet lime scrubbing
- Lime spray dryer
- Circulating dry scrubber
- Fabric filter
- Wet electrostatic precipitation

6.3.4.2 Step 2 – Eliminate Technically Infeasible Options

All of the control options listed above are technically feasible for use in reducing H_2SO_4 emissions. However, based on site-specific considerations, circulating dry scrubbing, wet lime scrubbing, and lime spray drying must be excluded from further consideration. As discussed in Section 6.2.3.2, the use of a circulating dry scrubber generally requires the use of high calcium fly ash to provide the alkalinity needed to react with SO_3. The potential coals for IPP Unit 3 are not particularly high in calcium. Furthermore, because of the high particulate loading associated with a circulating dry scrubbing system, the pressure drop across a fabric filter is generally unacceptable, and electrostatic precipitators are generally used for particulate control. IPA has concluded that a fabric filter represents BACT for particulate matter control, and will not consider electrostatic precipitation for particulate matter control. Finally, the circulating dry scrubber has limited application, and has not been used on large pulverized coal-fired boilers. Assuming that a circulating dry scrubber system could be designed for the proposed project, it is anticipated that the SO_2 and SO_3 control efficiencies would be lower than the control efficiency of the proposed control system. For these reasons, circulating dry scrubbing was eliminated from further consideration.

In addition, IPA cannot define BACT for H_2SO_4 control unless the H_2SO_4 control technology is compatible with the control technology defined as BACT for SO_2 and PM_{10}. In other words, the unit cannot be equipped with a wet FGD system for SO_2 control and a dry FGD system for H_2SO_4 control. In Section 6.2.7 IPA determined that a fabric filter represents BACT for the control of PM_{10}, and in Section 6.2.3 IPA determined that wet limestone scrubbing represents BACT for the control of SO_2. Therefore, only control technologies that can be used in conjunction with a fabric filter and wet limestone scrubbing will be considered technology feasible for the control of H_2SO_4.

With respect to wet electrostatic precipitation, there is limited commercial operating experience upon which to base a conclusion regarding the technical feasibility and effectiveness of WESP on a large utility boiler fired on Utah bituminous coal. The proposed Unit 3 is a nominal 950-gross MW unit, which is significantly larger than any existing unit equipped with a WESP. Furthermore, the proposed primary fuel, Utah bituminous coal, has a sulfur content significantly lower than the sulfur content of fuels typically associated with WESP, such as petroleum coke and high sulfur eastern bituminous coal. In fact, the maximum H_2SO_4 concentration in the Unit 3 flue gas is already expected to be significantly below 10 ppmvd @ 3% O_2, a level generally associated with a controlled H_2SO_4 emission rate.

Even though WESP has not been proven to be technically feasible and capable of reducing H_2SO_4 emissions from a pulverized coal-fired unit similar to IPA's proposed Unit 3, for completeness, IPA is including WESP as a potential H_2SO_4 control technology in this BACT evaluation.

6.3.4.3 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Emission rates for each of the technically feasible H_2SO_4 removal technologies are ranked in order of their control effectiveness. These effectiveness values are provided in Table 6-3.

TABLE 6-3
H_2SO_4 Control Technology Emission Rate Ranking

Control Technology	H_2SO_4 % Reduction [a]
Fabric Filter + Wet Limestone Scrubbing + Wet Electrostatic Precipitation	approximately 98%
Fabric Filter + Wet Limestone Scrubbing	approximately 90%

[a] Estimated maximum H_2SO_4 emission control efficiencies listed in Table 6-3 are the results of stack testing on IPP's existing Unit 1, and engineering estimates.

6.3.4.4 Step 4 – Evaluate Most Effective Controls and Document Results

This step involves the consideration of energy, environmental, and economic impacts associated with each technically feasible control technology. The top-down process requires that the evaluation begin with the most effective technology. For the new generating unit, the top H_2SO_4 control technology consists of a combination of fabric filter, wet limestone scrubbing, and wet electrostatic precipitation. This combination of control technologies will reduce potential H_2SO_4 emissions by approximately 98 percent. The second most effective combination of control technologies consists of fabric filter plus wet limestone scrubbing. This combination of control technologies will reduce potential H_2SO_4 emissions by approximately 90 percent.

Both combinations of control systems will result in collateral environmental impacts. For example, both systems will consume water and generate coal combustion wastes that must be managed and disposed of in a landfill. When comparing both combinations of controls, wet electrostatic precipitation will result in increased water consumption and energy consumption. However, the collateral environmental impacts associated with wet electrostatic precipitation do not exclude it from consideration as BACT.

Therefore, it is necessary to evaluate each combination of control systems for economic impacts. The white paper entitled *"Evaluation of Wet Electrostatic Precipitation to Control Sulfuric Acid Mist Emissions"* included in Appendix I-5 of this NOI addendum includes a detailed economic evaluation comparing the two potential H_2SO_4 control systems. Based on information included in Appendix I-5, it is clear that including wet electrostatic precipitation must be excluded from consideration as BACT for the control of H_2SO_4 based on economic impact. Assuming that a wet electrostatic precipitation system is technically feasible, the cost effectiveness of a WESP system designed to reduce post-FGD H_2SO_4 emissions by 80% is more than $100,000 per ton. This cost effectiveness exceeds the cost effectiveness guidelines used by UDAQ in prior BACT determinations.

6.3.4.5 Step 5 – Select BACT

The final step in the top-down BACT analysis process is to select BACT. EPA's RBLC database and other recently issued permits were again consulted to assist in selecting BACT for this project. The H_2SO_4 BACT limits from other recently issued PSD permits for PC-fired boilers are summarized in Table 6-4.

TABLE 6-4
Recently Issued PSD Permits – H_2SO_4 Limits

Name	Type/Size	H_2SO_4 Limit	Control Equipment
Hawthorne Unit 5 Missouri	Pulverized Coal 570 MW	No Limit	Dry Lime FGD
Springerville Units 3 and 4 Arizona	Pulverized Coal 450 MW each	0.0115 lb/mmbtu	Dry Lime FGD
Holcomb Unit 2 Kansas	Pulverized Coal 660 MW	No Limit	Dry Lime FGD
Thoroughbred Units 1 and 2 Kentucky	Pulverized Coal 750 MW each	0.00497 lb/mmbtu	Wet Limestone FGD + Wet Electrostatic Precipitation
Wygen Unit 2 Wyoming	Pulverized Coal 500 MW	0.00463 lb/mmbtu	Dry Lime FGD
Bull Mountain Roundup Unit 1 Montana	Pulverized Coal 780 MW	0.0064 lb/mmbtu	Dry Lime FGD
Plum Point Energy Station Units 1 and 2 Arkansas	Pulverized Coal 550 – 800 MW each	0.0061 lb/mmbtu	Dry Lime FGD
Rocky Mountain Power, Hardin Unit 1 Montana	Pulverized Coal 113 MW	No Limit	Wet Lime FGD

In each permit listed in Table 6-4, the technology identified as BACT for the control of H_2SO_4 is the same control technology identified as BACT for the control of SO_2. The only exception is the proposed Thoroughbred facility that included wet electrostatic precipitation to control H_2SO_4 emissions. However, the proposed Thoroughbred facility will be fired on high-sulfur midwestern bituminous coal. Based on information available in the Thoroughbred permit application, the potential uncontrolled SO_2 emission rate at Thoroughbred is approximately 8.51 lb/mmBtu. This emission rate is more then five times the uncontrolled SO_2 emission rate at IPA Unit 3. This high SO_2 concentration will result in significantly more SO_3 and H_2SO_4, and could contribute to acid mist opacity problems at the facility. Therefore, a wet electrostatic precipitation system may be required to address potential opacity issues, and the control efficiency of a wet electrostatic precipitation system will be more reasonable for a system fired on high-sulfur coal.

In Section 6.2.3 IPA concluded that wet limestone scrubbing would provide the most stringent SO_2 emission control on proposed Unit 3, and that wet limestone scrubbing represents BACT for the control of SO_2. Based on stack test conducted at the existing IPP station, it has been determined that the combination of fabric filters and wet scrubbing will also reduce potential H_2SO_4 emissions by approximately 90%. This combination of technologies will reduce the H_2SO_4 emission rate to approximately 174 lb/hr, or 0.0044 lb/mmBtu. This emission rate is already below the emission rates listed in Table 6-4.

Although wet electrostatic precipitation may provide some incremental reduction in H_2SO_4 emissions, the cost associated with the incremental emission reduction is excessive. Therefore, IPA is proposing the combination of fabric filter and wet limestone scrubbing as BACT for the control of H_2SO_4.

6.3.5 NO_x Analysis

The BACT analysis for NO_x is presented below.

6.3.5.1 Step 1 – Identify All Control Technologies

NO_x will be emitted by combustion of coal in the boiler. NO_x is formed in the combustion process when the peak flame temperature reaches a sufficiently high temperature (approximately 2,500ºF).

The first step is to evaluate NO_x controls determined to be BACT by permitting agencies across the United States. This information is available from the EPA RBLC database, which is accessible on the Internet. The printout from the database for NO_x is shown in Appendix F, Table F-9. Additional technology reviews from sources including EPA's NSR bulletin board, BACT guideline – South Coast Air Quality Management District, control technology vendors, technical journals and web sites, and other recently issued federal/state/local NSR permits are summarized in Appendix H.

Potential NO_x control technology options applicable to coal-fired boilers are:

- SCR
- Selective noncatalytic reduction (SNCR)
- LNB with overfire air
- LNB
- Good combustion control
- Flue gas recirculation

6.3.5.2 Step 2 – Eliminate Technically Infeasible Options

All of these technologies except flue gas recirculation are deemed to be feasible. Flue gas recirculation is an older technology that is not very effective in controlling NO_x on coal-fired units. Therefore it is eliminated as not being technically feasible. SNCR has not been proven on coal-fired units using the specific type of coal proposed for Unit 3. Based on consultation with manufacturers, from a technical point of view, and with the successful operating history at other facilities, SCR is being proposed for use on this project.

6.3.5.3 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Emission rates for each of the remaining technology combinations are required to rank them in order of effectiveness. These emission rates are provided in Table 6-5. The control efficiencies are from the RBLC database and are provided in Appendix F, Table F-9.

TABLE 6-5
NO_x Control Technology Emission Rate Ranking

Control Technology	NO_x Emission Rate [a]
SCR	0.07 – 0.15
SNCR	0.12 - 0.25
LNBs with Overfire Air	0.15 – 0.33
LNBs	0.32 – 0.39
Combustion Controls	0.23 – 0.55
NSPS Limit	0.16[b]

[a] Pounds per mmBtu as found in the RBLC database. Converted from NSPS limit of 1.6 pounds per MWH assuming a heat rate of 10,000 Btu per kWh.

[b] The regulations require that BACT be no higher than emissions limits contained in the NSPS. Because there is an NSPS that applies to the boilers, that NSPS emission limit is included in the ranking.

6.3.5.4 Step 4 – Evaluate Most Effective Controls and Document Results

SCR with LNBs and overfire air is being proposed for this project. SCR is a control technique that reacts ammonia with the NO_x in the flue gas at the appropriate temperature in the presence of a catalyst to form water and nitrogen.

SCR has two well-documented environmental impacts associated with it, emissions of unreacted ammonia and disposal of spent catalyst. Some ammonia emissions (called ammonia slip) from an SCR system is unavoidable because of imperfect distribution of the reacting gases and ammonia injection control limitations. Also, the NO_x removal efficiency depends on the ratio of ammonia to NO_x. Increasing the amount of ammonia injected increases the control efficiency but also increases the amount of unreacted ammonia that is emitted to the atmosphere. Ammonia emissions from a well-controlled SCR system can likely be limited to 5 ppmv or less. Ammonia emissions are of concern because ammonia is a significant contributor to regional secondary particulate formation and visibility degradation. In this case, reduced NO_x emissions as an environmental benefit would be traded for increased ammonia emissions as an environmental detriment.

The other environmental impact associated with SCR is disposal of the spent catalyst. The catalysts used in SCR systems must be replaced every 2 to 3 years. These catalysts contain heavy metals including vanadium pentoxide. Vanadium pentoxide is an acute hazardous waste under the Resource Conservation and Recovery Act (RCRA), Part 261, Subpart D – Lists of Hazardous Materials. This must be addressed when disposing of the spent catalyst.

The use of SCR may result in increased SO_2 to SO_3 oxidation which would result in a higher inlet concentration of H_2SO_4 entering the wet limestone FGD system. However, the FGD system will remove a significant portion of the H_2SO_4 prior to stack discharge.

There are also significant cost impacts associated with SCR. Since the use of SCR is thought to represent the most effective NO_x control technique that can be applied to PC-fired boilers, no economic evaluation is required. However, a cost estimate for SCR installation and operation has been prepared for this project and is provided in Appendix G. The effective cost of SCR has been estimated at $1,638 per ton of NO_x controlled. This cost does not include the additional cost of LNBs and the associated NO_x removal in the boiler.

The next control technology in the hierarchy is SNCR. The range of control efficiencies for SNCR ranges above the NSPS so it was not evaluated further. The other technologies listed in Table 6-5 were also not determined to achieve a level of control sufficient to meet NSPS and were not considered further either. As such, further evaluation of energy, environmental, and cost data is not required.

6.3.5.5 Step 5 – Select BACT

The final step in the top-down BACT analysis process is to select BACT. EPA's RBLC database and other recently issued permits were again consulted to assist in selecting BACT for this project. The NO_x BACT limits from other recently issued PSD permits for PC-fired boilers are summarized in Table 6-6.

TABLE 6-6
Recently Issued PSD Permits – NO_x Limits

Name	Type/Size	NO_x Limit	Control Equipment
Hawthorne Unit 5 Missouri	Pulverized Coal 570 MW	0.08 lb/mmbtu (30 day rolling avg) 0.10 lb/mmbtu (24 hour avg)	Low-NO_x Burners with SCR Initial limit of 0.12 lb/mmbtu for first 36 months
Springerville Units 3 and 4 Arizona	Pulverized Coal 450 MW each	1.6 lb/gross MWh (30 day rolling avg) 9,600 tpy Units 1-4	Low-NO_x Burners with SCR Netted with Units 1 and 2 – no increase in facility NO_x emissions
Holcomb Unit 2 Kansas	Pulverized Coal 660 MW	0.08 lb/mmbtu (30 day rolling avg)	Low-NO_x Burners with SCR Initial limit of 0.12 lb/mmbtu for first 18 months
Thoroughbred Units 1 and 2 Kentucky	Pulverized Coal 750 MW each	0.08 lb/mmbtu (30 day rolling avg)	Low-NO_x Burners with SCR
Wygen Unit 2 Wyoming	Pulverized Coal 500 MW	0.07 lb/mmbtu (30 day rolling avg)	Low-NO_x Burners with SCR
Bull Mountain Roundup Unit 1 Montana	Pulverized Coal 780 MW	0.07 lb/mmbtu (24 hour avg) 0.10 lb/mmbtu (1 hour avg)	Low-NO_x Burners with SCR
Plum Point Energy Station Units 1 and 2 Arkansas	Pulverized Coal 550 – 800 MW each	0.09 lb/mmbtu (30 day rolling avg)	Low-NO_x Burners with SCR Draft Permit
Rocky Mountain Power, Hardin Unit 1 Montana	Pulverized Coal 113 MW	0.09 lb/mmbtu (30 day rolling avg)	Low-NO_x Burners with SCR

All the permits above exempt startup, shutdown and malfunction in the short term (1 hour, 24 hour and 30 day) emission limits.

Of the projects found, only SCR is shown to meet NSPS. The installation of LNBs, OFA, and SCR on IPP Unit 3 will result in a NO_x outlet emission rate of 0.07 lb/mmBtu. This is lower than any project listed in the RBLC and as low as any of the recently issued permits that were reviewed for coal-fired utility boilers as outlined in Table 6-6. Therefore, LNBs and SCR are selected as BACT for this project with an emission limit of 0.07 lb/mmBtu based on a 30-day rolling average. The modeling was performed with a NO_x outlet emission rate of 0.07 lb/mmBtu.

Despite the fact that SCR is being used to control NO_x emissions from other pulverized coal-fired boilers, SCR is a relatively new control system and there is limited long-term operating experience. Furthermore, there is no actual operating experience demonstrating the affect that Utah bituminous coals may have on the SCR catalyst. Although Utah coals do not appear to exhibit qualities that will adversely impact SCR performance, without actual operating experience the possibility exists that flue gas characteristics unique to Utah coals may cause unforeseen catalyst deterioration or deactivation. If technical issues should arise following SCR installation on Unit 3 that demonstrate that with a NO_x outlet emission rate of 0.07 lb/mmBtu cannot be achieved in practice on Unit 3, the permit limit may need to be adjusted to reflect the long-term performance that the system is capable of achieving. In the unlikely event that this becomes an issue, modeling of a revised emission rate would be performed to ensure compliance with the NAAQS. Additional technical discussion relating to the proposed NO_x control technologies is provided in Appendix I-2 in the supplemental white paper entitled *Nitrogen Oxide Emissions and Control.*

6.3.6 CO and VOC Analysis

The BACT analysis for CO and VOCs is presented below.

6.3.6.1 Step 1 – Identify All Control Technologies

The first step is to evaluate CO and VOC controls determined to be BACT by permitting agencies across the United States. This information is available from the EPA RBLC database, which is accessible on the Internet. The printout from the database for CO and VOC is shown in Appendix F, Tables F-1 and F-2. Additional technology reviews from sources including EPA's NSR bulletin board, BACT guideline – South Coast Air Quality Management District, control technology vendors, technical journals and web sites, and other recently issued federal/state/local NSR permits are summarized in Appendix H.

Only two control technologies have been identified for control of CO and VOC on coal-fired boilers:

- Catalytic oxidation
- Combustion controls

Catalytic oxidation is a post-combustion control device that would be applied to the combustion system exhaust, while combustion controls are part of the combustion system design.

6.3.6.2 Step 2 – Eliminate Technically Infeasible Options

Catalytic oxidation has been the control alternative used to obtain the most stringent control level for CO and VOCs emitting from primarily combustion turbines firing natural gas. This alternative, however, has never been applied to a PC-fired unit so this technology has not been demonstrated in practice in this application.

For sulfur containing fuels, such as coal, an oxidation catalyst will convert SO_2 to SO_3 and therefore this conversion would result in unacceptable levels of corrosion to the flue gas system. Generally, oxidation catalysts are designed for a maximum particulate loading of 50 milligrams per cubic meter (mg/m^3). The proposed IPP Unit 3 boiler will have a particulate loading upstream of the fabric filter in excess of 5,000 mg/m^3. In addition, trace elements present in coal, in particular chlorine, are poisonous to oxidation catalysts. There are no catalysts developed that have or can be applied to PC-fired boilers due to the high levels of PM and trace elements present in the flue gas.

Although the catalyst could be installed downstream of the fabric filter where the concentration of PM in the flue gas is much lower than at the outlet of the boiler, the flue gas temperature at that point will be approximately 300°F.This is well below the minimum temperature required (600°F) for operation of oxidation catalyst. The flue gas would have to be reheated, resulting in significant unfavorable energy and economic impacts.

For these reasons, as well as the generally low levels of CO and VOCs in PC-fired units, no PC-fired boilers have been equipped with oxidation catalysts. Use of an oxidation catalyst system in the proposed IPP Unit 3 PC-fired boiler is thus considered technically infeasible. Thus, this alternative cannot be considered to represent BACT for control of CO and VOCs.

6.3.6.3 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Based on the Step 2 analysis, combustion control is the only remaining technology for this application.

6.3.6.4 Step 4 – Evaluate Most Effective Controls and Document Results

There are no environmental or energy costs associated with combustion control.

6.3.6.5 Step 5 – Select BACT

The EPA RBLC database for comparable sources related to CO and VOCs are shown in Tables F-1 and F-2 in Appendix F. The estimated emissions of CO and VOCs on IPP Unit 3 are among the lowest of the emissions shown for applicable projects in the RBLC or other recently issued permits. The final step in the top-down BACT analysis process is to select BACT. Based on the above analysis, combustion control for CO and VOCs is chosen as BACT for this project with an emission limit of 0.15 lb/mmBtu for CO and 0.0027 lb/mmBtu for VOCs.

6.3.7 PM and PM_{10} Analysis

PM and PM_{10} emissions will be emitted from the boilers, cooling tower, and the coal, limestone, and ash handling systems. An analysis for the emissions from the boilers is presented, followed by an analysis for the cooling tower followed by analyses of the coal, limestone, and ash handling systems.

6.3.7.1 Step 1 – Boilers: Identify All Control Technologies

The first step is to evaluate PM and PM_{10} controls determined to be BACT by permitting agencies across the United States. This information is available from the EPA RBLC database, which is accessible on the Internet. The printout from the database for PM and PM_{10} is shown in Appendix F, Table F-3 and F-4. Additional technology reviews from sources including EPA's NSR bulletin board, BACT guideline – South Coast Air Quality Management District, control technology vendors, technical journals and web sites, and other recently issued federal/state/local NSR permits are summarized in Appendix H.

Two control technologies for coal-fired boilers have been identified for PM and PM_{10} control:

- Electrostatic precipitators (ESPs)
- Fabric filters

6.3.7.2 Step 2 – Boilers: Eliminate Technically Infeasible Options

ESPs. ESP technology is applicable to a variety of coal combustion sources. ESPs remove PM from the flue gas stream by charging fly ash particles with a very high dc voltage and attracting these particles to grounded collection plates. A layer of collected particles forms on the collecting plates and is removed by rapping the plates. The collected ash particles drop into hoppers below the precipitator and are periodically removed by the fly ash handling system.

Fabric Filters. Fabric filtration has been widely applied to coal combustion sources since the early 1970s and consists of a number of filtering elements (bags) along with a bag cleaning system contained in a main shell structure incorporating dust hoppers. Fabric filters use fiber glass fabric bags as filters to collect PM. The particulate-laden gas enters a fabric filter compartment and passes through the bags and through a layer of accumulated PM collected on the fabric of the filter bags. The collected PM forms a filter cake layer on the bag that enhances the bag's filtering efficiency. However, excessive caking will increase the pressure drop across the fabric filter. When this occurs, the fabric filter is placed into a cleaning cycle and the excess PM is removed to the ash collection system.

Fabric filtration is a constant-emission device. Pressure drop across the filters, inlet particulate loading, or changes in gas volumes may change the rate of filter cake buildup, but will not change the final emission rate. Actual performance of a fabric-filter depends on specific items such as air/cloth ratio, permeability of the filter cake, the loading and nature of the particles (e.g., irregular-shaped or spherical), particle size distribution, and to some extent, the frequency of the cleaning cycle.

Fabric filter system design involves inlet loading rates, fly ash characteristics, the selection of the cleaning mechanism, and selection of a suitable filter fabric and finish. Specific design parameters cannot be established until the actual fabric filter manufacturer is determined; however, the fabric filter system will be designed to achieve a filterable PM_{10} emission rate no greater than 0.015 lb/mmBtu, which represents a control efficiency of 99.83 percent.

Fabric filters are effective in meeting NSPS emission requirements on PC-fired boilers. Fabric filters have been used as a control technology of choice on projects where lowest achievable emissions reduction (LAER) review is required. Unlike ESPs, fabric filter design is not based on any physical properties of the fly ash.

Additional technical discussion relating to the proposed PM_{10} control technologies is provided in Appendix I-3 in the supplemental white paper entitled *PM_{10} Emissions and Fabric Filter Control Efficiency.*

6.3.7.3 Step 3 – Boilers: Rank Remaining Control Technologies by Control Effectiveness

The fabric filter is more effective at capturing fine particulate than an ESP because ESPs tend to selectively collect larger particles. Large particles have a high mass to surface area ratio, which allows a charged particle to be efficiently dragged through the flue gas stream for collection on a charged plate. Ultra fine particles have a low terminal velocity and cannot carry a strong enough electrical charge to result in complete collection. The fabric filter is also more effective at collecting fly ash generated from western low sulfur coals such as those combusted at IPP. ESPs operate by first electrostatically charging for collection and then discharging the fly ash particles for removal in the ash handling system. Western low sulfur coal fly ash has a very high electrical resistivity that makes it difficult for the ESP to charge and then discharge the particles. One solution that has been attempted on western power plants is the use of a hotside precipitator that operates at approximately 800ºF as opposed to the approximately 250ºF operating temperature used on most ESPs. Another solution has been to inject a flue gas conditioning agent to alter the resistivity of the fly ash. However, even with this change in operating temperature or the injection of a conditioning agent, the ESP is still less effective than a fabric filter at collecting fly ash in western power plants.

6.3.7.4 Step 4 – Boilers: Evaluate Most Effective Controls and Document Results

No negative environmental impacts have been identified for use of a fabric filter to control particulate emissions from PC-fired boilers. There is, however, a high energy demand for this system. Energy is required to operate large fans to overcome the complete system's (fabric filter and associated ductwork) 8- to 12-inch water gauge pressure drop, and miscellaneous loads such as electric hopper heating. As baghouse filters are thought to represent the most effective PM and PM_{10} control technique that can be applied to PC-fired boilers, no economic evaluation is warranted.

6.3.7.5 Step 5 – Boilers: Select BACT

The fabric filter proposed for IPP Unit 3 will have a design collection efficiency of 99.83 percent. The PM_{10} BACT limits from other recently issued PSD permits for PC-fired boilers are summarized in Table 6-7.

TABLE 6-7
Recently Issued PSD Permits – PM_{10} Limits

Name	Type/Size	PM_{10} Limit	Control Equipment
Hawthorne Unit 5 Missouri	Pulverized Coal 570 MW	0.018 lb/mmbtu 20% Opacity	Fabric Filter Compliance based on annual test Condensable PM_{10} not specified
Springerville Units 3 and 4 Arizona	Pulverized Coal 450 MW each	0.015 lb/mmbtu (PM) (3 hour rolling avg) 0.055 lb/mmbtu (PM_{10}) (3 hour rolling avg) 15% Opacity	Fabric Filter Compliance based on annual test PM limit is filterable only. PM_{10} limit includes filterable and condensable
Holcomb Unit 2 Kansas	Pulverized Coal 660 MW	0.018 lb/mmbtu 20% Opacity	Fabric Filter Compliance based on 3 2-hr stack tests Condensable PM_{10} not specified
Thoroughbred Units 1 and 2 Kentucky	Pulverized Coal 750 MW each	0.018 lb/mmbtu (3 hour avg) 20% Opacity	Electrostatic Precipitator Limit is filterable PM_{10} only
Wygen Unit 2 Wyoming	Pulverized Coal 500 MW	0.012 lb/mmbtu 20% Opacity	Fabric Filter Limit is filterable PM_{10} only
Bull Mountain Roundup Unit 1 Montana	Pulverized Coal 780 MW	0.015 lb/mmbtu 20% Opacity	Fabric Filter Limit may be reduced to 0.012 lb/MMBtu based on performance test Condensable PM_{10} not specified
Plum Point Energy Station Units 1 and 2 Arkansas	Pulverized Coal 550 – 800 MW each	0.018 lb/mmbtu 10% Opacity	Draft Permit Fabric Filter Limit is filterable PM_{10} only
Rocky Mountain Power, Hardin Unit 1 Montana	Pulverized Coal 113 MW	0.015 lb/mmbtu	Multiclones and Wet Lime FGD Limit is filterable PM_{10} only

All the permits above exempt startup, shutdown and malfunction in the short term (lb/mmbtu) emission limits.

Based on the above analysis, the recently issued PSD permits listed in Table 6-7, and the EPA RBLC database (refer to Tables F-3 and F-4 in Appendix F), a fabric filter with a filterable PM emission rate of 0.020 lb/mmBtu based on a 3-hour rolling average and a filterable PM_{10} emission rate of 0.015 lb/mmBtu based on a 3-hour rolling average, is selected as BACT for this project.

6.3.8 Unit 3 Cooling Towers

6.3.8.1 Step 1 – Cooling Tower: Identify All Control Technologies

The first step is to evaluate PM and PM_{10} controls determined to be BACT by permitting agencies across the United States. This information is available from the EPA RBLC database, which is accessible on the Internet. The printout from the database for PM and PM_{10} is shown in Appendix F, Table F-5. Additional technology reviews from sources including EPA's NSR bulletin board, BACT guideline – South Coast Air Quality Management District, control technology vendors, technical journals and web sites, and other recently issued federal/state/local NSR permits are summarized in Appendix H.

The only control method for reducing PM and PM_{10} emissions from cooling towers is the use of drift eliminators.

6.3.8.2 Step 2 – Cooling Tower: Eliminate Technically Infeasible Options

Drift eliminators are technically feasible for this project and will be used.

6.3.8.3 Step 3 – Cooling Tower: Select BACT

Drift eliminators are the only control method identified for control of PM and PM_{10} emissions from cooling towers. Based on the above analysis and the EPA RBLC database (refer to Table F-5 in Appendix F), drift eliminators with a control efficiency of 0.0005 percent (gallons of drift per gallon of cooling water flow) is chosen as BACT for this project.

6.3.9 Unit 3 Coal, Limestone, and Ash Handling Systems

6.3.9.1 Step 1 – Coal, Limestone, and Ash Handling Systems: Identify All Control Technologies

PM and PM_{10} will be emitted from the handling of the coal for the power plant, the ash that results from the combustion process, and limestone that is used as a reagent for the wet scrubber. These emissions are fugitive dust that comes from the various transfer points in the handling systems for these materials and fugitive emissions from the open storage and disposal areas.

Technology reviews from sources including the EPA RBLC database, EPA's NSR bulletin board, BACT guideline – South Coast Air Quality Management District, control technology vendors, technical journals and web sites, and other recently issued federal/state/local NSR permits are summarized in Appendix H.

The potential technologies that can be used to control the fugitive dust emissions are as follows for various operations:

Coal Pile: Potential control technologies for an active coal storage pile include the use of an enclosed storage barn or the use of water sprays and dust suppression chemicals on an outside pile. Water sprays and dust suppression chemicals are potential control technologies for inactive (long-term storage) coal piles.

Coal Handling: Potential control technologies for coal storage, transfer, and handling operations include the use of enclosures vented to fabric filters. Telescopic chutes can be utilized for coal unloading onto storage piles.

Limestone Handling: Potential control technologies for limestone storage, transfer, and handling operations include the use of enclosures vented to fabric filters. Limestone truck unloading can be performed in enclosures vented to fabric filters.

Fly Ash Handling: Storage silos and associated transfer operations can be vented to fabric filters for control.

Fly Ash/FGD Waste Haul Roads: Potential technologies for control of fugitive emissions on haul roads are the use of paved roads, the use of covered haul trucks, the use of water sprays, the use of dust suppression chemicals, or the use of street sweepers on paved roads.

6.3.9.2 Step 2 – Coal, Limestone and Ash Handling: Eliminate Technically Infeasible Options

All of the potential control technologies listed in Step 1 are technically feasible.

6.3.9.3 Step 3 – Coal, Limestone and Ash Handling Systems: Rank Remaining Control Technologies by Control Effectiveness

Generally the use of fabric filters where possible is the most effective control option. In locations where fabric filters cannot be used, the use of water sprays and dust suppression chemicals are the most effective control methods.

6.3.9.4 Step 4 – Coal, Limestone and Ash Handling Systems: Evaluate Most Effective Controls and Document Results

Fabric filters are the control method of choice where the dust source can be completely enclosed in a building. For dust sources that cannot be completely enclosed, the use of water sprays and dust suppression chemicals are the control methods of choice.

There will be no addition to the Units 1 and 2 active coal pile to serve Unit 3. Chemical binding (dust suppression chemicals) will be used on the inactive (long-term) storage pile.

New and modified coal, fly ash, and limestone handling operations will have enclosures with fabric filters for dust control.

The paved ash haul and unpaved conditioned sludge haul roads will use water sprays and dust suppression chemicals for dust control.

6.3.9.5 Step 5 – Coal, Limestone, and Ash Handling Systems: Select BACT

Fabric filters are BACT for the transfer points, silos, and crusher houses on the coal handling system. For the rail unloading stock outpile and the active coal storage pile, water sprays are BACT. The inactive coal storage pile will be controlled by the application of a chemical binder. Fabric filters are also BACT for the transfer points and silos on the limestone and ash handling systems. For the haul roads, water sprays with dust suppression chemicals will be used for dust control.

6.3.10 Lead Analysis

Lead emissions will be emitted from the boiler. Lead will be present as a constituent of the fly ash and control technologies that are effective in controlling PM emissions will also control lead emissions.

6.3.10.1 Step 1 – Identify All Control Technologies

The first step is to evaluate lead controls determined to be BACT by permitting agencies across the United States. This information is available from the EPA RBLC database, which is accessible on the Internet. The printout from the database for lead is shown in Appendix F, Table F-6. Additional technology reviews from sources including EPA's NSR bulletin board, BACT guideline – South Coast Air Quality Management District, control technology vendors, technical journals and web sites, and other recently issued federal/state/local NSR permits are summarized in Appendix H.

Two control technologies for coal-fired boilers have been identified for lead control:

- ESPs
- Fabric filters

6.3.10.2 Step 2 – Eliminate Technically Infeasible Options

ESPs. ESP technology is applicable to a variety of coal combustion sources. ESPs remove PM from the flue gas stream by charging fly ash particles with a very high dc voltage and attracting these particles to oppositely charged collection plates. A layer of collected particles forms on the collecting plates (electrodes) and is removed by rapping the electrodes. The collected ash particles drop into hoppers below the precipitator and are periodically removed from the fly ash handling system.

Fabric Filters. Fabric filtration has been widely applied to coal combustion sources since the early 1970s and consists of a number of filtering elements (bags) along with a bag cleaning system contained in a main shell structure incorporating dust hoppers. Fabric filters use fiber glass fabric bags as filters to collect PM. The particulate-laden gas enters a fabric filter compartment and passes through the bags and through a layer of accumulated PM collected on the fabric of the filter bags. The collected PM forms a filter cake layer on the bag that enhances the bag's filtering efficiency. However, excessive caking will increase the pressure drop across the fabric filter. When this occurs, the fabric filter is placed into a cleaning cycle and the excess PM is removed to the ash collection system.

Fabric filters are effective in meeting NSPS emission requirements on PC-fired boilers. Fabric filters have been used as a control technology of choice on projects where LAER review is required. Unlike precipitators, fabric filter design is not based on any physical properties of the fly ash. Additional technical discussion relating to the proposed PM_{10} control technologies is provided in Appendix I-3 in the supplemental white paper entitled *PM_{10} Emissions and Fabric Filter Control Efficiency.*

6.3.10.3 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The fabric filter is more effective at capturing fine particulates than an ESP because ESPs tend to selectively collect larger particles. Large particles have a high mass to surface area ratio, which allows a charged particle to be efficiently dragged through the flue gas stream for collection on a charged plate. Ultra fine particles have a low terminal velocity and cannot carry a strong enough electrical charge to result in complete collection.

The fabric filter is also more effective at collecting fly ash generated from western low sulfur coals such as those combusted at IPP. ESPs operate by first electrostatically charging for collection and then discharging the fly ash particles for removal in the ash handling system. Western low sulfur coal fly ash has a very high electrical resistivity that makes it difficult for the ESP to charge and discharge the particles. One solution that has been attempted on western power plants is the use of a hotside precipitator that operates at approximately 800ºF as opposed to the approximately 250ºF operating temperature used on most ESPs. However, even with this change in operating temperature, the ESP is still less effective than fabric filters at collecting fly ash in western power plants.

6.3.10.4 Step 4 – Evaluate Most Effective Controls and Document Results

No negative environmental impacts have been identified for use of a fabric filter to control particulate emissions from PC-fired boilers. There is, however, a high energy demand for this system. Energy is required to overcome the complete system's (fabric filter and associated ductwork) 8- to 12-inch water gauge pressure drop, and miscellaneous loads such as electric hopper heating. As baghouse filters are thought to represent the most effective PM and PM_{10} control technique that can be applied to PC-fired boilers, no economic evaluation is warranted.

6.3.10.5 Step 5 – Select BACT

The EPA RBLC database shows four comparable sources related to lead. They are shown in Table F-6 in Appendix F. Based on the above analysis, the RBLC database, and other recently issued permits, a fabric filter is selected as BACT for the control of lead emissions for this project with an emission rate of 0.00002 lb/mmBtu.

6.3.11 Fluoride Analysis

Fluoride compounds will be emitted from the boilers from the combustion of coal. The fluoride compounds will be mainly in the gaseous form of HF in the flue gas exiting the boiler.

6.3.11.1 Step 1 – Identify All Control Technologies

The first step is to evaluate flouride controls determined to be BACT by permitting agencies across the United States. This information is available from the EPA RBLC database, which is accessible on the Internet. The printout from the database for flouride is shown in Appendix F, Table F-7. Additional technology reviews from sources including EPA's NSR bulletin board, BACT guideline – South Coast Air Quality Management District, control technology vendors, technical journals and web sites, and other recently issued federal/state/local NSR permits are summarized in Appendix H.

Two control technologies for fluoride control of flue gas from coal-fired boilers have been identified:

- Wet scrubbers
- Spray dryers followed by fabric filters

6.3.11.2 Step 2 – Eliminate Technically Infeasible Options

Wet Scrubber. Wet SO_2 scrubbers operate by flowing the flue gas upward through a large reactor vessel that has an alkaline reagent (i.e., lime or limestone slurry) flowing down from the top. The scrubber mixes the flue gas and alkaline reagent using a series of spray nozzles to distribute the reagent across the scrubber vessel and a bed material to force the mixing of the alkaline reagent and the flue gas. The calcium in the reagent reacts with the fluoride in the flue gas to form calcium fluoride that is removed from the scrubber with the sludge and is disposed.

The creation of sludge from the scrubber does create a solid waste handling and disposal problem. This sludge needs to be handled in a manner that doesn't result in groundwater contamination. Also, the sludge disposal area needs to be permanently set aside from future surface uses since the disposed sludge cannot bear any weight from such uses as buildings or cultivated agriculture.

Spray Dryer Followed by Fabric Filter. Spray dryers operate by flowing the flue gas upward through a large vessel. In the top of the vessel is a rapidly rotating atomizer wheel through which lime slurry is flowing. The rapid speed of the atomizer wheel causes the lime slurry to separate into very fine droplets that intermix with the flue gas where the fluorides in the flue gas react with the calcium in the lime slurry to form particulate calcium fluoride. This dry material is captured in the fabric filter along with the fly ash and calcium sulfate from the sulfur removal process.

Fabric filtration has been widely applied to coal combustion sources since the early 1970s and consists of a number of filtering elements (bags) along with a bag cleaning system contained in a main shell structure incorporating dust hoppers. Fabric filters use fiberglass fabric bags as filters to collect PM. The particulate-laden gas enters a fabric filter compartment and passes through the bags and through a layer of accumulated PM collected on the fabric of the filter bags. The collected PM forms a filter cake layer on the bag that enhances the bag's filtering efficiency. However, excessive caking will increase the pressure drop across the fabric filter. When this occurs, the fabric filter is placed into a cleaning cycle and the excess PM is removed to the ash collection system.

6.3.11.3 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Either control technology will achieve 90 percent or greater control of fluorides.

6.3.11.4 Step 4 – Evaluate Most Effective Controls and Document Results

Either approach can achieve 90 percent or greater control of fluorides. No negative environmental impacts have been identified for use of a spray dryer absorber followed by a fabric filter to control fluoride emissions from PC-fired boilers. The use of a wet scrubber has the negative environmental impact of wet sludge disposal.

6.3.11.5 Step 5 –Select BACT

The EPA RBLC database shows six comparable sources related to fluoride. They are shown in Table F-7 in Appendix F. Five of the sources determined that the use of a dry lime scrubber followed by a fabric filter was BACT. The other source selected an ESP followed by a wet limestone FGD system as BACT for fluoride. A number of other units not identified in the RBLC have identified high fluoride removal rates including IPP Units 1 and 2. The EPRI HAP report uses a factor of 97 percent control for units burning western coal and utilizing wet FGD systems.

Based on the technology and RBLC database discussion above, the use of a wet limestone scrubber is selected as BACT for this project with a fluoride (as HF) emission rate of 0.0005 lb/mmBtu.

6.4 Case-by-Case MACT Demonstration for HAPs

6.4.1 Background

IPP is proposing the addition of one nominal 950-gross MW PC-fired boiler at its existing facility located in Millard County, Utah. The new PC-fired boiler will burn western bituminous coal, and will be equipped with a forced oxidation wet limestone scrubber for acid gas control, fabric filters for fine particulate control, and SCR for NO_x control. Combustion control will be used to minimize products of incomplete combustion (PICs) such as CO and VOCs. This combination of control technology will also provide substantial control of the HAPs emitted from the proposed PC-fired boiler.

The EPA's regulations for case-by-case MACT, which were promulgated in 1996, are set out in 40 CFR Part 63, Subpart B. Those regulations require case-by-case determinations of MACT by the Title V permitting authority for each major source of HAP which is constructed or reconstructed after the effective date of the Section 112(g) program. For electric utility steam generating units, the case-by-case provisions contain an exemption from applicability "unless and until such time as these units are added to the source category list." On December 14, 2000, the EPA announced that it was adding PC-fired power plants to the Section 112(c) list of sources (65 FR 79825 published December 20, 2000). Therefore, each PC-fired electric utility steam generating unit which is constructed or reconstructed is now subject to the case-by-case provisions of the Act until the EPA promulgates a nationally applicable MACT standard to address HAPs for this source category. The EPA expects to promulgate a final standard in December 2004.

Pursuant to 40 CFR Part 63, Subpart B, case-by-case MACT determination must be made by the permit applicant for each new unit that has emissions above the major source threshold for HAPs. This document represents the case-by-case MACT determination for the IPP Unit 3, as required for a new major source of HAPs.

6.4.2 Applicability of Section 112(g) Requirements

Table 6-8 presents a summary of projected potential emissions of HAPs emitted from IPP Unit 3. These emission estimates have been derived from HAP constituent analyses of typical western coals, EPA's AP-42 emission factor database, and estimates of levels of control expected based on the configuration of the proposed boilers. We note that AP-42 factors represent the average of many field tests, and that HAP constituents of coal ash are highly variable. For these reasons, these values should not be construed to represent short-term compliance limits based on a one-time stack test.

TABLE 6-8
Annual Emission Estimate of HAPs

HAP[a]	Emissions (TPY)[b]
Antimony	0.02
Arsenic	0.18
Beryllium	0.00
Cadmium	0.03
Chromium	0.28
Cobalt	0.03
Hydrogen Chloride	167.01
Hydrogen Fluoride	20.00
Lead	0.79
Manganese	0.15
Mercury	0.09
Nickel	0.13
Organic HAPs	9.05
Selenium	1.02
Total PCDD/PCDF	0.00
Total	**199**

[a] USEPA - TTN, Unified Air Toxics website, Section 112 HAPs, (8/21/2000).
[b] Emission calculation details are provided in Tables 6-5, 6-6, and 6-7.

Based on the emission estimates shown in Table 6-8, two HAPs (HCl and HF) will potentially exceed annual emissions of 10 tpy and total HAPs will exceed 25 tpy. For purposes of new source permitting, IPP Unit 3 is being treated as a major source for HAPs, and will employ case-by-case MACT for these pollutants.

6.4.3 Case-by-Case MACT Analysis

6.4.3.1 Case-by-Case MACT for Non-Mercury HAP Metals

The PM emitted from IPP Unit 3 will include entrained metals that are contained in coal. These metals will include antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, and selenium.

As noted in the BACT analysis for PM presented in Section 6.2, the top control option is a fabric filter baghouse. The control options for non-mercury HAP metals are those identified in the BACT analysis for PM, and the control efficiencies for non-mercury HAP metals correspond to the control efficiencies for PM. Thus, it is concluded that a fabric filter baghouse represents case-by-case MACT for non-mercury HAP metals.

As was also noted in the BACT analysis, the proposed BACT emission limit of 0.020 lb PM per mmBtu heat input (0.015 lb/mmBtu for PM_{10}) is the most stringent limit identified for any PC-fired boiler of any type. Based on precedent established by EPA in establishing MACT standards for several categories of sources emitting non-mercury HAP metals, a PM emission limit is an effective surrogate for individual HAP metals emission limits and is an acceptable format for expressing the MACT standard. For example, EPA described its rationale for setting PM emission limits in the proposed iron and steel MACT standard:

"For the proposed rule, we decided that it is not practical to establish individual standards for each specific type of metallic HAP that could be present in the various processes (e.g., separate standards for manganese emissions, separate standards for lead emissions, and so forth for each of the metals listed as HAP and potentially could be present). When released, each of the metallic HAP compounds behaves as PM. As a result, strong correlation exists between air emissions of PM and emissions of the individual metallic HAP compounds. The control technologies used for the control of PM emissions achieve comparable levels of performance on metallic HAP emissions. Therefore, standards requiring good control of PM will also achieve good control of metallic HAP emissions. Therefore, we decided to establish standards for total PM as a surrogate pollutant for the individual types of metallic HAP. In addition, establishing separate standards for each individual type of metallic HAP would impose costly and significantly more complex compliance and monitoring requirements and achieve little, if any, HAP emissions reductions beyond what would be achieved using the surrogate pollutant approach based on total PM." (66 FR 36835, published July 13, 2001)

For the above reasons, and in light of the precedent established by EPA in setting MACT standards using a surrogate pollutant, it is determined that the BACT emission limit for PM will suffice as MACT standards for non-mercury HAP metals for IPP Unit 3.

6.4.3.2 Case-by-Case MACT for Acid Gas HAPs

Fluoride emissions from PC-fired boilers result from trace concentrations of fluoride-containing compounds in the fuel. These emissions occur primarily in the form of HF. In addition, HCl emissions will occur as a result of chloride-containing compounds present in the fuel. Both HF and HCl are HAPs subject to the case-by-case MACT requirement.

The control options and relative control effectiveness hierarchy is the same for HCl and HF. The top control option for these acid gases is same as that for SO_2. A wet limestone scrubber in conjunction with a fabric filter baghouse is considered the top control technology for these acid gases. Thus, it is concluded that this control equipment configuration at 90 percent acid gas control represents case-by-case MACT for HF and HCl.

6.4.3.3 Case-by-Case MACT for Organic HAPs including Dioxin/Furans

The emissions of the organic compounds depend on the combustion efficiency of the boiler. Therefore, combustion modifications that change combustion residence time, temperature, or turbulence may increase or decrease concentrations of organic compounds in the flue gas. Organic emissions include volatile, semivolatile, and condensable organic compounds either present in the coal or formed as a PIC. Organic emissions are primarily characterized by the criteria pollutant class of unburned vapor-phase hydrocarbons. These emissions include alkanes, alkenes, aldehydes, alcohols, and substituted benzenes (e.g., benzene, toluene, xylene, and ethyl benzene). The remaining organic emissions are composed largely of compounds emitted from combustion sources in a condensed phase. These compounds can almost exclusively be classed into a group known as polycyclic organic matter (POM), and a subset of compounds called poly aromatic hydrocarbons (PAH). POM is more prevalent in the emissions from coal combustion because of the more complex chemical structure of coal.

While trace quantities of organic PIC HAPs will be emitted, these are well controlled by implementation of BACT for CO/VOC and PM/PM_{10}, which also represents case-by-case MACT for these HAP species.

Emissions of PCDD/PCDF also result from the combustion of coal. Of primary interest environmentally are tetrachloro- through octachloro- dioxins and furans. Dioxin and furan emissions are influenced by the extent of destruction of organics during combustion and through reactions in the air pollution control equipment. The formation of PCDD/PCDF in air pollution control equipment is primarily dependent on flue gas temperature, with maximum potential for formation occurring at flue gas temperatures of 450°F to 650°F.

The formation of dioxin in a combustion source is dependent on the presence of chlorine and complex unburned hydrocarbon chains that may recombine within a certain temperature window of the process as the gases cool. For example, polychlorinated biphenyls (PCB) incinerators have been identified with high dioxin emission levels due to the extreme resistance to complete thermal destruction of this "engineered" complex hydrocarbon molecule and the presence of substantial chlorine. Coal combustion, on the other hand, is a process designed to completely burn organic hydrocarbons at high temperature and ample excess O_2 in the presence of only trace amounts of chlorine. Note that the western coals to be burned in IPP Unit 3 contain very low levels of chlorine, which will limit formation of any chlorine compounds to a fraction of EPA's published generic AP 42 factors for coal combustion. Further, what chlorine is emitted will be effectively captured by the proposed wet limestone scrubber acid gas control system, and any dioxin that does form will be captured within unburned carbon, expressed as loss on ignition (LOI), and other adsorbents deposited on the filter cake of the baghouse.

Activated carbon injection (ACI) has been shown to be effective at controlling high dioxin emissions from incinerators that burn highly chlorinated waste. In this case, the dioxin emission level is simply too low to be effectively captured by the inherent adsorbents in the baghouse filters. The trace levels of chlorine in the IPP Unit 3 coal and flue gas, combined with the LOI associated with combustion of western coals, yields an effective carbon adsorption mechanism for the trace levels of dioxin which might be emitted from IPP Unit 3. There is no evidence that any additional or measurable dioxin control could actually be achieved by the injection of additional carbon in the proposed unit.

The premise that ACI would result in measurable dioxin control beyond levels achieved by the best controlled similar source is entirely speculative. Good combustion controls and adsorption onto western coal ash and LOI in a fabric filter represents case-by-case MACT for control of dioxin and organics from the proposed IPP Unit 3.

6.4.3.4 Case-by-Case MACT for Mercury

EPA has specifically targeted mercury for new MACT standards to be developed by 2003, and has determined that mercury is the HAP of primary concern from PC-fired utility boilers. The control level approved as case-by-case MACT in this application may be revised in the future based on EPA's promulgation of MACT rule. The starting point of this case-by-case MACT demonstration is to establish the lowest mercury emission rate that has been achieved in operating PC-fired boilers on western bituminous coal, and then adjusting that value to the coal-specific mercury content of the coal burned at IPP Unit 3. This represents the minimum level of mercury control that would qualify as case-by-case MACT, "the emission limitation which is not less stringent than the emission limitation achieved in practice by the best controlled similar source".

The analysis also requires consideration of alternative levels of control which go beyond that of the best controlled similar source, i.e., "which reflects the maximum degree of reduction in emissions that the permitting authority, taking into account the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements, determines is achievable by the [proposed] source." These MACT emission levels are considered in the following sections.

Mercury Emissions. Mercury is a naturally occurring constituent of soil and mineral deposits, including deposits of coal. When coal is burned, any trace quantities of mercury present is vaporized at the high temperatures within the furnace section of the boiler. In the presence of chlorine, a portion of the gaseous mercury may react to form mercuric chloride ($HgCl_2$), with most of the remaining mercury emitted as a gas in elemental form. The speciation of the emitted mercury depends on the coal composition (primarily the ash and chlorine content), the combustion system, and the temperature of the flue gas. At the temperatures within the boiler and air pollution control train, a portion of these gaseous mercury species will be emitted to the atmosphere.

Testing performed at IPP Unit 2 indicates that high removal of mercury is achieved in the wet limestone scrubbing system. Up to 90 percent removal efficiency was measured during the tests conducted at this facility while burning Utah bituminous coal.

The other primary variable affecting mercury emissions is the quantity of mercury contained in the particular coal being burned. Western coals exhibit generally lower mercury content than eastern coals. The mercury content of bituminous coal proposed for IPP Unit 3 ranges from as low as 0.02 parts per million (ppm) to 0.15 ppm. Establishment of a MACT emission rate for mercury must take this variability into account in order to ensure that MACT will be achieved regardless of coal properties over the life of the units.

Mercury Control Levels and Alternatives. The case-by-case MACT determination for IPP Unit 3 contained in this application focuses on the application of the best level of mercury control being achieved in practice by similar utility scale PC-fired boilers burning western bituminous coals. Then an evaluation was done of the practical potential for achieving even greater levels of control using available technology.

The application for MACT must demonstrate how the project will obtain a degree of emission reduction that is at least as stringent as the emissions reduction that would have been obtained had EPA promulgated MACT standards for mercury control for this source category. EPA has indicated that it does plan to promulgate a MACT standard for the source category of PC-fired steam electric generating units by 2003.

Very limited mercury emission rate data is available for PC-fired boilers in general. EPA has gathered test data from a number of various PC-fired utility boilers for mercury, particularly within the last few years. This “snapshot” sampling was conducted on PC-fired utility boilers ranging from smaller to larger, new to archaic, wall- and tangential-fired, with various coal types and properties, and various combinations of air pollutant control equipment. Even within apparently similar units, the data are highly variable, and this variability is not yet fully understood. Because of the many variables that make each tested unit somewhat unique, and unexplained variability within the data itself, it is difficult at this time to determine a precise emission factor and degree of control that would apply to the proposed units. For example, for boilers burning western coals, available data did not identify a clear advantage one way or the other for units that employed wet scrubbers and ESPs versus units that employed spray dryers and fabric filters.

Although many pilot-scale tests have been performed and a few demonstration projects are scheduled for alternative approaches to mercury control, existing coal plants use either spray dryer/fabric filter, ESP, or ESP/wet FGD systems. FGD systems may control mercury chloride and oxide forms to 85 to 95 percent but are not effective in treating elemental mercury. Conversely, elemental mercury can be adsorbed onto carbon and ash particles, particularly on units that employ fabric filters. This is a technique that has been employed for mercury control in certain incineration processes. Since mercury is emitted from the combustion of western bituminous coals primarily in the form of elemental mercury (due to its lower chlorine content), adsorption with fabric filters should provide the maximum level of control for these particular units. EPA has determined that bituminous fly ash adsorbs elemental mercury very effectively, even if it has little unburned carbon, particularly in combination with fabric filters. Western coals tend to also exhibit higher LOI which builds up on the surface of the filter bags. This is the same postulated adsorption mechanism that has been used successfully on municipal waste incinerators by injecting carbon into the flue gas.

Mercury is found predominantly in vapor phase in the boiler flue gas. If this vapor phase mercury is condensed onto PM, the PM can be easily removed with the baghouse. Cooler temperatures of flue gases significantly improve mercury removal efficiency. The flue gas exiting the boiler and air pre-heater has a temperature in the range of 280°F to 300°F.

6.4.3.5 ICR Mercury Data

The EPA issued an Information Collection Request (ICR) under the authority of Section 114 of the Clean Air Act (CAA) to all coal–fired electric utility steam generating units requesting mercury in coal trace analysis data. In addition, 80 of these units were selected to represent a cross section of boiler and control device types and were required to conduct stack tests to evaluate their mercury emissions.

Data from the ICR study were reviewed to identify the best-controlled similar source for mercury emissions. This data was sorted first by boiler type and fuel type to eliminate facilities that were not similar to the proposed IPP Unit 3. Only 25 facilities that utilized conventional PC-fired boilers and burned bituminous coal were considered for MACT analysis. Facilities that indicated negative mercury removal efficiencies were assumed to have zero percent control efficiency. Data was further ranked by average control device efficiency. Table 6-9 provides the minimum, maximum, and average control efficiencies of various control technologies arranged by the average degree of emission reduction of mercury for each type of control device.

TABLE 6-9
Control Efficiencies of Air Pollution Control Devices for Mercury Sorted by the Type of Control Device[a]

PM Control	SO_2 Control	No. of Units in the database	Minimum Control Efficiency %	Maximum Control Efficiency %	Average Control Efficiency %
Particulate Scrubber	None	1	12	12	12.00
Hot Side Electrostatic Precipitator	None	2	0	30.41	15.21
Hot Side Electrostatic Precipitator	Compliance Coal	1	18.73	18.73	18.73
Cold Side Electrostatic Precipitator	None	3	4.95	35.72	23.30
Cold Side Electrostatic Precipitator	Sorbent Injection	1	44.89	44.89	44.89
Cold Side Electrostatic Precipitator	Compliance Coal	4	25.19	89.88	48.68
Hot Side Electrostatic Precipitator	Wet Lime/Limestone Scrubber	3	20.95	75.75	56.65
Cold Side Electrostatic Precipitator	Wet Lime/Limestone Scrubber	3	44.89	68.61	60.67
Baghouse	Wet Lime/Limestone Scrubber	2	74.53	76.33	75.43
Baghouse	Compliance Coal	1	86.52	86.52	86.52
Baghouse	None	1	92.51	92.51	92.51
Baghouse	Lime Spray Dryer Absorber	3	97.36	98.81	98.09

Note:
[a] All data downloaded from www.epa.gov/ttn/atw/combust/utiltox/icrdata.xls dated January 2002.

Based on ICR study data, the following four technologies have been identified as possible control technologies that can be applied to the proposed IPP Unit 3 for achieving case-by-case MACT requirements contained in 40 CFR 63.41.

1. Baghouse with wet lime or limestone scrubber
2. Baghouse with compliance coal
3. Baghouse with no SO_2 control
4. Baghouse with lime spray dryer absorber

Since SO_2 control is required by the New Source Performance Standards and the Prevention of Significant Deterioration program, no further consideration was given to No. 2 and 3 technology options listed above.

The remaining two technologies, baghouse with wet lime or limestone scrubber and baghouse with lime spray dryer absorber were further analyzed for achieving the maximum degree of emission reduction with consideration of costs, non-air quality health, and environmental impacts and energy requirements. The wet scrubber technology was considered as MACT for the IPP Unit 3 application because it not only provides a high level of emission reduction for mercury but also provides a higher level of emission reduction for SO_2, sulfur related compounds TRS and RSC, HCl and HF than the baghouse with dry lime spray dryer adsorber technology.

In September 1999, GE –Energy and Environmental Research Corporation conducted speciated mercury testing at IPP Unit 2. Unit 2 employs a baghouse and wet limestone scrubber for air pollution control similar to those proposed for Unit 3. Unit 2 burns bituminous and sub-bituminous Utah coal. Coal planned for Unit 3 will be of similar composition. The test results showed an overall removal efficiency of 77.65 percent for mercury. Test results from this mercury testing are shown in Table 6-10.

TABLE 6-10
Summary of Mercury Stack Test Results for IPP Unit 2[a]

Mercury Species	Wet Scrubber Inlet Emission Rate (lb/hr)	Wet Scrubber Outlet Concentration (lb/hr)	Scrubber Removal Efficiency %	Overall Mercury Removal Efficiency %[b]
Particle Bound Mercury	1.30E-04	6.70E-05		
Oxidized Mercury	7.80E-03	4.40E-04		
Elemental Mercury	1.40E-03	2.50E-03		
Total Mercury	9.40E-03	3.00E-03	68.09	77.65

[a] Mercury Emissions and Speciation Testing at Intermountain Power Plant Unit 2 SGA Test Report, January 5, 2000.

[b] Overall mercury removal efficiency calculated based on mercury concentration of 0.02 ppm in the coal and a coal feed rate of 67,100 lb/hr.

A fabric filter combined with the use of the wet limestone scrubber was determined to represent the best technology for control of mercury from the combustion of bituminous western coal from existing utility scale PC-fired boilers. This is the control technology proposed for IPP Unit 3. Because the flue gas exiting the boiler and air preheater has a temperature in the range of 280°F to 300°F, additional cooling such as water spraying would be required prior to carbon injection for effective removal of mercury in the baghouse. This carbon injection was not considered for this facility as testing at Unit 2 has shown high mercury removal efficiency using a baghouse and wet limestone scrubber.

40 CFR 63.40 defines the MACT emission limitation for new sources as the emission limitation which is not less stringent the emission limitation achieved by the best controlled similar source, and which reflects the maximum degree of reduction in emissions that permitting authority, taking into consideration the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements, determines is achievable by the constructed and reconstructed source. This MACT emission limitation can be calculated based on uncontrolled emission level for an

emission unit and maximum achievable control efficiency identified in previous section. The uncontrolled annual emissions for the proposed IPP Unit 3 are 0.42 tpy based on the ICR test data and coal trace analysis data. The maximum achievable control efficiency is 77.65 percent based on the proposed baghouse and wet lime scrubber design. This results in an estimated controlled mercury emission rate of 0.0215 lb/hr , 2.37 lb/10^{12}Btu heat input, or 0.09 tons per year. IPP believes that a permit emission limit for mercury is not required by the 40 CFR Part 63 case-by-case MACT rule, thus none is requested.

6.4.3.6 Comparison to Previously Issued Similar Source Permits

IPP has identified seven coal-fired power plant permits that have been issued after December 14, 2000 and that were evaluated for case-by-case MACT requirements in the permits pursuant to Section 112(g). The controlled mercury emission rate expected for IPP Unit 3 is lower than these other reported mercury emission rates. Table 6-11 provides a comparison of other permit mercury emission rates with the rate proposed for IPP Unit 3.

TABLE 6-11
Comparison of Mercury Emission Rates Established in Previously Issued Permits

Plant Name and Location	Size	Emission Rate
Tucson Electric Power Springerville, Unit 3 and 4 Arizona	450 MW each	6.9 lb/10^{12}Btu
Holcomb Unit 2 Kansas	660 MW	Considered minor source of HAPs. No emission limit established in the permit. Emission limit to be established after testing
Thoroughbred Units 1 and 2 Kentucky	750 MW each	3.86 lb/10^{12}Btu
Wygen Unit 2 Wyoming	500 MW	12.6 lb/10^{12}Btu
Plum Point Units 1 and 2 Arkansas	550 – 800 MW each	12.8 lb/10^{12}Btu
Bull Mountain Roundup Unit 1 Montana	780 MW	2.69 lb/TBtu
Rocky Mountain Power Hardin Unit 1 Montana	113 MW	Considered minor source of HAPs. No emission limit established in the permit.

6.4.4 Required Data for 40 CFR 63.43

The content of an application for a case-by-case MACT determination is described in 40 CFR 63.43. The following sections correspond to the case-by-case MACT application content prescribed in 40 CFR 63.53 (e).

- **The name and address (physical location) of the major source to be constructed or reconstructed:** IPP Unit 3 is proposed to be located on the existing IPP site in Millard

County, Utah. The project is a major source of HAPs (i.e., greater than 10 tpy of HCl and HF and greater than 25 tpy of total HAPs), as shown in Table 6-8.

- **A brief description of the major source to be constructed or reconstructed and identification of any listed source category or categories in which it is included:** The IPP Unit 3 Project consists of one nominal 950-gross MW, PC-fired, utility steam-electric generating unit. The applicable source category is "utility steam-electric generating units". The PC-fired boiler is the source requiring new source MACT. The boiler is to be equipped with a limestone wet scrubber for acid gas control and fabric filters for PM and PM_{10} control.
- **The expected date of commencement of construction:** Construction of IPP Unit 3 is expected to commence by 2004.
- **The expected date of completion of construction:** Construction is expected to be completed in 2008.
- **The anticipated date of startup of operation:** Startup of the Unit 3 is anticipated in 2008.
- **The HAP emitted by the constructed major source, and the estimated emission rate for each such HAP:** The HAPs projected to be emitted annually from the PC-fired boiler are summarized in Table 6-8. These values are estimates based on EPA AP-42 emission factors, the EPRI Coal HAP report, Sargent & Lundy's (owner's engineer for this project) engineering estimates, and properties of the proposed coal to be fired and maximum rated heat input. Additional details on emissions is provided in Table 6-12 for trace metals, Table 6-13 for organic chemicals, and Table 6-14 for acid gases.

TABLE 6-12
Emissions of Trace Metals

Pollutant[a]	Controlled Emissions (lb/hr)	Controlled Emissions (tpy)	Uncontrolled[e] Emissions (lb/hr)	Uncontrolled[e] Emissions (tpy)
Antimony[b]	0.01	0.02	2.23	9.75
Arsenic[b]	0.04	0.18	17.46	76.47
Beryllium[b]	0.00	0.00	0.17	0.75
Cadmium[b]	0.01	0.03	3.40	14.91
Chromium[b]	0.06	0.28	27.93	122.33
Cobalt[b]	0.01	0.03	3.24	14.20
Lead[b]	0.181	0.79	17	74.37
Manganese[b]	0.03	0.15	15.17	66.47
Mercury[c]	0.02	0.09	0.09	0.42
Nickel[b]	0.03	0.13	12.85	56.29
Selenium[d]	0.23	1.02	1.94	8.50

[a]USEPA - TTN, Unified Air Toxics website, Section 112 HAPs, (8/21/2000)

[b]AP-42 Section 1.1, Table 1.1-18, (9/1998)

[c]Engineering calculations based on mercury stack test conducted at IPP Units 1 and 2

[d]Engineering calculations based on EPRI Coal HAP report

[e]Uncontrolled emissions for all metals except mercury and selenium were calculated based on a control efficiency of 99.8 percent. Mercury control was estimated based on coal analysis and stack testing. Selenium control was based on the EPRI Coal HAP report.

TABLE 6-13
Emissions of Organic Compounds

Pollutant[a]	Controlled Emissions (lb/hr)	Controlled Emissions (tpy)
Acenaphthene[b]	0.00	0.00
Acenaphthylene[b]	0.00	0.00
Acetaldehyde[b]	0.23	1.01
Acetophenone[b]	0.01	0.03
Acrolein[b]	0.12	0.51
Anthracene[b]	0.00	0.00
Benzene[c]	0.03	0.15
Benzo(a)anthracene[b]	0.00	0.00
Benzo(a)pyrene[b]	0.00	0.00
Benzo(b,j,k)fluoranthene[b]	0.00	0.00
Benzo(g,h,i)perylene[b]	0.00	0.00
Benzyl chloride[b]	0.28	1.24
Biphenyl[b]	0.00	0.00
Bis(2-ethylhexyl)phthalate (DEHP)[b]	0.03	0.13
Bromoform[b]	0.02	0.07
Carbon disulfide[b]	0.05	0.23
2-Chloroacetophenone[b]	0.00	0.01
Chlorobenzene[b]	0.01	0.04
Chloroform[b]	0.02	0.10
Chrysene[b]	0.00	0.00
Cumene[b]	0.00	0.01
2,4-Dinitrotoluene[b]	0.00	0.00
Dimethyl sulfate[b]	0.02	0.08
Ethyl benzene[b]	0.04	0.17
Ethyl chloride[b]	0.02	0.07
Ethylene dichloride[b]	0.02	0.07
Ethylene dibromide[b]	0.00	0.00

TABLE 6-13 (CONTINUED)
Emissions of Organic Compounds

Pollutant[a]	**Controlled Emissions (lb/hr)**	**Controlled Emissions (tpy)**
Fluoranthene[b]	0.00	0.00
Fluorene[b]	0.00	0.00
Formaldehyde[c]	0.03	0.12
Hexane[b]	0.03	0.12
Indeno(1,2,3-cd)pyrene[b]	0.00	0.00
Isophorone[b]	0.23	1.03
Methyl bromide[b]	0.06	0.28
Methyl chloride[b]	0.21	0.94
5-Methyl chrysene[b]	0.00	0.00
Methyl ethyl ketone[b]	0.16	0.69
Methyl hydrazine[b]	0.07	0.30
Methyl methacrylate[b]	0.01	0.04
Methyl tert butyl ether[b]	0.01	0.06
Methylene chloride[b]	0.12	0.51
Naphthalene[b]	0.01	0.02
Phenanthrene[b]	0.00	0.00
Phenol[b]	0.01	0.03
Propionaldehyde[b]	0.15	0.67
Pyrene[b]	0.00	0.00
Tetrachloroethylene[b]	0.02	0.08
Toluene[c]	0.01	0.06
1,1,1-Trichloroethane[b]	0.01	0.04
Styrene[b]	0.01	0.04
Xylenes[b]	0.01	0.07
Vinyl acetate[b]	0.00	0.01
Total PCDD/PCDF[c]	0.00	0.00

[a]USEPA - TTN, Unified Air Toxics website, Section 112 HAPs, (8/21/2000)
[b]AP-42 Section 1.1, Table 1.1-13 and Table 1.1-14 (9/1998)
[c]Emission calculations based on EPRI Coal HAP Report

TABLE 6-14
Emissions of Acid Gases

Pollutant[a]	Controlled[b] Emissions (lb/hr)	Controlled[b] Emissions (tpy)	Uncontrolled[b] Emissions (lb/hr)	Uncontrolled[c] Emissions (tpy)
Hydrogen Chloride	38.13	167.01	381.31	1670.14
Hydrogen Fluoride	4.69	20.00	46.85	205.20

[a]USEPA - TTN, Unified Air Toxics website, Section 112 HAPs, (8/21/2000)

[b]Engineering calculations based on Sargent and Lundy's engineering estimates for uncontrolled and controlled acid gas emissions

[c]Uncontrolled emissions were calculated based on a control efficiency of 90 percent.

- **Any federally enforceable emission limitations applicable to the constructed or reconstructed major source:** Federally enforceable emission limits will be established in the PSD permit as BACT requirements. In addition, 40 CFR 60 Subpart Da and 40 CFR 72-75 are also applicable requirements for the proposed IPP Unit 3.
- **The maximum and expected utilization of capacity of the constructed or reconstructed major source, and the associated uncontrolled emission rates for that source:** The expected capacity factor of the boiler is expected to be higher than 90 percent. The HAP emission rates provided in Tables 6-12, 6-13, and 6-14 are based on a capacity factor of 100 percent for the unit taking into account the use of all add on controls. However, combustion controls that are inherent to the boiler have been excluded for the calculation of uncontrolled emissions.
- **The controlled emissions for the constructed or reconstructed major source in tpy at expected and maximum utilization capacity:** The controlled emissions of HAPs are provided in Tables 6-12, 6-13, and 6-14. These emissions are also calculated based on 100-percent capacity factor but taking into account all proposed air pollution control devices.
- **A recommended emission limitation for the constructed or reconstructed major source consistent with the principles set forth in paragraph (d) of this section:** Table 6-15 provides recommended emission limits and test method for each HAP or category of HAP.

TABLE 6-15
Proposed Emission Limits

HAP Category	Surrogate Pollutant	Emission Limit	Test Method
Organics	CO	0.15 lb/mmBtu	Reference Method 10
Acid Gases	SO_2	0.10 lb/mmBtu	CEM for SO_2
Trace Metals	PM	0.020 lb/mmBtu	Reference Method 5
Mercury	SO_2, PM	Same as above	Same as above

- **The selected control technology to meet the recommended MACT emission limitation, including technical information on the design, etc.:** MACT for HAPs from IPP Unit 3 burning western bituminous coal is concluded to be control technology capable of demonstrating BACT for CO, VOC, PM, PM_{10}, and SO_2. Technical information on the design of the proposed control technology is provided in the PSD application in Sections 6.1 and 6.2.
- **Supporting documentation including identification of alternative control technologies considered, and analysis of cost of non-air quality health environmental impacts or energy requirements for the selected control technology:** The project is required to meet BACT for CO and VOC as well as PM and PM_{10}. This combination of technology also represents the most stringent control that has been demonstrated in practice for mercury control from similar PC-fired utility boilers burning western bituminous coal; less effective control technologies would not satisfy BACT requirements, and hence no alternatives analysis is required.
- **Any other relevant information required pursuant to subpart A:** No other relevant information has been identified.

6.4.5 MACT Compliance

Since a fabric filter has been determined to be MACT for trace metals from the combustion of bituminous coal; for IPP Unit 3, compliance will be by demonstrating proper operation of the fabric filter. A detailed CAM plan has been proposed to ensure continuous compliance with the PM and PM_{10} emission limits. Adherence to this CAM plan will similarly ensure that the fabric filters are performing at design efficiency for control of HAP metals, including mercury.

Compliance with MACT for organic HAPs will be based on good combustion practices while compliance with acid gases HAPs will be based on proper operation and maintenance of the SO_2 scrubbing system.

6.5 References

EPA, 1990. *New Source Review Workshop Manual, Draft.* Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina, October, 1990.

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7.0 Far-Field (CALPUFF) Air Quality Impact Analysis

This section presents a detailed description of the far-field air quality impact analysis (AQIA) that was conducted for the IPP Unit 3 Project.

7.1 Introduction

Located in the Sevier Desert in Millard County of west central Utah, the IPP is approximately 13 miles north of the town of Delta, Utah. The plant is located within 150 km of Capitol Reef NP in Utah, and within 250 km of several other NPs in Utah, including Zion NP, Bryce Canyon NP, and Canyonlands NP. Arches NP is located 259 km from the project. Other areas administered by the National Park Service (NPS) that are located within 250 km include Glen Canyon National Recreation Area (NRA) and Great Basin NP in eastern Nevada. With the exception of Great Basin NP, all of the aforementioned NPs are federally-designated Class I areas, and as such are afforded special protection under the CAA. Figure 7-1 shows the location of the IPP and the nearest Class I and Class II areas administered by the NPS.

At a February 7, 2002, meeting with CH2M HILL, the NPS requested that air quality analyses be conducted for each of the Class I and Class II areas shown in Figure 7-1. Specifically, the NPS requested an analysis of the visibility impacts, acid deposition impacts, and Class I increment consumption at each of the Class I areas. The NPS also requested an evaluation of increment consumption at the Class II areas, and (for informational purposes only) the visibility and acid deposition impacts for the Class II areas. Furthermore, the NPS requested that each of the analyses be conducted for emissions from the proposed Unit 3 and that Class I and Class II increment consumption be evaluated for emissions from Units 1 through 3 for informational purposes only. A Class I area modeling protocol was presented to the NPS on February 22, 2002, and verbal approval of the protocol was given to CH2M HILL on April 5, 2002.

This section describes the modeling analysis that was conducted for the NPS areas potentially affected by the proposed Unit 3. The analysis was conducted in accordance with specific guidance provided by the NPS in the February 7, 2002 meeting and general guidance found in the following documents: *Federal Land Managers' Air Quality Related Values Workgroup (FLAG) Phase I Report* (FLAG, 2000), and *Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts* (EPA, 1998).

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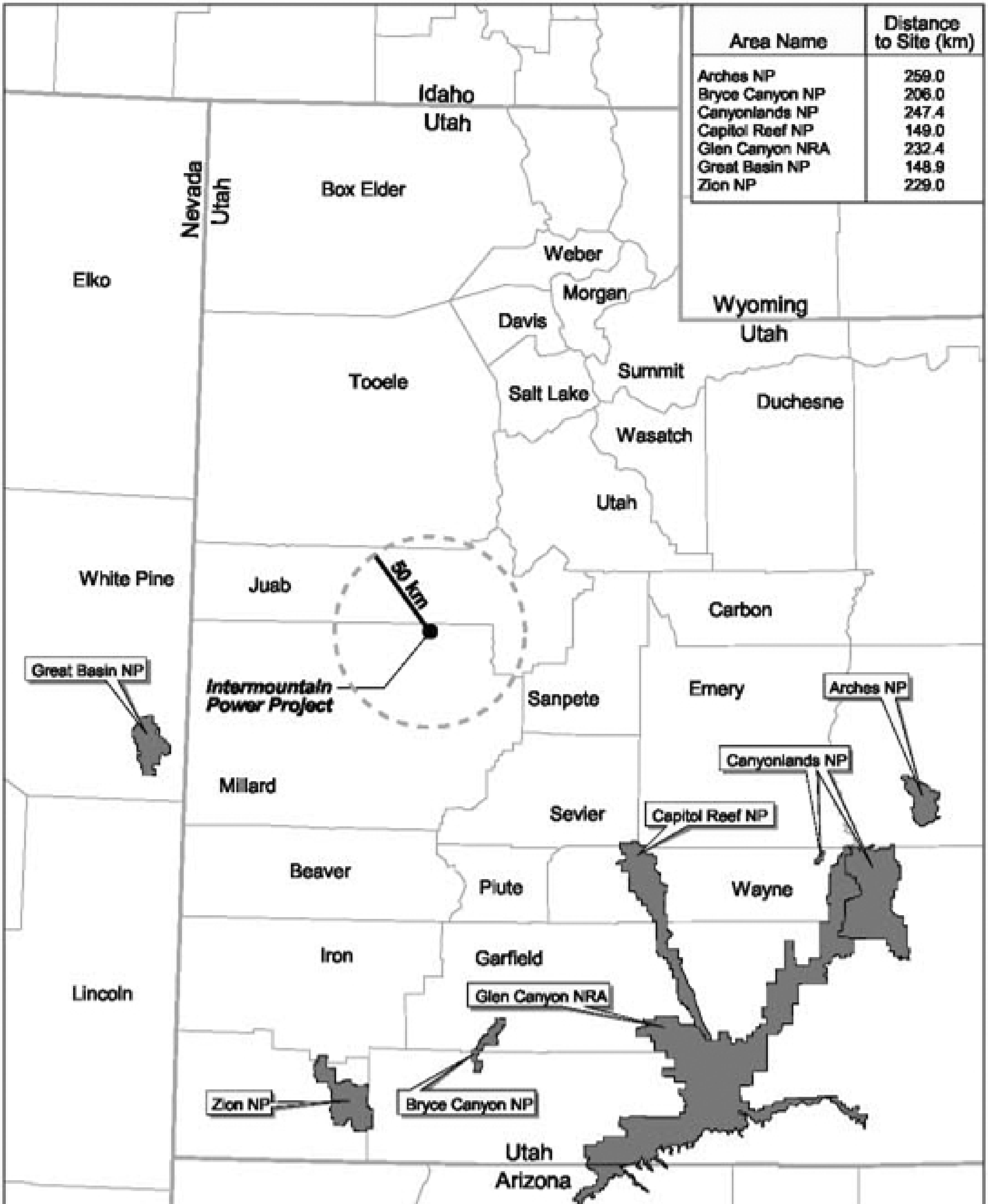

Figure 7-1
NPS Class I and Class II Areas

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Table 7-1 lists, in micrograms per cubic meter (μg/m³), the PSD modeling significance levels and increment levels that apply to the project.

TABLE 7-1
Air Quality Standards Applicable to the Proposed Unit 3

Averaging Period/ Pollutant	Class II Modeling Significance Level (μg/m³)	Class I Modeling Significance Level (μg/m³)[c]	Class II PSD Increment (μg/m³)	Class I PSD Increment (μg/m³)
Annual NO_2	1	0.1	25	2.5
3-hour SO_2	25	1.0	512[a]	25 [a]
24-hour SO_2	5	0.2	91[a]	5[a]
Annual SO_2	1	0.1	20	2
24-hour PM_{10}	3[b]	0.3	30[a]	8[a]
Annual PM_{10}	1	0.2	17	4
1-hour CO	2,000	NS	NS	NS
8-hour CO	500	NS	NS	NS

[a] Not to be exceeded more than once per year.

[b] UDAQ requirement. PSD level set at 5 μg/m³.

[c] Class I Modeling Significance Level is proposed, but not yet promulgated.

[d] NS – no standard

7.2 Model Selection

NPS Class I and Class II areas affected by the proposed Unit 3 are all located more than 50 km from the IPP. Workgroups that represent the interests of the federal land managers (FLMs) in the PSD permitting process (IWAQM, FLAG) recommend that a "far-field" analysis of the effect of a proposed source on air quality and AQRVs be performed for sources located more than 50 km from affected areas. CH2M HILL used the EPA CALPUFF modeling system, as recommended by the FLMs for transport distances of more than 50 km, to obtain predicted air quality and AQRV impacts at the affected areas. The CALPUFF modeling system includes the CALMET meteorological model, a gaussian puff dispersion model (CALPUFF) with algorithms for chemical transformation and deposition, and a post processor model (CALPOST) used in this case to calculate air quality concentrations, visibility impacts, and acid deposition.

The CALPUFF modeling system was applied in a full, refined mode rather than a screening mode. Although a screening technique that allows for abbreviated inputs to CALMET/CALPUFF has been established by IWAQM, this screening technique ordinarily produces very conservative results. The emissions levels expected for the proposed Unit 3 are relatively large, and thus CH2M HILL used the CALPUFF model in a refined mode in order to produce more realistic and sophisticated model input/output.

The CALPUFF model is a non-steady-state Gaussian puff transport and dispersion model containing modules for complex terrain effects, over water transport, coastal interactive effects, building downwash, wet and dry removal, and simple chemical transformation processes. It has the capability to simulate the effects of spatially and temporally varying meteorological conditions on pollutant transport, transformation, and removal. The current EPA guidance recommends the application of this model for estimating long-range transport impacts of air pollutants (concentration and deposition fluxes) on federal Class I areas and impacts on regional visibility. However, the model is not limited to such applications and is capable of modeling nearfield impacts, particularly for situations where chemical transformation and the effects of terrain are influential in accurately characterizing the dispersion of multiple sources. The CALPUFF model has flexible input requirements for meteorological, receptor, terrain, and source term data. Meteorological data options include the following:

- ASCII, "ISC-type" (straight-line, non-gridded) data, including flow vectors, wind speed, stability class, mixing heights, temperature, precipitation rates, short-wave radiation, and relative humidity (used for CALPUFF screening analysis)
- Gridded meteorological data set generated by the CALMET pre-processor

Other input parameters include gridded or non-gridded (discrete) receptors in simple or complex terrain, time-varying emission rates, and topographic information. The plume rise is computed within the CALPUFF model for each source using the numerical plume rise algorithm (derivation of Briggs plume rise equations). Output from the CALPUFF model includes the concentration and deposition (wet and dry) for each receptor location. These output data can be used as input to the CALPOST post-processor module, which creates a list file of the CALPUFF output and plot files containing the "top N" highest concentration at each receptor location.

7.3 CALMET

The application of the CALMET model for the production of meteorological input to the CALPUFF model is described in this section.

7.3.1 Dimensions of the CALMET Domain

CALMET was used to generate a three-dimensional wind field and boundary layer parameters suitable for use by the CALPUFF model. CH2M HILL established a modeling domain to encompass the IPP and the areas of interest. The domain covers a region approximately 524 km by 408 km with a grid resolution of 4 km. The selected domain allows for coverage of each of the areas of concern, with a 50-km buffer beyond the farthest boundary of the most distant areas of interest. Figure 7-2 shows the CALMET modeling domain.

The default technical options listed in Appendix A of the IWAQM Phase 2 report were used for CALMET modeling. User-specified model options were determined by CH2M HILL's professional staff to produce the most realistic wind field. Appendix E presents a CALMET input file that shows the complete list of the chosen technical options. CH2M HILL used a universal transverse mercator (UTM) coordinate system for the CALMET grid. As was discussed during the February 7, 2002 meeting with the NPS, the CALMET modeling domain is contained almost entirely within a single UTM zone (Zone 12), and therefore did not require the use of a Lambert conformal projection.

Vertical resolution of the wind field included 11 layers, with vertical cell face heights as follows (in meters):

- 0, 20, 100, 200, 350, 500, 750, 1000, 2000, 3000, 4000, 5000

7.3.2 CALMET Input Data

7.3.2.1 Mesoscale Prognostic Data

Mesoscale Model – Version 5 (MM5) data for the period from January 5, 1996 through December 27, 1996 (at 36-km resolution), as compiled by the EPA Air Quality Modeling Group for the entire continental United States were used as the first guess wind field for CALMET. The use of this MM5 wind field data set in effect established the calendar year 1996 as the representative year within which to estimate the air quality impact of proposed Unit 3 on the Class I and Class II areas of interest. Accordingly, all other meteorological and air quality data used in this Class I and Class II AQIA were also collected in the area during 1996.

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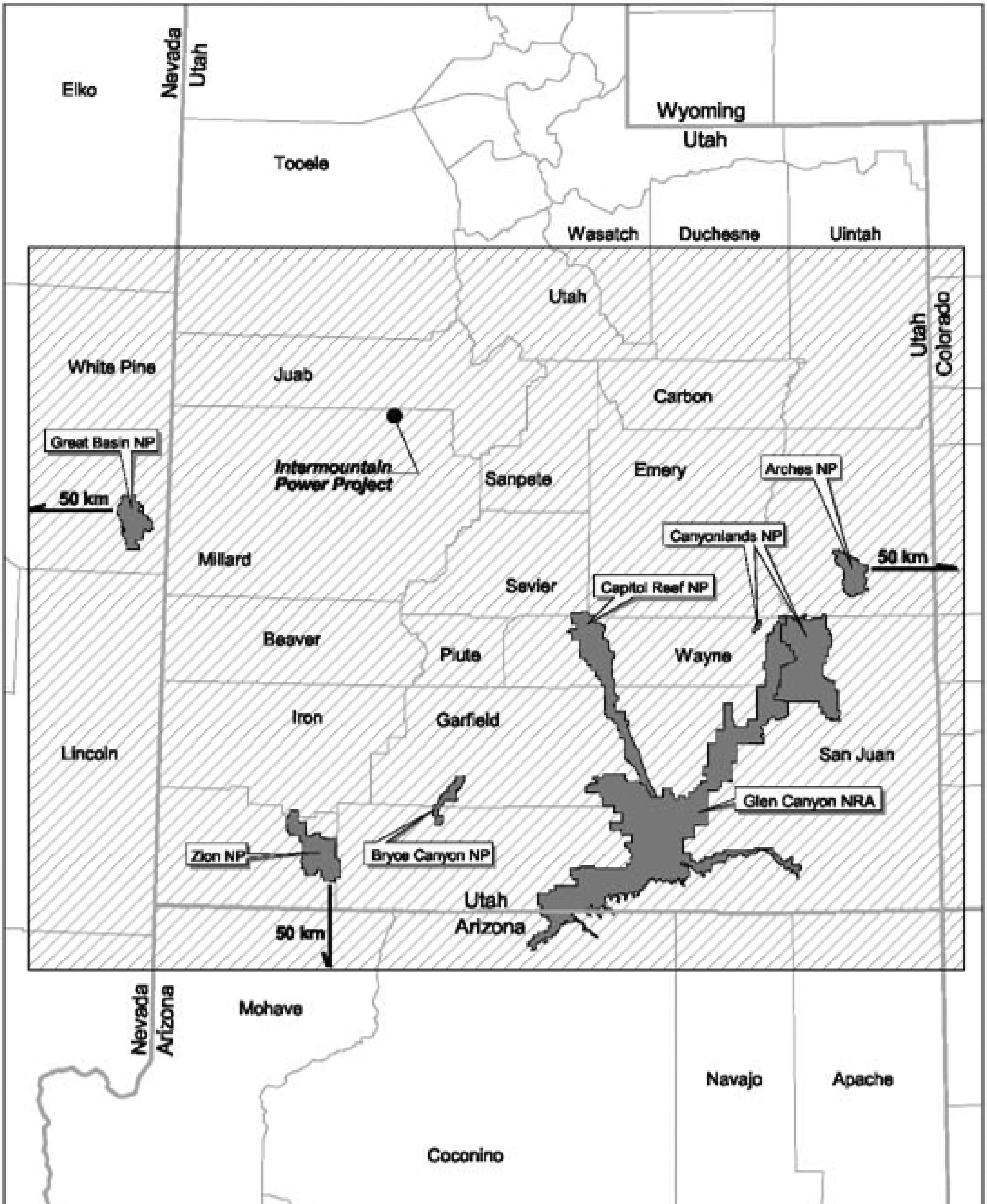

DOMAIN EXTENTS
SW Corner
UTM Zone 12 Meters: 157938.46, 4062172.56
Lat/Long Decimal Degrees: 36.646, -114.826
NE Corner
UTM Zone 12 Meters: 685938.46, 4470172.56
Lat/Long Decimal Degrees: 40.363, -106.810

Figure 7-2
CALMET Modeling Domain

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The NPS and other FLMs operate the Interagency Monitoring of Protected Visual Environments (IMPROVE) network at many Class I areas across the country. However, not all Class I areas have an IMPROVE station. Therefore, the IMPROVE stations are intended to gather air quality data that are considered to be regionally representative. IMPROVE stations operated by the NPS are located in the study area at Canyonlands NP and Great Basin NP. Data from these stations collected by the NPS during 1996 were used in this analysis. Grand Canyon NP is located just outside the study area and data from this location were also used in the analysis.

7.3.2.2 Surface Data

Hourly surface data for 1996 were collected at National Weather Service (NWS) and NPS meteorological monitoring stations in (or near) the CALMET modeling domain. The source of the NWS data is the National Climatic Data Center (NCDC). The source of the NPS data was the IMPROVE web site on the Colorado State University (CSU) Server: http://vista.cira.colostate.edu/DatawareHouse/IMPROVE/. The surface stations are:

- Grand Junction, Colorado
- Cedar City, Utah
- Salt Lake City, Utah
- Canyonlands NP

Relative humidity data for the second half of 1996 were missing from the Cedar City, Utah surface file. Substitute values for relative humidity were created for hours that included valid temperature and dew point temperature observations using the following relationship:

$RH = [(173 - 0.1T + Td) / (173 + 0.9T)]^8$

where:

RH=relative humidity

T= temperature (°F)

Td=dew point temperature (°F)

7.3.2.3 Upper-Air Data

Upper-air data were processed for the NWS stations nearest to the modeling domain:

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

Elko and Desert Rock are located more than 50 km from the western edge of the modeling domain, but were included because they are situated upwind of the domain. Figure 7-3 shows the location of the surface and upper-air stations.

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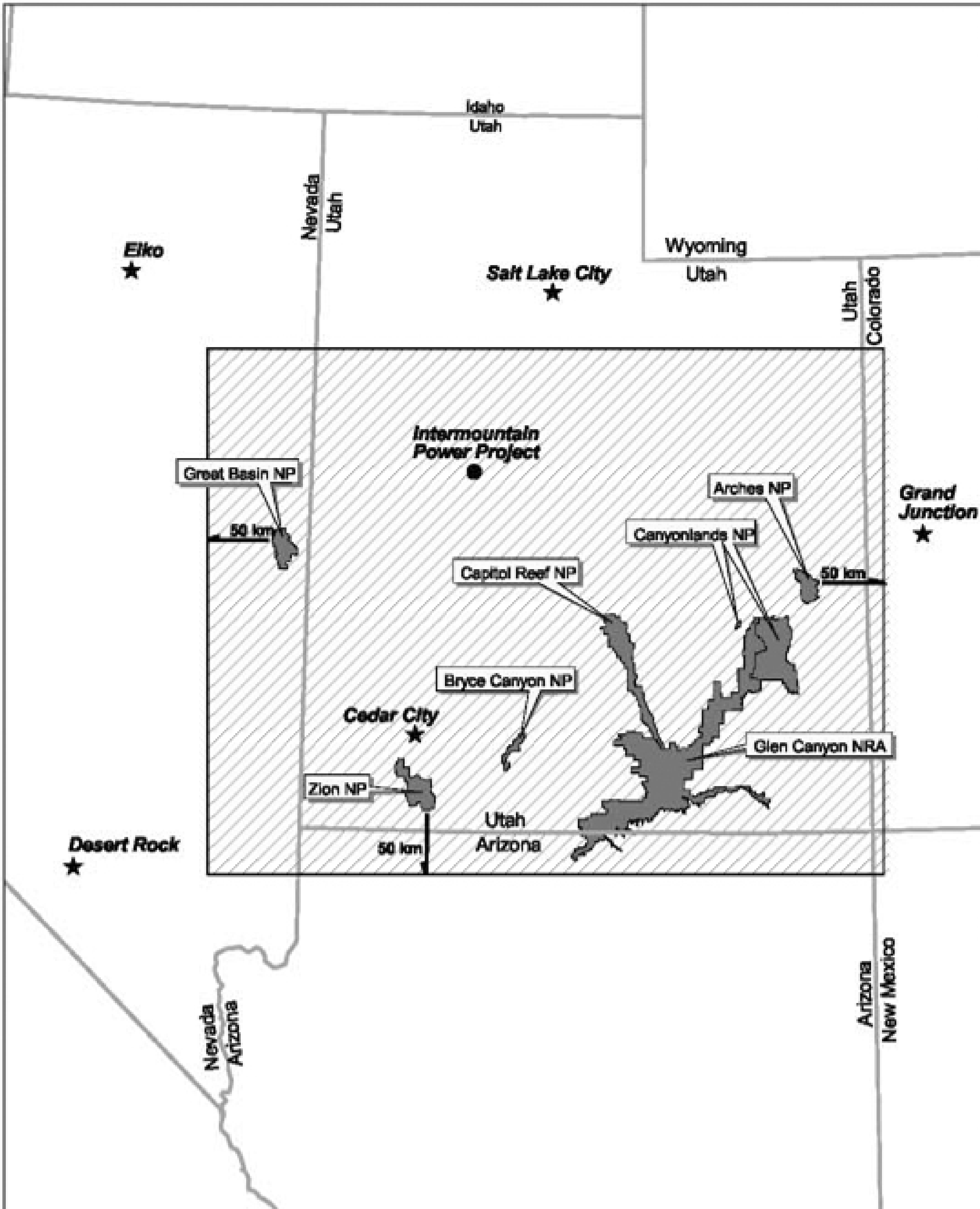

Figure 7-3
Surface and Upper-Air Stations

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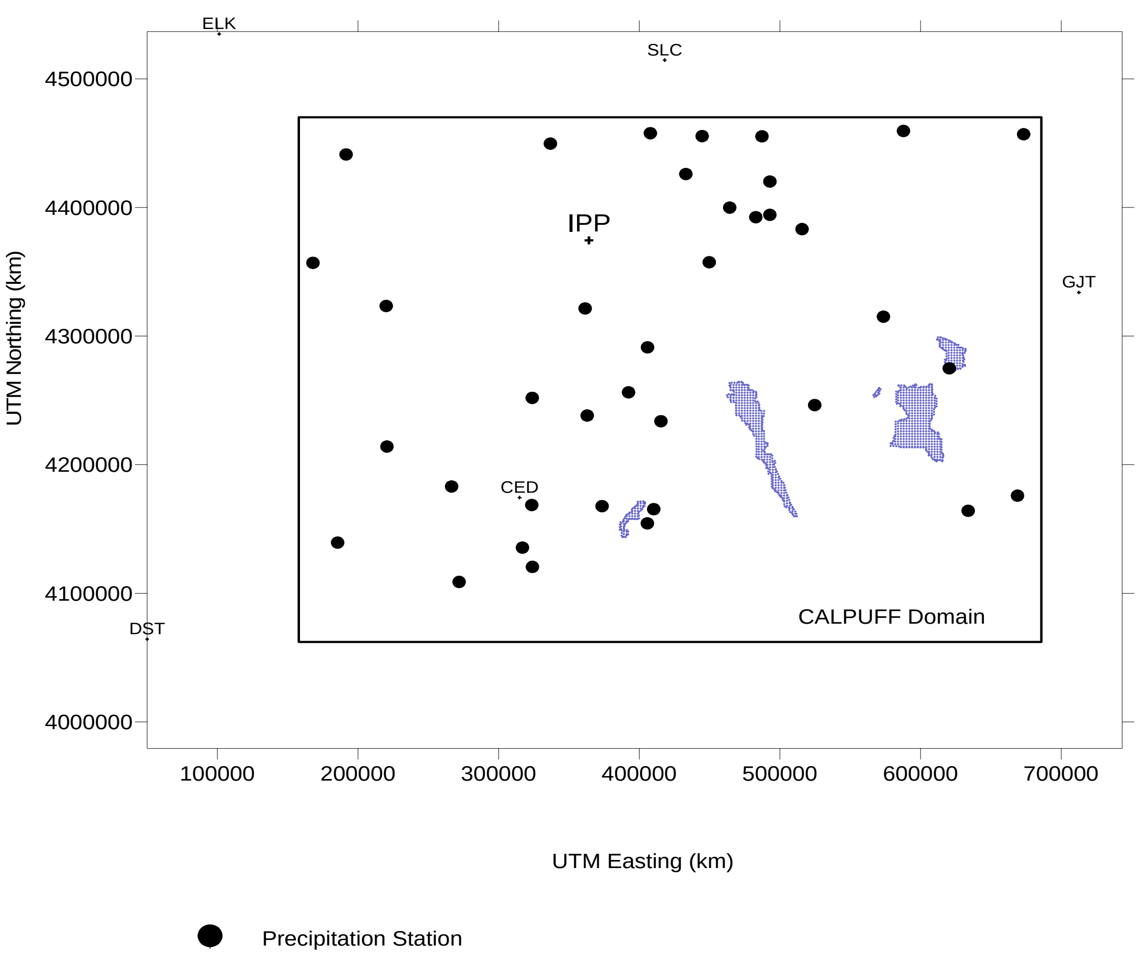
7.3.2.4 Geophysical Data

Land use and terrain data were obtained from the United States Geological Survey (USGS). Land use data were obtained in Composite Theme Grid (CTG) format from the USGS, and the 37 Level I USGS land use categories were mapped into the 14 primary CALMET land use categories. Surface properties such as albedo, Bowen ratio, roughness length, and leaf area index were computed from the land use values. Terrain data were taken from USGS 1-degree Digital Elevation Model (DEM) data, which are primarily derived from USGS 1:250,000 scale topographic maps. Missing land use data were filled with a value that is appropriate as a domain-wide average. The largest block of missing land use data was found near Bryce Canyon NP. Inspection of the land use associated with the areas adjacent to the missing block revealed that the predominant land use category was "shrub and brush rangeland", which is representative of the missing block of data as well as the modeling domain as a whole.

7.3.2.5 Precipitation Data

Precipitation data were taken from the available TD-3240 files from the NCDC. Valid data records were available for 1996 for 37 stations in the modeling domain. Figure 7-4 shows the distribution of the precipitation stations.

FIGURE 7-4
Precipitation Stations in CALMET Domain



7.3.3 Validation of CALMET Wind Field

CH2M HILL produced vector plots of selected periods within the CALMET output for validation of the wind field with the PRTMET routine. The evaluation allowed for the determination that the various "user defined" CALMET technical options were chosen properly. The hours for evaluation were chosen with the objective of obtaining a sample for both winter and summer, and at various times of the day. The days chosen, January 29 and June 18, 1996, were both days with low windspeeds. A third day was chosen as the day with the highest predicted visibility impacts in Capital Reef NP, November 15, 1996. The hours chosen were the hour before sunrise, noon, and sunset, based on the likelihood of occurrence of upslope and downslope winds. All of these windfields were generated using Level 1, or ground level, winds. For the day of maximum impact, the windfields were also generated at the level of expected plume height (Level 5) and at the very top level (Level 11).

As expected, the windfield plots did show evidence of upslope flows on the June 18th afternoon hours, resulting from upward convection of warm valley air. Likewise, there was evidence of downslope flows in early morning hours when cool mountain air sinks down into the nearby valleys. Windfield plots are included on the enclosed CD.

7.4 CALPUFF

CH2M HILL drove the CALPUFF model with the meteorological wind field output from CALMET over the modeling domain described earlier. Source emission rates, exhaust parameters, background ozone concentrations, and technical options used within CALPUFF are described below. The CALPUFF model was initially used to estimate the impacts from the proposed Unit 3 only. The results of this initial analysis were then compared to the established thresholds for cumulative analysis.

7.4.1 Source Emission Rates and Exhaust Parameters

The NO_x, SO_2, PM_{10}, and sulfate (SO_4) emissions from the main units at the IPP (Units 1 through 3) were considered within CALPUFF. Other miscellaneous sources at the facility emit much lower levels of these pollutants at such low release heights that their plumes would not significantly contribute to long-range transport impacts.

For modeling 3-hour SO_2 impacts from Unit 3, an emission rate of 1,357.5 pounds per hour (lb/hr)/171.0 grams per second (g/s) was used within CALPUFF. This 3-hour emission rate is based on 0.15 lb SO_2/MMBtu, which is an estimate of the highest rate that would be expected from Unit 3 for a 3-hour period. The 24-hour SO_2 emission rate was 1,086 lb/hr (136.8 g/s), as based on 0.12 lb SO_2/MMBtu. Annual SO_2 impacts and sulfur deposition for Unit 3 were estimated with an emission rate based on the long-term (30-day rolling average) limit that will apply to the Unit, 0.10 lb SO_2/MMBtu.

Emissions for SO_2 PSD increment modeling for Units 1 and 2 at IPP were derived from CEM data for 2000 and 2001. The highest 3-hour and 24-hour emissions measured over that time period were input to the model. In each case, the CEM data was below the PTE for those sources (0.15 lb/MMBtu):

- Maximum 3-hour SO_2 for Unit 1 = 137.9 g/s (0.129 lb/MMBtu)
- Maximum 24-hour SO_2 for Unit 1 = 128.9 g/s (0.120 lb/MMBtu)
- Maximum 3-hour SO_2 for Unit 2 = 144.4 g/s (0.135 lb/MMBtu)
- Maximum 24-hour SO_2 for Unit 2 = 123.3 g/s (0.115 lb/MMBtu)

Table 7-2 presents the emissions and stack parameters input to CALPUFF.

TABLE 7-2
Unit 3 Project Source Parameters

Source	Stack Height (ft/ m)	Stack Diameter (ft/m)	Exit Velocity (ft/s)/(m/s)	Exhaust T (F/K)	SO_2 Emission Rate (lb/hr)	NO_x Emission Rate (lb/hr)	PM_{10} Emission Rate (lb/hr)	SO_4 Emission Rate (lb/hr)
Unit 3	712/217	32/9.75	67.9/20.7	135/330.4	905 (long-term)	633.5	178.4	42.4
					1,357.5 (3-hour)			
					1,086 (24-hour)			
Unit 1	712/217	28/8.53	82.7/25.2	115/319.3	1,094.2 (3-hour actual)	4250	177.5	n/a
					1,022 (24-hour)			
Unit 2	712/217	28/8.53	82.7/25.2	115/319.3	1,146.1 (3-hour)	4250	177.5	n/a
					978.9 (24-hour)			

7.4.2 Technical Options

For CALPUFF modeling, CH2M HILL used the default CALPUFF technical options that are listed in the IWAQM Phase 2 guidance document. Table 7-3 highlights a subset of the CALPUFF model technical options. For wet and dry deposition, CH2M HILL used the CALPUFF default values for particle size parameters and scavenging coefficients. Particle size parameters and wet deposition scavenging coefficients for PM_{10} particles were assumed to be the same as for nitrate (NO_3) and SO_4.

TABLE 7-3
CALPUFF Model Options

Parameter	Setting
Pollutant Species Modeled	SO_2, SO_4, NO_x, HNO_3, PM_{10}, and NO_3
Chemical Transformation	MESOPUFF II scheme with CALPUFF defaults
Deposition	Wet and Dry
Meteorological/Land Use Input	CALMET
Plume Rise	Transitional, stack-tip downwash, partial plume penetration
Dispersion	PG/MG coefficients
Terrain Effects	Partial plume path adjustment
CDIV*	0.0, 0.0
Output	Create binary file: output species SO_2, SO_4, NO_X, HNO_3, PM_{10}, and NO_3
Background Ammonia Concentration (domain-wide)	1 ppb**

* Default for CDIV listed as 0.01 in IWAQM Phase 2 guidance, but 0.0 now considered as a more appropriate value.

** IWAQM default is 10 ppb, but the NPS recommended a domain-wide average of 1 ppb.

7.4.3 Background Ozone

Hourly values of background ozone concentrations are used by CALPUFF for the calculation of SO_2 and NO_X transformation with the MESOPUFF II chemical transformation scheme. CH2M HILL used available hourly ozone data from within or near the modeling domain for this purpose. Hourly data for 1996 were obtained from the NPS IMPROVE stations for Canyonlands NP and Great Basin NP, and from a UDEQ site in St. George, Utah. Data for Canyonlands NP and Great Basin NP are mostly complete for the entire calendar year, but data from the St. George site were only collected during the high ozone season (May through September) of 1996. Missing data from the St. George site, as well as any missing data from the Canyonlands NP or Great Basin NP sites, were filled with a default, domain-wide average concentration of 49.8 ppb as recommended by the NPS. This default value represents a 6-year average of the daytime concentrations measured at Canyonlands NP and Great Basin NP during the high-ozone season of May through September. As such, the default value represents a conservative (high) estimate of hourly ozone concentrations during the non-summer months, especially for the winter.

7.4.4 CALPUFF Receptor Grids

Discrete receptors for the CALPUFF modeling were placed at uniform receptor spacing along the boundary and in the interior of each area of concern. As recommended by the NPS, Class I areas receptors were spaced at 2-km intervals for the following areas:

- Zion NP

- Bryce Canyon NP
- Capitol Reef NP
- Canyonlands NP
- Arches NP

The NPS recommended that Class II area receptors be created with coarser spacing. For the Great Basin NP, receptors were placed with a spacing of 4 km. For Glen Canyon NRA, the receptor spacing was set at 5 km because of the large distance from the IPP.

7.5 CALPOST

7.5.1 Visibility

Visibility impacts were estimated through the use of the modeled concentrations produced by CALPUFF and hourly relative humidity data from the CALMET output, both within the CALPOST postprocessor. CALPOST calculates the percent change in extinction attributable to the project emissions as compared to the background extinction in the areas of concern for natural conditions.

The percent change in light extinction (Δ) is calculated using:

$$\Delta = \frac{\Delta b}{b_{back}} * 100$$

Where Δb is the incremental increase in light extinction due to the project emissions and b_{back} is the background light extinction under natural conditions.

The incremental increases in light extinction from the project were determined from the modeled concentrations of nitrate, sulfate, and PM_{10}. Because their scattering effects are dependent on relative humidity, sulfates and nitrates are referred to as hygroscopic species. Relative humidity for the consideration of extinction from the hygroscopic particles was calculated on an hourly basis from data in the CALMET file, and then averaged for each 24-hour period. This is Method 2 in CALPOST, which is the recommended method in FLAG for a refined CALPUFF visibility analysis. Concentrations of PM_{10} from the IPP sources were treated within CALPOST as "fine" particulate (extinction efficiency of 1.0).

Background extinction (b_{back}) due to natural aerosols for the areas of concern was calculated within CALPOST using the equation:

$$b_{back} = b_{hygro} \times f(RH) + b_{NonHygro} + Rayleigh$$

Where b_{hygro}, $b_{NonHygro}$, and Rayleigh scattering components are provided in Appendix 2.B of the FLAG Phase I report. As shown in the FLAG report, the values for b_{hygro} [0.6 inverse megameters (Mm^{-1})], $b_{NonHygro}$, (4.5 Mm^{-1}), and Rayleigh scattering (10 Mm^{-1}) are the same for each of the Class I areas of concern. These values are the current FLAG-recommended estimates of "natural background" for these western areas. Although such values are not provided for Great Basin NP or Glen Canyon NRA within the FLAG document, CH2M HILL will assume that the background extinction provided within the FLAG document for the Class I areas will also apply for Glen Canyon NRA and Great Basin NP.

The FLAG document defines natural conditions as "[c]onditions substantially unaltered by humans or human activities. As applied in the context of visibility, natural conditions include naturally occurring phenomena that reduce visibility as measured in terms of light extinction, visual range, contrast, or coloration." Aerosols that occur naturally in the ambient air affect background visibility under natural conditions. Natural background visibility is also affected by water in various physical states that naturally occur in the ambient air in the form of relative humidity, water vapor, clouds, fog, or in the form of precipitation as snow or rain.

As stated above, the FLAG document provides a method of adjustment of natural background visibility for one form of atmospheric water expressed as relative humidity. However, FLAG does not provide a method of adjusting natural background visibility for atmospheric water naturally occurring in other physical states. Therefore, to correct this apparent oversight in FLAG and to fully account for the impact on natural visibility due to atmospheric water in all forms not just relative humidity, a method was devised to estimate and adjust for background extinction caused by condensed water as well.

The NPS operates the IMPROVE transmissometer at Canyonlands NP to measure actual background visibility. The NPS operates similar instruments at Grand Canyon NP and Great Basin NP. This Canyonlands instrument measures actual atmospheric light extinction at a location in the park with an elevation of approximately 1,800 meters over a path length of approximately 6.43 km. The Canyonlands transmissometer has been operated continuously by the NPS since December 1, 1986.

Hourly Canyonlands NP transmissometer data for 1996 were obtained from the CSU IMPROVE web site. The Canyonlands transmissometer data were used for determining natural background in all Class I and Class II sites except for Great Basin NP where its own transmissometer data were used.

Since Grand Canyon NP is just outside of the domain of this analysis, transmissometer data from Grand Canyon NP were used to see if visibility obscuration events at Canyonlands NP also occurred at roughly the same time at Grand Canyon NP, thus indicating that the meteorological event causing the visibility obscuration was regional in scale. For 1996 this was largely the case, but not always. However, since the IMPROVE sites are chosen by the NPS to be regionally representative, these data were considered representative of the project site.

The transmissometer readings are actual light extinction measured at the time of collection. This measurement includes the effects of both natural and man-caused conditions. Since only natural conditions are to be considered in the estimation of natural background, a method was devised to remove the effect of man-caused visibility impairment from the transmissometer data leaving an estimate of natural background.

The NPS publishes, on the CSU IMPROVE web site for each of the IMPROVE transmissometer sites, a 5-year visibility trends analysis of the 10^{th}, 50^{th}, and 90^{th} percentile averages of reconstructed light extinction and the light scattering of the major aerosol types. The 10^{th}

percentile days are the best in terms of visibility and the 90th are the worst. The 90th percentile atmospheric extinction is defined as the average of the reconstructed light extinction between the 80th and 100th percentile. The reconstruction of these light extinction estimates by NPS accounts only for the effect of aerosols measured in the atmosphere at the IMPROVE site and specifically excludes any effect on visibility due to water.

The 1996 90th percentile reconstructed light extinction and the light scattering for each IMPROVE site are reported in the web document titled BEXT_5yr_Mar2002_TXT.htm. For Canyonlands for 1996 the 90th percentile value reported by NPS for reconstructed visibility impairment is 24.41 Mm^{-1}. This represents the highest average reconstructed light extinction at the Canyonlands IMPROVE site in 1996 due to measured aerosols both natural- and man-caused. This 24.41 Mm^{-1} total light scattering is contributed to by the measured atmospheric concentrations of the following aerosols: sulfate 36.7 percent; nitrate 9 percent, organic carbon 22.6 percent, elemental carbon 8.67 percent, and fine soil and coarse material 23 percent.

Hourly transmissometer light extinction readings at Canyonlands NP for 1996 range from 608 Mm^{-1} (indicating total blockage of the 6.43-km transmissometer light path) to 14 Mm^{-1}. Generally the highest light obscuration events occur when condensed water is present in the atmosphere in the form of clouds, fog, snow, or rain. A method was devised to separate those hours from other hours when aerosols potentially of anthropogenic origin are the dominant cause of visibility impairment. In order to be conservative, a light extinction level of 50 Mm^{-1} (twice the maximum aerosol light extinction reconstructed by NPS for 1996) was chosen to represent the transition between aerosol dominated and condensed water dominated light extinction at Canyonlands NP.

Background light extinction for each Class I or Class II area (except Great Basin NP) was determined for each hour by examining the Canyonlands transmissometer data for that hour. If the measured light extinction was 50 Mm^{-1} or more, indicating condensed water dominated light extinction, the transmissometer reading was used for that hour. If the measured extinction was less than 50 Mm^{-1}, indicating aerosol dominated light extinction, the light extinction value calculated using the equation above was used. The 24-hour average natural conditions background light extinction was then calculated from these 24 individual hourly values and compared to the calculated change in light extinction for the proposed Unit 3 for that 24-hour period at that Class I or Class II area. A similar process was followed for the Great Basin NP Class II area using transmissometer data from the Great Basin IMPROVE site.

For the proposed Unit 3 at IPP, the maximum visibility impacts derived from CALPUFF were less than 5 percent for each Class I area of concern after the consideration of natural obscuration. For Great Basin NP, which is classified as a Class II area, the maximum 24-hour impact was 7.2 percent. The calculations used to produce the adjusted maximum visibility impacts are presented in Appendix E, and Table 7-4 provides a summary of the results for the visibility analysis.

TABLE 7-4
Visibility Results for Unit 3 Project Only

Area	Δb (Mm^{-1})	b_{back} (Mm^{-1})	Maximum Percentage Change	Number of Days with Percentage Change > 5%	Number of Days with Percentage Change > 10%
<u>Class I Areas</u>					
Arches NP	0.434	15.337	2.83	0	0
Bryce Canyon NP	0.767	15.602	4.92	0	0
Capitol Reef NP	0.482	15.986	3.02	0	0
Canyonlands NP	0.462	15.133	3.05	0	0
Zion NP	0.595	15.353	3.87	0	0
<u>Class II Areas</u>					
Great Basin NP	1.142	15.891	7.18	1	0
Glen Canyon NRA	0.654	15.291	4.28	0	0

Notes:
Δb = Estimated increase in light extinction due to source
b_{back} = Natural background light extinction
Mm^{-1} = Inverse megameters
NP = National Park
NRA = National Recreation Area

This natural background conditions adjustment described above is the same that was used in Montana for the Roundup Power Plant (RPP). This is described in a letter from the Department of Interior to the Montana Department of Environmental Quality (Manson, 2003). The letter says "[I]t is our interpretation that 'natural conditions' include significant meteorological events such as fog, precipitation, or naturally occurring haze. Based on the information received and subsequent analysis of that data and the policy guidance, I have concluded that on those days when RPP was shown in the original analysis to have resulted in a visibility extinction of 5 percent or more a weather event was the most significant source of the visibility extinction and not the RPP emissions." Accordingly, the natural background conditions adjustment used in this NOI is acceptable to the Department of the Interior.

Another concern with the natural background value in the FLAG document is that it does not contain any consideration of the impact on visibility due to sea salt. While this is mainly an issue on the seacoasts, it could be an issue in Utah with the Great Salt Lake and the Bonneville Salt Flats as sources of salt in the atmosphere. An analysis of the IMPROVE aerosol data for 1996 at the Canyonlands IMPROVE site shows that an average of 0.06 $\mu g/m^3$ with a peak of 0.4 $\mu g/m^3$ of sodium was measured. This demonstrating that a small amount of salt can be present in the air at Canyonlands. This constituent of natural background is not accounted for in the FLAG background light extinction value of 15.6 Mm^{-1} so this value may be artificially low resulting in a higher computed impact on visibility from the plant.

Some scientists have suggested that the computation of light extinction by a proposed source should be limited to daylight hours (when visibility is a potential concern as opposed to during the night when one cannot see landscape features due to the darkness) or those hours with relative humidifies of 90 percent or less. To do either would lessen the impact of IPP since the CALPUFF computations of the plant impact tend to be highest during very high humidity (>90 percent) periods when the atmosphere is more likely to contain condensed water vapor. This was taken into account in the background adjustment described above using the IMPROVE transmissometer data, but the computed light extinction of the source was not limited to those times when the relative humidity was less than 90 percent. The computations should also not be made at night (when the relative humidity tends to be higher) when one cannot see anyway due to the darkness. For this reason as well the visibility impact results may be overstated in this NOI.

For all of these reasons, the calculated visibility impact of the plant in the Class I and Class II areas is likely overstated from what an observer would actually experience.

7.5.2 Criteria Pollutant Impacts

CALPOST was also used to produce estimated concentrations of NO_x, SO_2, and PM_{10} for comparison to the Class I and Class II modeling significance levels as shown in Table 7-5.

TABLE 7-5
Criteria Pollutant Impacts for Proposed Unit 3

Area	Annual NO_2	3-hour SO_2	24-Hour SO_2	Annual SO_2	24-Hour PM_{10}	Annual PM_{10}
Class I Areas						
Arches NP	0.001	0.71	0.17	0.01	0.032	0.002
Bryce Canyon NP	0.001	0.92	0.25	0.01	0.04	0.002
Capitol Reef NP	0.004	1.42	0.23	0.02	0.05	0.004
Canyonlands NP	0.002	0.96	0.17	0.01	0.04	0.003
Zion NP	0.002	1.23	0.18	0.01	0.04	0.002
Class I Modeling Significance Levels[a]	0.1	1	0.2	0.1	0.3	0.2
Class II Areas						
Great Basin NP	0.002	0.94	0.38	0.01	0.08	0.002
Glen Canyon NRA	0.002	0.91	0.20	0.01	0.05	0.003
Class II Modeling Significance Levels	1	25	5	1	5	1

[a] Class I Modeling Significance Levels were proposed by EPA on July 23, 1996 [61 FR 38250], but were never adopted as a final rule.

As shown in Table 7-5, the proposed EPA Class I modeling significance levels were exceeded for several of the Class I areas for 3-hour and 24-hour SO_2. Therefore, a cumulative increment consumption analysis was conducted for those areas, namely, Bryce Canyon NP, Capitol Reef NP, and Zion NP. Although not required based on the results of the preliminary analysis, a cumulative analysis was also conducted for the two other Class I areas in Utah (Arches NP and Canyonlands NP) and for all five Class I areas for PM_{10} and NO_2. Emissions rates for IPP Unit 3 were those described earlier that reflect the potential 3-hour performance of the unit. The increment-consuming emissions for the existing Units 1 and 2 at IPP were taken from the worst case 3-hour emission rates from CEM data, as described earlier. All averaging periods for SO_2 were modeled with 3-hour emission rates for the IPP units, and the analysis was therefore conservative for 24-hour and annual impacts. Table 7-6 summarizes the emissions rates used for IPP sources for the cumulative analysis. The emission rates for NO_X and PM_{10} (filterable and condensable) shown in the table reflect the PTE for those pollutants.

TABLE 7-6
Emission Rates (pounds per hour) for IPP Sources

Unit	PM_{10}	SO_X	NO_X
Unit 1	177.5	1,094.2	4,250
Unit 2	177.5	1,146.1	4,250
Unit 3	221	1,357.5	633.5

Model input parameters for outside sources were obtained from UDAQ data conveyed to CH2M HILL on May 28, 2003. The data, approved by UDAQ for this analysis, provided input parameters for major increment-consuming sources located in central and southern Utah. Emission rates from the UDAQ data were actual increment consuming NO_2, SO_2, and PM_{10} emissions for the 2-year period from 2000 to 2001. These sources have been identified as increment consuming, but CH2MHILL has not independently confirmed the accuracy of the data. CH2MHILL has used the list in our models, but has no independent knowledge whether all of the sources on this list are actually “increment consuming”. A copy of the UDAQ data is provided in Appendix E.

Table 7-7 presents the results of the cumulative Class I increment modeling for each Class I area in the IPP Unit 3 Project modeling domain. For each pollutant and averaging period, the results were all well below the allowable Class I increments. The predicted cumulative impact for 24-hour SO_2 at Canyonlands NP represents 42 percent of the available increment, 33 percent of the increment for 3 hour SO_2. and 30 percent of the increment for annual NO_x. All other predicted impacts for SO_2 and PM_{10} at Canyonlands and all pollutants at all other Class I areas represented only 10 to 20 percent or less of the available increment cumulatively consumed by all increment consuming sources in the area. This modeling shows that in no case is the Class I increment in any Class I area in southern or eastern Utah threatened by the addition of emissions from IPP Unit 3 to those from existing sources in the area.

TABLE 7-7
Cumulative Increment Consumption (all reported values are in units of µg/m^3)

Area	Annual NO_2	3-hour SO_2	24-Hour SO_2	Annual SO_2	24-Hour PM_{10}	Annual PM_{10}
Class I PSD Increment	2.5	25[a]	5[a]	2	8[a]	4
Class I Areas						
Arches NP	0.047	2.65	0.76	0.13	0.15	0.015
Bryce Canyon NP	0.029	2.42	0.83	0.04	0.14	0.009
Capitol Reef NP	0.109	3.66	0.91	0.10	0.17	0.020
Canyonlands NP	0.074	8.39	2.10	0.12	0.20	0.019
Zion NP	0.030	3.13	0.59	0.03	0.13	0.007

[a] Not to be exceeded more than once per year.

7.5.3 Acid Deposition

Impacts to both flora and water quality at the areas of concern were assessed through an analysis of total sulfur (S) and nitrogen (N) deposition. Annual deposition rates were determined for the first modeling scenario only (proposed Unit 3).

The NPS has established deposition analysis thresholds (DAT) for eastern and western regions of the United States. A DAT is the amount of deposition within an area below which estimated impacts from a proposed new or modified source are considered insignificant. The DAT for western United States areas is 0.005 kilograms per hectare per year (kg/ha/yr) for total N and also for total S (NPS, 2002).

Annual deposition rates of NO_x, nitric acid (HNO_3), and NO_3 were calculated by CALPUFF, converted to equivalent levels of N and summed within the POSTUTIL routine, and then converted to units of kg/ha/yr within CALPOST. Likewise, deposition rates of SO_2 andSO_4^{-2} were converted to equivalent levels of N and S and summed. Because DAT levels for deposition established by the NPS are expressed in units of kg/ha/yr for total N or S, the CALPUFF deposition fluxes of each of the oxides of N and S were adjusted to account for the difference in molecular weights between the oxides and the elements. CH2M HILL used the molecular weight ratios shown in Table 7-8 within the POSTUTIL routine to perform the adjustment.

TABLE 7-8
Molecular Weight Ratios for Deposition Calculations in POSTUTIL

Element	Ratio of Molecular Weight of Oxidant to S or N
N from SO_4 (as constituents of $(NH_4)_2SO_4$)	0.29167
N from HNO_3	0.22222
N from NO_3	0.45161
N from NO_x	0.30435
S from SO_2	0.50000
S from SO_4	0.33333

Table 7-9 presents the estimated deposition of N and S compounds for the first modeling scenario (proposed Unit 3 only).

TABLE 7-9
Acid Deposition Impacts for Proposed Unit 3

Area	Total N Deposition (kg/ha/yr)	Total S Deposition (kg/ha/yr)
Class I Areas		
Arches NP	0.002	0.003
Bryce Canyon NP	0.001	0.004
Capitol Reef NP	0.002	0.006
Canyonlands NP	0.002	0.004
Zion NP	0.001	0.004
Class II Areas		
Great Basin NP	0.002	0.0046
Glen Canyon NRA	0.002	0.004
NPS DAT	0.005	0.005

7.6 Evaluation of Utah County PM_{10} Nonattainment Area Impacts

IPSC evaluated the Unit 3 project impact on the particulate matter less than 10 microns (PM_{10}) nonattainment area in Utah County pursuant to UAC R307-403. The nonattainment area is located approximately 57 kilometers (km) to the northeast of IPP. The evaluation was performed using the CALPUFF model, which is the Environmental Protection Agency (EPA)-preferred model for transport distances of greater than 50 km. The modeling was conducted without using the chemical transformation capability of CALPUFF, resulting in a very conservative estimate of PM_{10} impacts in Utah County.

IPSC performed preliminary and refined modeling to evaluate the impact of the Unit 3 project on Utah County. Preliminary modeling utilized all but one of the regulatory default settings (other than chemical transformation) within the model. Refined modeling used technical settings within the model that would produce a more accurate estimate of pollutant dispersion and ground-level concentrations in Utah County. The refined modeling results demonstrate that the Unit 3 project will have an insignificant impact on Utah County, i.e. that the impact is less than the “maximum allowable impact” allowed under Utah rules, and far below the “significance level” allowed under the federal rules.

7.6.1 Preliminary Modeling

IPSC used the same three-dimensional meteorological windfield that was developed for the Class I area analysis. Receptors were placed at 1-km spacing along the boundary and interior of the southern one-half of Utah County, as shown in Figure 7-5 1. IPSC modeled emissions of primary PM_{10} and gaseous nitrogen oxides and sulfur dioxide from the proposed Unit 3 stack, as well as PM_{10} emissions from fugitive sources associated with the handling of coal and ash for the Unit 3 project.

An estimate of total PM_{10} impacts consists of the concentrations of primary PM_{10}, gaseous sulfur dioxide, and gaseous nitrogen dioxide summed at each receptor. Nitrogen oxide impacts were multiplied by 0.75, the national default ratio of ambient nitrogen oxide to nitrogen dioxide as listed in the GAQM, to arrive at impacts of nitrogen dioxide.

The results of the preliminary conservative modeling yielded 4 days for which the 24-hour impacts exceeded the Utah "maximum allowable impact" level of 3.0 $\mu g/m^3$ for 24-hour impacts, yet all 4 days were below the federal significance level of 5.0 µg/m3. Annual impacts were well below the Utah "maximum allowable impact" level and federal significance level of 1.0 $\mu g/m^3$.

7.6.2 Selection of Appropriate Refinement

The preliminary analysis made use of the current regulatory default option within CALPUFF for the determination of plume growth, which employs the same dispersion coefficients used with the EPA's Industrial Source Complex Short-Term (ISCST3) model. Specifically, the current default option uses Pasquill-Gifford (PG) coefficients in rural areas and McElroy-Pooler coefficients in urban areas. Using this method, the dispersion coefficients are functions of the distance from the source and six discrete stability classes.

IPSC decided (in consultation with UDAQ) that the use of similarity-based (turbulence-based) dispersion would more accurately represent the behavior expected for conditions of plumes occurring in stable air over a ground-based inversion (based on the detailed examination of the preliminary results obtained when using CALPUFF with PG-based dispersion). The turbulence-based dispersion coefficients include effects of a continuous range of stability, height above ground, and time.

The meteorology, dispersion analysis, and model refinement selection process are summarized in the White Paper entitled *PM_{10} IMPACTS Impacts in the Utah County IN THE UTAH COUNTY PM_{10} Nonattainment Area Using Calpuff and No Chemical Transformation NONATTAINMENT AREA USING CALPUFF AND NO CHEMICAL TRANSFORMATION* submitted by IPA to UDAQ on October 16, 2003.

7.6.3 Refined Modeling

To refine the preliminary Utah County PM_{10} impact modeling, IPSC initiated turbulence-based dispersion modeling in CALPUFF with the following refinements:

- MDISP = 2, to select dispersion coefficients from internally calculated sigmas using micrometeorological variables
- MPDF = 1, to select the Probability Distribution Function method for dispersion in the convective boundary layer

With these refinements to the very conservative CALPUFF setup (due to no chemical transformation), the maximum 24-hour impact in Utah County occurred on Julian Day 361 (JD361), at a modeled impact concentration of 1.94 $\mu g/m^3$, as shown in Figure 7-6. UDAQ requested further refinement to the turbulence-based analysis to include finer resolution on the

CALMET/CALPUFF grid to confirm that the maximum impact with turbulence-based dispersion modeling was adequately resolved.

This UDAQ requested refinement was performed by reducing the CALMET grid spacing from 4 kilometers to 250 meters to allow for a better approximation of puff movement in elevated terrain in and around Utah County. The CALMET domain allowed for a 50-kilometer buffer around the IPP facility and the maximum receptor for the turbulence-based run.

IPSC ran CALMET for the period from 1-week prior to the date (JD 361) that yielded the maximum 24-hour PM_{10} impact through the end of the available data for 1996 with turbulence-based dispersion. This allowed for reduced computational time and output file size, but still allowed for the consideration of all puffs that could influence the maximum result that occurred in late December.

For modeling receptors, the 1-km grid used previously for Utah County was limited to a subset of receptors that fell within the new CALMET domain. The computational grid for CALPUFF was the same as the domain used for CALMET described above, and all other technical approaches for CALMET/CALPUFF/CALPOST were the same as those that were used for previous modeling.

The predicted impact is 0.22 $\mu g/m^3$ on JD 361 at the receptor that yielded the highest result with the 4-kilometer windfield. The predicted impact elsewhere on the receptor grid for JD 361 is as high as 0.28 $\mu g/m^3$, which is well below the maximum allowable impact 3.0 $\mu g/m^3$ on a 24-hour basis. The overall maximum for the 11-day period with the 250-m grid is 1.3 $\mu g/m^3$ on JD 357.

Receptor spacing for the overall maximum was adequate in accordance with UDAQ modeling guidelines. As stated in the UDAQ guidelines:

"In general, the receptor network will be considered adequate if the difference of concentrations at neighboring receptors is no larger than one-half the difference between the maximum modeled concentration and the NAAQS (or increment) under consideration..."

In this case, the maximum difference of concentrations at neighboring receptors is only 0.33 $\mu g/m^3$. One half of the difference between the maximum modeled concentration (1.3 $\mu g/m^3$) and the air quality standard in question (3.0 $\mu g/m^3$) is 0.86 $\mu g/m^3$.

An examination of the wind flow on the day in question (JD 361) reveals that the 250-m windfield more accurately captures the flow around the large terrain features of the Tintic mountain range to the northeast of IPP. With the 4-km windfield on this day, the wind flow was persistently toward Utah County despite the presence of the prominent high terrain along the path. These grid refinements more accurately predict increased turbulence due to intervening terrain under wind conditions that produce the highest predicted Utah County PM_{10} impacts.

The overall analysis, including refinements, demonstrates that the predicted impacts for IPP Unit 3 are comfortably below Utah's 3 $\mu g/m^3$ "maximum allowable impact" threshold, and well below EPA's 5 $\mu g/m^3$ "significance level" for PM_{10} nonattainment areas.

Isopleths of the 24-hour average concentrations for JD362 (which come from the preceeding 24 hours) were generated for the 250-meter grid (see Figure 7-7). As can be seen, the maximum concentration occurs nearly 40 kilometers southwest of the Utah County boundary. It should be noted that these concentration contours are based on the concentrations that occur on the regularly spaced gridded receptors, which are a grid with a 250-meter spacing. Comparing Figures 7-6 and 7-7, it can be seen that the area of maximum concentrations occurs where the plume first encounters complex terrain. The high concentrations at these locations are due to the enhanced dispersion caused by the terrain effects on the wind field. The 250-meter grid allows for a better treatment of intervening terrain between the site and Utah County. This intervening terrain would result in increased turbulence during times when winds blow from the site towards Utah County. As there is intervening complex terrain for all possible paths from IPP3 to Utah County, this same lowering of concentrations from the 4-kilometer grid to the 250-meter grid are expected. Finally, it should be noted that every time the modeling has been refined to more accurately represent the wind fields and dispersion the maximum 24-hour concentration has decreased. This is not unexpected given the distance (≥57 kilometers) and terrain that occur between IPP3 and Utah County.

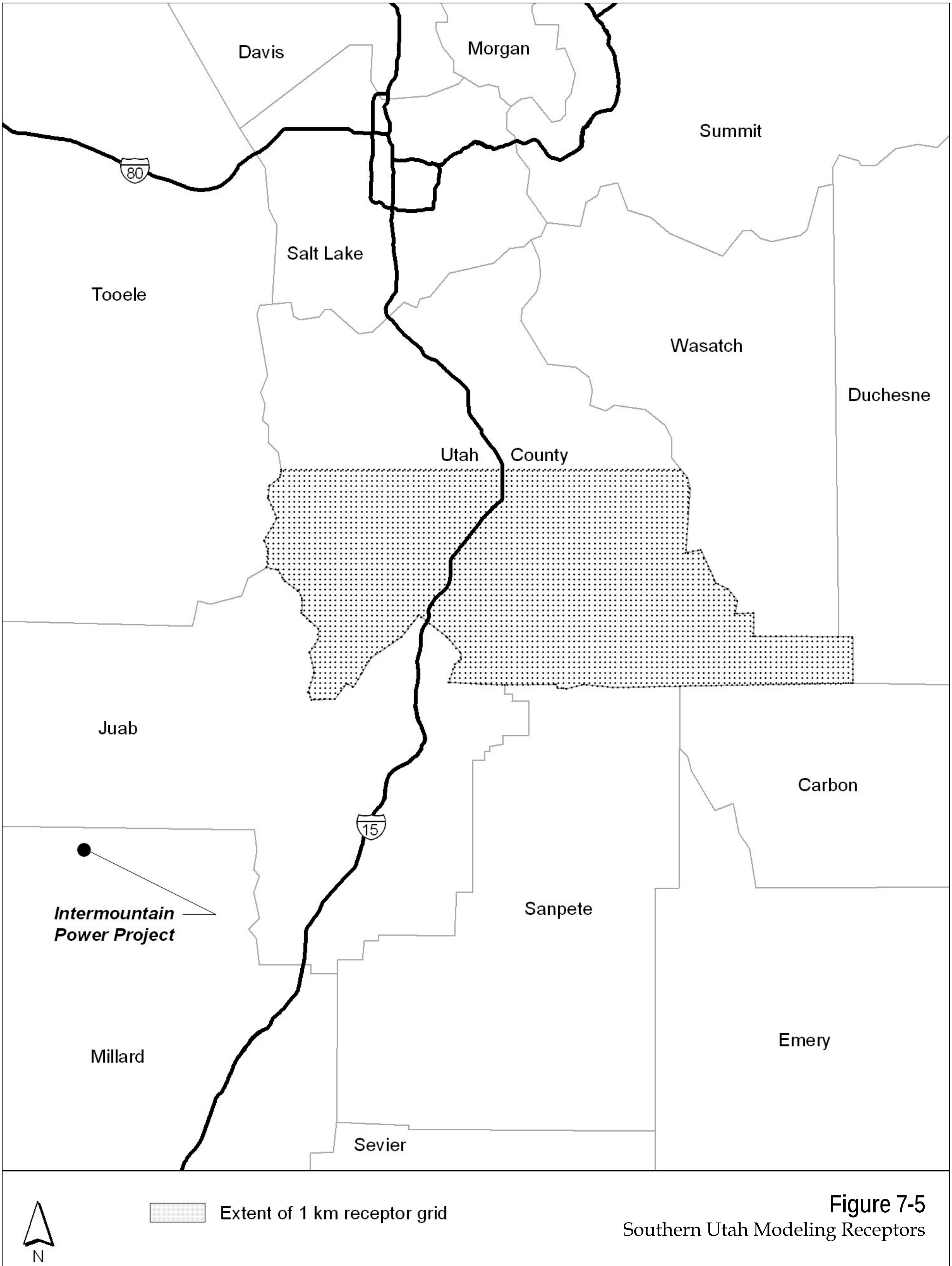


Figure 7-5
Southern Utah Modeling Receptors

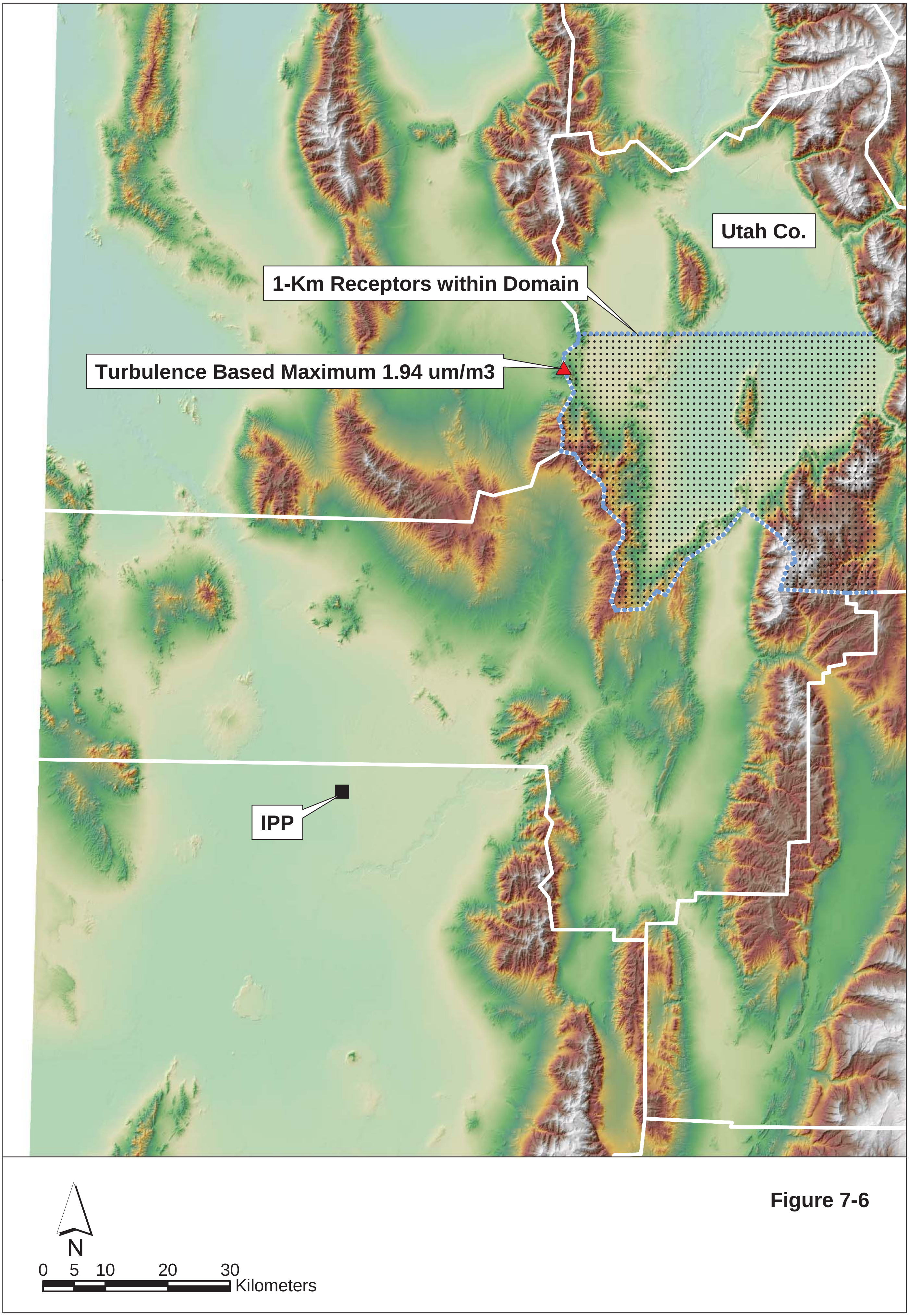
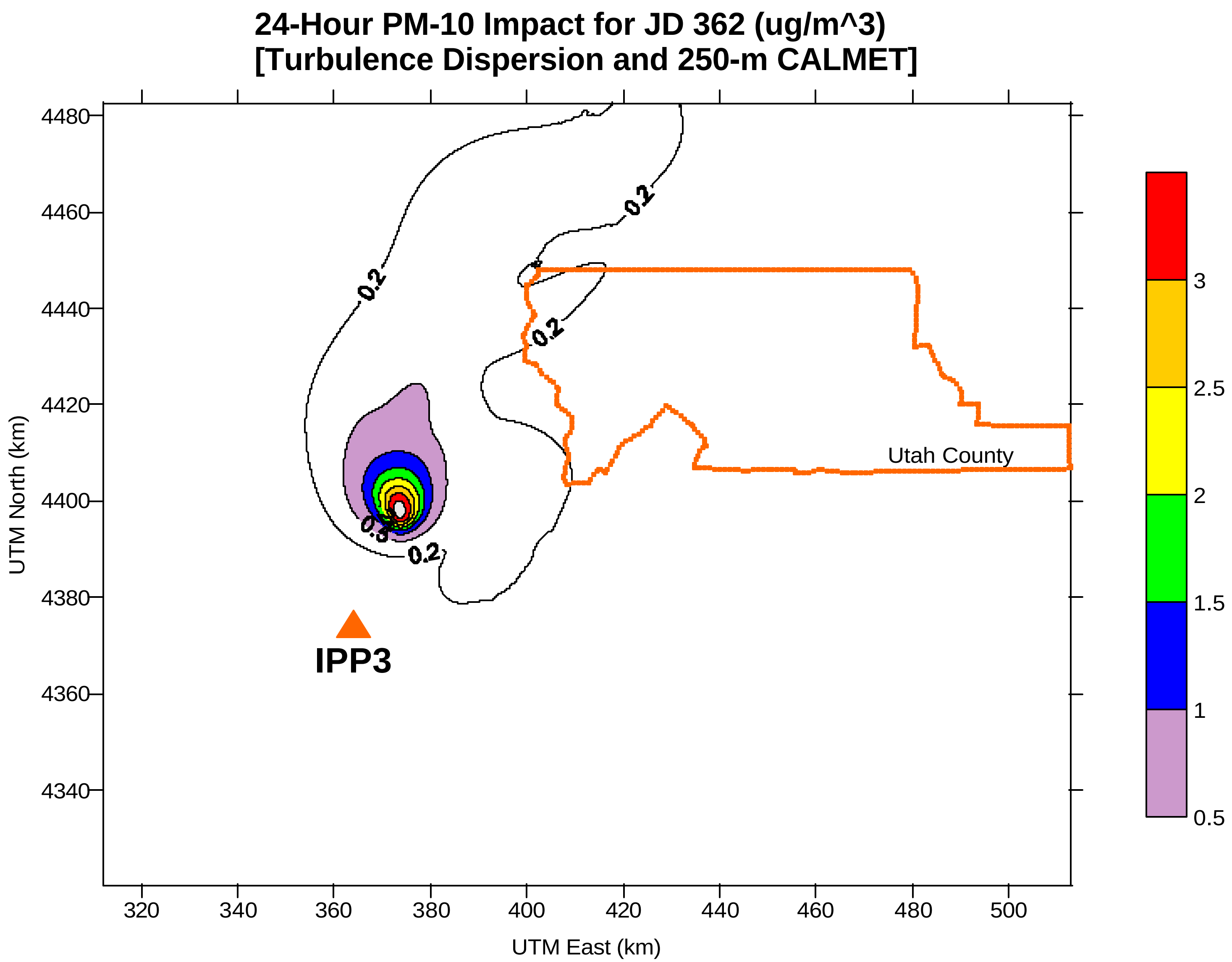

Utah Co.
1-Km Receptors within Domain
Turbulence Based Maximum 1.94 um/m3
IPP
N
0 5 10 20 30
Kilometers

Figure 7-6


24-Hour PM-10 Impact for JD 362 (ug/m^3)
[Turbulence Dispersion and 250-m CALMET]
4480
4460
4440
4420
4400
4380
4360
4340
320
340
360
380
400
420
440
460
480
500
UTM North (km)
UTM East (km)
0.2
0.2
0.2
0.2
0.3
IPP3
Utah County
3
2.5
2
1.5
1
0.5

7.7 References

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Manson, 2003. A letter from Craig Manson, Assistant Secretary of Interior for Fish, Wildlife and Parks to Ms. Jan Sensibaugh, Director of the Montana Department of Environmental Quality, January 10, 2003.

NPS, 2002. *Guidance on Nitrogen and Sulfur Deposition Analysis Thresholds.* National Park Service Air Resources Division, Denver, Colorado. January 2002.

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8.0 Near-Field Dispersion Modeling Analysis

This section presents a description of the near-field AQIA that was conducted for the proposed Unit 3.

8.1 Project Overview

CH2M HILL conducted an air quality modeling analysis as part of this NOI. This section describes the modeling analysis for the Class II areas that are within 50 km of the IPP. The modeling analysis that was conducted for distant Class I and Class II areas located more than 50 km from the IPP is described in Section 7 of this document. Representatives of IPA andCH2M HILL met with UDAQ personnel on January 25, 2002 for a discussion of the near-field Class II modeling requirements for the project. A Class II area modeling protocol was presented to the UDAQ on February 15, 2002, and a letter dated February 27, 2002 indicating approval of the protocol was sent from UDAQ to IPA. A copy of the UDAQ Air Quality Modeling Checklist is included in Appendix E.

8.2 Project Description

The IPP is located in the Sevier Desert in western Utah, approximately 13 miles north of the town of Delta, Utah. The plant is at an approximate elevation of 4,675 feet (1,425 meters) above mean sea level (msl). The highest terrain within 40 km of the IPP is located in the Canyon Mountain Range, approximately 30 km to the east of the plant. Fool Creek Peak in the Canyon Mountains reaches an elevation of 9,717 feet msl. Figure 8-1 shows the terrain adjacent to the IPP.

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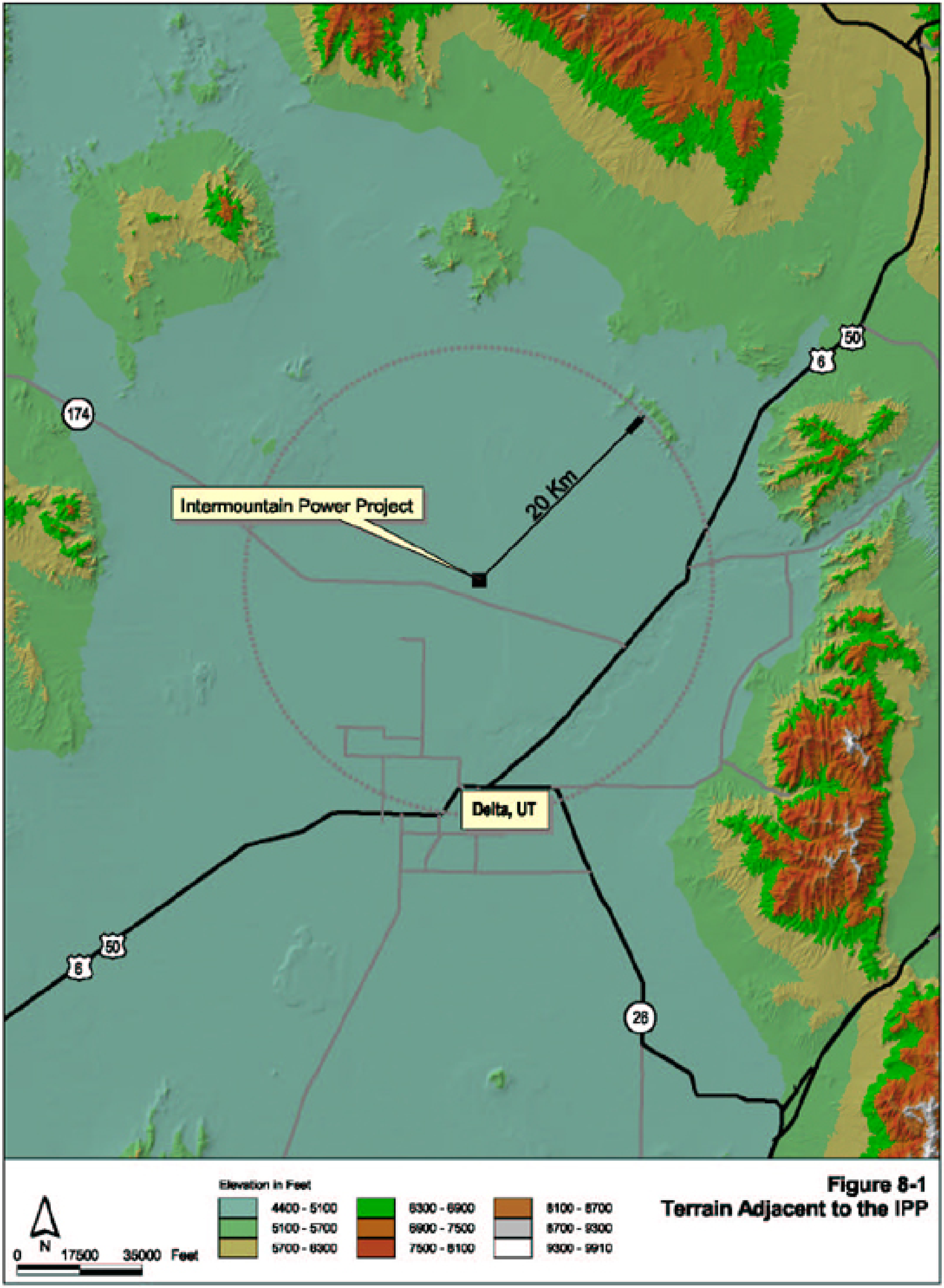

Figure 8-1
Terrain Adjacent to the IPP

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8.3 Source Designation

The proposed project will constitute a major modification to a major stationary source with respect to the PSD rules established under the federal NSR program. The existing IPP belongs to one of the 28 categorical sources listed under PSD and UDAQ regulations for which the major source threshold is 100 tpy of any regulated pollutant (fossil-fuel boilers, combinations thereof, totaling more than 250 MMBtu per hour heat input). The goals of the air quality modeling analysis were to demonstrate compliance with state and federal air quality regulations that are applicable to the proposed project.CH2M HILL performed a dispersion modeling analysis, summarized in Table 8-1, for each criteria pollutant proposed to have a significant net emission increase under PSD regulations. Table 8-2 summarizes the modeling significance levels, PSD increments, and air quality standards that apply to criteria pollutant emissions from the project.

TABLE 8-1
Emissions Levels that Trigger Requirements for Dispersion Modeling

Pollutant	PSD Significant Emission Rates (tpy)
CO	100
NO_X	40
SO_2	40
PM/PM_{10}	25/15 (5 for fugitive PM_{10} emissions per UDAQ guidance)
Lead	0.6

TABLE 8-2
Air Quality Standards Applicable to the Project

Averaging Period/ Pollutant	Class II Modeling Significance Level ($\mu g/m^3$)	Class II PSD Increment ($\mu g/m^3$)	Class I PSD Increment ($\mu g/m^3$)	Significant Monitoring Concentrations ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)
Annual NO_2	1 (NO_X)	25	2.5	14	100
3-hour SO_2	25	512[a]	25 [a]	NS	1,300[a]
24-hour SO_2	5	91[a]	5[a]	13	365[a]
Annual SO_2	1	20	2	NS	80
24-hour PM_{10}	3[b]	30[a]	8[a]	10	150[a]
Annual PM_{10}	1	17	4	NS	50
Lead	NS	NS	NS	0.1[c]	1.5[c]
1-hour CO	2,000	NS	NS	NS	40,000[a]
8-hour CO	500	NS	NS	575	10,000[a]

[a] Not to be exceeded more than once per year.

[b] UDAQ requirement. PSD level set at 5 $\mu g/m^3$.

[c] quarterly

8.4 Area Classifications

The IPP is located in Millard County, Utah. The proposed project is in an area that is designated as attainment for all criteria pollutants. The surrounding areas are designated as Class II areas for PSD permitting.

8.5 Baseline Dates

8.5.1 Major Source Baseline Date

The major source baseline date is the date after which actual emissions associated with construction at any major stationary source affect the available PSD increment. The major source baseline dates are established dates that have passed. These dates are as follows:

- PM_{10}—August 17, 1979
- SO_2—August 17, 1979
- NO_2—April 21, 1988

8.5.2 Minor Source Baseline Date

The minor source baseline date identifies the point in time after which actual emissions changes from all sources (major and minor) affect available increment. The amount of PSD increment consumption within an area is determined from the actual emission increases and decreases that have occurred since the applicable baseline date. The minor source baseline dates are as follows:

- PM_{10}—April 1, 1990
- SO_2—April 1, 1990
- NO_2—April 21, 1988

8.6 Model Selection

CH2M HILL used the EPA Industrial Source Complex Short-Term (ISCST3) dispersion model to evaluate Class II air quality impacts. The ISCST3 model (Version 02305) is the latest generation of the EPA's ISC short-term model that is recommended for predicting impacts from industrial point sources as well as area and volume sources. The model combines simple terrain and complex terrain algorithms, which make it ideal for the terrain surrounding the IPP.

8.7 Model Input Defaults and Options

The ISCST3 model was used with regulatory default options as recommended in the EPA *Guideline on Air Quality Models* (EPA, 2000a) as listed below:

- Use stack-tip downwash (except for Schulman-Scire downwash)
- Use buoyancy-induced dispersion (except for Schulman-Scire downwash)
- Do not use gradual plume rise (except for building downwash)

- Use the calm processing routines
- Use upper-bound concentration estimates for sources influenced by building downwash from super-squat buildings
- Use default wind profile exponents
- Use default vertical potential temperature gradients

CH2M HILL used the ISCST3 model option for processing missing meteorological data. By using the missing data processing routine, the model can recognize the periods of missing data and adjust calculated impacts in the same manner that calm winds are processed.

Open land surrounds IPP in all directions, with no significant development. Therefore, rural dispersion coefficients were utilized within the ISCST3 model.

CH2M HILL initially assumed that modeled emissions of NO_X will convert completely to NO_2. If this assumption had led to predicted exceedances of any air standards, the national default factor of 0.75 for NO_2/NO_X would have been applied to the predicted impacts to estimate NO_2 concentrations.

Point sources were modeled with stack heights that do not exceed GEP stack height. Building downwash effects for point sources (including cooling tower cells) were determined with the EPA Building Profile Input Program (BPIP, version 95086). Figure 8-2 shows the downwash structures at the IPP.

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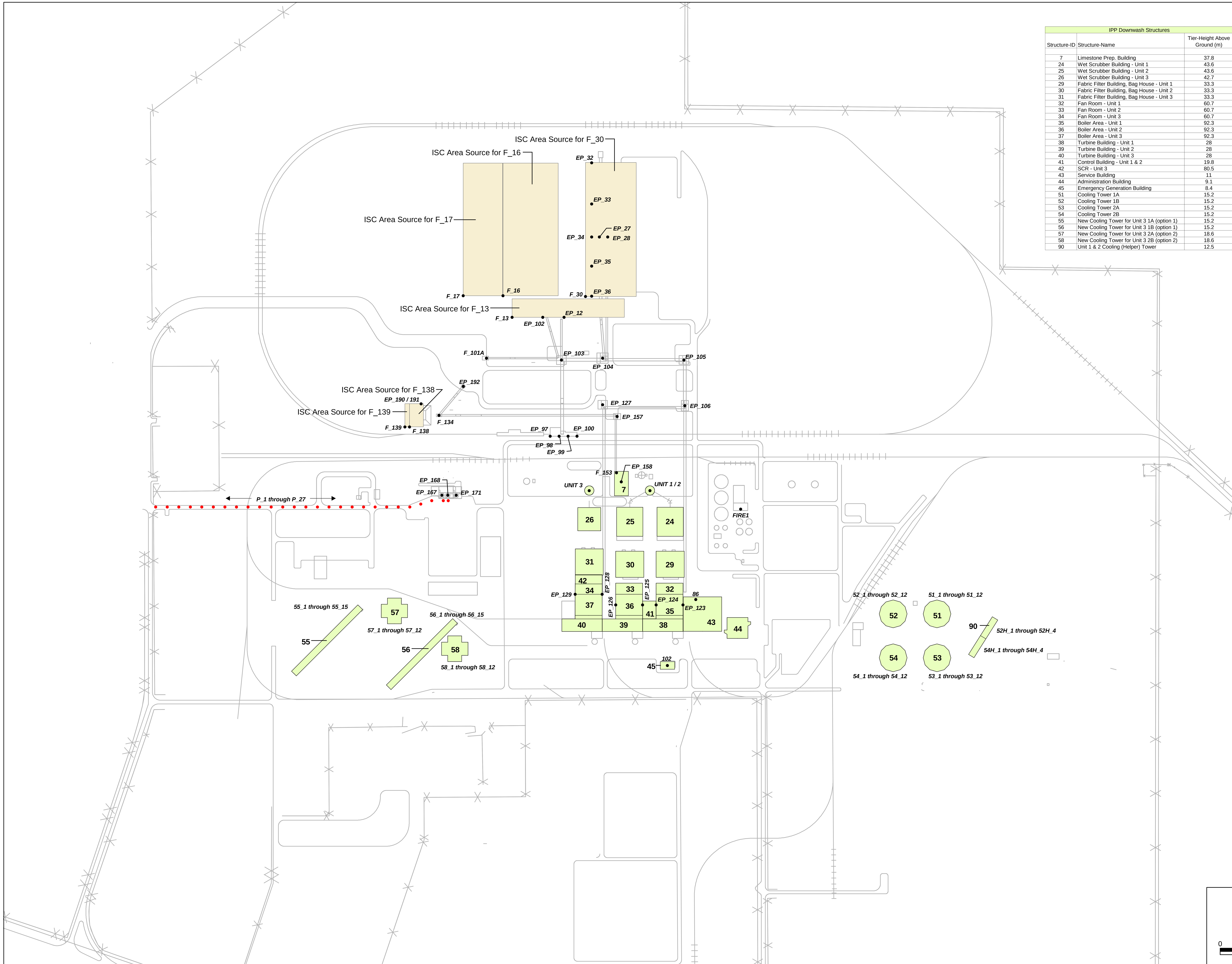

IPP Downwash Structures		
Structure-ID	Structure-Name	Tier-Height Above Ground (m)
7	Limestone Prep. Building	37.8
24	Wet Scrubber Building - Unit 1	43.6
25	Wet Scrubber Building - Unit 2	43.6
26	Wet Scrubber Building - Unit 3	42.7
29	Fabric Filter Building, Bag House - Unit 1	33.3
30	Fabric Filter Building, Bag House - Unit 2	33.3
31	Fabric Filter Building, Bag House - Unit 3	33.3
32	Fan Room - Unit 1	60.7
33	Fan Room - Unit 2	60.7
34	Fan Room - Unit 3	60.7
35	Boiler Area - Unit 1	92.3
36	Boiler Area - Unit 2	92.3
37	Boiler Area - Unit 3	92.3
38	Turbine Building - Unit 1	28
39	Turbine Building - Unit 2	28
40	Turbine Building - Unit 3	28
41	Control Building - Unit 1 & 2	19.8
42	SCR - Unit 3	80.5
43	Service Building	11
44	Administration Building	9.1
45	Emergency Generation Building	8.4
51	Cooling Tower 1A	15.2
52	Cooling Tower 1B	15.2
53	Cooling Tower 2A	15.2
54	Cooling Tower 2B	15.2
55	New Cooling Tower for Unit 3 1A (option 1)	15.2
56	New Cooling Tower for Unit 3 1B (option 1)	15.2
57	New Cooling Tower for Unit 3 2A (option 2)	18.6
58	New Cooling Tower for Unit 3 2B (option 2)	18.6
90	Unit 1 & 2 Cooling (Helper) Tower	12.5

Sources		
Source ID	Description	Release Height (m)
UNIT1	Unit 1 Stack	217.0
UNIT2	Unit 2 Stack	217.0
UNIT3	Unit 3 Stack	217.0
102	Emergency Generator	12.5
86	Aux Boiler	17.1
FIRE1	Fire Pump Engine	12.2
New Unit 3 Coal Handling Sources		
EP_127	Emissions from dust collection system exhaust fan - Transfer Building #5	3.4
EP_128	Emissions from dust collection system exhaust fan - Unit 3 East Silo Bay	50.3
EP_129	Emissions from dust collection system exhaust fan - Unit 3 West Silo Bay	50.3
F_101A	Fugitives from Coal Truck Unloading	1.5
EP_101B	Emissions from dust collection system exhaust fan -Coal Truck Unloading	2.4
Modified Coal Handling Sources		
EP_12	Emissions from transfer of coal from Stockout Conveyor C-3 to Reserve Coal Stockout Pile	19.2
EP_27	Emissions from transfer of coal from Conveyor C-6 to Stacker Conveyor.	20.4
EP_28	Emissions from transfer of coal from Stacker Conveyor to Active Storage PilePile	18.9
EP_32	Emissions from transfer of coal from the Active Coal Storage Pile to Conveyor C-7 by Rotary Plow Feeders 7A, 7B, 7C and 7D and transfer from Conveyor C-7 to C-8	1.8
EP_33	Emissions from transfer of coal from the Active Coal Storage Pile to Conveyor C-7 by Rotary Plow Feeders 7A, 7B, 7C and 7D and transfer from Conveyor C-7 to C-8	1.8
EP_34	Emissions from transfer of coal from the Active Coal Storage Pile to Conveyor C-7 by Rotary Plow Feeders 7A, 7B, 7C and 7D and transfer from Conveyor C-7 to C-8	1.8
EP_35	Emissions from transfer of coal from the Active Coal Storage Pile to Conveyor C-7 by Rotary Plow Feeders 7A, 7B, 7C and 7D and transfer from Conveyor C-7 to C-8	1.8
EP_36	Emissions from transfer of coal from the Active Coal Storage Pile to Conveyor C-7 by Rotary Plow Feeders 7A, 7B, 7C and 7D and transfer from Conveyor C-7 to C-8	1.8
EP_97	Emissions from dust collection system exhaust Fans 1A, 1B, 1C and 1D - Coal Car Unloading Building	3.1
EP_98	Emissions from dust collection system exhaust Fans 1A, 1B, 1C and 1D - Coal Car Unloading Building	3.1
EP_99	Emissions from dust collection system exhaust Fans 1A, 1B, 1C and 1D - Coal Car Unloading Building	3.1
EP_100	Emissions from dust collection system exhaust Fans 1A, 1B, 1C and 1D - Coal Car Unloading Building	3.1
EP_102	Emissions from dust collection system exhaust fan -Reserve Reclaim Hopper	2.4
EP_103	Emissions from dust collection system exhaust fan -Transfer Building 1	3.4
EP_104	Emissions from dust collection system exhaust fan -Transfer Building 2	3.4
EP_105	Emissions from dust collection system exhaust fan-Transfer Building 4	3.4
EP_106	Emissions from dust collection system exhaust fan - Crusher Building 1	3.4
Units 1 and 2 Coal Handling Sources		
EP_123	Emissions from dust collection system 13A exhaust fan - Unit 1 East Silo Bay	50.3
EP_124	Emissions from dust collection system 13B exhaust fan - Unit 1 West Silo Bay	50.3
EP_125	Emissions from dust collection system 14A exhaust fan - Unit 2 East Silo Bay	50.3
EP_126	Emissions from dust collection system 14B exhaust fan - Unit 2 West Silo Bay	50.3
New Unit 3 Fly Ash Handling Sources		
EP_171	Emissions from sealed loading spout vent filter - Fly Ash Storage Silo 1C	7.6
EP_172	Emissions from silo vent filter-Fly Ash Storage Silo 1C	36.6
Units 1 and 2 Fly Ash Handling Sources		
EP_167	Emissions from sealed loading spout vent filter - Fly Ash Storage Silo 1A	7.6
EP_168	Emissions from sealed loading spout vent filter - Fly Ash Storage Silo 1B	7.6
EP_169	Emissions from silo vent filter-Fly Ash Storage Silo 1A	36.6
EP_170	Emissions from silo vent filter-Fly Ash Storage Silo 1B	36.6
Units 1 and 2 Limestone Handling Sources		
EP_190/191	Fugitives from transfer of limestone from Truck to Limestone Storage Pile	1.5
EP_192	Emissions from transfer of limestone from Truck to Hopper in Limestone Truck Unloading Building	1.5
F_134	Emissions from transfer of limestone from Conveyor L-1 to Limestone Silo	9.1
F_153	Fugitives from transfer of limestone from Front Loader to Bucket Elevator	1.5
EP_155	Emissions from dust collection system exhaust fan- Limestone Truck Unloading Hopper.	2.4
EP_156	Emissions from dust collection system exhaust fan- Limestone Reclaim Hopper.	2.4
EP_157	Emissions from dust collection system exhaust fan- Limestone Crusher Building.	11.6
EP_158	Emissions from dust collection system exhaust fan- Limestone Preparation Building.	37.8
Area Sources		
F_13	Unit 1 & 2 Emergency Stackout Coal Storage Pile	12.8
F_16	Unit 1 & 2 Long Term Reserve Coal Storage Pile	9.1
F_17	Unit 3 addition to Long Term Reserve Coal Storage Pile	9.1
F_30	Active Coal Storage Pile	12.2
F_139	Unit 3 Reserve Limestone Storage Pile	6.1
F_138	Units 1 and 2 Reserve Limestone Storage Pile	6.1
Cooling Towers		
55_1 through 55_15	New Cooling Tower for Unit 3A (rect)	15.3
56_1 through 56_15	New Cooling Tower for Unit 3B (rect)	15.3
57_1 through 57_12	New Cooling Tower for Unit 3A (cross)	18.5
58_1 through 58_12	New Cooling Tower for Unit 3B (cross)	18.5
51_1 through 51_12	Cooling Tower 1A	15.2
52_1 through 52_12	Cooling Tower 1B	15.2
53_1 through 53_12	Cooling Tower 2A	15.2
54_1 through 54_12	Cooling Tower 2B	15.2
52H_1 through 52H_4	Cooling Tower 1C (helper)	14.6
54H_1 through 54H_4	Cooling Tower 2C (helper)	14.6
Paved Haul Roads		
P_1 through P_27		2.0

IPP Unit 3 Project

Figure 8-2
IPP Plot Plan

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8.8 Modeling Receptors

8.8.1 Receptor Configuration

The base receptor grid for ISCST3 modeling consisted of receptors placed at the ambient air boundary, and Cartesian-grid receptors placed beyond the boundary at spacing that increases with distance from the origin. Ambient boundary receptors were placed at 100-meter (m) intervals. Beyond the ambient boundary, receptor spacing was as follows:

- 100 m spacing from property boundary to 1 km from the origin
- 250 m spacing from beyond 1 km to 3 km from the origin
- 500 m spacing from beyond 3 km to 20 km from the origin
- 1,000 m spacing from beyond 20 km to 50 km from the origin

CH2M HILL supplemented the base receptor grid with receptors at closer (tighter) receptor spacing, where appropriate, to ensure that the maximum points of impact have been identified, in accordance with UDAQ modeling guidelines, as described later in this document.

8.8.2 Receptor Elevations

Terrain in the vicinity of IPP was accounted for by assigning elevations to each modeling receptor.CH2M HILL used the DEM data from the USGS to determine receptor elevations. We obtained DEM data from the USGS national elevation dataset (NED). The NED has been developed by merging the highest-resolution, best-quality elevation data available across the United States, and is the result of the maturation of the USGS effort to provide 1:24,000-scale (7.5-minute) DEM data for the entire continental United States.

8.9 Meteorological Input Data

8.9.1 Meteorological Data for Class II Area Modeling

CH2M HILL used data collected from a meteorological monitoring station at the IPP for modeling Class II air quality impacts. Data from the IPP station meet all EPA requirements for being representative of the site. According to the EPA's *Guideline on Air Quality Models* (EPA, 2000a), whether the meteorological data used in dispersion modeling is representative depends on the following factors:

- proximity of the meteorological monitoring site to the area under consideration
- complexity of the terrain
- exposure of the meteorological monitoring site
- period of time during which data are collected

The monitoring station is located within the IPP facility boundary. Terrain surrounding the station consists primarily of farm and ranch fields in flat terrain. The site is well exposed, with no influence from obstructions such as trees or buildings. The period of record represented by the data is the most current, as the continuous collection of valid meteorological data began at the IPP station on July 19, 2001. A full calendar year of data was used for the modeling, spanning from August 1, 2001 to July 31, 2002.

8.9.1.1 Data Collection and QA

IPA installed the meteorological monitoring station at the IPP in accordance with EPA and UDAQ guidelines, as described in the document *Meteorological Monitoring and Quality Assurance Plan for the Intermountain Power Service Company 1000 Megawatt Coal-Fired Power Generation Unit* (MSI, 2001). The station is located approximately 1.5 miles west of the Units 1 and 2 stack and just west of the plant water reservoir. The site is in flat terrain with no tall structures nearby. Equipment specifications and QC procedures meet EPA and UDAQ criteria for PSD-quality monitoring. Performance audits of the meteorological instruments are conducted on a semi-annual schedule, and monthly data reports and QA audit reports are submitted to UDAQ.

A Campbell Scientific data acquisition system (DAS) is used to store data from the sensors. The sampling frequency is set at 1 second for the parameters that were used for dispersion modeling, and data are stored as 15-minute and 60-minute averages, as computed from the 1-second samples. The monitoring system is maintained to keep data recovery for meteorological parameters at or above 90 percent per calendar quarter.

Wind speed and wind direction are measured at the 10-m and 50-m levels on the IPP meteorological tower, while temperature is collected at the 2-m, 10-m, and 50-m levels. Total solar radiation is measured at the 2-m level.

8.9.1.2 Data Processing

The onsite meteorological data was processed using the Meteorological Processor for Regulatory Models (MPRM, version dated 99349) developed by EPA.

8.9.1.3 Wind Speed and Wind Direction

In dispersion modeling, wind speed is used in determining plume rise and plume dilution. Wind direction is used to approximate the direction of plume transport.CH2M HILL used the mean scalar wind speed and unit-vector wind direction from the 50-m level on the IPP meteorological tower to model all sources with release heights of 20 m or more. The mean scalar wind speed and unit-vector wind direction from the 10-meter level were used to model sources with release heights of less than 20 m. Figure 8-3 presents a wind rose for the 50-m wind speed and wind direction data collected from August 1, 2001 through July 31, 2002, and Figure 8-4 presents a wind rose for the 10-m level for the same period.

8.9.1.4 Stability Class

Dispersion models such as ISCST3 use stability categories as indicators of atmospheric turbulence. The categories used in many EPA models range from very unstable to stable. Stability categories for the proposed Unit 3 analysis were determined using the solar radiation/delta-T (SRDT) method, which is the EPA's preferred method when site-specific meteorological data are available, but site-specific cloud cover observations are not available. The SRDT method uses the 10-m wind speed in combination with either total solar radiation during the day, or a temperature difference at night.CH2M HILL used the temperature difference between 2 m and 50 m for the nighttime SRDT calculations within MPRM. For hours with missing data that prevent the use of the SRDT method, the Sigma-A (Sigma Theta) method was used as an alternate method. The Sigma Theta method is a turbulence-based method using the standard deviation of the wind direction in combination with the scalar mean wind speed.

8.9.1.5 Temperature

Temperature data was taken from the 50-m level of the onsite tower. Although formal EPA monitoring guidance (EPA, 2000b) recommends monitoring of ambient temperature at 2 m above ground, the EPA does not prohibit monitoring of temperature at a higher elevation more representative of meteorological conditions at the IPP stack top (50 m above ground).

8.9.1.6 Treatment of Calms

The ISCST3 model was executed with the calms processing option. Periods of calm winds are identified in the meteorological data processing by defining a threshold wind speed (0.22 meters per second for the onsite data). If the recorded wind speed is less than the threshold wind speed, the wind speed for that given hour is reset (and wind direction adjusted) to reflect a value that the model will recognize as a period of calm wind.

8.9.2 Upper Air Data

Twice-daily mixing heights to couple with the onsite surface data were obtained through the use of raw Balloon Release (RAOB) data from the Salt Lake City NWS station, and the EPA Mixing Heights program. Missing values were substituted based on season of the year, from the EPA document *Mixing Heights, Wind Speeds, and Potential for Urban Air Pollution throughout the Contiguous United States* (EPA, 1972).

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FIGURE 8-3
50-Meter Wind Rose

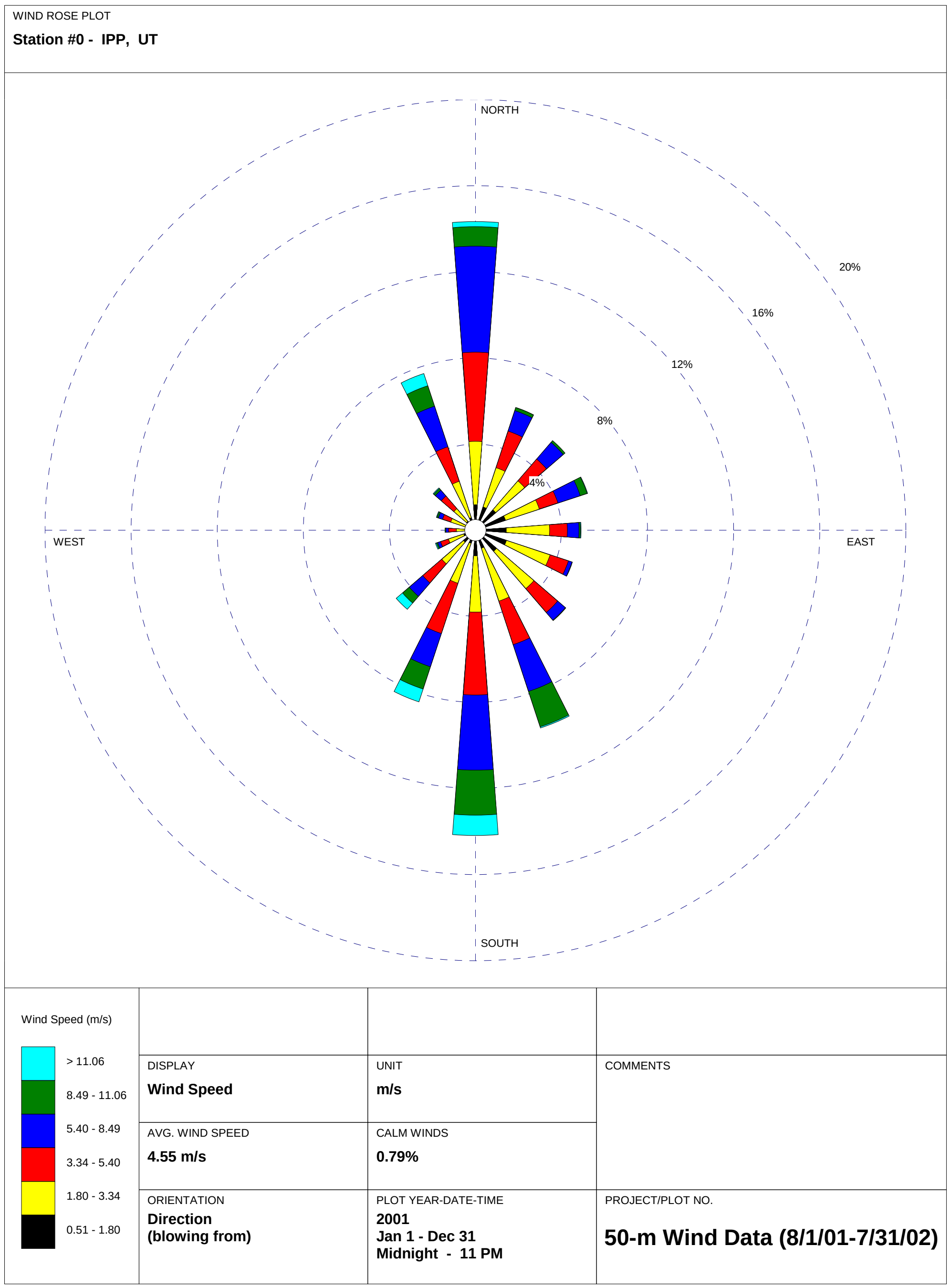

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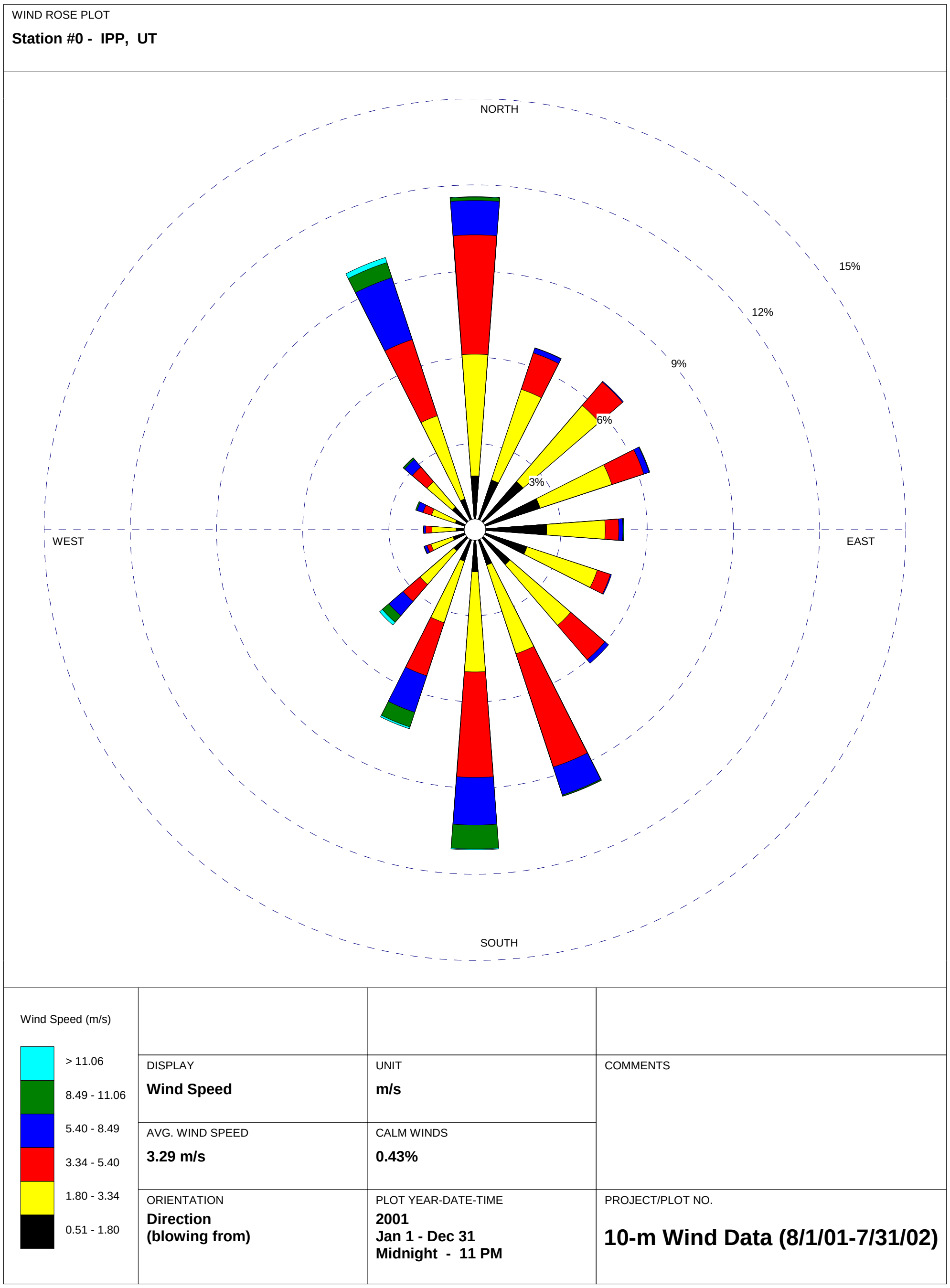
FIGURE 8-4
10-Meter Wind Rose



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8.10 Emission Source Characterization

8.10.1 Point Sources

The proposed Unit 3 and existing Units 1 and 2 were modeled as a point source within ISCST3, as were other existing equipment such as emergency generators. Cooling tower cells were modeled as a series of point sources.

8.10.2 Area Sources

Fugitive emissions from storage piles were modeled as area sources within ISCST3. Area source length and width approximated the actual dimensions of the piles. The area sources were elevated at heights that represents two-thirds of the average heights of the piles (per UDAQ guidance).

8.10.3 Volume Sources

In general, material handling sources were modeled as volume sources within ISCST3. The fugitive emissions from haul roads were modeled as a series of volume sources. Volume source parameters for the haul roads were taken in part from the EPA document *Modeling Fugitive Dust Impacts from Surface Coal Mining Operations – Phase II Model Evaluation Protocol* (EPA, 1994). The source height of the haul road volume sources was 2 m, as based on the statement from the EPA document that the maximum mass flux from haul road dust plumes occurs at that height. Initial vertical dispersion terms (3 m) for the haul road volumes were also taken from the EPA document. The initial horizontal dispersion terms were calculated from the separation distance of the volume sources (two road widths), in accordance with recommendations in the *User's Guide for the Industrial Source Complex (ISC3) Dispersion Models, Volume I – User Instructions* (EPA, 1995). Initial horizontal dimensions for the volume sources were determined from Table 3-1 in the ISC3 User's Guide using the factor for a "line source represented by separated volume sources."

8.11 Source Locations and Parameters

The point, area, and volume sources were placed where operations for the IPP facility dictate. Material transfer volume sources were elevated at an appropriate height representative of the actual release height of the source. Material transfer volume sources were modeled with initial dimensions that represent a 12-m by 12-m plume for each source.

Figure 8-2 (map pocket) shows the general layout of the IPP area, and the location of the various modeled sources. Figure 8-5 shows the configuration of the ambient boundary for the IPP and the sources located away from the main IPP power block.

8.12 Preliminary Analysis

For a preliminary analysis of impacts from the proposed Unit 3, CH2M HILL compared the maximum model-predicted impacts from the sources associated with proposed Unit 3 to the modeling significance levels for Class II areas. These Class II ambient air quality significant impact levels (SIL's) are codified at 40 CFR 51.165. If the predicted impacts for a given pollutant were below the modeling significance levels, no further analysis was conducted for that pollutant. This is pursuant to EPA guidance as contained in the 1990 draft New Source Review Workshop Manual. The manual on page C-30 states "[i]n the event that the maximum ambient impact of a proposed emissions increase is below the appropriate ambient air quality significance level for all locations and averaging times, a full impact analysis for that pollutant is not required by EPA. Consequently, a preliminary analysis which predicts an insignificant ambient impact everywhere is accepted by EPA as the required air quality analysis (NAAQS and PSD increments) for that pollutant."

Conversely, if the predicted impacts equaled or exceeded the significance levels for any pollutant, CH2M HILL conducted a full impact analysis for compliance with the NAAQS and PSD increments pursuant to EPA guidance. The determination of preliminary impacts for the proposed project sources was made using the highest modeled impact for each pollutant and averaging period. The results of the preliminary analysis for each pollutant are contained in the following sections.

Sources associated with the proposed Unit 3 include the main stack, the cooling towers, and sources associated with the handling of coal and other materials.

8.12.1 Screening Analysis for Unit 3

CH2M HILL began the proposed Unit 3 preliminary analysis by performing a screening analysis of the Unit 3 boiler at various operating conditions. Operation at full load and at selected reduced loads (75 percent and 50 percent) were evaluated to determine which operating condition produced the worse-case predicted impacts for short-term averaging periods. This screening analysis was performed in accordance with guidance found in Section 9.1 of Appendix W of 40 CFR Part 51 (EPA, 2000a). The load condition that yielded the highest impacts for a particular pollutant/averaging period was used to represent the proposed Unit 3 in subsequent modeling analyses.

The proposed Unit 3 boiler will have the capability to operate at 105-percent load. Emissions from this 105-percent load condition are higher than those associated with 100-percent load, and therefore the 105-percent load emissions were modeled under the "full" load scenario. The exit velocity associated with the 105-percent load condition is also higher than the 100-percent load case. To be conservative, the 100-percent load exit velocity was used to model "full" load. Table 8-3 presents the exhaust characteristics for the Unit 3 screening analysis. Table 8-4 presents the results of the analysis. Operation at full load yielded the highest impacts for all pollutants and all short-term averaging periods, and therefore, full load was used to represent the proposed Unit 3 in all subsequent modeling analyses. Annual impacts were predicted assuming full load.

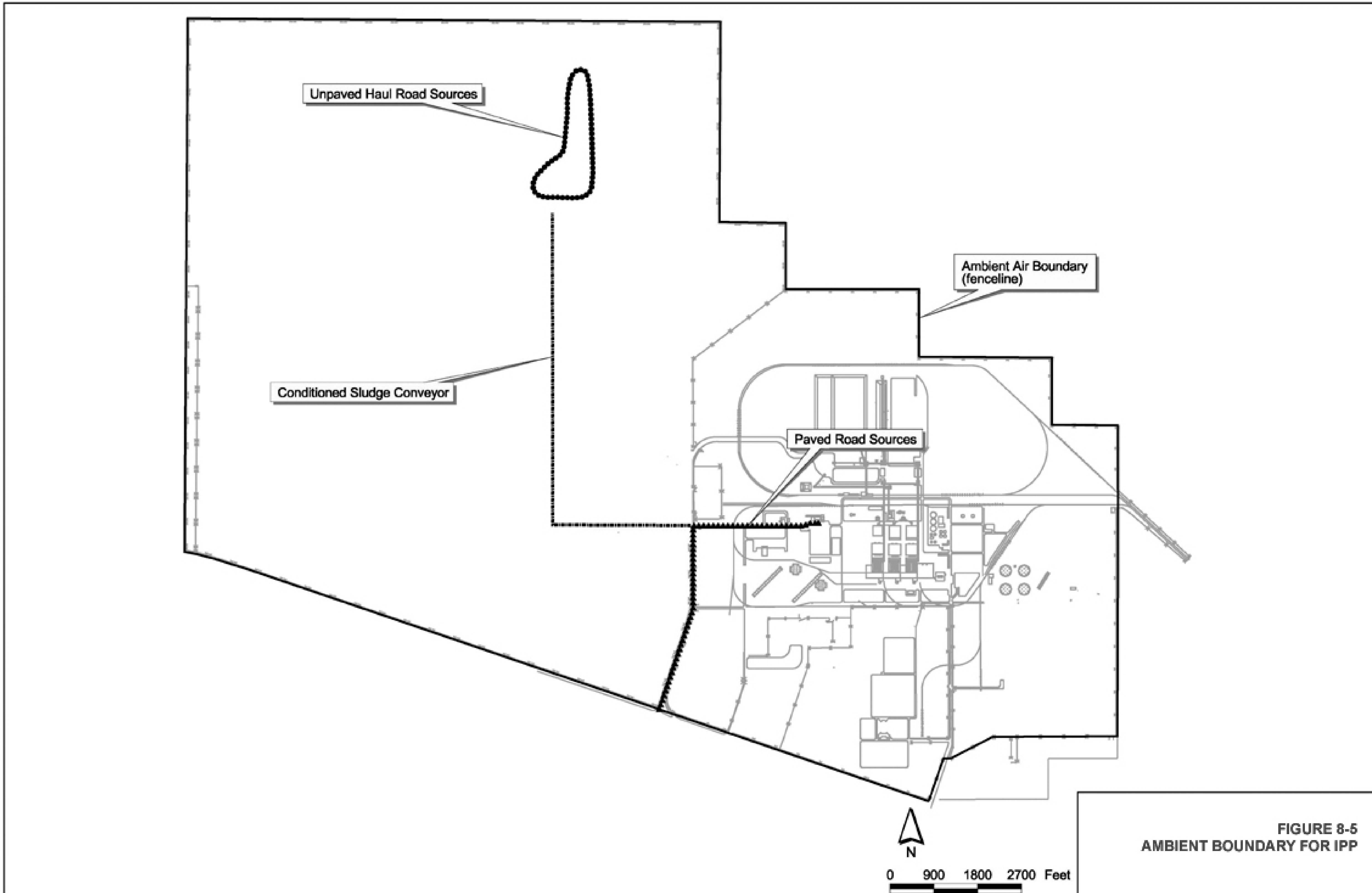

FIGURE 8-5
AMBIENT BOUNDARY FOR IPP

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TABLE 8-3
Input Parameters for Proposed Unit 3 Load Screening

Parameter	Full Load	75% Load	50% Load
Exit Velocity (m/s)	19.8	15.1	10.3
Exhaust Temperature (K)	330.4	330.4	330.4
SO_2 Emissions (g/s)	114.0	83.1	56.6
PM_{10} Emissions (g/s)	53.7	39.2	26.7
CO Emissions (g/s)	175.2	127.7	86.9

TABLE 8-4
Results of Proposed Unit 3 Load Screening

Parameter	Maximum Predicted Impact for Full Load ($\mu g/m^3$)	Maximum Predicted Impact for 75% Load ($\mu g/m^3$)	Maximum Predicted Impact for 50% Load ($\mu g/m^3$)
3-Hour SO_2	30.6	28.0	24.9
24-Hour SO_2	5.4	4.3	3.7
1-Hour CO	84.0	75.7	69.1
8-Hour CO	21.8	19.2	17.0
24-Hour PM_{10}	2.6	2.0	1.7

8.12.2 Preliminary Analysis for CO

The emissions for the proposed Unit 3 at full load were modeled to determine the preliminary impacts for CO. The highest 1-hour CO impact for the Unit 3 boiler was 84.0 $\mu g/m^3$, which is well below the Class II modeling significance level of 2,000 $\mu g/m^3$. For 8-hour CO, the highest impact for the Unit 3 boiler was 21.8 $\mu g/m^3$. This predicted impact is well below the Class II modeling significance level of 500 $\mu g/m^3$. The predicted concentrations and coordinates of the maximum impact locations are summarized in Table 8-5.

TABLE 8-5
Preliminary Analysis Results

Averaging Period/ Pollutant	Maximum Predicted Concentration ($\mu g/m^3$)	Class II Modeling Significance Level ($\mu g/m^3$)	X (UTM) meter	Y (UTM) meter	Receptor Elevation
Annual NO_2	0.51	1 (NO_X)	364653.5	4399764	1758.1
3-hour SO_2	46.0	25	362880.1	4374011	1419.4
24-hour SO_2	6.5	5	391053.5	4384464	1839.3
Annual SO_2	0.73	1	364653.5	4399764	1758.1
24-hour PM_{10}	17.3	3[a]	362703.1	4377579	1418.7
Annual PM_{10}	2.2	1	362103.1	4377583	1415.3
Lead (Pb)	0.00018	NS	365053.5	4400464	1749.8
1-hour CO	84.0	2,000	362053.5	4401464	1693.6
8-hour CO	21.8	500	339053.5	4403464	1714.1
24-hour Fluoride	0.028	0.25[b]	391053.5	4384464	1839.3
1-hour Total Reduced Sulfur	0.40	10[b]	362053.5	4401464	1693.6
1-hour Reduced Sulfur Compounds	0.40	10[b]	362053.5	4401464	1693.6

[a] UDAQ requirement. PSD level set at 5 $\mu g/m^3$.

[b] Monitoring de minimis levels.

Although 8-hour CO concentrations should be determined with a running average rather than a block average, the ISCST3 model reports 8-hour concentrations as block averages (i.e., only 8-hour periods ending at 0800, 1600, or 2400 hours). Because the preliminary impacts for 8-hour CO were less than 25 percent of the Class II modeling significance level, no further adjustment was made to the modeled impacts and no further analysis was conducted for CO.

8.12.3 Preliminary Analysis for SO_2

For a preliminary analysis of the SO_2 impacts for the proposed Unit 3 project, the boiler was modeled with exhaust parameters reflective of the load condition (105 percent) that was found to produce the highest short-term impacts, as described in Section 7.4.1.

The emission rate for the evaluation of 3-hour SO_2 impacts from Unit 3 was 171.0 grams per second (g/s). This emission rate is based on 0.15 lb/MMBtu SO_2, which is an estimate of the highest rate that would be expected from Unit 3 for a 3-hour period. Similarly, the 24-hour emission rate was 136.8 g/s, as based on 0.12 lb/MMBtu SO_2. Annual impacts were estimated with an emission rate based on the long-term (30-day rolling average) limit that will apply to Unit 3, 0.10 lb/MMBtu SO_2. These emission rates were carried through to the full-impact analysis if required for any of the averaging periods.

The highest predicted 3-hour SO_2 impact for the proposed Unit 3 boiler was 46.0µg/m^3. This impact exceeded the Class II modeling significance level of 25.0 µg/m^3. Predicted 24-hour impacts for the proposed Unit 3 boiler also exceeded the Class II modeling significance level of 5.0 µg/m^3, with a maximum modeled impact of 6.5µg/m^3. Annual impacts for the Unit 3 boiler were below the modeling significance level of 1.0 µg/m^3 , with a maximum modeled impact of 0.69 µg/m^3. An additional model run was conducted with a finer grid with 100-m spacing to further refine the annual impact. The maximum impact using the refined grid was 0.73 ug/m^3, which is also below the Class II modeling significance level of 1.0 µg/m^3 for annual SO_2.

With predicted 3-hour and 24-hour impacts for the proposed Unit 3 boiler exceeding the Class II modeling significance levels,CH2M HILL next determined the impact area for SO_2. The impact area for a particular pollutant, as described in the draft EPA *New Source Review Workshop Manual* (EPA 1990), is "a circular area extending from the source to the most distant point where approved dispersion modeling predicts a significant impact will occur." The impact area will define the area over which the analyses for NAAQS compliance and PSD increment consumption will be performed. For a given pollutant, the impact area is determined for each averaging period, and the area used for a given pollutant is the largest of the impact areas. For the proposed Unit 3 project, the impact area for 24-hour impacts has a radius of 43.3 km. For 3-hour impacts, receptors yielding an impact above the modeling significance level were widespread across the receptor grid. As a result, the full-impact analysis for SO_2 was conducted with the complete 50-km receptor grid. Table 8-5 presents the results of the preliminary analysis for SO_2.

8.12.4 Preliminary Analysis for NO_X

The NO_X emissions from the proposed Unit 3 were modeled to determine the preliminary impacts. The maximum annual impact predicted for the base receptor grid was 0.48 ug/m^3, in an area with receptor spacing of 500 m. An additional model run was conducted with a finer grid with 100-m spacing to further refine the result. The maximum impact using the refined grid was 0.51 ug/m^3, which is below the Class II modeling significance level of 1.0 µg/m^3 for annual NO_X. The maximum impact and coordinates of the maximum impact are summarized in Table 8-5.

8.12.5 Preliminary Analysis for Lead

Estimated lead emissions from the proposed Unit 3 exceed the PSD significant emission rate of 0.6 tpy. Because no modeling significance level has been established for lead impacts,CH2M HILL conservatively modeled total lead impacts by including emissions from Units 1 through 3 at the IPP. The modeled lead impacts were compared to the NAAQS for lead of 1.5 µg/m^3. Because the NAAQS for lead is set for an averaging period of a calendar quarter, the ISCST3 model was run for quarterly periods representing January through March, April through June, July through September, and October through December.

The highest modeled lead impact for a calendar quarter was 0.00018 µg/m^3. Because the estimated maximum impact is four orders of magnitude lower than the NAAQS for lead, and because background levels of lead in the vicinity of the IPP are assumed to be negligible (according to UDAQ, there are no significant lead emissions at any of the sources near the

IPP), the modeling analysis demonstrates that the NAAQS for lead will not be threatened by the proposed Unit 3 or the existing facility together with the proposed Unit 3.

8.12.6 Preliminary Analysis for PM_{10}

Emissions of PM_{10} from the proposed Unit 3 and other sources associated with the project, including cooling towers and material handling sources, were modeled to determine if modeling significance levels would be exceeded. The proposed cooling towers for the proposed Unit 3 include two alternate configurations. One possible configuration consists of two 12-cell cross-shaped towers, while the other configuration would consist of two 15-cell rectangular towers. Preliminary impacts for PM_{10} were evaluated for both potential configurations.CH2M HILL was directed by UDAQ to model low-level source (release heights less than 20 m) with the 10-m onsite meteorological data, and high-level sources (20 m and above) with the 50-m onsite meteorological data. Results for the two model runs were summed to arrive at the total impacts for all sources.

Predicted impacts for 24-hour and annual averaging periods exceeded the modeling significance levels for both configurations. The radius of impact for 24-hour impacts was 12.4 km for both cooling tower configurations, and 4.2 km for annual impacts. The predicted impacts are summarized in Table 8-5.

8.12.7 Preliminary Analysis for Other Pollutants

Emissions from the proposed Unit 3 will exceed the PSD-significant emission rates for regulated non-criteria pollutants including fluoride, total reduced sulfur (TRS), and reduced sulfur compounds (RSC). CH2M HILL conducted a significant impact analysis for these pollutants and found that the maximum model-predicted impacts for each are well below the monitoring de minimus levels listed in UAC R307-405-6. The results for this analysis are summarized in Table 8-5.

8.13 Full Impact Analysis

As described above, the modeling significance levels were exceeded for 3-hour and 24-hour SO_2, and 24-hour and annual PM_{10}. Full-impact analyses were conducted for these pollutants and averaging periods to demonstrate compliance with the NAAQS and PSD increments. For the full-impact analyses,CH2M HILL modeled all sources at IPP and nearby sources as provided by UDAQ. These sources include the Ashgrove, Brush Wellman, and Continental Lime facilities. The source parameters and emission rates for these sources are included in Appendix E.

Limited information was available for the Brush Wellman sources. Stack parameters and source-specific PM_{10} emissions for three point sources at Brush Wellman were used to determine the stack parameters for a composite stack to represent all sources at the facility. The potential emissions for PM_{10} and SO_2 referenced in the latest AO for the facility were modeled according to the EPA screening guidance for merged stack parameters for multiple stacks (EPA, 1992).

For the Ashgrove facility, source-specific emission rates were available for PM_{10}, but not for SO_2. Because the Ashgrove facility is a minor source of SO_2, and the facility is located more than 30 km from IPP, SO_2 sources from Ashgrove were not included in the analysis. The source-specific emissions for PM_{10} for Ashgrove were available and were modeled. However, based on the distance of Ashgrove from the IPP facility, the multiple volume sources were combined into a single volume source within the center of the matrix of volume sources. All the point and area sources for the facility were modeled.

For the Continental Lime facility, source-specific emission rates were available for both SO_2 and PM_{10}. As with the Ashgrove facility, the multiple volume sources for PM_{10} were combined into a single volume source within the center of the matrix of volume sources.

Increment modeling for the outside sources for SO_2 was conducted with the actual emission rates reported to UDAQ for 2000 and 2001, if available. The highest rate reported for either year was input to the model.

8.13.1 Background Concentrations and Air Quality Monitoring

Background concentrations represent all air pollution sources other than those that are explicitly modeled. Commonly, the impacts of distant background sources are accounted for by using appropriate, monitored air quality data (i.e., a background concentration). Air quality monitoring data for SO_2 and PM_{10} have been gathered at the IPP since September 2001 under the guidance of UDAQ. Representatives of UDAQ have deemed that the data are suitable for use as background concentrations for dispersion modeling of the proposed Unit 3.CH2M HILL used these data as background concentrations for full impact analyses to demonstrate compliance with NAAQS, as described later in this document.

Background concentrations for 3-hour and 24-hour SO_2 were 28.0 $\mu g/m^3$ (10.7 ppb), and 11.5 $\mu g/m^3$ (4.4 ppb) respectively. The background concentrations for 24-hour and annual PM_{10} were 56.0 $\mu g/m^3$ and 17.7 $\mu g/m^3$. The short-term background values for SO_2 were the highest values measured at the IPP site from October 2001 through June 2002. For 24-hour PM_{10}, the second highest value measured at the IPP site over the same period was used. The annual PM_{10} concentration was the average of the 24-hour values that have been collected at the IPP site since September 2001 on a 6-day schedule.

8.13.2 Increment Consumption and Expansion

CH2M HILL worked with UDAQ staff to identify increment-affecting sources that need to be included in any analysis of increment consumption. For determining PSD increment consumption, as stated in UDAQ modeling guidelines (UDAQ, 2000): "the baseline date for PSD and minor sources with respect to NO_2 , SO_2, and PM_{10} has been triggered for the entire state of Utah. The baseline date for all NO_2 sources is April 21, 1988. The baseline date for minor SO_2 and PM_{10} sources is April 1, 1990. The baseline date for major SO_2 and PM_{10} sources is August 17, 1979 (UDAQ, 2000). According to UDAQ personnel at the January 25, 2002 meeting to discuss project modeling requirements, the entire IPP facility is an increment-consuming source. Emissions and stack parameters for sources nearby IPP to include in a full-impact analysis were provided to CH2M HILL by UDAQ. No distinction was made as to which sources were increment-consuming, so all nearby sources were conservatively assumed to be increment-consuming.

Emission for SO_2 increment modeling for Units 1 and 2 at IPP were derived from CEM data for 2000 and 2001. The highest 3-hour and 24-hour emissions measured over that time period were input to the model. In each case, the CEM data was below the PTE for those sources (0.15 lb/MMBtu):

- Maximum 3-hour SO_2 for Unit 1 = 137.9 g/s (0.129 lb/MMBtu)
- Maximum 24-hour SO_2 for Unit 1 = 128.9 g/s (0.120 lb/MMBtu)
- Maximum 3-hour SO_2 for Unit 2 = 144.4 g/s (0.135 lb/MMBtu)
- Maximum 24-hour SO_2 for Unit 2 = 123.3 g/s (0.115 lb/MMBtu)

8.13.3 NAAQS Analysis for PM_{10} and SO_2

The potential PM_{10} emissions for the proposed Unit 3 and associated sources, the other IPP facility sources, and the Ashgrove, Brush Wellman, and Continental Lime facilities were all modeled to determine compliance with the NAAQS for PM_{10}. Auxiliary equipment at the IPP was also included in the analysis. Because the auxiliary equipment at the IPP (emergency generators, auxiliary boilers, fire pump engines) would not normally operate when the main IPP units were operating, CH2M HILL conservatively assumed that one unit of each type of the auxiliary equipment would be in operation along with the main units. As with the preliminary analysis for PM_{10}, the two possible configurations for the proposed Unit 3 cooling towers were both modeled. The maximum modeled annual PM_{10} concentration was 5.0 μg/m^3. When the predicted annual impact is added to the background concentration of 17.7 μg/m^3, total annual impacts (22.7 μg/m^3) are below the NAAQS of 50 μg/m^3. The maximum modeled second highest, 24-hour PM_{10} concentration was 28.5 μg/m^3. When added to the background concentration of 56 μg/m^3, total 24-hour impacts (84.5 μg/m^3) remain below the NAAQS of 150 μg/m^3. For both 24-hour and annual averaging periods, the maximum predicted impact occurred at the north facility boundary, directly north of the conditioned sludge and unpaved road hauling sources, in an area of 50-m receptor spacing. The results of the PM_{10} NAAQS analysis are summarized in Table 8-6.

To determine compliance with the NAAQS for SO_2, CH2M HILL modeled the potential emissions of SO_2 from the proposed Unit 3 at the IPP (as described in Section 8.12.3 for various averaging periods), potential emissions from Units 1 and 2 at the IPP, and auxiliary equipment at the IPP as described above for PM_{10} modeling. Outside sources of SO_2 from the Brush Wellman and Continental Lime facilities were included in the modeling, with emission rates and other modeling input parameters provided by UDAQ.

Initial modeling for NAAQS compliance for SO_2 indicated that the maximum predicted impacts were dominated by the contribution from the auxiliary boiler at IPP. Because the maximum predicted impacts were occurring at the IPP ambient boundary, it was apparent that building downwash was exerting a major influence on the auxiliary boiler plume. CH2M HILL therefore used a version of the ISCST3 model that incorporates enhanced building downwash algorithms to reassess the impacts of SO_2. The enhanced downwash algorithms are referred to as Plume Rise Model Enhancements (PRIME), and the model, ISC-PRIME, is being evaluated as the next generation building downwash model. The enhanced algorithms in ISC-PRIME provide better performance for estimates of building downwash effects. The latest EPA version of ISC-PRIME (Version 01228) was used for the analysis. Because the ISC-PRIME model allowed for a maximum of 15,000 receptors, the rectangular 50-km base receptor grid was reduced to a circular grid that maintained a 50-km radius around the IPP facility.

An auxiliary boiler stack height of 72 feet was used for the ISC-PRIME analysis for SO_2. This represents an increase of 16 feet in the stack height shown in previous submittals for IPP, and represents the height that will be required for proper Method 1 stack testing for the source. The permanent stack height increase will be installed during the construction phase of the Unit 3 project and will be completed prior to Unit 3 operation. Previously submitted modeling for NAAQS and increment compliance for PM_{10} conservatively made use of the lower (56-foot) stack height for the auxiliary boiler. Due to the relatively low PM_{10} emission rate from the auxiliary boiler, changes to the auxiliary boiler stack height would only slightly decrease the conservative impact predicted by prior PM_{10} modeling at the 56-foot stack height. As a result, this prior PM_{10} modeling was not updated to reflect the auxiliary boiler stack height increase.

The maximum modeled, second highest, 3-hour SO_2 concentration was 192.4 $\mu g/m^3$. When added to the background concentration of 28.0 $\mu g/m^3$, impacts remain well below the NAAQS of 1,300 $\mu g/m^3$. The maximum modeled second highest, 24-hour SO_2 concentration was 41.1 $\mu g/m^3$. When added to the background concentration of 11.5 $\mu g/m^3$, impacts remain below the NAAQS of 365 $\mu g/m^3$. Both of these predicted maximums occurred at the IPP ambient boundary in an area with 50-m receptor spacing. Specifically, the maximum impacts occurred at the north end of the access road that ends approximately 200 m south of the administration building. The results of the SO_2 NAAQS analysis are summarized in Table 8-6.

TABLE 8-6
Results of NAAQS Analysis for SO_2 and PM_{10}

Averaging Period/ Pollutant	Predicted Impact ($\mu g/m^3$)	Background Impact ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	X (UTM, m)	Y (UTM, m)	Elevation (m)
3-hour SO_2	192.4	28.0	220.4	1300	364496.7	4373703	1426.6
24-hour SO_2	41.1	11.5	52.6	365	364496.4	4373803	1427.0
24-hour PM_{10}	28.5	56	84.5	150	362103.1	4377583	1415.3
Annual PM_{10}	5.0	17.7	22.7	50	362103.1	4377583	1415.3

8.13.4 Increment Analysis for PM_{10} and SO_2

To determine compliance with PSD increments for PM_{10} and SO_2, the emissions from outside sources provided by UDAQ were all conservatively assumed to be increment-consuming emissions. Potential emissions of PM_{10} for each IPP source were modeled to determine increment consumption, while actual emissions of SO_2 from CEM data were used for the existing main units (Units 1 and 2) at IPP. The list of IPP and outside sources included in the increment modeling for PM_{10} and SO_2 was identical to the list of sources modeled for NAAQS compliance.

The maximum modeled annual PM_{10} concentration was 5.0 $\mu g/m^3$, which is well below the Class II PSD increment for annual PM_{10} of 17 $\mu g/m^3$. The maximum modeled second highest, 24-hour PM_{10} concentration was 28.5 $\mu g/m^3$, which is below the Class II PSD increment of 30 $\mu g/m^3$. For both 24-hour and annual averaging periods, the maximum predicted impact occurred at the north facility boundary, directly north of the conditioned sludge and unpaved road hauling sources, in an area of 50-m receptor spacing. The results of the PM_{10} increment analysis are summarized in Table 8-7.

To determine compliance with the PSD increments for SO_2, CH2M HILL modeled the potential emissions of SO_2 from the proposed Unit 3 at the IPP (as described in Section 8.12.3 for various averaging periods), actual emissions (based on CEM data described in Section 8.13.2) from Units 1 and 2, and the potential emissions from auxiliary equipment at the IPP. As with the NAAQS analysis, outside sources of SO_2 from the Brush Wellman and Continental Lime facilities were included in the modeling, with emission rates and other modeling input parameters provided by UDAQ. As with the NAAQS analysis for SO_2, the ISC-PRIME model was used to assess the SO_2 increment consumption.

The maximum modeled, second highest, 24-hour SO_2 concentration was identical to the result for NAAQS modeling, 41.1 $\mu g/m^3$, which is well below the PSD increment of 91 $\mu g/m^3$. The maximum modeled second highest 3-hour SO_2 concentration was also identical to the result for NAAQS modeling, 192.4 $\mu g/m^3$, and occurred at the southeast IPP fence line. This predicted impact is well below the PSD increment of 512 $\mu g/m^3$.

Figures 8-6 and 8-7 present graphical representations of the increment modeling for SO_2. Results of the increment analysis for SO_2 are summarized in Table 8-7.

TABLE 8-7
Results of PSD Increment Analysis for SO_2 and PM_{10}

Averaging Period/ Pollutant	Predicted Concentration ($\mu g/m^3$)	PSD Increment ($\mu g/m^3$)	X (UTM) meter	Y (UTM) meter	Receptor Elevation
3-hour SO_2	192.4	512	364496.7	4373703	1426.6
24-hour SO_2	41.1	91	364496.4	4373803	1427.0
24-hour PM_{10}	28.5	30	362103.1	4377583	1415.3
Annual PM_{10}	5.0	17	362103.1	4377583	1415.3

8.13.5 Predicted Impacts Above 50 Percent of PSD Increment

Figure 8-8 shows the receptors that yielded a PM_{10} impact that was greater than 50 percent of the 24-hour Class II increment of 30 µg/m³. As shown in the figure, the only receptors with impacts above this level (15 µg/m³) are located at or very near the IPP ambient boundary (fenceline). The only receptor beyond the IPP fenceline that yielded an impact above 50 percent of the Class II increment is located approximately 400 m north of the IPP fence. The 24-hour impact for this receptor was 15.8 µg/m³ , which represents a consumption of only 53 percent of the available increment.

As shown in Figure 8-8, the ambient boundary for IPP is the property boundary for the power plant. Along the entire property line is a fence that acts as a physical barrier to public access. In the southern part of the plant site there are two access roads that enter the plant from the south that are on IPP property and are maintained by IPP but there is no physical barrier to public access until some distance onto the plant site where there is gate on each road. At each gate members of the public are barred from traveling further north on each road. Along both sides of each road there are fences to keep people from getting off the side of the road onto the plant property. Accordingly, the ambient boundary used for modeling purposes follows the fenced property line except along these two roads where the ambient boundary goes up the fence along the road on one side to the plant gate and back down the other side of the road.

UDAQ Rule R307-401.6(3) requires that if at any location more than 50% if the PSD increment is consumed by a facility, approval of the Utah Air Quality Board (Board)is required. This is a method whereby the State of Utah can control the industrial development in a area. If any facility can consume most or all of the increment in an area to the future exclusion of other industrial development, the Board must approve. This is strictly a growth allocation issue and is not a health issue since as shown above in section 8.13.3 the 24-hour NAAQS for PM_{10} is not in any way threatened.

The points shown in Figure 8-8 are all locations where more than 50% of the PM_{10} 24 hour increment will be consumed by the IPP plant. This will not adversely impact any plans for future development by other industry since the land to the north of the IPP property, owned either by the federal government, the Bureau of Land Management, or the State of Utah, is not likely to be used for future industrial development. This is because areas to the east of the plant have existing infrastructure and have already been specially designated for industrial development. The area to the north of the plant is not readily accessible, and other significant infrastructure improvements would be required for development in the area immediately north of the plant.

For the locations near the gates on the two plant access roads, the occurrence of more than 50% consumption of the PM_{10} 24 hour increment will only limit further development of the IPP plant itself. This is because these points are well within the IPP property boundary and only industrial activities within the IPP plant itself can significantly affect these locations and thus in the future be curtailed by the limited remaining portion of the increment not already consumed.

FIGURE 8-6
3-Hour PSD Increment Consumption for SO_2

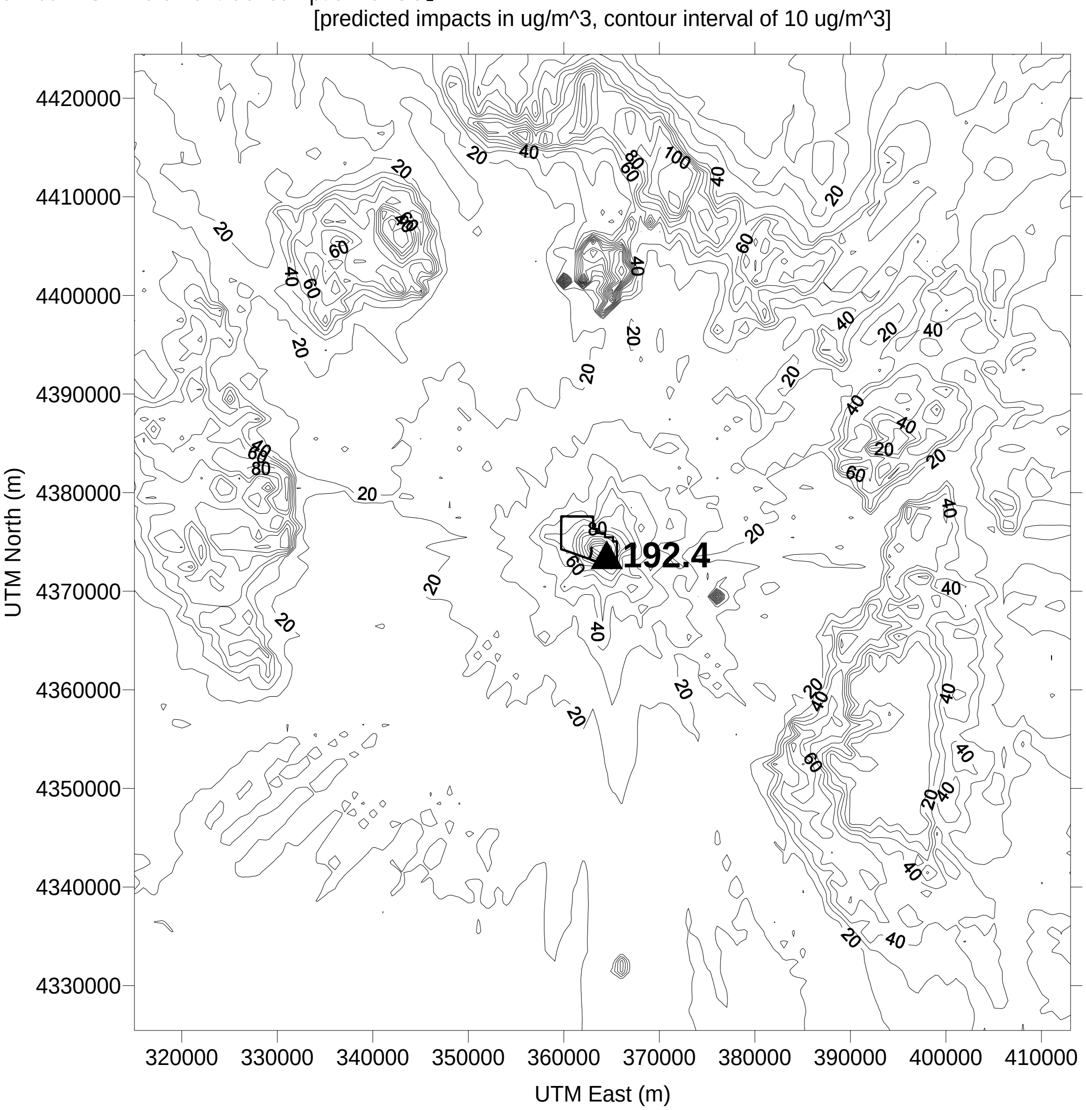

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FIGURE 8-7
24-Hour PSD Increment Consumption for SO_2

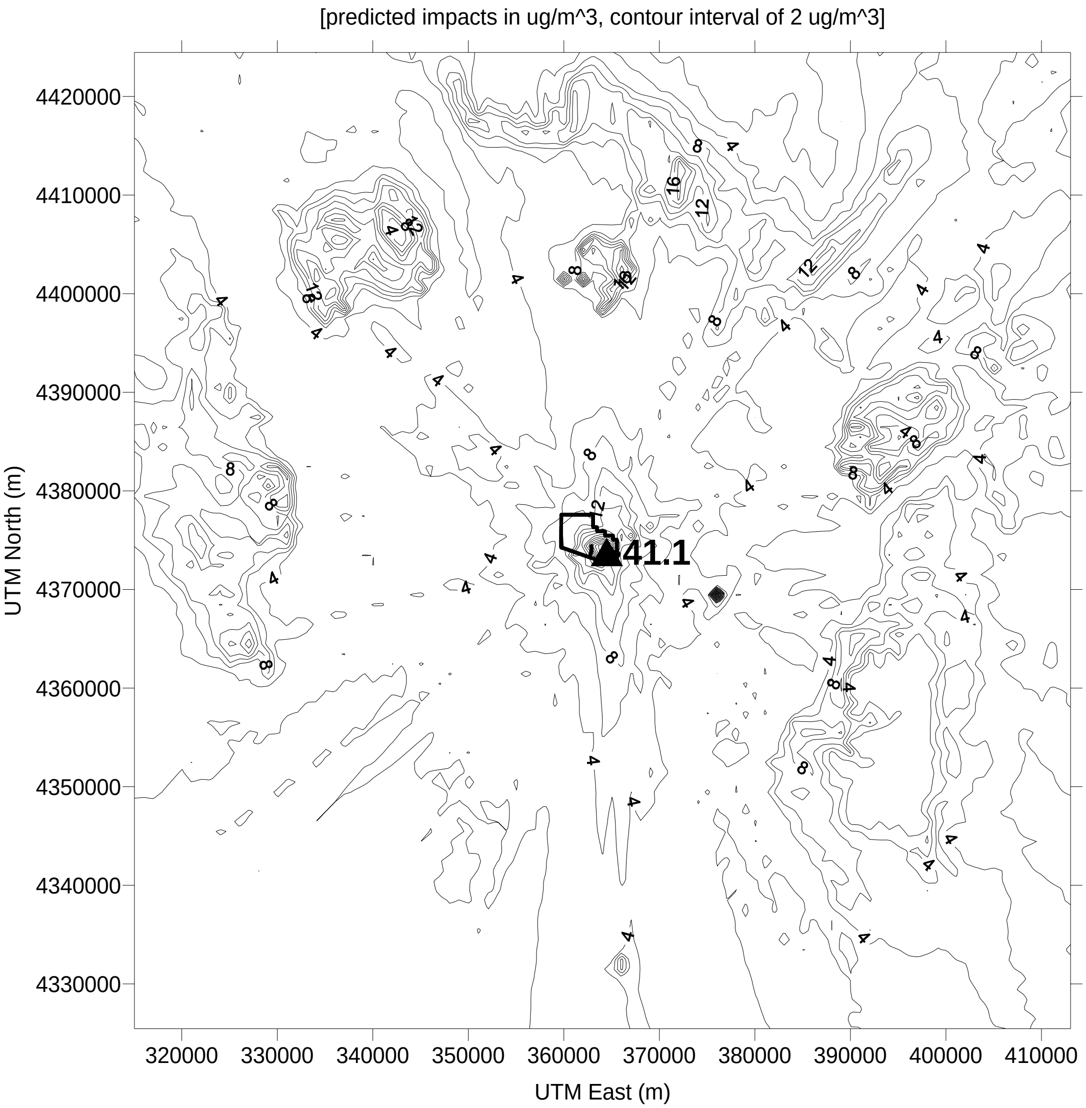

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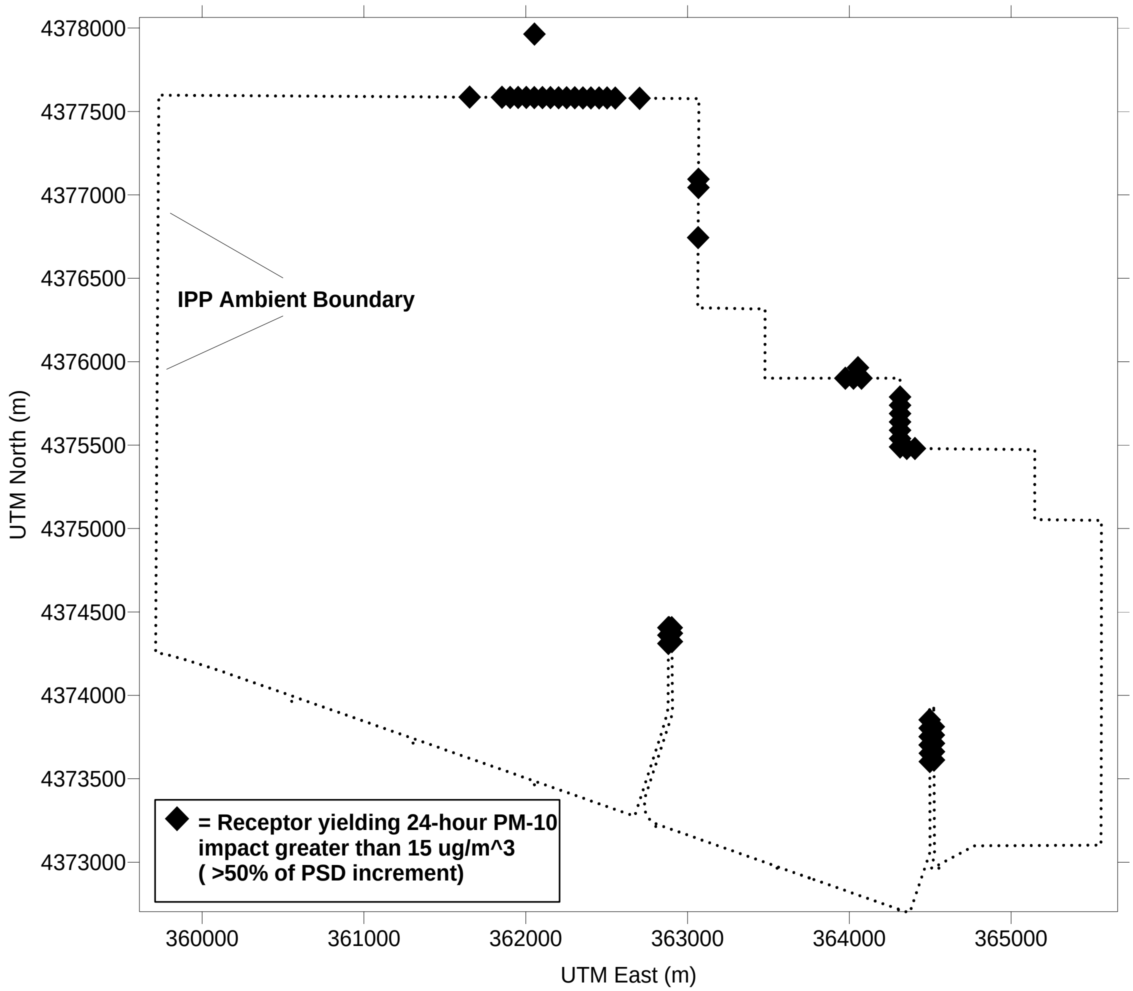
FIGURE 8-8
Receptors Yielding Impacts Greater Than 50 Percent of 24-hour Class II Increment for PM_{10}



Non-Criteria Pollutant Impacts

Information regarding HAP emissions and release characteristics must be provided as part of a complete NOI. The following items are listed in UDAQ's Modeling Guidance (UDAQ, 2000):

- Estimated maximum pound per hour emission rates
- Type of pollutant release (i.e., vertically restricted or unrestricted)
- Maximum release duration in minutes per hour
- Release height of the emission point(s) as measured from ground level
- Height of any adjacent building(s) that could cause downwash effects
- The shortest distance from each release point to the ambient air boundary

- The emission threshold value (ETV), as determined from the Emission Threshold Factor (ETF) multiplied by the Threshold Limit Value (TLV) for each HAP

CH2M HILL has evaluated the potential HAP impacts from the proposed Unit 3 stack. The proposed Unit 3 is a vertically unrestricted release. Emissions from the unit will be continuous, and the closest approach of the ambient boundary is approximately 705 m. Information regarding HAP emission rates is provided in Appendix E.

CH2M HILL calculated ETVs for each HAP as described in UDAQ modeling guidelines to determine which HAPs should be modeled. Modeling was conducted for those HAPs for which emissions exceeded the ETVs. As with the criteria pollutant modeling described earlier, the HAP modeling was conducted with the ISCST3 model. Meteorological input data consisted of the data created from the 50-meter level of the IPP tower as described in Section 8.9. The base receptor network was the same as described in Section 8.8.

The HAPs were modeled for a 1-hour and 24-hour averaging period using an emission rate of 1 pound per hour. The concentrations were then scaled for each individual HAP based on their emission rate. Modeling results were then compared to toxic screening levels (TSLs) that have been derived from the TLVs for each HAP according to the classification of acute, chronic, or carcinogenic. Predicted impacts were below the TSLs for each HAP that was modeled. The results indicate that ambient concentrations are extremely low and not of concern since the maximum concentrations are well below the TSL. Table 8-8 provides a summary of the HAP modeling.

TABLE 8-8
Summary of HAP Modeling

Pollutant	Averaging Period	Modeled Impact Concentrations (μg/m^3)	Toxic Screening Levels* (μg/m^3)
Arsenic	1 Hour	3.04 E-03	1.00
Beryllium	1Hour	3.17 E-05	0.20
Cadmium	1 Hour	5.40 E-04	1.00
	24 Hours	5.36E-05	0.11
Chromium	1 Hour	4.53 E-03	5.00
	24 Hours	4.49E-05	0.56
Cobalt	24 Hours	5.36 E-05	0.67
Lead	24 Hours	1.93 E-04	1.67
Manganese	24 Hours	2.45 E-04	3.33
Mercury	1 Hour	1.03E-03	2.50
	24Hours	1.02 E-04	0.83
Selenium	24 Hours	1.39 E-03	6.67
Acrolein	1 Hour	7.08 E-03	22.93
	24 Hour	7.02E-04	7.64
Methyl hydrazine	24 Hours	4.12 E- 04	0.63

* TSLs = TLVs divided by 10 for acute HAPs
TLV/30 for chronic HAPs, TLV/90 for carcinogenic HAPs

8.14 Growth Analysis

8.14.1 Work Force

An analysis of the air quality impacts from commercial, residential, industrial, and other growth associated with the project was conducted as required by UDAQ and PSD regulations.

CH2M HILL consulted with IPA personnel to obtain information on project labor requirements and availability. Although the final labor requirements are not yet available, a preliminary estimate was made by IPA. All of the approximate 800 to 900 construction jobs needed for the project will be filled by workers commuting to the site, most from the Delta, Utah area. Of the estimated 100 to 120 permanent positions needed for operation of the proposed Unit 3, about 50 percent will be filled by local workers, and approximately 50 percent will be filled by nonlocal workers who will relocate to the vicinity of Delta.

8.14.2 Housing and Industry

Due to the need for temporary and permanent positions for the project, there will be some emissions associated with the construction of housing in the Delta area. However, these emissions will be temporary, and because of the limited number of new homes expected, are considered to be insignificant.

The small number of people that would be brought into the Delta area to support the project are not expected to generate commercial growth. The expansion of the IPP is not expected to generate industrial growth because operational and maintenance systems are already in place for existing plant operations. Because no associated commercial or industrial growth is anticipated, there will be no growth-related air quality impacts.

8.15 Soils and Vegetation Analysis

CH2M HILL conducted a search for information regarding sensitive soils, sensitive vegetation, and vegetation with commercial or recreational value in the vicinity of the IPP. A literature search was conducted to determine the ambient air pollution levels that may cause damage to sensitive species or vegetation with commercial or recreational value.CH2M HILL then compared the maximum impacts predicted with the ISCST3 model to the levels of criteria pollutants that are known to produce damage to soil and vegetation, as described later. The search for sensitive soils and vegetation did not yield information relative to any specific sensitive species in the area.

The latest agricultural census for Millard County, Utah reveals that the county had 162,805 acres of total cropland in 1997 (USDA, 1999). Of that total, the highest acreage was devoted to hay-alfalfa, grass silage, and green chop (69,737 total acres). Other crops grown in 1997 included barley (13,328 acres), wheat (5,035 acres), corn for silage (3,465 acres), and oats (692 acres).

Of the species identified in the Millard County vicinity, alfalfa, oats, and barley have been identified as crops sensitive to pollutant effects. The exact tolerance of a given crop is dependent on the particular horticultural varieties. Table 8-9 indicates levels of NO_X which have been found to result in plant damage for different species. Photosynthesis is found to be inhibited in alfalfa at 2-hour NO_2 exposures of 4,105 $\mu g/m^3$ (Hill, 1974). In addition, a mixture of approximately 191 ug/m^3 of NO_X and 265 ug/m^3 of SO_x administered for 4 hours has been discovered to cause foliar injury to oats (DNR, 2002).

CH2M HILL used the ISCST3 model to determine the maximum NO_X and SO_x impacts that would result from the project. The worst-case 3-hour SO_x impact from the proposed unit is 46.0 ug/m^3 while the worst-case 3-hour NO_X impact is 21.5 ug/m^3. As a result, the worst-case combined NO_X and SO_x 3-hour impact is 67.5 ug/m^3. All predicted concentrations are well below those that would be expected to impact vegetation.

TABLE 8-9
Pollutant Effects on Species

Species	Category of Plant	4-hour NO_X Concentrations which Result in 5% Foliar Injury	Unit 3 Worst-Case 3-hour NO_X Concentration
Alfalfa, Oats	Sensitive	3.76-11.28 mg/m^3	
Corn, Wheat	Intermediate	9.4-18.8 mg/m^3	0.022 mg/m^3
Elder, Ash	Tolerant	> 16.92 mg/m^3	

Based on "Air Quality Criteria for Oxides of Nitrogen", EPA/600/8-91049bF, August, 1993.

8.16 Visibility Impairment Analysis

CH2M HILL used the EPA VISCREEN model to estimate the Class II area visibility impacts near the IPP from the proposed project. The Class II area chosen for analysis is the town of Delta, Utah which is located approximately 13 miles north of the project site.

The VISCREEN model calculates visibility impact by computing the color and intensity of the plume and comparing it to its background sky or hillside. Contrasts at all wavelengths in the visible spectrum characterize the brightness and color of a viewed plume relative to its viewing background. In the plume visual impact screening model VISCREEN, contrasts at three wavelengths (0.45, 0.55, and 0.65 μm) are used to characterize blue, green, and red regions of the visible spectrum. If the plume contrast is positive, the plume is brighter than its viewing background; if negative, the plume is darker. If contrasts are different at different wavelengths, the plume is discolored. If contrasts are all zero, the plume is indistinguishable from its background (i.e., it is imperceptible).

The perceptibility of a plume depends on the plume contrasts at all visible wavelengths. With a range of wavelengths, a measure of contrast must recognize both "overall" brightness and color. To address the added dimension of color as well as brightness, the color contrast parameter, ΔE, was chosen for use in the VISCREEN model as the primary basis for determining the perceptibility of plume visual impacts in screening analyses.

Four lines of sight were selected by VISCREEN. The lines of sight are described by a view number. The plume is viewed in 5-degree increments of azimuth starting from the emission source. The other three views or lines of sight are for plume parcels 1 km downwind from the source and the nearest and most distant park boundary. Results are provided for two assumed worst-case sun angles, forward scatter (looking toward the sun), and backward scatter (looking away from the sun).

Emission rates required by VISCREEN include particulates, NO_X (as NO_2), primary NO_2, soot, and primary SO_4. The emission rates input for IPP Unit 3 were as follows:

- Particulates: 178.4 lb/hr (filterable PM_{10} plus condensable flourine and chloride)
- NO_X : 633.5 lb/hr
- Primary SO_4 : 42.4 lb/hr

The results of the Level 1 screening analysis using the VISCREEN model for Delta, Utah are presented in Table 8-10. There are no established criteria for determining how visible a plume may be in a Class II air quality area. The values presented are the worst-case impact Level-1 VISCREEN screening results in Delta, Utah. Actual plume contrast parameters would be much lower under most conditions. An output file from the VISCREEN run is provided on CD.

A VISCREEN Level-2 modeling analysis was conducted to determine the visibility impacts of IPP Unit 3 on Capitol Reef NP. The UDAQ requested the VISCREEN analysis because Capitol Reef NP is within 200 km of the proposed project. This analysis was conducted in accordance with guidance for the VISCREEN model found in the EPA document titled *Workbook for Plume Visual Impact Screening and Analysis (Revised)* (EPA, 2000). To determine the Level-2 "1 percent worst-case" meteorological condition to use in the analysis, we sorted the 50-meter onsite meteorological data that was used for the ISC modeling for the project.

As described in the EPA workbook for the VISCREEN model, plume transport times of more than 12 hours toward a particular area would result in plume material that is much more dispersed than a standard Gaussian plume model would predict. The plume would likely be broken up by convective mixing and changes in wind direction and speed. Therefore, wind speeds less than 3.5 meters per second yield transport times of greater than 12 hours and were not considered in the determination of the 1 percent worst-case condition, as suggested in the EPA workbook.

The most severe 1 percent worst-case condition occurred for the hours between 1800 and 2400. This condition, which included D (neutral) stability and a wind speed of 6 meters per second (m/s), was then adjusted for complex terrain. As described in the EPA workbook:

"If the observer is located on terrain at least 500 meters above the effective stack height for stable conditions or such elevated terrain separates the emission source and the observer, the worst-case stability class should be shifted one category less stable"

The proposed IPP Unit 3 would be at a base elevation of 1425.4 meters above ground level (agl). The effective stack height for IPP Unit 3 under stable conditions (considering stack height and plume rise) would be, at most, approximately 1,789 meters agl. Terrain at the leading edge of Capitol Reef NP exceeds this value by more than 500 meters. Therefore, the 1 percent worst-case condition was shifted to one category less stable (C stability and 6 m/s wind speed). Using this meteorological combination and other Level-2 defaults, the predicted results within Capitol Reef NP were more than two orders of magnitude below the thresholds for plume perceptibility. The VISCREEN summary output file is provided on CD.

TABLE 8-10
Visual Plume Impacts in Delta, Utah

Background	Theta°	Azimuth°	Distance from IPP (km)	Alpha°	Delta E		Contrast	
					Criteria *	Plume	Criteria *	Plume
Maximum Visual Impacts Inside Class II Area								
Sky	10	84	20.9	84	**	14.168	**	0.284
Sky	140	84	20.9	84	**	11.987	**	-0.234
Terrain	10	84	20.9	84	**	43.994	**	0.387
Terrain	140	84	20.9	84	**	7.076	**	0.090

* Plume contrast criteria have not been established for Class II areas in Utah.

8.17 References

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EPA, 1992. *Screening Procedures for Estimating the Air Quality Impact of Stationary Sources.* Revised, Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina, October 1992.

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9.0 Monitoring Information

This section describes the compliance monitoring devices and activities. The applicable test methods used for determining compliance are also described.

9.1 Compliance Monitoring Devices and Activities

9.1.1 Compliance Monitoring

Unit 3 will be equipped with 40 CFR Part 75 CEMS for the measurement of SO_2 and NO_x. Visible emissions (opacity) will be measured continuously with a COMS installed at the inlet of the scrubber.

9.1.2 Other Methods to Demonstrate Compliance

As referenced in the existing Title V Operating Permit for IPP Units 1 and 2, other methods are also used to demonstrate compliance for various emission sources including the material handling operations. Other compliance methods include recordkeeping; monthly and annual emission calculations based on production rate, hours of operation, and/or equipment capacity using AP-42 or other acceptable emission estimation methods; visual emission observations; specific production or hour limits; dust collector pressure drop; quarterly equipment maintenance; and adherence to the fugitive dust control plan.

9.2 Applicable Test Methods

Listed below are the EPA test methods from 40 CFR 60 Appendix A that are applicable to this project, that will be used to demonstrate compliance with permit limits.

9.2.1 Method 1—Sample and Velocity Traverses for Stationary Sources

This method is designed to aid in the representative measurement of pollutant emissions and/or total volumetric flow rate from a stationary source. A measurement site where the effluent stream is flowing in a known direction is selected, and the cross-section of the stack is divided into a number of equal areas. Traverse points are then located within each of these equal areas.

9.2.2 Method 2, 2F, 2G, and 2H—Determination of Stack Gas Velocity and Volumetric Flow Rate (Type S Pitot Tube)

This method with all of its submethods for determining flow velocity in nonuniform flow conditions is applicable for the determination of the average velocity and the volumetric flow rate of a gas stream.

9.2.3 Method 3A—Determination of O_2 and CO_2 Concentrations in Emissions from Stationary Sources (Instrumental Analyzer Procedure)

This method is applicable to the determination of O_2 and CO_2 concentrations in emissions from stationary sources only when specified within the regulations.

9.2.4 Method 5B —Determination of Non-Sulfuric Acid PM Emissions from Stationary Sources

This method is applicable for the determination of non-sulfuric acid PM from stationary sources. PM is withdrawn isokinetically from the source and collected on a glass fiber filter maintained at a temperature of 160 ± 14°C (320 ± 25°F). The collected sample is then heated in an oven at 160°C (320°F) for 6 hours to volatilize any condensed sulfuric acid that may have been collected, and the non-sulfuric acid particulate mass is determined gravimetrically.

9.2.5 Method 6C—Determination of SO_2 Emissions from Stationary Sources (Instrumental Analyzer Procedure)

This method is applicable to the determination of SO_2 concentrations in controlled and uncontrolled emissions from stationary sources. A gas sample is continuously extracted from a stack, and a portion of the sample is conveyed to an instrumental analyzer for determination of SO_2 gas concentration using an ultraviolet, nondispersive infrared (NDIR), or fluorescence analyzer.

9.2.6 Method 7E—Determination of NO_x Emissions from Stationary Sources (Instrumental Analyzer Procedure)

This method is applicable to the determination of NO_x concentrations in emissions from stationary sources. A gas sample is continuously extracted from a stack, and a portion of the sample is conveyed to an instrumental chemiluminescent analyzer for determination of NO_x concentration.

9.2.7 Method 9—Visual Determination of the Opacity of Emissions from Stationary Sources

This method is applicable for the determination of the opacity of emissions from stationary sources pursuant to § 60.11(b) and for qualifying observers for visually determining opacity of emissions. The opacity of emissions from stationary sources is determined visually by a qualified observer.

9.2.8 Method 10—Determination of CO Emissions from Stationary Sources

This method is applicable for the determination of CO emissions from stationary sources only when specified by the test procedures for determining compliance with NSPS. The test procedure will indicate whether a continuous or integrated sample is to be used. The integrated or continuous gas sample is extracted from a sampling point and analyzed for CO content using a Luft-type NDIR or equivalent.

9.2.9 Method 19—Determination of SO_2 Removal Efficiency and PM, SO_2, and NO_x Emission Rates

9.2.9.1 Emission Rates

O_2 or CO_2 concentrations and appropriate F factors (ratios of combustion gas volumes to heat inputs) are used to calculate pollutant emission rates from pollutant concentrations.

9.2.9.2 Sulfur Reduction Efficiency and SO_2 Removal Efficiency

An overall SO_2 emission reduction efficiency is computed from the efficiency of fuel pretreatment systems, where applicable, and the efficiency of SO_2 control devices.

The sulfur removal efficiency of a fuel pretreatment system is determined by fuel sampling and analysis of the sulfur and heat contents of the fuel before and after the pretreatment system.

The SO_2 removal efficiency of a control device is determined by measuring the SO_2 rates before and after the control device.

The inlet rates to SO_2 control systems (or, when SO_2 control systems are not used, SO_2 emission rates to the atmosphere) are determined by fuel sampling and analysis.

9.2.10 Method 22—Visual Determination of Fugitive Emissions from Material Sources and Smoke Emissions from Flares

This method is applicable for the determination of the frequency of fugitive emissions from stationary sources and visible smoke emissions from flares. Fugitive emissions produced during material processing, handling, and transfer operations or smoke emissions from flares are visually determined by an observer without the aid of instruments. This method determines the amount of time that visible emissions occur during the observation period. The method does not require that the opacity of emission be determined, thus, observer certification according to procedures of Method 9 is not required.

9.2.11 Method 202 — Determination of Condensable PM Emissions from Stationary Sources

This method applies to the determination of condensable particulate matter (CPM) emissions from stationary sources. The method may be used in conjunction with Method 201 or 201A if the probe is glass-lined. The CPM is collected in the impinger portion of a Method 17 type sampling train. The impinger contents are immediately purged after the run with nitrogen to remove dissolved SO_2 gases from the impinger contents. The impinger solution is then extracted with methylene chloride. The organic and aqueous fractions are then taken to dryness and the residues weighed. The total of both fractions represents the CPM.

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10.0 Compliance Plan and Certification

10.1 Evidence of Compliance with Standards

The present Title V permit requires submittal of semiannual compliance certification documents, demonstrating compliance with the standards. These compliance certificates have been submitted to UDEQ and are in their file.

10.2 Compliance Status

The IPP is in full compliance with all applicable environmental laws and regulations. There are no known enforcement actions for compliance plans in progress for the IPP.

10.3 Compliance Plan

Since the IPP is in compliance with all applicable requirements, there are no compliance plans.

10.3.1 Compliance Schedule

The IPP is in compliance with all applicable requirements; therefore, no compliance schedule is provided.

10.3.2 Other Requirements

The IPP will meet all other applicable requirements that become effective during the term of the permit as required by the UAC.

10.4 Compliance Certification

A compliance certification signed by a responsible official of the IPP is provided at the end of this section.

10.5 CAM Plan

10.5.1 Applicability

The CAM rule requirements established by 40 CFR Part 64 apply to pollutant-specific emission units at a major source that is required to obtain a Title V permit and that uses a control device to comply with an emission limitation.

Unit 3 will be subject to CAM requirements for PM_{10}. Unit 3 will not be subject to CAM for SO_2 and NO_x because of the acid rain program exemption listed under 40 CFR Part 64.2(b)(1)(iii). The CAM plan for PM_{10} is provided below.

10.5.2 CAM Plan — PM_{10}

The CAM plan to control PM_{10} for the IPP Unit 3 consists of a fabric filter for PM_{10} control on the generating unit. The suggested CAM plan format from the EPA Technical Guidance Document will be used.

10.5.2.1 Background

A. Emission Unit

Facility:	Intermountain Generating Station Delta, Utah
Description:	PC-Fired Utility Boiler
Identification:	Unit 3 Boiler

B. Applicable Regulations, Emission Limits, and Monitoring Requirements

Applicable Regulations:	40 CFR Part 60.42a
Regulated Pollutant:	PM_{10}
Emission Limits:	Unit 3: 0.015 lb/mmBtu (BACT, filterable only)
Monitoring Requirements:	Visible Emissions (COMS) 40 CFR Part 60, Appendix A, Reference Method 5B

C. Control Technology — Fabric Filter

10.5.2.2 Monitoring Approach

The key elements of the monitoring approach are presented below. In general, continuous opacity will be measured and recorded by the COMS and will serve as an indicator of fabric filter performance. A stack test will be performed once per year to directly show PM_{10} compliance. Site-specific testing at the Intermountain Generating Station has shown opacity to have excellent correlation with particulate emissions, and thus serves as the best indicator. Stack testing continues to be the best method for direct particulate measurement.

A.	Indicator	Opacity and Method 5B Stack Test
B.	Measurement Approach	**Opacity** Opacity will be measured continuously with a COMS installed on the outlet of the unit's fabric filter. Opacity measurements will ensure control equipment is operating properly and bags are not deteriorating. If opacity increases above certain levels, a check is performed to determine if the control device is operating properly based upon other parameters and that the unit is in compliance with the given standard. **Method 5B Stack Test** PM is measured directly once per year using 40 CFR

Part 60, Appendix A, Reference Method 5B to determine that actual compliance is still correlating to good fabric filter performance.

C. Indicator Range

Opacity
An excursion is defined as opacity measurements in excess of 45 percent as measured by the COMS, except for periods of startup, shutdown, maintenance/planned outage, or malfunction. Excursions shall trigger an inspection and review of fabric filter performance as indicated by other parameters (to confirm if opacity is valid and to determine fabric filter operating deficiencies), corrective action, and a reporting requirement.

Method 5B Stack Test
An excursion is defined as an actual measurement based upon a full Method 5B test in excess of the applicable PM_{10} limit. An excursion shall trigger an inspection, corrective action, and a reporting requirement.

D. Performance Criteria

Data Representativeness:

Opacity
Measurements are made by a COMS located after the fabric filter and induced draft fans and prior to the wet limestone FGD system, thereby providing a direct indicator of fabric filter performance. Each COMS is installed, calibrated, and maintained as required by the applicable performance specification.

Method 5B Stack Test
Stack testing occurs at the mid-point section of the stack flue. This location shall meet 40 CFR Part 60, Appendix A, Reference Method 1 criteria. The testing follows Method 5B requirements.

QA/QC Practices and Criteria

Opacity
The COMS is operated, calibrated and maintained to meet 40 CFR Part 60, Appendix B, Performance Specification 1, “Specification and Test Procedures for Opacity Continuous Emission Monitoring Systems in Stationary Sources.”

Method 5B Stack Test
Testing protocol shall follow the requirements of 40 CFR Part 60, Subpart Da.

Monitoring Frequency	**Opacity** Continuous opacity measurement recorded as 6-minute averages. **Method 5B Stack Test** Annual
Data Collection Procedure:	**Opacity** Opacity data is recorded and stored electronically. **Method 5B Stack Test** Test results are manually recorded and submitted to UDAQ.
Averaging Period:	**Opacity** 6 minutes **Method 5B Stack Test** Three 2-hour stack tests

10.5.2.3 Justification

A. Background

The IPP produces electricity. The pollutant-specific emission unit is a PC-fired utility boiler. PM_{10} is controlled by fabric filters prior to the discharge stack. The design collection efficiency of the fabric filter is 99.83 percent.

B. Rationale for Selection of Performance Indicator

Opacity

Continuous opacity monitoring was selected as the performance indicator because it is indicative of good operation and maintenance of the fabric filter. When the fabric filter is operating properly, opacity will be low. Large increases in opacity indicate reduced performance of the particulate control device, therefore, opacity is selected as a performance indicator.

Site-specific testing at Intermountain Generating Station has shown a strong correlation between opacity and PM_{10} emissions. Monitoring opacity is a means of detecting a change in performance that could lead to an increase in emissions. An increase in opacity can indicate the presence of excessive broken bags, insufficient compartments in service, or other fabric filter operational or maintenance deficiencies.

Method 5B Stack Test

Annual stack testing was selected as an indicator because it provides a direct measurement of PM_{10} emissions which can confirm good fabric filter performance. Stack tests provide actual compliance status, and can be compared to fabric filter operating and maintenance parameters to verify that good fabric filter performance still relates to low PM_{10} emissions.

C. Rationale for Selection of Indicator Level

Opacity
The first selected indicator range is COMS opacity measurement of less than 45 percent. Based on site specific Intermountain Generating Station testing, 45 percent opacity is expected to correlate to less than the 0.015 lb/mmBtu PM_{10} emission limit. When an excursion occurs, except for startup, shutdown, maintenance/planned outage, or malfunction, corrective action will be initiated. All excursions will be documented and reported. Stack testing conducted on the existing Intermountain Generating Station units indicates that a PM_{10} emission limit of 0.015 lb/mmBtu would not be exceeded until COMS opacity measurements exceed 49 percent.

Method 5B Stack Test
The second selected indicator range is stack test Method 5B results of less than the applicable limit (0.015 lb/mmBtu). An excursion triggers an inspection, corrective action, and a reporting requirement. The tests are performed annually. Test results will confirm that low PM_{10} emissions correlates with good fabric filter performance.

10.6 Acid Rain Compliance Plan

The IPP is in compliance with all Title IV acid rain program requirements. An application for amendment for their acid rain permit will be submitted separately.

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Intermountain Power Service Corporation Compliance Certification Pursuant to Utah Administrative Code (UAC) R307-415-5d:

I, George W. Cross, as responsible official for IPSC, hereby certify that, based on information and belief formed after reasonable inquiry, the statements and information in this NOI Addendum to the original NOI dated December 16, 2002 are true, accurate, and complete.

____

George W. Cross
President & Chief Operations Officer & Responsible Official

Date:________________________

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APPENDIX A

NOI Application Forms

Utah Division of Air Quality
New Source Review Section

Form 1
General Information

Application for: ☒ Initial Approval Order ☐ Approval Order Modification

A PERMIT TO CONSTRUCT MUST BE APPROVED BEFORE ANY ACTUAL WORK IS BEGUN ON THE FACILITIES. This is not a stand alone document. Please refer to the Permit Application Instructions for specific details required to complete the application. Please print or type all information requested. All information requested herein must be completed and submitted before an engineering review can be completed. Contact the Engineering Section of the Division of Air Quality with any questions at (801) 536-4000. Written inquiries may be addressed to: Division of Air Quality, Engineering Section, P.O. Box 144820, Salt Lake City, Utah 84114-4820.

General Owner and Facility Information	
1. Company name and address: Intermountain Power Service Corporation 850 West Brush Wellman Road Delta, Utah 84624 Phone No.: (435) 864-4414 Fax No.: (435) 864-4970	2. Company contact for environmental issues: Dennis Killian, Technical Services Superintendant Intermountain Power Service Corporation 850 West Brush Wellman Road Delta, Utah 84624 Phone No.: (435) 864-4414 Fax No.: (435) 864-6670
3. Facility address (if different from above): Intermountain Generation Station 850 West Brush Wellman Road Delta, Utah 84624 Phone no.: (435) 864-4414 Fax no.: (435) 864-4970	4. Owners name and address: Intermountain Power Service Corporation 850 West Brush Wellman Road Delta, Utah 84624 Phone no.: (435) 864-4414 Fax no.: (435) 864-4970
5. County facility is located in: Millard	6. Latitude & longitude, township & range, and/or UTM coordinates of plant: 4,374.4 km Northing, 364.2 km Easting, Zone 12 datum NAD27
7. Directions to Installation (street address and/or directions to site) (include U.S. Coast and Geodetic Survey map if necessary): 850 West Brush Wellman Road, Delta, Utah 84624	
8. Identify any current Approval Order(s): AO#_DAQE-049-02___ Date__01/11/2002___ AO#________ Date________ AO#________ Date________ AO#________ Date________ AO#________ Date________ AO#________ Date________	
9. If request for modification, previous permit # and date: DAQE #________ DATE: ________	
10. Type of business at this facility: **Coal-fired electric generating facility**	
11. Total company employees greater than 100? ☒ Yes ☐ No	12. Standard Industrial Classification Code **4 9 1 1**

New Source Review Application
Form 1 (Continued)

13. Application for:
14. ☒ New construction ☐ Modification
☐ Existing equipment operating without permit ☐ Permanent site
☐ Change of permit condition ☐ Change of location

14. For new construction or modification, enter estimated start date: 7/2004 Estimated completion date: 7/2008

15. For change of permittee, location or condition, enter date of occurrence: N/A	16. For existing equipment in operation without prior permit, enter initial operation date:N/A

17. Has facility been modified or the capacity increased since November 29, 1969: ☐Yes ☒ No

Process Information

18. Site plan of facility (Figure 8-2):

Flow diagram of entire process to include flow rates and other applicable information: See Fig. 2-2 through 2-6.

20. Detailed process/equipment description. See Section 2
Description must include:
Process/Equip specific form(s) identified in the instructions (in this appendix)

Fuels and their use	Equipment used in process	Description of product(s)
Raw materials used	Operation schedules	Description of changes to process (if applicable)
Production rates	(including daily/seasonal variances)	

21. Does this application contain confidential data? ☐ Yes ☒No

Emissions Related Information

22. Describe all potential emissions of air pollutants. See Section 3
Include the following:
☒ Emissions for which the source is major.
☒ Emissions of regulated and/or hazardous air pollutants.
☒ Description of any operational constraints or work practices imposed that limit the amount of regulated or hazardous air pollutants.
☒ Emissions above described in terms of lbs/hr, lbs/day, and tons/year.
☒ All calculations used to support the emissions data above.
☒ All Material Safety Data sheets for products used in process.

23. Identify on the site plan (see #18 above) all emissions points, building dimensions, stack parameters, etc. (Figure 8-2)

Air Pollution Control Equipment Information

24. List all air pollution control equipment and include equipment specific forms identified in the instructions. See Sections 2 and 6

25. List and describe all compliance monitoring devices and/or activities (such as CEM, pressure gages See Section 9.

26. Submit modeling for the project if required. See Section 8

27. As part of BACT, Attach an evaluation of the control technologies that have been considered. See Section 6

28. I hereby certify that the information and data submitted in and with this application is completely true, accurate and complete, based on reasonable inquiry and to the best of my knowledge and belief.

Signature: George W. Cross Title: President & Chief Operations Officer & Responsible Official

29. George W. Cross Name (Type or print)	30. Telephone Number: (435) 864-4414	30. Date: 12/10/02

New Source Review Application
Form 1 Instructions

1. Identify the name, address, phone number, and fax number of the legal entity that operates the equipment.
2. Identify the person who is to be contacted regarding this application; also include the phone number and fax number of this person.
3. Identify the address where the equipment will be located.
4. If you are not the owner of the equipment under this application, enter the name, address, phone number, and fax number of the owner.
5. Identify in what county the facility is located. If this is portable equipment, state in what county the first location is.
6. Indicate the technical location of the facility so that it can be located on a map for modeling and inventory purposes. The location can be read from a 7.5" map.
7. Indicate the geographical location or address of facility and directions to site if needed for remote locations. For example, "Go five miles south on highway 1, turn left at farmhouse, go 1.5 miles."
8. List any valid Approval Orders (AO) which are for equipment at this site.
9. Indicate previous AO number (if any) and date for AO modification.
10. State the type of business you conduct at this facility.
11. Indicate if the total number of people employed by your company is over 100 people.
12. Using the provided list of business codes (page 8), enter the code which best describes your business activity at this facility.
13. Check all applicable boxes
    New Construction: new equipment which has not yet been constructed and requires a permit to construct.
    Existing Equipment Operating Without Permit: equipment which has been in operation without a prior permit issued by the state.
    Change of permit condition: permitted equipment which will be operated contrary to permit conditions.
    Modification: existing equipment which is physically altered by the removal, addition, or non-identical replacement of parts.
    Permanent site: equipment will be located continuously at one site for more than 180 days.
    Change of location: permitted equipment which will be transferred from one property to another.
14. Enter the start date and the completion date of any new installation, construction, or modification.
15. For cases in this category, enter the future date when the change is anticipated.
16. For this category of equipment, enter the date when this equipment was first operated.
17. This is for equipment that was operated before November 29, 1969. Indicate whether the facility has been modified or increased capacity since that date.
18. Attach as Appendix A to the application a site plan in sufficient detail to identify: general location of site, buildings, roads, process equipment, emission points, and site characteristics that may effect plume dispersion.
19. Attach as Appendix B to the application a flow diagram which illustrates the entire process from introduction of raw materials to the emission of exhaust to the atmosphere and includes at least the following: generating equipment, process equipment, control equipment, monitoring devices, duct work, hoods, fans, stacks, flow rates/direction, gauges, etc.
20. Attach as Appendix C to the application a narrative description of the process and equipment to be permitted. Essentially include a narrative of the flow chart above. **The description must include equipment or process specific forms as appropriate.** The attached general supplemental process form (Form 2) must be filled out by all sources. Please mark which forms below apply to this project. Forms available upon request are as follows:
    ___ Form 11 Internal Combustion Engines
    ___ Form 12 Incinerators
    ___ Form 13 Spray Booths
    ___ Form 14 Concrete Batch Plants
    ___ Form 15 Rock Crushing and Screening
    ___ Form 16 Soil/groundwater Remediation
    ___ Form 17 Diesel Powered Standby Generator
    ___ Form 18 Portable Hot Mix Drum Asphalt Plants
    _X_ Form 19 Fuel Burning Equipment (Boilers, Heaters, Steam Generators)
    ___ Form 20 Organic Liquid Storage Tank
    ___ Form 21 Solvent Metal Cleaning (degreasers)
    ___ Form 22 Combustion Turbines
21. To claim confidentiality on information submitted with this application, check "yes". Be sure that all submitted information which you wish kept confidential is clearly marked as such. Also state the reason(s) for claiming confidentiality. Examples of acceptable reasons are trade secrets and production data. Note that information on emissions and permits cannot be confidential.

22. Attach as Appendix D to the application a description of all **potential** emissions of air pollutants, including the emissions of major, regulated, and hazardous air pollutants as applicable. Definitions are found in R307-1-1 of the UACR. Include all MSD Sheets for chemicals used in the process.
23. List emission points and parameters on the site plan (#14 above).
24. Attach as Appendix E to the application a list of all air pollution control equipment. **Must include form(s) as appropriate.** Please mark which forms apply to this project. Forms available upon request are as follows:

___	Form 3	Afterburners
___	Form 4	Flares
___	Form 5	Adsorption Unit
___	Form 6	Cyclone
___	Form 7	Condenser
___	Form 8	Electrical Precipitators
_X_	Form 9	Scrubber
_X_	Form 10	Fabric Filter

25. Attach as Appendix F to the application a list with description of all compliance monitoring devices and/or activities. Include such things as make, model, type, size, capability, accuracy, calibration frequency, etc. for the devices and monitoring frequency, outline of training program, level of certification required of inspectors, etc. for monitoring activities.
26. Dispersion modeling will be required under two circumstances:
    1. if the Executive Secretary determines that modeling is to be performed.
    2. if the proposed emissions are in the range of values given in given in Table 1.

This requirement holds for new as well as modified sources. For modified sources, the values in Table 1. denote emission increases. If the emission values are greater than values in Table 1, higher level modeling will be required. Call the Planning Section at (801) 536-4000 for additional information. The meteorological data to be used in the modeling must be submitted to the Executive Secretary for review and approval *before* they are used in the dispersion modeling exercise.

Table 1. Criteria For Screen Modeling (tons/year)

SO_2	40
NO_X	40
PM_{10} fugitive	5
PM_{10} non-fugitive	15
CO*	100/250
HAPS**	10/25
lead	0.6

* 100 tons if one of the 28 source categories in UAC R307-1-3.6.5.B; 250 tons if not

** Ten tons of any pollutant; 25 tons of all pollutants combined. TLV/100 for toxic substances. TLV/300 for cancer-causing substances.

27. For BACT analysis see attached instructions (page 19).
28. Signature of authorized company agent.
29. Name of signing party.
30. Telephone number of signing party.
31. Date of application.

ADDITIONAL INFORMATION MAY BE REQUIRED FOR SOME PROJECTS. If so, the reviewing engineer will contact the individual listed in question number 2.

Date__May, 2003__________________________
Company___Intermountain Power Service Corporation
Site_________Intermountain Generation Station_______

Utah Division of Air Quality
New Source Review Section

Form 2
Process Information

Process Data

1. Name of process: Coal-fired electric utility
2. End product of this process: Electricity

3. Primary process equipment: PC-fired boilers
   Manufacturer: Undetermined
   Make or model: Undetermined
   Identification #: Undetermined
   Capacity of equipment (lbs/hr): Undetermined
   Year installed: 2008 anticipated
   Rated Nominal 900-MW net
   Max. Nominal 950-MW gross
   (Add additional sheets as needed)

4. Method of exhaust ventilation:

   ☒ Stack ☐ Window fan ☐ Roof vent ☐ Other, describe ________________________

   Are there multiple exhausts: ☐ Yes ☒ No

Operating Data

5. Maximum operating schedule: 24 hrs/day
   7 days/week
   52 weeks per yr

6. Percent annual production by quarter:
   Winter 25 Spring 25
   Summer 25 Fall 25

7. Hourly production rates (lbs.):

   Average N/A Maximum N/A

8. Maximum Annual production (indicate units)
   ____

   Projected percent annual increase in production
   0% - New unit

9. Type of operation: ☒ Continuous ☐ Batch ☐ Intermittent

10. If batch, indicate minutes per cycle N/A
    Minutes between cycles N/A

11. **Materials Used in Process**

Raw Materials	Principal Use	Amounts (Specify Units)
Coal	Combustion	3,541,248 tons/yr
Fuel Oil (No. 2)	Combustion in Auxiliary Boiler Approved under Unit 1 and Unit 2 Permit (no increase resulting from Unit 3 operation is anticipated)	50,000 barrels/yr
Limestone	Pollution Control	20,072 lb/hr

Process
Form 2 (Continued)

12a.**Control Equipment** (attach additional pages if necessary)

Item	Primary Collector	Secondary Collector
a. Type	Baghouse	
b. Manufacturer	Undetermined	
c. Model	Undetermined	
d. Year installed	N/A	
e. Serial or ID#	N/A	
f. Pollutant controlled	Particulate	
g. Controlled pollutant emission rate (if known)	0.015 lb/MMBtu	
h. Pressure drop across control device	5 –6 in H_2O	
i. Design efficiency	99.8 %	
j. Operating efficiency	Undetermined	

12b.**Control Equipment** (attach additional pages if necessary)

Item	Primary Collector	Secondary Collector
a. Type	Low NOx burners	Selective Catalytic Reduction
b. Manufacturer	Undetermined	Undetermined
c. Model	Undetermined	Undetermined
d. Year installed	N/A	N/A
e. Serial or ID#	N/A	N/A
f. Pollutant controlled	NO_x	NO_x
g. Controlled pollutant emission rate (if known)	0.35 lb/MMBtu	0.07 lb/MMBtu
h. Pressure drop across control device	N/A	N/A
i. Design efficiency	Undetermined	Undetermined
j. Operating efficiency	80% (combined)	80% (combined)

12c. **Control Equipment** (attach additional pages if necessary)

Item	Primary Collector	Secondary Collector
a. Type	Wet Limestone Flue Gas Desulfurization System	
b. Manufacturer	Undetermined	
c. Model	Undetermined	
d. Year installed	N/A	
e. Serial or ID#	N/A	
f. Pollutant controlled	SO_2, HCl, HF, H_2SO_4	
g. Controlled pollutant emission rate (if known)	0.10 lb/MMBtu (SO_2)	
h. Pressure drop across control device	8 H_2O	
i. Design efficiency	SO2=92.5%, HCl=90%, HF=90%, H_2SO_4=90+%	
j. Operating efficiency	Undetermined	

Stack Data
(attach additional pages if necessary)

13. Stack identification: 4 - COAL

14. Height: Above roof ___N/A__ ft.
Above ground ___712__ ft.

15. Are other sources vented to this stack:
☐ Yes ☒ No

If yes, identify sources:

16. ☒ Round, top inside diameter dimension _31.85_ft_

☐ Rectangular, top inside dimensions
length ________ x width ________

17. Exit gas: Temperature __256__ °F Volume _8.775 x 10^6 @ 256 °F_ acfm Velocity _63__ ft/min

18. Continuous monitoring equipment: ☒ yes ☐ no
If yes, indicate: Type _Undetermined__, Manufacturer __Undetermined____________________

Make or Model _Undetermined__, Pollutant(s) monitored __SO_2, NO_x, Opacity______

19. Emission data: Supply maximum annual emission rates (in tons/year) of PM_{10}, SO_2, NO_x, Volatile Organic Compounds, CO, and Hazardous Air Pollutants from source.

PM10 = 595	SO2 = 3964	NOx = 2775
VOC = 107	CO = 5946	HAP = 199

Check source of data: ☐ Stack test ☒ Emission factor
☒ Material balance ☐ Manufacturer

Instructions

This is a general form regarding processes and should be completed by all sources.

Please answer all questions.
If the item does not apply to the source operation write "na".
If the answer is not known write "unknown".

1. Indicate the generally accepted name for the process (i.e., asphalt batching, glass manufacturing, oil refining, etc.).
2. Specify the end product of this process (i.e., asphaltic concrete, benzene, soaps, etc.).
3. Indicate the specific process equipment for this form along with the manufacturer, model number, identifying name or code year it was or will be installed, and rated (normal) and maximum capacity of equipment.
4. Indicate the method of exhaust ventilation and indicate if there are more than one exhausts.
5. Complete the process equipment's normal operating schedule in hours per day, days per week, and weeks per year.
6. Complete the percent annual production by season for a years production of finished units. The four seasons should total to 100%.
7. Specify the average and maximum hourly production rates in pounds. The average is the year's production rate divided by the total yearly hours of production or operation.
8. Specify the annual production for this process equipment and indicate the appropriate units. Estimate the annual increase in production.
9. Check whether the process is continuous, intermittent, or batch. A batch operation normally has significant down time between completion and startup of each operation or cycle.
10. If batch, complete the minutes per production cycle and minutes between the production cycles. A "cycle" refers to the time the equipment is in operation.
11. List all general types of raw materials employed in the process, indicate the principle use (i.e., product, binder, catalyst, fuel, etc.) and specify the normal amount used in pounds per hours, tons per year, etc.
12. If your control device is not listed below complete items a through j. If your process includes any of the control devices listed below, please indicate which ones and submit the associated forms with your application. The primary collector and secondary collector refer to separate control devices or equipment for collecting similar or different air pollutants. If there is a third collector, complete the same data for that collector on a separate sheet. Addition information may be attached.

    Complete the proper form listed below for any air pollution control device:

___	Form 3	Afterburners
___	Form 4	Flares
___	Form 5	Adsorption Unit
___	Form 6	Cyclone
___	Form 7	Condenser
___	Form 8	Electrical Precipitators
_X_	Form 9	Scrubber
_X_	Form 10	Fabric Filter

13. Indicate the company's identification for the stack or exhaust.
14. Specify the stack's or exhaust's height, in feet (ft.) above ground and above the attached roof.
15. Indicate if other sources are also vented to this same stack or exhaust and identify those sources.
16. Specify the inside dimensions of the stack or exhaust at the outlet to the atmosphere.
17. Complete the specifications of the stack's or exhaust's exit gas. (Temperature in degrees Fahrenheit, volume flow rate in actual cubic feet per minute, and velocity in feet per minute.) If the properties of the exit gas vary, use the average values.
18. Indicate if the stack or exhaust is equipped with air pollution monitoring equipment. If so, specify the type, manufacturer, make or model, and the pollutant or pollutants monitored.
19. Submit the estimated emission figures from this project and indicate where the data was obtained. The stack test may be from either this reported process or a similar one located elsewhere. The emission factor calculation and determination factor should include a reference to the process emission factor and data relative to the collection or removal efficiency of any control equipments. The material balance method should include measurement methods and a flow diagram. If manufacturer data is used, a copy of it should be included with this application.

NOTE Call the Division of Air Quality at **(801) 536-4000** if you have problems or questions when completing this form. Ask for a New Source Review Section engineer. We will be glad to help!

Utah Division of Air Quality
New Source Review Section

Form 9
Scrubbers & Wet Collectors

Date May, 2003

Company Intermtn Power Service Corp .

Facility Intermountain Generation Station

Equipment Information

1. Provide diagram of internal components: See Figure 2-6	2. Manufacturer: Undetermined Model no.: Undetermined
3. Date installed: 2008, anticipated	4. Emission Equipment served: Coal-fired boiler
5. Type of pollutant(s) controlled: Particulate (type)____ ☒SO_x Odor ☒Other HF, HCl, H_2SO_4	6. Type of Scrubber: ☒ Spray Chamber ☐ Venturi ☐ Cyclone ☐ Packed Tower Type ☐ Orifice ☐ Mechanical

7. Gas Stream Characteristics

Flow rate (acfm)		Gas Stream Temperature (^oF)		Particulate Grain Loading (grains/scf)	
Design Maximum	Average Expected	Inlet	Outlet	Inlet	Outlet
3,617,028	3,617,028	284	135	Undetermined	Undetermined

8. Particulate size: Undetermined microns (mean geometric diameter)

Scrubbing Liquid Characteristics

9. Scrubbing Liquid

Composition	Wt. %
1. CaCO3	90
2. MgCO3	3
3. Ash	6.5
4. Moisture	0.5

10. Liquid Injection Rate (gpm)

Design Maximum	Average Expected
Undetermined	Undetermined

11. Pressure at Spray Nozzle Undetermined psia

12. Pressure drop through Scrubber in inches of H_2O: 8

Data for Venturi Scrubber		Data for Packed Towers	
13. Throat Dimensions (Specify Units)	14. Throat Velocity (ft/sec)	15. Type of Packing	16. Superficial Gas Velocity through Bed
N/A	N/A	N/A	N/A

Stack/exhaust Exit Data

17. Height: 712 feet	18. Temperature of exhaust stream: 135 ^oF	19. Inside dimensions: 31.85 feet diameter or feet x feet

20. **Monitoring Equipment**

Type	Manufacturer	Model	Range	Units
Gas Pressure	_Undetermined_______	__________________	________________	inches of water column
Water Flow	_____________________	__________________	________________	gallons per minute
Water Pressure	_____________________	__________________	________________	pounds per square inch

Settling Ponds

21. Dimensions of settling pond: N/A
    Width: N/A
    Length: N/A
    Depth: N/A

22. Flow rate through settling pond: N/A

23. Residence time of water in pond: N/A

NOTE: Call the Division of Air Quality (DAQ) at **(801) 536-4000** if you have problems or questions in filling out this form. We will be glad to help!

Instructions

1. Supply an assembly drawing, dimensioned and to scale of the interior dimensions and features of the equipment. Please include inlet and outlet liquid and gas flow directions and temperatures, and demister section.
2. Specify the manufacturer and model number of equipment.
3. Please indicate the date that the equipment was installed.
4. Specify what pollutant is being controlled by the scrubber/wet collector.
5. Specify what type of equipment or process the scrubber is being used for.
6. Specify the type of scrubber.
7. Supply the specifications for the gas stream including the flow rate at the design maximum and expected average, inlet and outlet temperatures, and particulate grain loading at inlet and outlet.
8. Supply the particulate mean geometric diameter.
9. Supply the composition of the scrubbing liquid used in the equipment.
10. Indicate what the liquid injection rate is for the design maximum and the expected average in gallons per minute.
11. Indicate the pressure at the spray nozzle.
12. Identify what the pressure drop through the scrubber is.
13. Indicate what the throat dimensions are for a venturi scrubber.
14. Indicate what the throat velocity is for a venturi scrubber.
15. Indicate what the type of packing is in a packed tower.
16. Specify what the gas velocity is through the bed in a packed tower.
17. Indicate what the stack height is of the scrubber.
18. Indicate the temperature of the exhaust gas.
19. Supply the inside dimensions of the stack.
20. Supply specifications of any monitoring equipment which is used in the system.
21. Specify the dimensions of the settling pond.
22. Indicate the flow rate of the water through the settling pond.
23. Supply the residence time of the water in the settling pond.

Utah Division of Air Quality
New Source Review Section

Form 10
Fabric Filters (Baghouses)

Date ______May 2003______
Company __Intermountain Power Service Corp
Site Name __Intermountain Generation Station_

Owner Information and Location of Proposed Installation

1. Briefly describe the process controlled by this baghouse:

Control for particulate matter produced from coal combustion.

Gas Stream Characteristics

2. Flow Rate (acfm):		3. Water Vapor Content of Effluent Stream (lb. water/lb. dry air)	4. Particulate Loading	
Design Max 3,628,000 @ 275 – 300 °F	Ave. Expected 3,199,000 @ 275 – 300 °F	Undetermined	Inlet 8.58 lb/MMBtu	Outlet 0.015 lb/MMBtu
5. Pressure Drop (inches H_2O) High _6________ Low _5_______		6. Gas Stream Temperature (°F): 275 – 300	7. Fan Requirements (hp) (ft^3/min) Undetermined	

Equipment Information and Filter Characteristics

8. Manufacturer and Model Number To be decided during design (TBD)

9. Bag Material	10. Bag Diameter (in.)	11. Bag Length (ft.)	12. Number of Bags:	13. Stack Height (ft.)
☐ Nomex nylon ☐ Polyester ☐ Acrylics ☐ Fiber glass ☐ Cotton ☐ Teflon ☒ Undetermined	Undetermined	Undetermined	Undetermined	___712_______ Stack Inside Diam. (in.) ___382.2___
	14. Filtering Efficiency Rating: __99.83 %	15. Air to Cloth Ratio: ____2 : 1	16. Operation Hours: Max Per day: __24____ Max Per yr: _8760_	17. Cleaning Mechanism: ☒ Reverse Air ☐ Shaker ☐ Pulse Jet ☐ Other ________________________

Fabric Filters (Baghouses)
Form 10 (Continued)

Instructions

1. Describe the process equipment that the filter controls, what product is being controlled, particle size data (if available), i.e., cement silo, grain silo, nuisance dust in work place, process control with high dust potential, etc.
2. The *maximum* and *design* exhaust gas flow rates through the filter control device in actual cubic feet per minute (ACFM). Check literature or call the sales agent.
3. The water/moisture content of the gas stream going through the filter.
4. The amount of particulate in the gas stream going into the filter and the amount coming out if available. Outlet default value = 0.016 grains PM_{10}/dscf.
5. The pressure drop range across the system. Usually given in the literature in inches of water.
6. The temperature of the gas stream entering the filter system in degrees Fahrenheit.
7. The horse power of the fan used to move the gas stream and/or the flow rate of the fan in ft^3/min.
8. Name of the manufacturer of the filter equipment and the model number if available.
9. Check the type of filter bag material or fill in the blank. Check literature or call the sales agent.
10. The diameter of the bags in the system. Check literature or call the sales agent.
11. The length of the bags in the system. Check literature or call the sales agent.
12. The number of bags. Check literature or call the sales agent.
13. The height to the top of the stack from ground level and the stack inside diameter.
14. The filtering efficiency rating that the manufacturer quotes. Check literature or call the sales agent.
15. The ratio of the flow rate of air to the cloth area (A/C).
16. The number of hours that the process equipment is in operation, maximum per day and per year.
17. The way in which the filters bags are cleaned. Check the appropriate box.

NOTE Call the Division of Air Quality at **(801) 536-4000** if you have problems or questions when completing this form. Ask for a New Source Review engineer. We will be glad to help!

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revised 2/3/97

APPENDIX B

Title V Application Forms

Utah Division of Air Quality

OPERATING PERMIT APPLICATION

APPLICATION FOR: ☐ INITIAL
☒ MODIFICATION
☐ RENEWAL

AN APPLICATION FOR A PERMIT TO OPERATE MUST BE SUBMITTED WITHIN 12 MONTHS OF COMMENCING OPERATION OR OCTOBER 10, 1995, WHICHEVER IS LATER; OR, FOR RENEWALS, NOT LATER THAN THE RENEWAL DATE. This is not a stand alone document. Please refer to the Utah Administrative Code or the Permit Application Instructions for specific details required to complete the application. Please print or type all information requested. A completeness review will be made utilizing a Completeness Checklist. If you would like a copy of the checklist or if you have any questions please contact the Operating Permit Section of the Division of Air Quality at (801) 536-4000. Written inquiries may be addressed to: Division of Air Quality, Operating Permit Section, P.O. Box 144820, Salt Lake City, Utah 84114-4820.

GENERAL OWNER AND PLANT INFORMATION

1. Company name and address: Intermountain Power Service Corporation 850 West Brush Wellman Road Delta, Utah 84624 Phone: (435) 864-4414 FAX: (435) 864-4970	2. Company contact for environmental issues: Dennis Killian, Technical Services Superintendant Intermountain Power Service Corporation 850 West Brush Wellman Road Delta, Utah 84624 Phone No.: (435) 864-4414 Fax No.: (435) 864-6670
3. Plant name and address, and plant contact (if different from above): Intermountain Generation Station 850 West Brush Wellman Road Delta, Utah 84624 Phone: (435) 864-4414 FAX: (435) 864-4970	4. Owner's name and address (if different from #1): N/A Phone: ( ) FAX: ( )

5. Is plant permanent? ☒ Yes ☐ No If not, how long will equipment be at this location?

6. County plant is located in: Millard Are you within 50 miles of state border? ☐ Yes ☒ No

7. Directions to plant (street address and/or directions to site to include U.S. Geological Survey map if necessary): 850 West Brush Wellman Road, Delta, Utah 84624

8. Identify any current Approval Order(s) (continue on separate sheet if necessary): Grandfathered? ☐ Yes ☒ No
AO# DAQE-049-02 Date __/__/__ AO#____ Date __/__/__
AO#____ Date __/__/__ AO#____ Date __/__/__
AO#____ Date __/__/__ AO#____ Date __/__/__

9. If request for modification, previous operating permit # and date:
DAQO # 27100010001 DATE: 11 / 05 / 01

10. Type of business at this plant: Coal – fired electric generating facility

11. Is your company a Small Business? ☐ Yes ☒ No	12. Standard Industrial Classification (SIC) Code (See Instructions): [4][9][1][1]

PROCESS INFORMATION

13. Site plan of plant drawn to scale to include location of emission units (Figure 8-2):

14. Flow diagram of emission unit(s) at the plant to include flow rates and other applicable information: See Figures 2-2 through 2-6

15. Detailed process/equipment description. See Section 2
Description must include:

☒ Process/Equipment specific form(s) identified in the instructions (In this appendix)
☒ Fuels and their use ☒ Equipment used in process ☒ Description of product(s)
☒ Raw materials used ☒ Operation schedules (include daily/seasonal variances) ☒ Description of changes to process (if applicable)
☒ Production rates

16. Does this application contain confidential information? ☐ Yes ☒ No
If yes, mark those portions claimed confidential and submit a statement in support of the claim.

17. Are you requesting that the permit include Alternative Operating Scenario(s)? ☐ Yes ☒ No
If yes, include the detailed information described in this application for each alternative requested.

EMISSIONS RELATED INFORMATION

18. Describe all potential emissions of air pollutants. See Section 3
Include the following:

☒ Emissions for which the source is major.
☒ Emissions of regulated air pollutants.
☒ Emissions of hazardous air pollutants.
☒ Description of any operational constraints or work practices imposed that limit the amount of regulated or hazardous air pollutants.
☒ Emissions above described in appropriate units (lbs/hr, lbs/day, ppm, etc.) based on the underlying standard, and in tons/year.
☒ All calculations, including conversion factors as appropriate, to support the emissions data above.

19. Identify on the site plan (see #13 above) all emissions points; and all relevant building dimensions, stack parameters, etc.

20. List and describe any insignificant emission units. (Section 3)

21. List all air pollution control equipment and include equipment specific forms identified in the instructions.
See Sections 2 and 6

MONITORING INFORMATION

22. List and describe all compliance monitoring devices and activities.See Section 9

23. Cite and describe any applicable test methods used for determining compliance. See Section 9

APPLICABLE REQUIREMENTS

24. Cite and describe all applicable requirements with regard to (but not limited to) the following: See Section 5
☐ SIP ☒ HAP ☒ NSPS ☒PSD ☐ NSR ☒ UACR ☒ Title IV ☒ Approval Order ☐ Other

25. Are there any proposed exemptions from applicable requirements? (If yes, attach as Appendix I) ☐ Yes ☒ No

ADDITIONAL INFORMATION

26. Is the trading of emissions involved? (If yes, include detailed description as Appendix J) ☐ Yes ☒ No

27. Has a Risk Management Plan been forwarded to Region VIII, EPA, in accordance with 40 CFR Part 68?
☒Yes ☐ No ☐ RMP Not Required
Current RMP on file at EPA for Units 1 & 2. RMP may require an update for the addition of Unit 3.

COMPLIANCE PLAN AND CERTIFICATION

28. Compliance Plan (Attach as Appendix K)
Plan must include the following:

- ☐ Description of compliance status with respect to all applicable requirements.
- ☐ A statement that source will continue to comply with all requirements with which the source is in compliance.
- ☐ A statement that source will comply with any requirement that becomes effective during term of permit.
- ☐ For requirements not being complied with, a detailed narrative description of how you will achieve compliance.

29. Compliance Schedule (Include with Appendix K)
Schedule must include the following:

- ☐ A statement that source will continue to comply with all requirements with which the source is in compliance.
- ☐ A statement that source will comply with any requirement that becomes effective during term of permit.
- ☐ A schedule of remedial measures to come into compliance with any requirement not being met. Include any outstanding Notice Of Violations (NOVs) and date.
- ☐ An enforceable sequence of actions, with milestones, leading to compliance.
- ☐ A schedule for submission of certified progress reports at least every 6 months for sources out of compliance.

30. Compliance Plan Certification (Include with Appendix K)
The responsible official must certify the truth, accuracy, and completeness of the compliance plan in accordance with R307-425-5c(9) and provide other information related to compliance.

- ☐ Include a certification of compliance with all applicable requirements by a responsible official consistent with R307-415-5d.
- ☐ Include a statement of the methods used for determining compliance, to include a description of:
  - ☐ Monitoring
  - ☐ Recordkeeping
  - ☐ Reporting requirements
  - ☐ Test methods
- ☐ Include a schedule for submission of compliance certifications during the permit term to be submitted annually or as specified by the applicable requirement.
- ☐ Include a statement indicating the compliance status with any applicable enhanced monitoring and compliance certification requirements of the Act.

CERTIFICATION OF APPLICATION

31. In accordance with UAC R307-415-5d, I hereby certify that the information and data submitted in and with this application are true, accurate and complete, based on information and belief formed after reasonable inquiry.

Signature: George W. Cross   Title: President & Chief Operations Officer & Designated Official

32. George W. Cross Name (Typed or printed)	33. Telephone Number: (435) 864-4414	34. Date: 12/10/02

APPENDIX C

Emissions Calculations

Intermountain Power Project
Unit 3
Emission Calculations

Revised May 13, 2003

Emission Workbook sheets include:

Units 1 and 2 Boiler Criteria Emissions	Units 1 and 2 Flyash Handling	Unit 3 Ash Hauling - Paved Roads
Unit 3 Boiler Criteria Emissions	Unit 3 Flyash Handling	Units 1 and 2 FGD Sludge Hailing - Unpaved Roads
Unit 1 Cooling Tower	Units 1, 2 and 3 Limestone Handling	Unit 3 FGD Sludge Hauling - Unpaved Roads
Unit 2 Cooling Tower	Units 1 and 2 Limestone Pile	Units 1 and 2 Coal Pile
Unit 3 Cooling Tower	Unit 3 Limestone Pile	Unit 3 Coal Pile
Auxilliary Boilers 1A and 1B	Units 1, 2 and 3 Water Treatment	Units 1 and 2 Coal Handling
Fire Pumps 1B and 1C	Units 1 and 2 FGD Sludge Handling	Units 1, 2 and 3 Coal Handling
Emergency Generators 1A, 1B and 1C	Unit 3 FGD Sludge Handling	Unit 3 Coal Handling
Unit 3 Hazardous Air Pollutants	Units 1 and 2 Ash Hauling - Paved Roads	Sargent & Lundy Unit 3 Design Calculations

IPP Unit 3 Project
Units 1 and 2 Boiler Criteria Emissions

	2000/2001 Average Pre-Construction			Post-Construction Design		
	Unit 1	**Unit 2**	**Total**	**Unit 1**	**Unit 2**	**Total**
Unit Design Information						
Design Gross Output (MW)	875	875		950	950	
Design Boiler Heat Input (mmBtu/hr)	8,500	8,500		9,225	9,225	
Operating Hours (hours)	8,219	8,243	16,462	8,760	8,760	
Coal Burned (tons)	2,662,538	2,655,715	5,318,252			
Fuel Oil Burned (gallons)	273,404	226,460	499,864			
Coal Heating Value (Btu/lb)	11,898	11,898				
Fuel Oil Heating Value (Btu/gal)	137,441	137,441				
Stack Parameters						
Stack Height (ft):	712	712		712	712	
Stack Exit Diameter (ft):	28.0	28.0		28.0	28.0	
Stack Temperature (F):	115	115		115	115	
Exhaust Flow (scfh)	125,000,000	125,000,000		133,000,000	133,000,000	
Exhaust Flow (acfm)	2,872,505	2,872,505		3,056,345	3,056,345	
Exit Velocity (ft/s):	77.8	77.8		82.7	82.7	
Permit Limits						
NO_x (lb/mmBtu)	0.50	0.50		0.461	0.461	
SO_2 (lb/mmBtu)	0.15	0.15		0.138	0.138	
PM_{10} (lb/mmBtu)	0.020	0.020		0.018	0.018	
Emissions						
NO_x (tons)	13,410.00	12,988.00	26,398.00			
NO_x (lb/hr)	3,263.17	3,151.47	6,414.64			
NO_x (short-term PTE, lb/hr)	4,250.00	4,250.00	8,500.00	4,252.73	4,252.73	8,505.45
SO_2 (tons)	1,884.60	1,952.70	3,837.30			
SO_2 (lb/hr)	458.60	473.81	932.41			
SO_2 (short-term PTE, lb/hr)	1,275.00	1,275.00	2,550.00	1,273.05	1,273.05	2,546.10
Filterable PM_{10} (tons)	153.20	87.40	240.60			
Filterable PM_{10} (lb/hr)	37.28	21.21	58.49			
Filterable PM_{10} (short-term PTE, lb/hr)	170.00	170.00	340.00	166.05	166.05	332.10
HCL (tons)	23.55	23.76	47.31			
HCL (lb/hr)	5.73	5.77	11.50			
HF (tons)	5.05	4.99	10.03			
HF (lb/hr)	1.23	1.21	2.44			
H_2SO_4 (tons)	2.00	2.01	4.01			
H_2SO_4 (lb/hr)	0.49	0.49	0.97			
Condensable PM_{10} (total, tons)	30.60	30.76	61.36			
Condensable PM_{10} (total, lb/hr)	7.45	7.46	14.91			
CO (tons)	665.63	663.93	1,329.56			
CO (lb/hr)	161.97	161.10	323.07			
CO (oil, tons)	0.68	0.57	1.25			
CO (oil, lb/hr)	0.17	0.14	0.30			
VOC (tons)	6.33	6.32	12.65			
VOC (lb/hr)	1.54	1.53	3.07			
VOC (oil, tons)	0.03	0.02	0.05			
VOC (oil, lb/hr)	0.01	0.01	0.01			
Lead (tons)	0.04	0.04	0.09			
Lead (lb/hr)	0.01	0.01	0.02			

Notes:

1) Unit design information and stack parameters for pre-construction and post-construction are based on the NOI for Modification Units 1 & 2, Attachment 1, Worksheet A, April 4, 2001.

2) NO_x, SO_2 and PM_{10} permit limits for pre-construction and post-construction based on UDAQ approval orders.

3) Pre-Construction emissions based on the average of Year 2000 and Year 2001 emission inventories.

4) Facility is permitted for 600,000 gallons of fuel oil use per year.

5) Emissions of CO and VOC for fuel oil combustion based on AP-42 factors. (5.0 lbs CO/1000 gallons oil burned, 0.2 lbs VOC/1000 gallons oil burned).

6) Short-term Potential to Emit (PTE) lb/hr emission rates for NO_x, SO_2 and PM_{10} were determined by multiplying the Approval Order permit limits times the maximum boiler hourly heat input.

7) Condensable PM_{10} emissions include HCL, HF and H_2SO_4. Emissions based on average of 2000 and 2001 emission inventories.

IPP Unit 3 Project
Unit 3 Boiler Criteria Pollutant Potential To Emit

Revised May 13, 2003

Design Western Bituminous Coal

	Maximum 105% Load	100% Load	75% Load	50% Load	Emission Factor Source
Gross Unit Output (MW)	998	950	713	475	Sargent & Lundy
Net Unit Output (MW)	924	880	656	433	Sargent & Lundy
Coal Feed Rate (tons/hr)	404	385	295	201	Sargent & Lundy
Coal Feed Rate (tons/year)	3,541,246	3,372,614	2,581,051	1,756,988	Calculated
Heat Input to Boiler (MMBtu/hr)	9,050	8,619	6,596	4,490	Sargent & Lundy
Fuel Heat Value (Btu/lb)	11,193	11,193	11,193	11,193	Calculated
Annual Capacity Factor (%/yr)	100	100	100	100	Sargent & Lundy
NOx [PSD sig level = 40 tpy]					
NOx Boiler Emissions (lb/MMBtu)	0.35	0.35	0.35	0.35	Sargent & Lundy
NOx Boiler Emissions (lb/hr)	3167.4	3016.5	2308.5	1571.5	Calculated
SCR Control Efficiency (%)	80.0	80.0	80.0	80.0	Sargent & Lundy
NOx Stack Emissions (lb/MMBtu)	0.070	0.070	0.070	0.070	Sargent & Lundy
NOx Stack Emissions (lb/hr)	633.5	603.3	461.7	314.3	Calculated
NOx Stack Emissions (tpy)	2,775	2,642	2,022	1,377	Calculated
SO_2 [PSD sig level = 40 tpy]					
SO_2 Boiler Emissions (lb/MMBtu)	1.34	1.34	1.34	1.34	Sargent & Lundy
SO_2 Boiler Emissions (lb/hr)	12,128	11,550	8,839	6,017	Calculated
FGD Control Efficiency (%)	92.6	92.6	92.6	92.6	Sargent & Lundy
SO_2 Stack Emissions (lb/MMBtu)	0.100	0.100	0.100	0.100	Sargent & Lundy
SO_2 Stack Emissions (lb/hr)	905.0	861.9	659.6	449.0	Calculated
SO_2 Stack Emissions (tpy)	3,964	3,775	2,889	1,967	Calculated
CO [PSD sig level = 100 tpy]					
CO Emission Factor (lb/MMBtu)	0.154	0.154	0.154	0.154	Sargent & Lundy
CO Stack Emissions (lb/hr)	1390.6	1324.4	1013.6	690.0	Calculated
CO Stack Emissions (tpy)	6,091	5,801	4,439	3,022	Calculated
Filterable PM [PSD sig level = 25 tpy]					
Baghouse Control Efficiency (%)	99.83	99.83	99.83	99.83	Sargent & Lundy
Filterable PM Stack Emissions (lb/MMBtu)	0.020	0.020	0.020	0.020	BACT analysis
Filterable PM Stack Emissions (lb/hr)	181.0	172.4	131.9	89.8	Calculated
Filterable PM Stack Emissions (tpy)	793	755	578	393	Calculated
PM_{10} [PSD sig level = 15 tpy]					
Filterable PM_{10}					
Baghouse Control Efficiency (%)	99.83	99.83	99.83	99.83	Sargent & Lundy
Filterable PM_{10} Stack Emissions (lb/MMBtu)	0.015	0.015	0.015	0.015	Sargent & Lundy
Filterable PM_{10} Stack Emissions (lb/hr)	135.7	129.3	98.9	67.3	Calculated
Filterable PM_{10} Stack Emissions (tpy)	595	566	433	295	Calculated
Condensable PM_{10}[2]					
Cond. PM_{10} Stack Emissions (lb/MMBtu)	0.009	0.010	0.010	0.010	Sargent & Lundy
Cond. PM_{10} Stack Emissions (lb/hr)	85.2	82.3	63.0	42.9	Calculated
Cond. PM_{10} Stack Emissions (tpy)	373	360	276	188	Calculated
Total PM_{10}					
Total PM_{10} Stack Emissions (lb/MMBtu)	0.024	0.025	0.025	0.025	Calculated Total
Total PM_{10} Stack Emissions (lb/hr)	221.0	211.5	161.9	110.2	Calculated
Total PM_{10} Stack Emissions (tpy)	968	927	709	483	Calculated
Lead [PSD sig level = 0.6 tpy]					
Lead Emission Factor (lb/ton)	4.2E-04	4.2E-04	4.2E-04	4.2E-04	AP-42 Table 1.1-18
Lead Emissions (lb/hr)	0.17	0.16	0.12	0.08	Calculated
Lead Emissions (tpy)	0.74	0.71	0.54	0.37	Calculated
VOC [PSD sig level = 40 tpy[3]]					
VOC Emissions (lb/MMBtu)	0.00268	0.00268	0.00268	0.00268	Sargent & Lundy
VOC Emissions (lb/hr)	24.3	23.1	17.7	12.0	Calculated
VOC Emissions (tpy)	106.2	101.2	77.4	52.7	Calculated

IPP Unit 3 Project
Unit 3 Boiler Criteria Pollutant Potential To Emit

Revised May 13, 2003

	Design Western Bituminous Coal				
	Maximum 105% Load	100% Load	75% Load	50% Load	Emission Factor Source
Sulfuric Acid Mist [PSD sig level = 7 tpy]					
FGD Control Efficiency for H_2SO_4 (%)	90.3	90.0	90.0	90.0	Sargent & Lundy
H_2SO_4 Stack Emissions (lb/MMBtu)	0.00439	0.00451	0.00451	0.00451	Based on IPP Unit 1 Stack Test and S&L design calculations
H_2SO_4 Stack Emissions (lb/hr)	39.7	38.9	29.8	20.3	Calculated
H_2SO_4 Stack Emissions (tpy)	174	170	130	89	Calculated
Ammonium Sulfate [No PSD sig level]					
FGD Control Efficiency for $(NH_4)_2SO_4$ (%)	90.0	90.0	90.0	90.0	Sargent & Lundy
$(NH_4)_2SO_4$ Stack Emissions (lb/MMBtu)	0.00030	0.00030	0.00030	0.00030	Sargent & Lundy
$(NH_4)_2SO_4$ Stack Emissions (lb/hr)	2.7	2.6	2.0	1.3	Calculated
$(NH_4)_2SO_4$ Stack Emissions (tpy)	12	11	9	6	Calculated
Hydrogen Chloride [No PSD sig level]					
FGD Control Efficiency for HCl (%)	90.0	90.0	90.0	90.0	Sargent & Lundy
HCl Stack Emissions (lb/MMBtu)	0.00421	0.00421	0.00421	0.00421	Sargent & Lundy
HCl Stack Emissions (lb/hr)	38.1	36.3	27.8	18.9	Calculated
HCl Stack Emissions (tpy)	167	159	122	83	Calculated
Hydrogen Fluoride [PSD sig level = 3 tpy]					
FGD Control Efficiency for HF (%)	90.0	90.0	90.0	90.0	Sargent & Lundy
HF Stack Emissions (lb/MMBtu)	0.001	0.001	0.001	0.001	Sargent & Lundy
HF Stack Emissions (lb/hr)	4.7	4.5	3.4	2.3	Calculated
HF Stack Emissions (tpy)	21	20	15	10	Calculated
Total Reduced Sulfur [PSD sig level = 10 tpy[4]]					
TRS Stack Emissions (lb/MMBtu)	0.001	0.001	0.001	0.001	AP-42 Table 1.1-3 (b)
TRS Stack Emissions (lb/hr)	6.7	6.4	4.9	3.3	Calculated
TRS Stack Emissions (tpy)	29	28	21	14	Calculated
Reduced Sulfur Compounds [PSD sig level = 10 tpy[4]]					
RSC Stack Emissions (lb/MMBtu)	0.001	0.001	0.001	0.001	AP-42 Table 1.1-3 (b)
RSC Stack Emissions (lb/hr)	6.7	6.4	4.9	3.3	Calculated
RSC Stack Emissions (tpy)	29	28	21	14	Calculated
Stack Conditions					
Stack Exit Flow (acfm)	3,244,126	3,089,643	2,364,494	1,609,573	Sargent & Lundy
Stack Exit Diameter (feet)	31.85	31.85	31.85	31.85	Sargent & Lundy
Stack Exit Temperature (degF)	135	135	135	135	Sargent & Lundy
Stack Exit Velocity (fps)	67.85	64.62	49.45	33.66	Calculated

Notes:

(1) Emissions based on design data from Sargent & Lundy

(2) Condensible PM_{10} includes HCL, HF, H_2SO_4 and $(NH_4)_2SO_4$.

(3) No modeling significance level has been established for VOC. From the EPA NSR Workshop Manual: *No significant ambient concentration has been established. Instead any net emission increase of 100 tpy of VOC subject to PSD would be required to perform an ambient impact analysis.*

(4) Emission Factor for Total Reduced Sulfur and Reduced Sulfur Compounds based on Footnote b of AP-42 Table 1.1-3.

(5) Emission Factor for H_2SO_4 developed based on IPP Unit 1 acid mist testing conducted on 04/23/03 and 04/24/03 and engineering calculations related to Unit 3 SCR SO_2 to SO_3 conversion and resultant H_2SO_4 collection in FGD.

IPP Unit 3 Project
Unit 1 Cooling Towers (Towers 1A, 1B, Helper 1)

Method from AP 42, Sect.13.4-1

Emissions	Tower 1A	Tower 1B	Helper Tower 1
Water Flow Rate (gal/min)	136,500	136,500	50,000
Flow of cooling water (lbs/hr)	68,222,700	68,222,700	24,990,000
TDS of blowdown (mg/l or ppmw)	14,928	14,928	14,928
Flow of dissolved solids (lbs/hr)	1,018,428	1,018,428	373,051
Fraction of flow producing PM_{10} drift (see Note 2)	0.05	0.05	0.05
Control efficiency of drift eliminators (gal drift/gal flow)	0.000020	0.000020	0.000010
PM emissions from tower (lb/hr)	20.369	20.369	3.731
PM_{10} emissions from tower (lb/hr)	1.018	1.018	0.187
PM emissions from tower (tpy)	89.214	89.214	16.340
PM_{10} emissions from tower (tpy)	4.461	4.461	0.817
Particulate (PM-10) emissions from each tower cell (g/s)	0.011	0.011	0.006
Particulate (PM-10) emissions from each tower cell (lb/hr)	0.085	0.085	0.047

Other Parameters

Number of cells per tower (outlet fans)	12	12	4
Height at cell release (ft):	50	50	48
Discharge flow per cell (ACFM):	1,340,000	1,340,000	1,340,000
Diameter of each cell (ft):	36	36	44
Area of cell discharge (ft^2):	1,018	1,018	1,521
Average Temperature of cell discharge (degF):	79	75	82
Exit Velocity (ft/s):	21.9	21.9	14.7

Notes:

(1) The total circulating water flow rate for Unit 1 is 323,000 gpm. The helper tower has a design circulating water flow rate of 50,000 gpm. The circulating tower flow rate for towers 1A and 1B is (323,000 - 50,000)/2.
(2) From "Calculating Realistic PM_{10} Emissions From Cooling Towers" (J. Reisman, G. Frisbie). Presented at 2001 AWMA Annual Meeting.
(3) TDS based on 2001 average data for Unit 1 towers.
(4) Average Cell Discharge Temperature based on 2001 data for towers 1A and 1B and design data for helper tower.
(5) Discharge Air Flow for helper tower estimated to be the same as towers 1A and 1B on a per cell basis.

IPP Unit 3 Project
Unit 2 Cooling Towers (Towers 2A, 2B, Helper 2)

Method from AP 42, Sect.13.4-1

Emissions (each tower)	Tower 2A	Tower 2B	Helper Tower 2
Water Flow Rate (gal/min)	136,500	136,500	50,000
Flow of cooling water (lbs/hr)	68,222,700	68,222,700	24,990,000
TDS of blowdown (mg/l or ppmw)	15,220	15,220	15,220
Flow of dissolved solids (lbs/hr)	1,038,349	1,038,349	380,348
Fraction of flow producing PM_{10} drift (see Note 2)	0.05	0.05	0.05
Control efficiency of drift eliminators (gal drift/gal flow)	0.000020	0.000020	0.000010
PM emissions from tower (lb/hr)	20.767	20.767	3.803
PM_{10} emissions from tower (lb/hr)	1.038	1.038	0.190
PM emissions from tower (tpy)	90.959	90.959	16.659
PM_{10} emissions from tower (tpy)	4.548	4.548	0.833
Particulate (PM-10) emissions from each tower cell (g/s)	0.011	0.011	0.006
Particulate (PM-10) emissions from each tower cell (lb/hr)	0.087	0.087	0.048

Other Parameters

Number of cells per tower (outlet fans)	12	12	4
Height at cell release (ft):	50	50	48
Discharge flow per cell (ACFM):	1,340,000	1,340,000	1,340,000
Diameter of each cell (ft):	36	36	44
Area of cell discharge (ft^2):	1,018	1,018	1,521
Average Temperature of cell discharge (degF):	81	81	82
Exit Velocity (ft/s):	21.9	21.9	14.7

Notes:
(1) The total circulating water flow rate for Unit 2 is 323,000 gpm. The helper tower has a design circulating water flow rate of 50,000 gpm. The circulating tower flow rate for towers 2A and 2B is (323,000 - 50,000)/2.
(2) From "Calculating Realistic PM_{10} Emissions From Cooling Towers" (J. Reisman, G. Frisbie). Presented at 2001 AWMA Annual Meeting.
(3) TDS based on 2001 average data for Unit 2 towers.
(4) Average Cell Discharge Temperature based on 2001 data for towers 2A and 2B and design data for helper tower.
(5) Discharge Air Flow for helper tower estimated to be the same as towers 2A and 2B on a per cell basis.

IPP Unit 3 Project
Unit 3 Cooling Towers (Towers 3A, 3B)

Method from AP 42, Sect.13.4-1

	Option 1 Rectangular Tower		Option 2 Cross Design Tower	
Emissions	**Tower 3A**	**Tower 3B**	**Tower 3A**	**Tower 3B**
Water Flow Rate (gal/min)	187,500	187,500	187,500	187,500
Flow of cooling water (lbs/hr)	93,712,500	93,712,500	93,712,500	93,712,500
TDS of blowdown (mg/l or ppmw)	15,074	15,074	15,074	15,074
Flow of dissolved solids (lbs/hr)	1,412,622	1,412,622	1,412,622	1,412,622
Fraction of flow producing PM_{10} drift (See Note 2)	0.05	0.05	0.05	0.05
Control efficiency of drift eliminators (gal drift/gal flow)	0.000005	0.000005	0.000005	0.000005
PM emissions from tower (lb/hr)	7.063	7.063	7.063	7.063
PM_{10} emissions from tower (lb/hr)	0.353	0.353	0.353	0.353
PM emissions from tower (tpy)	30.936	30.936	30.936	30.936
PM_{10} emissions from tower (tpy)	1.547	1.547	1.547	1.547
Particulate (PM-10) emissions from each tower cell (g/s)	0.003	0.003	0.004	0.004
Particulate (PM-10) emissions from each tower cell (lb/hr)	0.024	0.024	0.029	0.029

Other Parameters

Number of cells per tower (outlet fans)	15	15	12	12
Height at cell release (ft):	50.3	50.3	60.8	60.8
Discharge flow per cell (ACFM):	1,532,000	1,532,000	1,658,000	1,658,000
Diameter of each cell (ft):	28	28	28	28
Area of cell discharge (ft^2):	616	616	616	616
Average Temperature of cell discharge (degF):	88	88	88	88
Exit Velocity (ft/s):	41.5	41.5	44.9	44.9

Notes:

(1) Cooling Tower design data from Sargent & Lundy.

(2) From "Calculating Realistic PM_{10} Emissions From Cooling Towers" (J. Reisman, G. Frisbie). Presented at 2001 AWMA Annual Meeting.

(3) TDS based on 2001 average data for IPP Units 1 and 2 cooling towers.

IPP Unit 3 Project
Auxiliary Boilers 1A and 1B

Design Information (per boiler)

Stack Height (ft):	56	
Stack Exit Diameter (ft):	4.5	[based on 48" square]
Area of Discharge (ft^2):	16.0	
Exhaust Temperature (degF)	528	
Exhaust Flow (ACFM):	76,507	
Exit Velocity (ft/s):	80	
Maximum Fuel Firing Rate (gal/hr)	1,212	
Annual Fuel Consumption (gal/yr))	1,050,000	
Fuel Oil Heating Calue (Btu/gal)	137,000	

Emissions (per boiler)

Unit	Heat Input Rating (MMBTU/hr)	Fuel Type (Diesel, LPG, or Natural Gas)	Fuel Consumption	Fuel Usage Units	NOx Emission Factor	CO Emission Factor	SO2 Emission Factor	PM10 Emission Factor	VOC Emission Factor	Lead Emission Factor	Emission Factor Units
1A	166.000	Diesel	1,050,000	gal/yr	0.020	0.005	0.0864	0.002	0.00034	8.30E-06	lbs/gal
1B	166.000	Diesel	1,050,000	gal/yr	0.020	0.005	0.0864	0.002	0.00034	8.30E-06	lbs/gal

	Annual Emissions						Maximum Hourly Emissions					
Unit	NOx Emissions (TPY)	CO Emissions (TPY)	SO2 Emissions (TPY)	PM10 Emissions (TPY)	VOC Emissions (TPY)	Lead Emissions (TPY)	NOx Emissions (lbs/hr)	CO Emissions (lbs/hr)	SO2 Emissions (lbs/hr)	PM10 Emissions (lbs/hr)	VOC Emissions (lbs/hr)	Lead Emissions (lbs/hr)
1A	10.500	2.625	45.360	1.050	0.179	4.36E-03	24.23	6.06	104.69	2.42	0.41	1.01E-02
1B	10.500	2.625	45.360	1.050	0.179	4.36E-03	24.23	6.06	104.69	2.42	0.41	1.01E-02

Notes:
1.) Auxilliary Boilers 1A and 1B serve the exisiting plant (Units 1 and 2)
2.) Design information based on Intermountain Generating Station Title V Permit application.
3.) Fuel consumption based on maximum of 25,000 barrels per year per boiler based on Title V permit condition.
4.) Diesel emission factors obtained from Tables 1.3-1 through 1.3-7 in AP-42 Guidance Document dated October 1996. Sulfur content was assumed to be 0.05% of diesel fuel.

IPP Unit 3 Project
Fire Pumps 1B and 1C

Unit	Engine Power (BHP)	Hours of Operation (hrs/yr)	Potential Hours of Operation (hrs/yr)	Fuel Type (Diesel or Mogas)	NOx Emission Factor (lbs/hp-hr)	CO Emission Factor (lbs/hp-hr)	SO2 Emission Factor (lbs/hp-hr)	PM10 Emission Factor (lbs/hp-hr)	VOC Emission Factor (lbs/hp-hr)	NOx Emissions (TPY)	NOx Annual (lbs/hr)	NOx Maximum (lbs/hr)	CO Emissions (TPY)	CO Annual (lbs/hr)	CO Maximum (lbs/hr)	SO2 Emissions (TPY)	SO2 Annual (lbs/hr)	SO2 Maximum (lbs/hr)	PM10 Emissions (TPY)	PM10 Annual (lbs/hr)	PM10 Maximum (lbs/hr)	VOC Emissions (TPY)	VOC Annual (lbs/hr)	VOC Maximum (lbs/hr)
1B	290	500	500	Diesel	3.10E-02	6.70E-03	2.10E-03	2.20E-03	2.50E-03	2.248	0.004	8.990	0.486	0.001	1.943	0.152	0.000	0.609	0.160	0.000	0.638	0.181	0.000	0.725
1C	290	500	500	Diesel	3.10E-02	6.70E-03	2.10E-03	2.20E-03	2.50E-03	2.248	0.004	8.990	0.486	0.001	1.943	0.152	0.000	0.609	0.160	0.000	0.638	0.181	0.000	0.725

Notes:
1.) Fire Pumps 1B and 1C serve the exisiting plant (Units 1 and 2)
2.) Design information based on Intermountain Generating Station Title V Permit application.
3.) Diesel emission factors based on AP-42 Section 3.3. Sulfur content was assumed to be 0.05% of diesel fuel.

IPP Unit 3 Project
Emergency Generators 1A, 1B and 1C

Unit	Engine Power (BHP)	Hours of Operation (hrs/yr)	Potential Hours of Operation (hrs/yr)	Fuel Type (Diesel or Mogas)	NOx Emission Factor (lbs/hp-hr)	CO Emission Factor (lbs/hp-hr)	SO2 Emission Factor (lbs/hp-hr)	PM10 Emission Factor (lbs/hp-hr)	VOC Emission Factor (lbs/hp-hr)	NOx Emissions (TPY)	NOx Annual (lbs/hr)	NOx Maximum (lbs/hr)	CO Emissions (TPY)	CO Annual (lbs/hr)	CO Maximum (lbs/hr)	SO2 Emissions (TPY)	SO2 Annual (lbs/hr)	SO2 Maximum (lbs/hr)	PM10 Emissions (TPY)	PM10 Annual (lbs/hr)	PM10 Maximum (lbs/hr)	VOC Emissions (TPY)	VOC Annual (lbs/hr)	VOC Maximum (lbs/hr)
1A	4000	500	500	Diesel	3.10E-02	6.70E-03	2.10E-03	2.20E-03	2.50E-03	31.000	0.062	124.000	6.700	0.013	26.800	2.100	0.004	8.400	2.200	0.004	8.800	2.500	0.005	10.000
1B	4000	500	500	Diesel	3.10E-02	6.70E-03	2.10E-03	2.20E-03	2.50E-03	31.000	0.062	124.000	6.700	0.013	26.800	2.100	0.004	8.400	2.200	0.004	8.800	2.500	0.005	10.000
1C	4000	500	500	Diesel	3.10E-02	6.70E-03	2.10E-03	2.20E-03	2.50E-03	31.000	0.062	124.000	6.700	0.013	26.800	2.100	0.004	8.400	2.200	0.004	8.800	2.500	0.005	10.000

Notes:
1.) Emergency Generators 1A, 1B and 1C serve the exisiting plant (Units 1 and 2)
2.) Design information based on Intermountain Generating Station Title V Permit application.
3.) Diesel emission factors based on AP-42 Section 3.3. Sulfur content was assumed to be 0.05% of diesel fuel.

IPP Unit 3 Project
Unit 3 Coal Hazardous Air Pollutants
Revised May 13, 2003

POLLUTANT	Class	Fuel	Throughput (tons) (a)	Heating Value (Btu/lb) (b)	Particulate Matter Emission Factor (lbs/MMBtu) (c)	Concentration (ppm) (d)	Coal % Ash	Controlled Pollutant Emission Factor (lbs/10^12 Btu)	Control Device Efficiency (CE) Percent	Table or Method Used	Actual Emission Factor (EF)	Calculation	Controlled Emissions (lb/yr)	Controlled Emissions (tons/yr)	Uncontrolled Emissions (lb/yr)	Controlled Emissions (lb/hr)	Uncontrolled Emissions (lb/hr)	Category	ACGIH TLV	Units	MW	Convert to mg/m3	ETF	ETV	TSL	Modeling Required ?
Metals																										
Antimony	HAP	Coal	3,541,252	11,193	0.015	3.7	12.00	0.92*(C/A*PM)^0.63	99.77	AP-42 1.1-16	0.566	E=[EF(lbs/10^12 Btu)*Thruput(tons)*2000lbs/ton*HV(Btu/lb)]/10^12	44.87	0.02243	19,508.04	0.005	2.227	Chronic	0.5	mg/m3		0.500	0.368	0.1840	0.0056	N
Arsenic	HAP	Coal	3,541,252	11,193	0.015	12.2	12.00	3.1*(C/A*PM)^0.85	99.77	AP-42 1.1-16	4.438	E=[EF(lbs/10^12 Btu)*Thruput(tons)*2000lbs/ton*HV(Btu/lb)]/10^12	351.78	0.17589	152,948.97	0.040	17.460	A1	0.01	mg/m3		0.010	0.123	0.0012	0.0010	Y
Beryllium	HAP	Coal	3,541,252	11,193	0.015	0.39	12.00	1.2*(C/A*PM)^1.1	99.77	AP-42 1.1-16	0.043	E=[EF(lbs/10^12 Btu)*Thruput(tons)*2000lbs/ton*HV(Btu/lb)]/10^12	3.43	0.00171	1,490.59	0.000	0.170	A1	0.002	mg/m3		0.002	0.123	0.0002	0.0002	Y
Cadmium	HAP	Coal	3,541,252	11,193	0.015	0.55	12.00	3.3*(C/A*PM)^0.5	99.77	AP-42 1.1-16	0.865	E=[EF(lbs/10^12 Btu)*Thruput(tons)*2000lbs/ton*HV(Btu/lb)]/10^12	68.59	0.03430	29,823.31	0.008	3.404	A2	0.01	mg/m3		0.010	0.123	0.0012	0.0010	Y
Chromium	HAP	Coal	3,541,252	11,193	0.015	24.6	12.00	3.7*(C/A*PM)^0.58	99.77	AP-42 1.1-16	7.098	E=[EF(lbs/10^12 Btu)*Thruput(tons)*2000lbs/ton*HV(Btu/lb)]/10^12	562.71	0.28136	244,656.86	0.064	27.929	A1	0.05	mg/m3		0.050	0.123	0.0062	0.0050	Y
Cobalt	HAP	Coal	3,541,252	11,193	0.015	2.8	12.00	1.7*(C/A*PM)^0.69	99.77	AP-42 1.1-16	0.824	E=[EF(lbs/10^12 Btu)*Thruput(tons)*2000lbs/ton*HV(Btu/lb)]/10^12	65.31	0.03266	28,396.27	0.007	3.242	Chronic	0.02	mg/m3		0.020	0.368	0.0074	0.0002	Y
Lead	HAP	Coal	3,541,252	11,193	0.015	6.5	12.00	3.4*(C/A*PM)^0.80	99.77	AP-42 1.1-16	2.880	E=[EF(lbs/10^12 Btu)*Thruput(tons)*2000lbs/ton*HV(Btu/lb)]/10^12	228.28	0.11414	99,252.88	0.026	11.330	Chronic	0.05	mg/m3		0.050	0.368	0.0184	0.0006	Y
Manganese	HAP	Coal	3,541,252	11,193	0.015	8.2	12.00	3.8*(C/A*PM)^0.60	99.77	AP-42 1.1-16	3.857	E=[EF(lbs/10^12 Btu)*Thruput(tons)*2000lbs/ton*HV(Btu/lb)]/10^12	305.74	0.15287	132,930.12	0.035	15.175	Chronic	0.1	mg/m3		0.100	0.368	0.0368	0.0011	N
Mercury	HAP	Coal	3,541,252	11,193		0.13			77.65	Eng. Calc.(1)		E=ConcHg(ppm)*Thruput(Mtons)*(1-0.0826)[(100 - Control Efficiency)/100]*2000lbs/ton	188.78	0.09439	844.67	0.022	0.096	Chronic	0.025	mg/m3		0.025	0.368	0.0092	0.0003	Y
Nickel	HAP	Coal	3,541,252	11,193	0.015	4.3	12.00	4.4*(C/A*PM)^0.48	99.77	AP-42 1.1-16	3.266	E=[EF(lbs/10^12 Btu)*Thruput(tons)*2000lbs/ton*HV(Btu/lb)]/10^12	258.92	0.12946	112,574.45	0.030	12.851	Chronic	0.1	mg/m3		0.100	0.368	0.0368	0.0011	N
Selenium	HAP	Coal	3,541,252	11,193		2.4			88.00	Eng. Calc.(2)		E=ConcSe(ppm)*Thruput(Mtons)*[(100 -Control Efficiency)/100]*2000lbs/ton	2,039.76	1.01988	16,998.01	0.233	1.940	Chronic	0.2	mg/m3		0.200	0.368	0.0736	0.0022	Y
Organics																										
Acenaphthene	HAP/PAH	Coal	3,541,252					0.00000051 (lbs/ton)	Note 3	AP-42 1.1-13	5.10E-07	E=EF(lbs/ton)*Thruput(tons)	1.81	0.00090		0.000										N
Acenaphthylene	HAP/PAH	Coal	3,541,252					0.00000025 (lbs/ton)	Note 3	AP-42 1.1-13	2.50E-07	E=EF(lbs/ton)*Thruput(tons)	0.89	0.00044		0.000										N
Acetaldehyde	HAP	Coal	3,541,252					0.00057 (lbs/ton)	Note 3	AP-42 1.1-14	5.70E-04	E=EF(lbs/ton)*Thruput(tons)	2,018.51	1.00926		0.230		Acute			44.05	44.050	0.310	13.6555	4.4050	N
Acetophenone	HAP	Coal	3,541,252					0.000015 (lbs/ton)	Note 3	AP-42 1.1-14	1.50E-05	E=EF(lbs/ton)*Thruput(tons)	53.12	0.02656		0.006		Chronic	10	ppm	120.15	49.141	0.368	18.0839	0.5460	N
Acrolein	HAP	Coal	3,541,252					0.00029 (lbs/ton)	Note 3	AP-42 1.1-14	2.90E-04	E=EF(lbs/ton)*Thruput(tons)	1,026.96	0.51348		0.117		Acute	0.1	ppm	56.06	0.229	0.310	0.0711	0.0229	Y
Anthracene	HAP/PAH	Coal	3,541,252					0.00000021 (lbs/ton)	Note 3	AP-42 1.1-13	2.10E-07	E=EF(lbs/ton)*Thruput(tons)	0.74	0.00037		0.000										N
Benzene	HAP	Coal	3,541,252	11,193				3.8 (lbs/10^12 BTU)	Note 3	Eng. Calc.(2)	3.80E+00	E=[EF(lbs/10^12 Btu)*Thruput(tons)*2000lbs/ton*HV(Btu/lb)]/10^12	301.24	0.15062		0.034		Chronic	0.5	ppm	78.11	1.597	0.368	0.5878	0.0177	N
Benzo(a)anthracene	HAP/PAH	Coal	3,541,252					0.00000008 (lbs/ton)	Note 3	AP-42 1.1-13	8.00E-08	E=EF(lbs/ton)*Thruput(tons)	0.28	0.00014		0.000										N
Benzo(a)pyrene	HAP/PAH	Coal	3,541,252					0.000000038 (lbs/ton)	Note 3	AP-42 1.1-13	3.80E-08	E=EF(lbs/ton)*Thruput(tons)	0.13	0.00007		0.000										N
Benzo(b,j,k)fluoranthene	HAP/PAH	Coal	3,541,252					0.00000011 (lbs/ton)	Note 3	AP-42 1.1-13	1.10E-07	E=EF(lbs/ton)*Thruput(tons)	0.39	0.00019		0.000										N
Benzo(g,h,i)perylene	HAP/PAH	Coal	3,541,252					0.000000027 (lbs/ton)	Note 3	AP-42 1.1-13	2.70E-08	E=EF(lbs/ton)*Thruput(tons)	0.10	0.00005		0.000										N
Benzyl chloride	HAP	Coal	3,541,252					0.0007 (lbs/ton)	Note 3	AP-42 1.1-14	7.00E-04	E=EF(lbs/ton)*Thruput(tons)	2,478.88	1.23944		0.283		Chronic	1	ppm	126.58	5.177	0.368	1.9052	0.0575	N
Biphenyl	HAP/PAH	Coal	3,541,252					0.0000017 (lbs/ton)	Note 3	AP-42 1.1-13	1.70E-06	E=EF(lbs/ton)*Thruput(tons)	6.02	0.00301		0.001		Chronic	0.2	ppm	154.20	1.261	0.368	0.4642	0.0140	N
Bis(2-ethylhexyl)phthalate (DEHP)	HAP	Coal	3,541,252					0.000073 (lbs/ton)	Note 3	AP-42 1.1-14	7.30E-05	E=EF(lbs/ton)*Thruput(tons)	258.51	0.12926		0.030					160.26					N
Bromoform	HAP	Coal	3,541,252					0.000039 (lbs/ton)	Note 3	AP-42 1.1-14	3.90E-05	E=EF(lbs/ton)*Thruput(tons)	138.11	0.06905		0.016		Chronic	0.5	ppm	252.80	5.170	0.368	1.9025	0.0574	N
Carbon disulfide	HAP	Coal	3,541,252					0.00013 (lbs/ton)	Note 3	AP-42 1.1-14	1.30E-04	E=EF(lbs/ton)*Thruput(tons)	460.36	0.23018		0.053		Chronic	10	ppm	76.14	31.141	0.368	11.4599	0.3460	N
2-Chloroacetophenone	HAP	Coal	3,541,252					0.000007 (lbs/ton)	Note 3	AP-42 1.1-14	7.00E-06	E=EF(lbs/ton)*Thruput(tons)	24.79	0.01239		0.003		Chronic	0.05	ppm	154.59	0.316	0.368	0.1163	0.0035	N
Chlorobenzene	HAP	Coal	3,541,252					0.000022 (lbs/ton)	Note 3	AP-42 1.1-14	2.20E-05	E=EF(lbs/ton)*Thruput(tons)	77.91	0.03895		0.009		Chronic	10	ppm	112.56	46.037	0.368	16.9415	0.5115	N
Chloroform	HAP	Coal	3,541,252					0.000059 (lbs/ton)	Note 3	AP-42 1.1-14	5.90E-05	E=EF(lbs/ton)*Thruput(tons)	208.93	0.10447		0.024		Chronic	10	ppm	119.38	48.826	0.368	17.9680	0.5425	N
Chrysene	HAP/PAH	Coal	3,541,252					0.0000001 (lbs/ton)	Note 3	AP-42 1.1-13	1.00E-07	E=EF(lbs/ton)*Thruput(tons)	0.35	0.00018		0.000										N
Cumene	HAP	Coal	3,541,252					0.0000053 (lbs/ton)	Note 3	AP-42 1.1-14	5.30E-06	E=EF(lbs/ton)*Thruput(tons)	18.77	0.00938		0.002		Chronic	50	ppm	120.19	245.787	0.368	90.4497	2.7310	N
2,4-Dinitrotoluene	HAP	Coal	3,541,252					0.00000028 (lbs/ton)	Note 3	AP-42 1.1-14	2.80E-07	E=EF(lbs/ton)*Thruput(tons)	0.99	0.00050		0.000					182.15					N
Dimethyl sulfate	HAP	Coal	3,541,252					0.000048 (lbs/ton)	Note 3	AP-42 1.1-14	4.80E-05	E=EF(lbs/ton)*Thruput(tons)	169.98	0.08499		0.019		Chronic	0.1	ppm	126.10	0.516	0.368	0.1898	0.0057	N
Ethyl benzene	HAP	Coal	3,541,252					0.000094 (lbs/ton)	Note 3	AP-42 1.1-14	9.40E-05	E=EF(lbs/ton)*Thruput(tons)	332.88	0.16644		0.038		Chronic	100	ppm	106.16	434.192	0.368	159.7827	4.8244	N
Ethyl chloride	HAP	Coal	3,541,252					0.000042 (lbs/ton)	Note 3	AP-42 1.1-14	4.20E-05	E=EF(lbs/ton)*Thruput(tons)	148.73	0.07437		0.017		Chronic	100	ppm	64.52	263.885	0.368	97.1099	2.9321	N
Ethylene dichloride	HAP	Coal	3,541,252					0.00004 (lbs/ton)	Note 3	AP-42 1.1-14	4.00E-05	E=EF(lbs/ton)*Thruput(tons)	141.65	0.07083		0.016		Chronic	10	ppm	98.96	40.474	0.368	14.8946	0.4497	N
Ethylene dibromide	HAP	Coal	3,541,252					0.0000012 (lbs/ton)	Note 3	AP-42 1.1-14	1.20E-06	E=EF(lbs/ton)*Thruput(tons)	4.25	0.00212		0.000		Chronic			187.88	187.880	0.368	69.1398	2.0876	N
Fluoranthene	HAP/PAH	Coal	3,541,252					0.00000071 (lbs/ton)	Note 3	AP-42 1.1-13	7.10E-07	E=EF(lbs/ton)*Thruput(tons)	2.51	0.00126		0.000										N
Fluorene	HAP/PAH	Coal	3,541,252					0.00000091 (lbs/ton)	Note 3	AP-42 1.1-13	9.10E-07	E=EF(lbs/ton)*Thruput(tons)	3.22	0.00161		0.000					38.00					N
Formaldehyde	HAP	Coal	3,541,252	11,193				3.0 (lbs/10^12 BTU)	Note 3	Eng. Calc.(2)	3.00E+00	E=[EF(lbs/10^12 Btu)*Thruput(tons)*2000lbs/ton*HV(Btu/lb)]/10^12	237.82	0.11891		0.027		Acute	0.3	ppm	30.03	0.368	0.123	0.0453	0.0368	N
Hexane	HAP	Coal	3,541,252					0.000067 (lbs/ton)	Note 3	AP-42 1.1-14	6.70E-05	E=EF(lbs/ton)*Thruput(tons)	237.26	0.11863		0.027		Chronic	500	ppm	86.18	1762.372	0.368	648.5530	19.5819	N
Indeno(1,2,3-cd)pyrene	HAP/PAH	Coal	3,541,252					0.000000061 (lbs/ton)	Note 3	AP-42 1.1-13	6.10E-08	E=EF(lbs/ton)*Thruput(tons)	0.22	0.00011		0.000										N
Isophorone	HAP	Coal	3,541,252					0.00058 (lbs/ton)	Note 3	AP-42 1.1-14	5.80E-04	E=EF(lbs/ton)*Thruput(tons)	2,053.93	1.02696		0.234		Acute	5	ppm	138.21	28.264	0.310	8.7618	2.8264	N
Methyl bromide	HAP	Coal	3,541,252					0.00016 (lbs/ton)	Note 3	AP-42 1.1-14	1.60E-04	E=EF(lbs/ton)*Thruput(tons)	566.60	0.28330		0.065		Chronic	1	ppm	94.95	3.883	0.368	1.4291	0.0431	N
Methyl chloride	HAP	Coal	3,541,252					0.00053 (lbs/ton)	Note 3	AP-42 1.1-14	5.30E-04	E=EF(lbs/ton)*Thruput(tons)	1,876.86	0.93843		0.214		Chronic	50	ppm	50.49	103.252	0.368	37.9966	1.1472	N
5-Methyl chrysene	HAP/PAH	Coal	3,541,252					0.000000022 (lbs/ton)	Note 3	AP-42 1.1-13	2.20E-08	E=EF(lbs/ton)*Thruput(tons)	0.08	0.00004		0.000										N
Methyl ethyl ketone	HAP	Coal	3,541,252					0.00039 (lbs/ton)	Note 3	AP-42 1.1-14	3.90E-04	E=EF(lbs/ton)*Thruput(tons)	1,381.09	0.69054		0.158		Chronic	200	ppm	72.10	589.775	0.368	217.0372	6.5531	N
Methyl hydrazine	HAP	Coal	3,541,252					0.00017 (lbs/ton)	Note 3	AP-42 1.1-14	1.70E-04	E=EF(lbs/ton)*Thruput(tons)	602.01	0.30101		0.069		Chronic	0.01	ppm	46.07	0.019	0.368	0.0069	0.0002	Y
Methyl methacrylate	HAP	Coal	3,541,252					0.00002 (lbs/ton)	Note 3	AP-42 1.1-14	2.00E-05	E=EF(lbs/ton)*Thruput(tons)	70.83	0.03541		0.008		Chronic	50	ppm	100.13	204.765	0.368	75.3535	2.2752	N
Methyl tert butyl ether	HAP	Coal	3,541,252					0.000035 (lbs/ton)	Note 3	AP-42 1.1-14	3.50E-05	E=EF(lbs/ton)*Thruput(tons)	123.94	0.06197		0.014		Chronic	40	ppm	88.17	144.245	0.368	53.0823	1.6027	N
Methylene chloride	HAP	Coal	3,541,252					0.00029 (lbs/ton)	Note 3	AP-42 1.1-14	2.90E-04	E=EF(lbs/ton)*Thruput(tons)	1,026.96	0.51348		0.117		Chronic	50	ppm	84.93	173.681	0.368	63.9146	1.9298	N
Naphthalene	HAP/PAH	Coal	3,541,252					0.000013 (lbs/ton)	Note 3	AP-42 1.1-13	1.30E-05	E=EF(lbs/ton)*Thruput(tons)	46.04	0.02302		0.005		Chronic	10	ppm	128.19	52.429	0.368	19.2940	0.5825	N
Phenanthrene	HAP/PAH	Coal	3,541,252					0.0000027 (lbs/ton)	Note 3	AP-42 1.1-13	2.70E-06	E=EF(lbs/ton)*Thruput(tons)	9.56	0.00478		0.001										N
Phenol	HAP	Coal	3,541,252					0.000016 (lbs/ton)	Note 3	AP-42 1.1-14	1.60E-05	E=EF(lbs/ton)*Thruput(tons)	56.66	0.02833		0.006										N
Propionaldehyde	HAP	Coal	3,541,252					0.00038 (lbs/ton)	Note 3	AP-42 1.1-14	3.80E-04	E=EF(lbs/ton)*Thruput(tons)	1,345.68	0.67284		0.154										
Pyrene	HAP/PAH	Coal	3,541,252					0.00000033 (lbs/ton)	Note 3	AP-42 1.1-13	3.30E-07	E=EF(lbs/ton)*Thruput(tons)	1.17	0.00058		0.000										N
Tetrachloroethylene	HAP	Coal	3,541,252					0.000043 (lbs/ton)	Note 3	AP-42 1.1-14	4.30E-05	E=EF(lbs/ton)*Thruput(tons)	152.27	0.07614		0.017		Chronic	25	ppm	165.80	169.530	0.368	62.3869	1.8837	N
Toluene	HAP	Coal	3,541,252	11,193				1.4 (lbs/10^12 BTU)	Note 3	Eng. Calc.(2)	1.40E+00	E=[EF(lbs/10^12 Btu)*Thruput(tons)*2000lbs/ton*HV(Btu/lb)]/10^12	110.98	0.05549		0.013		Chronic	50	ppm	92.13	188.405	0.368	69.3330	2.0934	N
1,1,1-Trichloroethane	HAP	Coal	3,541,252					0.00002 (lbs/ton)	Note 3	AP-42 1.1-14	2.00E-05	E=EF(lbs/ton)*Thruput(tons)	70.83	0.03541		0.008		Chronic	350	ppm	133.40	1909.611	0.368	702.7370	21.2179	N
Styrene	HAP	Coal	3,541,252					0.000025 (lbs/ton)	Note 3	AP-42 1.1-14	2.50E-05	E=EF(lbs/ton)*Thruput(tons)	88.53	0.04427		0.010		Chronic	20	ppm	104.16	85.202	0.368	31.3545	0.9467	N
Xylenes	HAP	Coal	3,541,252					0.000037 (lbs/ton)	Note 3	AP-42 1.1-14	3.70E-05	E=EF(lbs/ton)*Thruput(tons)	131.03	0.06551		0.015		Chronic	100	ppm	106.16	434.192	0.368	159.7827	4.8244	N
Vinyl acetate	HAP	Coal	3,541,252					0.0000076 (lbs/ton)	Note 3	AP-42 1.1-14	7.60E-06	E=EF(lbs/ton)*Thruput(tons)	26.91	0.01346		0.003		Chronic	10	ppm	86.09	35.211	0.368	12.9575	0.3912	N
Total PCDD/PCDF	HAP	Coal	3,541,252	11,193				0.000002 (lbs/10^12 BTU)	Note 3	Eng. Calc.(2)	2.00E-06	E=[EF(lbs/10^12 Btu)*Thruput(tons)*2000lbs/ton*HV(Btu/lb)]/10^12	0.00	0.00000												
Acid Gases																										
Hydrogen Chloride	HAP	Coal	3,541,252						90.00	Eng. Calc.(3)			334,025.24	167.01	3,340,252.41	38.131	381.307									
Hydrogen Fluoride	HAP	Coal	3,541,252						90.00	Eng. Calc.(3)			41,036.70	20.52	410,366.99	4.685	46.846									
Total Unit 3 Coal Metal HAP Emissions													4,118.18	2.06												
Total Unit 3 Coal Organic HAP Emissions													18,098.29	9.05												
Total Unit 3 Coal Acid Gas HAP Emissions													375,061.94	187.53												
Total Unit 3 Coal HAP Emissions													**397,278.41**	**198.64**												

General Notes:
1) Notes on column headings:
   a) Annual throughput based on tons/hr of coal for maximum boiler load times 8760 hours per year times 100% capacity factor.
   b) Fuel heating value based on design coal
   c) PM factor based on Sargent & Lundy fabric filter design. Value is outlet emission level, filterable PM10 only.
   d) Trace metal concentrations in coal taken from representative coal analysis that was conducted on IPP Units 1/2 in Year 2000. Mercury concentration is based on Unit 3 design coal.
2) Notes on emission calculation methods
   Engineering Calculation (1) based on mercury stack test conducted at IPP Units 1 and 2, Unit 3 design coal, and a FGD mercury collection efficiency of 77.65%.
   Engineering Calculation (2) based on EPRI's Coal HAP Report
   Engineering Calculation (3) based on Sargent & Lundy's engineering estimates for uncontrolled and controlled acid gas emissions.
3) Uncontrolled HAP emissions determined from controlled HAP emissions divided by the estimated control efficiency (CE) shown in column J. Control efficiency and resultant uncontrolled emissions not estimated for organic HAPs due to unavailable data. It is estimated that the organic HAPs are primarily destructed in the boiler with secondary removal in the fabric filter and wet limestone FGD systems.

IPP Unit 3 Project
Units 1 & 2 Fly Ash Handling

E (lb PM_{10} per ton handled) = 1.00E-01
E (lb PM per ton handled) = 2.00E-01
Emission Factor (PM) for ash from Air Pollution Engineering Manual, Page 793, Table 1. Air Pollution Manual (2000 Ed). PM10 estimated as 50% of total PM.

Source ID	Source Name	Process Rate (ton/hour)	Uncontrolled Emissions (lb PM_{10}/hr)	Uncontrolled Emissions (lb PM/hr)	Control %	Controlled Emissions (lb PM_{10}/hr)	Controlled PM_{10} Emissions (g/s)	Controlled Emissions (lb PM/hr)	Controlled PM_{10} Emissions (tpy)	Controlled PM Emissions (tpy)	Control System and Comments
EP-167	Emissions from sealed loading spout vent filter - Fly Ash Storage Silo 1A	150	15.00	30.00	99	0.150	0.019	0.300	0.097	0.194	Transfer points are 2 drops per subsystem (2). 75 TPH per subsystem. Fabric Filter used for dust collection
EP-168	Emissions from sealed loading spout vent filter - Fly Ash Storage Silo 1B	150	15.00	30.00	99	0.150	0.019	0.300	0.097	0.194	Transfer points are 2 drops per subsystem (2). 75 TPH per subsystem. Fabric Filter used for dust collection
EP-169	Emissions from silo vent filter-Fly Ash Storage Silo 1A	150	15.00	30.00	99	0.150	0.019	0.300	0.097	0.194	Transfer points are 2 drops per subsystem (2). 75 TPH per subsystem. Fabric Filter used for dust collection
EP-170	Emissions from silo vent filter-Fly Ash Storage Silo 1B	150	15.00	30.00	99	0.150	0.019	0.300	0.097	0.194	Transfer points are 2 drops per subsystem (2). 75 TPH per subsystem. Fabric Filter used for dust collection

Notes:
1) Units 1 and 2 generated 386,271 tons of flyash in 2000 and 393,103 tons in 2001 for an average of 389,687 tons. The controlled annual PM10 and PM emissions were ratioed with the factor of (389,687) / (150 tons/hour x 2 units x 8760 hour/yr) = 14.8%
2) Sample calculations (EP167):
Uncontrolled emissions (lb PM_{10} per hour): hourly process rate (150 tons/hour) x emission factor (1.0 E-01 lb/ton) = 15.00 lb/hr
Controlled emissions (lb PM_{10} per hour): uncontrolled emissions (15.0 lb/hr) x control efficiency [1-(control%/100)] = 15.0 x .01 = 0.15 lb/hr

IPP Unit 3 Project
Unit 3 Fly Ash Handling

E (lb PM_{10} per ton handled) = 1.00E-01
E (lb PM per ton handled) = 2.00E-01
Emission Factor (PM) for ash from Air Pollution Engineering Manual, Page 793, Table 1. Air Pollution Manual (2000 Ed). PM10 estimated as 50% of total PM.

Source ID	Source Name	Process Rate (ton/hour)	Uncontrolled Emissions (lb PM_{10}/hr)	Uncontrolled Emissions (lb PM/hr)	Control %	Controlled Emissions (lb PM_{10}/hr)	Controlled PM_{10} Emissions (g/s)	Controlled Emissions (lb PM/hr)	Controlled PM_{10} Emissions (tpy)	Controlled PM Emissions (tpy)	Control System and Comments
EP-171	Emissions from sealed loading spout vent filter - Fly Ash Storage Silo 1C	150	15.00	30.00	99	0.150	0.019	0.300	0.170	0.339	Transfer points are 2 drops per subsystem (2). 75 TPH per subsystem. Fabric Filter used for dust collection.
EP-172	Emissions from silo vent filter-Fly Ash Storage Silo 1C	150	15.00	30.00	99	0.150	0.019	0.300	0.170	0.339	Transfer points are 2 drops per subsystem (2). 75 TPH per subsystem. Fabric Filer used for dust collection.

Notes:
1) Based on the worst case coal, the maximum quantity of flyash generated per year for Unit 3 is 339,365 tons per year. The controlled annual PM10 and PM emissions were ratioed with the factor of (339,365) / (150 x 8760) = 25.8%
2) Sample calculations (EP171):
Uncontrolled emissions (lb PM_{10} per hour): hourly process rate (150 tons/hour) x emission factor (1.0 E-01 lb/ton) = 15.00 lb/hr
Controlled emissions (lb PM_{10} per hour): uncontrolled emissions (15.0 lb/hr) x control efficiency [1-(control%/100)] = 15.0 x .01 = 0.15 lb/hr

IPP Unit 3 Project
Units 1, 2 and 3 Limestone Handling

Emission factor from AP-42, Section 13.2.4: *Aggregate Handling and Storage Piles* (1/95), Equation (1) - batch or continuous drop operation

E (lb PM_{10} per ton material handled) = k (0.0032) (U/5)^1.3 / [(M/2)^1.4]

where:

k = 0.35	[particles < 10um]	
k = 0.74	[particles < 30um]	
U = 7	[mph, avg 10-m wind speed from IPP]	
	[used for exposed sources and to conservatively estimate internal ventilation for enclosed sources]	
M = 0.7	[%, mean moisture content for limestone (as received), Table 13.2.4-1 (stone quarrying and processing, crushed limestone)	

E (lb PM_{10} per ton handled) = 7.54E-03
E (lb PM per ton handled) = 1.59E-02
Unit 3 sources % of emissions = 0.576

Source ID	Source Name	Process Rate (ton/hour)	Uncontrolled Emissions (lb PM_{10}/hr)	Uncontrolled Emissions (lb PM/hr)	Control %	Controlled Emissions (lb PM_{10}/hr)	Controlled PM_{10} Emissions (g/s)	Controlled PM_{10} Emissions (g/s, Unit 3 operation)	Controlled Emissions (lb PM/hr)	Controlled PM_{10} Emissions (tpy)	Controlled PM Emissions (tpy)	Control System and Comments
F-130	Fugitives from transfer of limestone from Truck to Limestone Storage Pile	13	0.10	0.21	0	0.101	0.013	0.007	0.213	0.058	0.122	Process rate based on maximum of 40 tons in 3 hour period. A maximum of 10% of total limestone received is transferred to pile. No controls on pile.
F-153	Fugitives from transfer of limestone from Front Loader to Bucket Elevator	100	0.75	1.59	0	0.754	0.095	0.055	1.595	0.038	0.080	No controls. Bucket elevator is used in emergencies only.
EP-155	Emissions from dust collection system exhaust fan- Limestone Truck Unloading Hopper.	1200	9.05	19.14	99	0.091	0.011	0.007	0.191	0.006	0.012	Transfers associated with this source are TP-132 and TP-133 (2 transfers x 600 tph). Fabric Filter used for dust collection.
EP-156	Emissions from dust collection system exhaust fan- Limestone Reclaim Hopper.	2400	18.10	38.27	99	0.181	0.023	0.013	0.383	0.006	0.012	Transfers associated with this source are TP-140, TP-141, TP-142 and TP-143 (4 transfers x 600 tph). Fabric Filter used for dust collection.
EP-157	Emissions from dust collection system exhaust fan- Limestone Crusher Building.	600	4.53	9.57	99	0.045	0.006	0.003	0.096	0.006	0.012	Transfer associated with this source is TP-144 (1 transfer x 600 tph). Fabric Filter used for dust collection.
EP-158	Emissions from dust collection system exhaust fan- Limestone Preparation Building.	3700	27.91	59.00	99	0.279	0.035	0.020	0.590	0.006	0.012	Transfers associated with this source are TP-145, TP-146, TP-147, TP-148, TP-149, TP-150, and TP-154 (6 transfers x 600 tph and 1 transfer x 100 tph). Fabric Filter used for dust collection. Discharges inside Limestone Preparation Building.
EP-190 and EP-191	Emissions from dust collection system exhaust fans - Limestone Truck Unloading Building	600	4.53	9.57	99	0.045	0.006	0.003	0.096	0.006	0.012	Transfer associated with this source is TP-131 (600 tph). Enclosed building with two fabric filters for dust control.
EP-192	Emissions from dust collection system exhaust fan - Limestone Storage Silo.	600	4.53	9.57	99	0.045	0.006	0.003	0.096	0.006	0.012	Transfer associated with this source is TP-134 (600 tph) from Conveyor L-1 to Limestone Silo. Limestone Silo has fabric filter dust collection system.

Notes:

1) Based on the worst case coal and design FGD control efficiencies, the maximum quantity of limestone required per year for Unit 3 is 87,915 tons. Units 1 and 2 used 59,902 tons in 2000 and 69,544 tons in 2001 for an average of 64,723 tons. Thus, total limestone usage is estimated at 152,638 with Unit 3 being 57.6% of total.

2) The controlled annual PM10 and PM emissions for each emission source were ratioed with the factor of (152,638) / (hourly process rate x 8760). Assumed 100 hours per year for the emergency bucket elevator (F-153). The limestone process rate for the truck dump to the limestone storage pile (F-130) is based on 10% of the total limestone throughput or 15,264 tons per year.

3) Emission points EP-159, EP-160, EP-161, EP-162, EP-163, EP-164, and EP-165 were not included in emission calculations. These emission points are limestone building ventilation exhaust fans. The other emissions sources in the building are controlled with fabric filter dust collectors. Thus, there would be insignificant emissions from the ventilation exhaust fans.

4) Limestone preparation system serves the exisitng Units 1and 2 and the proposed Unit 3.

5) Sample calculations (EP155):

Uncontrolled emissions (lb PM_{10} per hour): hourly process rate (1200 tons/hour) x emission factor (7.54E-03 lb/ton) = 9.05 lb/hr

Controlled emissions (lb PM_{10} per hour): uncontrolled emissions (9.05 lb/hr) x control efficiency [1-(control%/100)] = 9.05 x .01 = 0.09 lb/hr

IPP Unit 3 Project
Units 1 & 2 Limestone Pile

Wind Erosion
Reference: Control of Open Fugitive Dust Sources, Section 4.1.3, EPA-450/3-98-008
[Wind Emissions From Continuously Active Piles]

E (lb PM per day per acre) = 1.7 (s/1.5) (365-p/235) (f/15)

where:

s =	1.6	silt content % [from AP-42 Table 13.2.4-1 (lcrushed limestone - stone quarry and processing)
p =	60	number of days with >0.01 inches precip. per year [from AP-42 Figure 13.2.2-1]
f =	12	percentage of time that wind speed exceeds 5.4 m/s at mean pile height [from 10-m IPP wind data 7/01 - 3/02]
E =	1.9	lb PM per day per acre
E =	0.9	lb PM-10 per day per acre [using PM-10 to PM ratio of 0.5 from EPA-450/3-98-008]

Source ID	Source Name	Limestone pile size (acres) (1)	Uncontrolled Emissions (lb PM_{10}/hr)	Uncontrolled Emissions (lb PM/hr)	Control %	Controlled Emissions (lb PM_{10}/hr)	Controlled Emissions (lb PM/hr)	Controlled PM_{10} Emissions (tpy)	Controlled PM Emissions (tpy)	Control System
F-138	Units 1 and 2 Reserve Limestone Storage Pile	0.55	0.02	0.04	0	0.022	0.043	0.095	0.189	No controls

(1) size of piles = 24,000 ft^2
0.55 acres

Maintenance of Active Pile (Bulldozing)
Reference: Intermountain Power Project Emission Factors from Annual Emission Inventory submitted to UDAQ

Limestone Pile PM-10 Fugitive Emissions = 0.0294 lb PM-10 per ton of limestone received
Limestone Pile PM Fugitive Emissions = 0.0320 PM per ton of limestone received
Limestone received in 2000 = 59,902 tons, Limestone received in 2001 = 69,544 tons, Average = 64,723 tons per year

Source ID	Source Name	Limestone Received on Pile (tons/yr)	Uncontrolled Emissions (lb PM_{10}/hr)	Uncontrolled Emissions (lb PM/hr)	Control %	Controlled Emissions (lb PM_{10}/hr)	Controlled Emissions (lb PM/hr)	Controlled PM_{10} Emissions (tpy)	Controlled PM Emissions (tpy)	Control System
F-137	Fugitives from bulldozing from Reserve Storage Pile to Reclaim Hopper	6,472	0.07	0.07	0	0.065	0.071	0.095	0.104	No controls

Total Fugitive Emissions from Units 1/2 Limestone Piles (Wind Erosion + Maintenance)	**0.087**	**0.114**	**0.190**	**0.293**

Notes:
1) The calculation of hourly PM and PM10 emissions assumed 2,920 hours of maintenance related to the piles per year (8 hours per day).
2) Limestone received on the pile (related to F-136) is approximately 10% of total limestone received for Units 1 and 2. The remainder is loaded directly to the silo.

IPP Unit 3 Project
Unit 3 Limestone Pile

Wind Erosion
Reference: Control of Open Fugitive Dust Sources, Section 4.1.3, EPA-450/3-98-008
[Wind Emissions From Continuously Active Piles]

E (lb PM per day per acre) = 1.7 (s/1.5) (365-p/235) (f/15)

where:
s = 1.6 silt content % [from AP-42 Table 13.2.4-1 (lcrushed limestone - stone quarry and processing)
p = 60 number of days with >0.01 inches precip. per year [from AP-42 Figure 13.2.2-1]
f = 12 percentage of time that wind speed exceeds 5.4 m/s at mean pile height [from 10-m IPP wind data 7/01 - 3/02]
E = 1.9 lb PM per day per acre
E = 0.9 lb PM-10 per day per acre [using PM-10 to PM ratio of 0.5 from EPA-450/3-98-008]

Source ID	Source Name	Limestone pile size (acres) (1)	Uncontrolled Emissions (lb PM_{10}/hr)	Uncontrolled Emissions (lb PM/hr)	Control %	Controlled Emissions (lb PM_{10}/hr)	Controlled Emissions (lb PM/hr)	Controlled PM_{10} Emissions (tpy)	Controlled PM Emissions (tpy)	Control System
F-139	Unit 3 Reserve Limestone Storage Pile	0.18	0.01	0.01	0	0.007	0.014	0.032	0.063	No controls

(1) size of piles = 8,000 ft^2
0.18 acres

Maintenance of Active Pile (Bulldozing)
Reference: Intermountain Power Project Emission Factors from Annual Emission Inventory submitted to UDAQ

Limestone Pile PM-10 Fugitive Emissions = 0.0294 lb PM-10 per ton of limestone received
Limestone Pile PM Fugitive Emissions = 0.0320 PM per ton of limestone received
Maximum Limestone Usage for Unit 3 = 87,915 tons per year

Source ID	Source Name	Limestone Received on Pile (tons/yr)	Uncontrolled Emissions (lb PM_{10}/hr)	Uncontrolled Emissions (lb PM/hr)	Control %	Controlled Emissions (lb PM_{10}/hr)	Controlled Emissions (lb PM/hr)	Controlled PM_{10} Emissions (tpy)	Controlled PM Emissions (tpy)	Control System
F-137	Fugitives from bulldozing from Reserve Storage Pile to Reclaim Hopper	8,792	0.09	0.10	0	0.089	0.096	0.129	0.141	No controls

Total Fugitive Emissions from Unit 3 Limestone Piles (Wind Erosion + Maintenance)	**0.096**	**0.111**	**0.161**	**0.204**

Notes:
1) The calculation of hourly PM and PM10 emissions assumed 2,920 hours of maintenace related to the piles per year (8 hours per day).
2) Limestone received on the pile (related to F-137) is approximately 10% of total limestone received for Unit 3. The remainder is loaded directly to the silo.

IPP Unit 3 Project
Units 1, 2 and 3 Water Treatment

Emission Factors for Lime and Soda Ash Handling
Reference: Intermountain Power Project Emission Factors from Annual Emission Inventory submitted to UDAQ

Lime Uncontrolled PM-10 Emissions = 0.0014 lb PM-10 per ton of lime received
Lime Uncontrolled PM Emissions = 0.0015 PM per ton of lime received
Soda Ash Uncontrolled PM-10 Emissions = 0.0014 lb PM-10 per ton of soda ash received
Soda Ash Uncontrolled PM Emissions = 0.0015 PM per ton of soda ash received

E (lb PM_{10} per ton handled) = 1.40E-03
E (lb PM per ton handled) = 1.50E-03

Source ID	Source Name	Process Rate (ton/hour)	Uncontrolled Emissions (lb PM_{10}/hr)	Uncontrolled Emissions (lb PM/hr)	Control %	Controlled Emissions (lb PM_{10}/hr)	Controlled Emissions (lb PM/hr)	Controlled PM_{10} Emissions (tpy)	Controlled PM Emissions (tpy)	Control System and Comments
EU-29	Emissions from Lime Silo Dust Collector	16	0.02	0.02	99	0.000	0.000	0.000	0.000	Plant received 5,995 tons lime in 2000 and 5,719 tons in 2001 for an average of 5,857. Assumed 3,000 tons additional for Unit 3. Fabric Filter used for dust collection.
EU-30	Emissions from Lime Hopper Dust Collector	16	0.02	0.02	99	0.000	0.000	0.000	0.000	Plant received 5,995 tons lime in 2000 and 5,719 tons in 2001 for an average of 5,857. Assumed 3,000 tons additional for Unit 3. Fabric Filter used for dust collection.
EU-31	Emissions from Soda Ash Silo Dust Collector	4	0.01	0.01	99	0.000	0.000	0.000	0.000	Plant received 0 tons soda ash in 2000 and 0 tons in 2001 for an average of 0. Assumed 100 tons total including Unit 3. Fabric Filter used for dust collection.
EU-32	Emissions from Soda Ash Hopper Dust Collector	4	0.01	0.01	99	0.000	0.000	0.000	0.000	Plant received 0 tons soda ash in 2000 and 0 tons in 2001 for an average of 0. Assumed 100 tons total including Unit 3. Fabric Filter used for dust collection.

Notes:
1) The controlled annual PM10 and PM emissions for each emission source were ratioed with the factor of (annual lime or soda ash throughput) / (hourly process rate x 8760).

2) Sample calculations (EU29):
Uncontrolled emissions (lb PM_{10} per hour): hourly process rate (16 tons/hour) x emission factor (1.40E-03 lb/ton) = 0.02 lb/hr
Controlled emissions (lb PM_{10} per hour): uncontrolled emissions (0.02 lb/hr) x control efficiency [1-(control%/100)] = 0.02 x .01 = 0.00 lb/hr

IPP Unit 3 Project
Units 1 & 2 Conditioned Sludge Handling (FGD Byproduct mixed with Flyash)

Wind Erosion
Reference: Control of Open Fugitive Dust Sources, Section 4.1.3, EPA-450/3-98-008
[Wind Emissions From Continuously Active Piles]

E (lb PM per day per acre) = 1.7 (s/1.5) (365-p/235) (f/15)

where:
s = 0.6 silt content % [from IPP related to present operation))
p = 60 number of days with >0.01 inches precip. per year [from AP-42 Figure 13.2.2-1]
f = 12 percentage of time that wind speed exceeds 5.4 m/s at mean pile height [from 10-m IPP wind data 7/01 - 3/02]
E = 0.7 lb PM per day per acre
E = 0.4 lb PM-10 per day per acre [using PM-10 to PM ratio of 0.5 from EPA-450/3-98-008]

Source ID	Source Name	Conditioned Sludge pile size (acres) (1)	Uncontrolled Emissions (lb PM_{10}/hr)	Uncontrolled Emissions (lb PM/hr)	Control %	Controlled Emissions (lb PM_{10}/hr)	Controlled Emissions (lb PM/hr)	Controlled PM_{10} Emissions (tpy)	Controlled PM Emissions (tpy)	Control System
EU-35	Conditioned Sludge Main Stock Out (near landfill disposal area)	1.00	0.01	0.03	50	0.007	0.015	0.032	0.064	Water Sprays
EU-35	Emergency Stockout Pile	0.23	0.00	0.00	50	0.002	0.002	0.007	0.007	Water Sprays

(1) size of piles =	Units 1/2 Main Stock Out	Emergency Stockout
	43,560 ft^2	10,000 ft^2
	1.00 acres	0.23 acres

Maintenance of Active Pile (Bulldozing)
Reference: Intermountain Power Project Emission Factors from Annual Emission Inventory submitted to UDAQ

Conditioned Sludge Pile PM-10 Fugitive Emissions = 0.0294 lb PM-10 per ton of sludge handled
Conditioned Sludge Pile PM Fugitive Emissions = 0.0320 PM per ton of sludge handled
Conditioned Sludge produced in 2000 = 280,478 tons, Conditioned Sludge produced in 2001 = 224,978 tons, Average = 252,728 tons per year

Source ID	Source Name	Conditioned Sludge Produced (tons/yr)	Uncontrolled Emissions (lb PM_{10}/hr)	Uncontrolled Emissions (lb PM/hr)	Control %	Controlled Emissions (lb PM_{10}/hr)	Controlled Emissions (lb PM/hr)	Controlled PM_{10} Emissions (tpy)	Controlled PM Emissions (tpy)	Control System
EU-35	Fugitives from conveying, bulldozing and trucking from Conditioned Sludge Main Stockout pile to landfill. Includes fugitives related to handling at Emergency Stockout pile.	252,728	2.54	2.77	50	1.272	1.385	3.715	4.044	Water Sprays

	Controlled Emissions (lb PM_{10}/hr)	Controlled Emissions (lb PM/hr)	Controlled PM_{10} Emissions (tpy)	Controlled PM Emissions (tpy)
Total Fugitive Emissions from Units 1/2 Sludge Conditioning Piles (Wind Erosion + Maintenance)	**1.281**	**1.401**	**3.755**	**4.115**

Notes:
1) The calculation of hourly PM and PM10 emissions assumed 2,920 hours of maintenance related to the piles per year (8 hours per day).

IPP Unit 3 Project
Unit 3 Conditioned Sludge Handling (FGD Byproduct mixed with Flyash)

Wind Erosion
Reference: Control of Open Fugitive Dust Sources, Section 4.1.3, EPA-450/3-98-008
[Wind Emissions From Continuously Active Piles]

E (lb PM per day per acre) = 1.7 (s/1.5) (365-p/235) (f/15)

where:
s = 0.6 silt content % [from IPP related to present operation))
p = 60 number of days with >0.01 inches precip. per year [from AP-42 Figure 13.2.2-1]
f = 12 percentage of time that wind speed exceeds 5.4 m/s at mean pile height [from 10-m IPP wind data 7/01 - 3/02]
E = 0.7 lb PM per day per acre
E = 0.4 lb PM-10 per day per acre [using PM-10 to PM ratio of 0.5 from EPA-450/3-98-008]

Source ID	Source Name	Conditioned Sludge pile size (acres) (1)	Uncontrolled Emissions (lb PM_{10}/hr)	Uncontrolled Emissions (lb PM/hr)	Control %	Controlled Emissions (lb PM_{10}/hr)	Controlled Emissions (lb PM/hr)	Controlled PM_{10} Emissions (tpy)	Controlled PM Emissions (tpy)	Control System
EU-35	Conditioned Sludge Main Stock Out (near landfill disposal area)	1.15	0.02	0.03	50	0.008	0.017	0.037	0.074	Water Sprays
EU-35	Emergency Stockout Pile	0.23	0.00	0.00	50	0.002	0.002	0.007	0.007	Water Sprays

(1) size of piles = Units 3 Main Stock Out: 50,000 ft^2, 1.15 acres; Emergency Stockout: 10,000 ft^2, 0.23 acres

Maintenance of Active Pile (Bulldozing)
Reference: Intermountain Power Project Emission Factors from Annual Emission Inventory submitted to UDAQ

Conditioned Sludge Pile PM-10 Fugitive Emissions = 0.0294 lb PM-10 per ton of sludge handled
Conditioned Sludge Pile PM Fugitive Emissions = 0.0320 PM per ton of sludge handled
Maximum Conditioned Sludge produced by Unit 3 = 142,054 tons FGD waste + 169,683 flyash (50% of total flyash) = 311,737 tons per year

Source ID	Source Name	Conditioned Sludge Produced (tons/yr)	Uncontrolled Emissions (lb PM_{10}/hr)	Uncontrolled Emissions (lb PM/hr)	Control %	Controlled Emissions (lb PM_{10}/hr)	Controlled Emissions (lb PM/hr)	Controlled PM_{10} Emissions (tpy)	Controlled PM Emissions (tpy)	Control System
EU-35	Fugitives from conveying, bulldozing and trucking from Conditioned Sludge Main Stockout pile to landfill. Includes fugitives related to handling at Emergency Stockout pile.	311,737	3.14	3.42	50	1.569	1.708	4.583	4.988	Water Sprays

Total Fugitive Emissions from Units 1/2 Sludge Conditioning Piles (Wind Erosion + Maintenance)	**1.579**	**1.727**	**4.627**	**5.069**

Notes:
1) The calculation of hourly PM and PM10 emissions assumed 2,920 hours of maintenance related to the piles per year (8 hours per day).

IPP Unit 3 Project
Units 1 & 2 Paved Haul Roads - Ash Hauling

Paved Road emission factor from AP-42, Section 13.2.1: *Paved Roads* (10/97)

E_U (lb per vehicle mile traveled) = k(sL/2)^.65(W/3)^1.5

where:

k =	0.016	[Table 13.2.1-1, for PM_{10}]	
k =	0.082	[Table 13.2.1-1, for Total PM]	
s =	8.2	[silt loading (%) for quarry road, Table 13.2.1-3]	
W=	27.5	[mean vehicle weight(tons)]	[empty truck=15 tons, loaded=40 tons]
E_U =	1.111	[PM_{10}]	
E_U =	5.694	[PM]	

Haul truck maximum load =	25	tons per truck		
Amount Flyash produced =	389,687	tons	[Units 1&2 generated 386,271 tons ash in 2000, 393,103 tons in 2001, average = 389,687]	
Amount Flyash sold =	226,304		[Sold 208,608 tons 2000, 244,000 tons 2001, remaining flyash is mixed with FGD sludge]	
Percentage trucked =	40%		[40% by truck offsite, 60% by rail offsite]	
Amount hauled (per year) =	90,522	tons		
Amount hauled (per day) =	248.0	tons	[24 hr/day, 7 days/wk]	
Hauling hours per day =	24	hours		
Amount hauled (per hour) =	10.3	tons		
Haul road round trip =	1.02	miles	[2700 feet one way]	Roundtrip = 2700 x2 = 5400 feet
Round trips per hour =	0.41			
Round trips per year =	3,620.86			
VMT (per hour) =	0.42	miles		
VMT (annual) =	3,703	miles		

Source ID	Source Name	Maximum Uncontrolled Emissions (lb PM/hr)	Annual Uncontrolled PM Emissions (tpy)	Maximum Uncontrolled Emissions (lb PM_{10}/hr)	Annual Uncontrolled PM_{10} Emissions (tpy)	Control %	Maximum Controlled Emissions (lb PM_{10}/hr)	Maximum Controlled Emissions (lb PM/hr)	Annual Controlled PM_{10} Emissions (tpy)	Annual Controlled PM Emissions (tpy)	Control System
	Paved haul roads	2.41	10.54	0.47	2.06	50.00	0.23	1.20	1.03	5.27	Water Sprays

IPP Unit 3 Project
Unit 3 Paved Haul Roads - Ash Hauling

Paved Road emission factor from AP-42, Section 13.2.1: *Paved Roads* (10/97)

E_U (lb per vehicle mile traveled) = k(sL/2)^.65(W/3)^1.5

where:

k =	0.016	[Table 13.2.1-1, for PM_{10}]	
k =	0.082	[Table 13.2.1-1, for Total PM]	
s =	8.2	[silt loading (%) for quarry road, Table 13.2.1-3]	
W=	27.5	[mean vehicle weight(tons)]	[empty truck=15 tons, loaded=40 tons]
E_U =	1.111	[PM_{10}]	
E_U =	5.694	[PM]	

Haul truck maximum load =	25	tons per truck		
Amount Flyash produced =	339,365	tons	[Sargent & Lundy - Unit 3 Design Calculations]	
Amount Flyash sold =	196,832		[58% flyash sold based on present Unit 1/2 operation]	
Precentage trucked =	40%		[Estimate 40% by truck offsite, 60% by rail offsite]	
Amount hauled (per year) =	78,733	tons		
Amount hauled (per day) =	215.7	tons	[24 hr/day, 7 days/wk]	
Hauling hours per day =	24	hours		
Amount hauled (per hour) =	9.0	tons		
Haul road round trip =	1.02	miles	[2700 feet one way]	Roundtrip = 2700 x2 = 5400 feet
Round trips per hour =	0.36			
Round trips per year =	3,149.31			
VMT (per hour) =	0.4	miles		
VMT (annual) =	3,221	miles		

Source ID	Source Name	Maximum Uncontrolled Emissions (lb PM/hr)	Annual Uncontrolled PM Emissions (tpy)	Maximum Uncontrolled Emissions (lb PM_{10}/hr)	Annual Uncontrolled PM_{10} Emissions (tpy)	Control %	Maximum Controlled Emissions (lb PM_{10}/hr)	Maximum Controlled Emissions (lb PM/hr)	Annual Controlled PM_{10} Emissions (tpy)	Annual Controlled PM Emissions (tpy)	Control System
	Paved haul roads	2.09	9.17	0.41	1.79	50.00	0.20	1.05	0.89	4.59	Water Sprays

IPP Unit 3 Project

Units 1 and 2 Unpaved Haul Roads - Conditioned Sludge (Conveyor Stackout to Landfill)

Unpaved Roads emission factor from AP-42, Section 13.2.2: *Unpaved Roads* (9/98), Equation (2) - corrected to account for annual precipitation

E_U (lb per vehicle mile traveled) = $((k(s/12)^a(W/3)^b)/(M/0.2)^c)((365-p)/365)$

where:

k =	2.6	[Table 13.2.2-2, for PM_{10}]	
k =	10	[Table 13.2.2-2, for PM]	
s =	5.1	[silt loading (%) for coal mine plant road, Table 13.2.2-1]	
a =	0.8	[Table 13.2.2-2, for PM_{10}]	
W=	27.5	[mean vehicle weight(tons)]	[empty truck=15 tons, loaded=40 tons]
b =	0.4	[Table 13.2.2-2, for PM_{10}]	
M=	0.2	[default value for moisture in the soil (%); dry, uncontrolled conditions]	
c =	0.3	[Table 13.2.2-2, for PM_{10}]	
p=	60	[annual precipitation (days), Figure 13.2.2-1]	
E_U =	2.658	[PM_{10}]	
E_U =	10.224	[PM]	

Haul truck maximum load =	25	tons per truck		
Amount of Sludge produced =	252,728	tons	Units 1 and 2 produced 280,478 tons of sludge in 2000 and 224,978 tons in 2001, average = 252,728 tons]	
Precentage trucked =	100%			
Amount hauled (per year) =	252,728	tons		
Amount hauled (per day) =	395.7	tons	[10 hr/day, 4 days/wk]	
Hauling hours per day =	10	hours		
Amount hauled (per hour) =	39.6	tons		
Haul road round trip =	1.36	miles	[3600 feet one way]	Roundtrip = 3600 x2 = 7200 feet
Round trips per hour =	1.58			
Round trips per year =	10,109			
VMT (per hour) =	2.2	miles		
VMT (annual) =	13,785	miles		

Source ID	Source Name	Maximum Uncontrolled Emissions (lb PM/hr)	Annual Uncontrolled PM Emissions (tpy)	Maximum Uncontrolled Emissions (lb PM_{10}/hr)	Annual Uncontrolled PM_{10} Emissions (tpy)	Control %	Maximum Controlled Emissions (lb PM_{10}/hr)	Maximum Controlled Emissions (lb PM/hr)	Annual Controlled PM_{10} Emissions (tpy)	Annual Controlled PM Emissions (tpy)	Control System
	Unpaved haul roads	22.06	70.47	5.74	18.32	50.00	2.87	11.03	9.16	35.23	Water Sprays

IPP Unit 3 Project
Units 1 and 2 Unpaved Haul Roads - Conditioned Sludge (Conveyor Stackout to Landfill)

Unpaved Roads emission factor from AP-42, Section 13.2.2: *Unpaved Roads* (9/98), Equation (2) - corrected to account for annual precipitation

E_U (lb per vehicle mile traveled) = $((k(s/12)^a(W/3)^b)/(M/0.2)^c)((365-p)/365)$

where:

k =	2.6	[Table 13.2.2-2, for PM_{10}]	
k =	10	[Table 13.2.2-2, for PM]	
s =	5.1	[silt loading (%) for coal mine plant road, Table 13.2.2-1]	
a =	0.8	[Table 13.2.2-2, for PM_{10}]	
W=	27.5	[mean vehicle weight(tons)]	[empty truck=15 tons, loaded=40 tons]
b =	0.4	[Table 13.2.2-2, for PM_{10}]	
M=	0.2	[default value for moisture in the soil (%); dry, uncontrolled conditions]	
c =	0.3	[Table 13.2.2-2, for PM_{10}]	
p=	60	[annual precipitation (days), Figure 13.2.2-1]	
E_U =	2.658	[PM_{10}]	
E_U =	10.224	[PM]	

Haul truck maximum load =	25	tons per truck		
Amount of Sludge produced =	252,728	tons	Units 1 and 2 produced 280,478 tons of sludge in 2000 and 224,978 tons in 2001, average = 252,728 tons]	
Precentage trucked =	100%			
Amount hauled (per year) =	252,728	tons		
Amount hauled (per day) =	395.7	tons	[10 hr/day, 4 days/wk]	
Hauling hours per day =	10	hours		
Amount hauled (per hour) =	39.6	tons		
Haul road round trip =	1.36	miles	[3600 feet one way]	Roundtrip = 3600 x2 = 7200 feet
Round trips per hour =	1.58			
Round trips per year =	10,109			
VMT (per hour) =	2.2	miles		
VMT (annual) =	13,785	miles		

Source ID	Source Name	Maximum Uncontrolled Emissions (lb PM/hr)	Annual Uncontrolled PM Emissions (tpy)	Maximum Uncontrolled Emissions (lb PM_{10}/hr)	Annual Uncontrolled PM_{10} Emissions (tpy)	Control %	Maximum Controlled Emissions (lb PM_{10}/hr)	Maximum Controlled Emissions (lb PM/hr)	Annual Controlled PM_{10} Emissions (tpy)	Annual Controlled PM Emissions (tpy)	Control System
	Unpaved haul roads	22.06	70.47	5.74	18.32	50.00	2.87	11.03	9.16	35.23	Water Sprays

IPP Unit 3 Project
Units 1 and 2 Coal Pile

Wind Erosion
Reference: Control of Open Fugitive Dust Sources, Section 4.1.3, EPA-450/3-98-008
[Wind Emissions From Continuously Active Piles]

E (lb PM per day per acre) = 1.7 (s/1.5) (365-p/235) (f/15)

where:

s = 2.2 silt content % [from AP-42 Table 13.2.4-1 (coal as received at coal-fired power plant)
p = 60 number of days with >0.01 inches precip. per year [from AP-42 Figure 13.2.2-1]
f = 12 percentage of time that wind speed exceeds 5.4 m/s at mean pile height [from 10-m IPP wind data 7/01 - 3/02]
E = 2.6 lb PM per day per acre
E = 1.3 lb PM-10 per day per acre [using PM-10 to PM ratio of 0.5 from EPA-450/3-98-008]

Source ID	Source Name	Coal pile size (acres) (1)	Uncontrolled Emissions (lb PM_{10}/hr)	Uncontrolled Emissions (lb PM/hr)	Control %	Controlled Emissions (lb PM_{10}/hr)	Controlled Emissions (lb PM/hr)	Controlled PM_{10} Emissions (tpy)	Controlled PM Emissions (tpy)	Control System*
F-16	Unit 1 & 2 Long Term Reserve Coal Storage Pile	12.6	0.68	1.36	99	0.007	0.014	0.030	0.059	Wet suppression with chemicals
F-13	Unit 1 & 2 Emergency Stackout Coal Storage Pile	1.8	0.10	0.19	99	0.001	0.002	0.004	0.008	Wet suppression with chemicals
F-13	Unit 1 & 2 Active Reclaim Stackout Coal Storage Pile	1.8	0.10	0.10	50	0.048	0.048	0.211	0.211	Moisture from water sprays, compaction of pile
F-30	Unit 1 & 2 Active Coal Storage Pile	11.7	0.63	0.63	50	0.316	0.316	1.382	1.382	Moisture from water sprays, compaction of pile

(1) size of pile =	Long Term Reserve	Emergency Stackout	Active Reclaim Storage	Active Coal Storage
	547,447 ft^2	77,463 ft^2	77,699 ft^2	509,732
	12.6 acres	1.8 acres	1.8 acres	11.7

Maintenance of Active Pile (Bulldozing)
Reference: AP-42, Table 11.9-1 (Western Surface Coal Mining)

E (lb PM per hour) = 78.4 (s)^1.2 / (M)^1.3
E (lb PM-10 per hour) = (0.75) 18.6 (s)^1.5 / (M)^1.4

where:

s = 2.2 silt content % [from AP-42 Table 13.2.4-1 (coal as received at coal-fired power plant)
M = 4.5 moisture % [from AP-42 Table 13.2.4-1 (coal as received at coal-fired power plant)
E = 28.58 lb/hr PM
E = 5.54 lb/hr PM-10

Source ID	Source Name	Coal pile size (acres) (1)	Uncontrolled Emissions (lb PM_{10}/hr)	Uncontrolled Emissions (lb PM/hr)	Control %	Controlled Emissions (lb PM_{10}/hr)	Controlled Emissions (lb PM/hr)	Controlled PM_{10} Emissions (tpy)	Controlled PM Emissions (tpy)	Control System*
F-14, F-15, F-29 and F-31	Fugitives from bulldozing Reserve Coal Stockout Pile to Reserve Coal Storage Pile, Reserve Piles to Reclaim Hopper, Active Coal Storage to Reserve Coal Storage, and Active or Reserve Piles to Reclaim Tunnel	11.7	5.54	28.58	50	0.924	4.763	4.046	20.863	Moisture from water sprays, compaction of pile

Total Fugitive Emissions from Units 1 and 2 Coal Storage Piles (Wind Erosion + Maintenance) **1.295** **5.142** **5.673** **22.523**

Notes:
1) Control Efficiencies rom Table 4 (*Summary of Control Alternatives and Their Control Efficiencies*), pg 694 of Air & Waste Management Association *Air Pollution Engineering Manual* (2000)
2) In addition to control %, a factor of 8/24 is incorporated into lb/hr and tpy emission rate to account for maximum daily maintenance of the active coal piles (8 hours per day)

IPP Unit 3 Project
Units 1 and 2 Coal Handling

Emission factor from AP-42, Section 13.2.4: *Aggregate Handling and Storage Piles* (1/95), Equation (1) - batch or continuous drop operation

E (lb PM_{10} per ton material handled) = k (0.0032) (U/5)^1.3 / [(M/2)^1.4]
where:
k = 0.35 [particles < 10um]
k = 0.74 [particles < 30um]
U = 7 [mph, avg 10-m wind speed from IPP]
[used for exposed sources and to conservatively estimate internal ventilation for enclosed sources]
M = 4.5 [%, mean moisture content for coal (as received), Table 13.2.4-1 (coal-fired power plant)]

E (lb PM_{10} per ton handled) = 5.57E-04
E (lb PM per ton handled) = 1.18E-03

Source ID	Source Name	Process Rate (ton/hour)	Uncontrolled Emissions (lb PM_{10}/hr)	Uncontrolled Emissions (lb PM/hr)	Control %	Controlled Emissions (lb PM_{10}/hr)	Controlled PM_{10} Emissions (g/s)	Controlled Emissions (lb PM/hr)	Controlled PM_{10} Emissions (tpy)	Controlled PM Emissions (tpy)	Control System and Comments
EP-123	Emissions from dust collection system 13A exhaust fan - Unit 1 East Silo Bay	4800	2.68	5.66	99	0.027	0.003	0.057	0.014	0.030	Transfers associated with this source are TP-47, TP-48, TP-49, TP-50, TP-51, TP-52, TP-53, TP-54, TP-59, TP-60, TP61 and TP-62. TP-49, TP-50, TP-51, TP-52, TP-53 and TP-54 are 600 TPH, the others are 1000 TPH. 6 of 12 operate at the same time. Fabric Filter used for dust collection.
EP-124	Emissions from dust collection system 13B exhaust fan - Unit 1 West Silo Bay	1800	1.00	2.12	99	0.010	0.001	0.021	0.014	0.030	Transfers associated with this source are TP-51, TP-52, TP-55, TP-56, TP-57, and TP-58. 600 TPH for each transfer. 3 of 6 operate at the same time. Fabric Filter used for dust collection.
EP-125	Emissions from dust collection system 14A exhaust fan - Unit 2 East Silo Bay	2800	1.56	3.30	99	0.016	0.002	0.033	0.014	0.030	Transfers associated with this source are TP-63, TP-64, TP-65, TP-66, TP-67, TP-68, TP-69, and TP-70. TP-63 and TP-64 are 1000 TPH, the others are 600 TPH. 4 of 8 operate at the same time. Fabric Filter used for dust collection.
EP-126	Emissions from dust collection system 14B exhaust fan - Unit 2 West Silo Bay	1800	1.00	2.12	99	0.010	0.001	0.021	0.014	0.030	Transfers associated with this source are TP-67, TP-68, TP-71, TP-72, TP-73, and TP-74. 600 TPH for each transfer. 3 of 6 operate at the same time. Fabric Filter used for dust collection.

Notes:
1) Control Efficiencies from Table 4 (*Summary of Control Alternatives and Their Control Efficiencies*), pg 694 of Air & Waste Management Association *Air Pollution Engineering Manual* (2000)
2) Annual PM and PM10 tpy emissions determined by using the ratio of the (Units 1 and 2 coal storage)/(hourly process rate x 8760). Average 2000/2001 storage for Units 1 and 2 = 5,172,676 tons.

3) Sample calculations (EP123):
Uncontrolled emissions (lb PM_{10} per hour): hourly process rate (4800 tons/hour) x emission factor (5.57E-04 lb/ton) = 2.675 lb/hr
Controlled emissions (lb PM_{10} per hour): uncontrolled emissions (2.675 lb/hr) x control efficiency [1-(control%/100)] = 2.675 x .01 = 0.027 lb/hr

IPP Unit 3 Project
Unit 3 Coal Pile

Wind Erosion
Reference: Control of Open Fugitive Dust Sources, Section 4.1.3, EPA-450/3-98-008
[Wind Emissions From Continuously Active Piles]

E (lb PM per day per acre) = 1.7 (s/1.5) (365-p/235) (f/15)

where:

s =	2.2	silt content % [from AP-42 Table 13.2.4-1 (coal as received at coal-fired power plant)
p =	60	number of days with >0.01 inches precip. per year [from AP-42 Figure 13.2.2-1]
f =	12	percentage of time that wind speed exceeds 5.4 m/s at mean pile height [from 10-m IPP wind data 7/01 - 3/02]
E =	2.6	lb PM per day per acre
E =	1.3	lb PM-10 per day per acre [using PM-10 to PM ratio of 0.5 from EPA-450/3-98-008]

Source ID	Source Name	Coal pile size (acres) (1)	Uncontrolled Emissions (lb PM_{10}/hr)	Uncontrolled Emissions (lb PM/hr)	Control %	Controlled Emissions (lb PM_{10}/hr)	Controlled Emissions (lb PM/hr)	Controlled PM_{10} Emissions (tpy)	Controlled PM Emissions (tpy)	Control System*
F-17	Unit 3 addition to Long Term Reserve Coal Storage Pile	9.0	0.48	0.97	99	0.005	0.010	0.021	0.042	Wet suppression with chemicals

(1) size of pile = Unit 3 Long Term Reserve
390,000 ft^2
9.0 acres

Maintenance of Active Pile (Bulldozing)
Reference: AP-42, Table 11.9-1 (Western Surface Coal Mining)

E (lb PM per hour) = 78.4 (s)^1.2 / (M)^1.3
E (lb PM-10 per hour) = (0.75) 18.6 (s)^1.5 / (M)^1.4

where:

s =	2.2	silt content % [from AP-42 Table 13.2.4-1 (coal as received at coal-fired power plant)
M =	4.5	moisture % [from AP-42 Table 13.2.4-1 (coal as received at coal-fired power plant)
E =	28.58	lb/hr PM
E =	5.54	lb/hr PM-10

Source ID	Source Name	Coal pile size (acres) (1)	Uncontrolled Emissions (lb PM_{10}/hr)	Uncontrolled Emissions (lb PM/hr)	Control %	Controlled Emissions (lb PM_{10}/hr)	Controlled Emissions (lb PM/hr)	Controlled PM_{10} Emissions (tpy)	Controlled PM Emissions (tpy)	Control System*
Maintenance Activities included in Units 1 and 2 coal pile operations										

Total Fugitive Emissions from Unit 3 Coal Storage Piles (Wind Erosion + Maintenance)	**0.005**	**0.010**	**0.021**	**0.042**

Notes:
1) Control Efficiencies rom Table 4 (*Summary of Control Alternatives and Their Control Efficiencies*), pg 694 of Air & Waste Management Association *Air Pollution Engineering Manual* (2000)
2) There is no added maintenance of coal piles with the Unit 3 addition. It is included in the Units 1&2 Coal Pile calculations.

IPP Unit 3 Project
Units 1, 2 and 3 Coal Handling

Emission factor from AP-42, Section 13.2.4: *Aggregate Handling and Storage Piles* (1/95), Equation (1) - batch or continuous drop operation

E (lb PM_{10} per ton material handled) = k (0.0032) (U/5)^1.3 / [(M/2)^1.4]

where:

k = 0.35 [particles < 10um]

k = 0.74 [particles < 30um]

U = 7 [mph, avg 10-m wind speed from IPP]
[used for exposed sources and to conservatively estimate internal ventilation for enclosed sources]

M = 4.5 [%, mean moisture content for coal (as received), Table 13.2.4-1 (coal-fired power plant)]

E (lb PM_{10} per ton handled) = 5.57E-04
E (lb PM per ton handled) = 1.18E-03
Unit 3 sources % of emissions = 0.439

Source ID	Source Name	Process Rate (ton/hour)	Uncontrolled Emissions (lb PM_{10}/hr)	Uncontrolled Emissions (lb PM/hr)	Control %	Controlled Emissions (lb PM_{10}/hr)	Controlled PM_{10} Emissions (g/s)	Controlled PM_{10} Emissions (g/s, Unit 3 operation)	Controlled Emissions (lb PM/hr)	Controlled PM_{10} Emissions (tpy)	Controlled PM Emissions (tpy)	Control System and Comments
EP-12	Emissions from transfer of coal from Stockout Conveyor C-3 to Reserve Coal Stockout Pile	4,000	2.23	4.71	75	0.557	0.070	0.031	1.178	0.639	1.351	Telescopic Chute used for dust suppression.
EP-27	Emissions from transfer of coal from Conveyor C-6 to Stacker Conveyor.	6,000	3.34	7.07	50	1.672	0.211	0.092	3.535	1.278	2.702	Enclosed loading chute on wind guard used for dust suppression.
EP-28	Emissions from transfer of coal from Stacker Conveyor to Active Storage PilePile	6,000	3.34	7.07	75	0.836	0.105	0.046	1.768	0.639	1.351	Telescopic Chute used for dust suppression.
EP-32, EP-33, EP-34, EP-35, and EP-36	Emissions from transfer of coal from the Active Coal Storage Pile to Conveyor C-7 by Rotary Plow Feeders 7A, 7B, 7C and 7D and transfer from Conveyor C-7 to C-8	6,000	3.34	7.07	70	1.003	0.126	0.055	2.121	0.767	1.621	Enclosure of conveyors and transfer points used for dust suppression.
EP-97, EP-98, EP-99, and EP-100	Emissions from dust collection system exhaust Fans 1A, 1B, 1C and 1D - Coal Car Unloading Building	16,000	8.92	18.85	99	0.089	0.011	0.005	0.189	0.026	0.054	Transfers associated with this source are TP-1, TP-2, TP-7 and TP-8. 4000 TPH per transfer point. TP-3, TP-4, TP-5 and TP-6 are included in TP-1 and TP-2 total. Fabric Filters used for dust collection.
F-101A	Fugitives from Coal Truck Unloading	1000	0.56	1.18	20	0.446	0.056	0.025	0.943	0.045	0.094	Operational measures and wetting of coal delivered by truck used for dust control.
EP-101B	Emissions from dust collection system exhaust fan -Coal Truck Unloading	1000	0.56	1.18	99	0.006	0.001	0.0003	0.012	0.001	0.001	Transfer associated with this source is TP-10. 1000 TPH per transfer. Fabric Filter used for dust collection.
EP-102	Emissions from dust collection system exhaust fan -Reserve Reclaim Hopper	2000	1.11	2.36	99	0.011	0.001	0.001	0.024	0.026	0.054	Transfer associated with this source is TP-18. 2000 TPH per transfer. Fabric Filter used for dust collection.
EP-103	Emissions from dust collection system exhaust fan -Transfer Building 1	14000	7.80	16.50	99	0.078	0.010	0.004	0.165	0.026	0.054	Transfers associated with this source are TP-11, TP-19, TP-20, TP-21, TP-22, TP-23 and TP-24. TP-11 and TP-24 are 4000 TPH, TP-19 and TP-20 are 2000 TPH and TP21 and TP-22 are 1000 TPH. Fabric Filter used for dust collection.

Source ID	Source Name	Process Rate (ton/hour)	Uncontrolled Emissions (lb PM_{10}/hr)	Uncontrolled Emissions (lb PM/hr)	Control %	Controlled Emissions (lb PM_{10}/hr)	Controlled PM_{10} Emissions (g/s)	Controlled PM_{10} Emissions (g/s, Unit 3 operation)	Controlled Emissions (lb PM/hr)	Controlled PM_{10} Emissions (tpy)	Controlled PM Emissions (tpy)	Control System and Comments
EP-104	Emissions from dust collection system exhaust fan -Transfer Building 2	14000	7.80	16.50	99	0.078	0.010	0.004	0.165	0.026	0.054	Transfers associated with this source are TP-25, TP-26, TP-37, TP-38, TP-39 and TP-40. TP-25 and TP-26 are 4000 TPH and the others are 1500 TPH. Fabric Filter used for dust collection.
EP-105	Emissions from dust collection system exhaust fan-Transfer Building 4	3000	1.67	3.54	99	0.017	0.002	0.001	0.035	0.026	0.054	Transfers associated with this source are TP-41 and TP-42. 1500 TPH per transfer. Fabric Filter used for dust collection.
EP-106	Emissions from dust collection system exhaust fan-Crusher Building 1	5000	2.79	5.89	99	0.028	0.004	0.002	0.059	0.026	0.054	Transfers associated with this source are TP-43, TP-44, TP-45, TP-46, TP-75 and TP-76. TP-43 and TP-44 are 1500 TPH, TP-45 and TP-46 are 1000 TPH and TP-75 and TP-76 are 600 TPH. TP-75 and TP-76 are not included in total - they are shown in "Unit 3 Coal Handling" table. Fabric Filter used for dust collection.

Notes:

1) Emission Sources EP-107 through EP-122 are not included in table. They are insignificant emission sources from ventilation exhaust fans on coal car unloading building and conveyor tunnels.

2) Control Efficiencies from Table 4 (*Summary of Control Alternatives and Their Control Efficiencies*), pg 694 of Air & Waste Management Association *Air Pollution Engineering Manual* (2000)

3) Annual PM and PM10 tpy emissions determined by using the ratio of the (maximum coal storage per year for all three units)/(hourly process rate x 8760). Maximum coal storage = average 2000/2001 storage for Units 1 and 2 plus design maximum storage for Unit 3 = 5,172,676 tons + 4,000,000 tons = 9,172,676 tons. An annual maximum of 200,000 tons was used for truck unloading (F-101A, EP-101B).

4) Sample calculations (EP106):

Uncontrolled emissions (lb PM_{10} per hour): hourly process rate (5000 tons/hour) x emission factor (5.57E-04 lb/ton) = 2.787 lb/hr

Controlled emissions (lb PM_{10} per hour): uncontrolled emissions (2.787 lb/hr) x control efficiency [1-(control%/100)] = 2.787 x .01 = 0.028 lb/hr

IPP Unit 3 Project
Unit 3 Coal Handling

Emission factor from AP-42, Section 13.2.4: *Aggregate Handling and Storage Piles* (1/95), Equation (1) - batch or continuous drop operation

E (lb PM_{10} per ton material handled) = k (0.0032) (U/5)^1.3 / [(M/2)^1.4]
where:
k = 0.35 [particles < 10um]
k = 0.74 [particles < 30um]
U = 7 [mph, avg 10-m wind speed from IPP]
[used for exposed sources and to conservatively estimate internal ventilation for enclosed sources]
M = 4.5 [%, mean moisture content for coal (as received), Table 13.2.4-1 (coal-fired power plant)

E (lb PM_{10} per ton handled) = 5.57E-04
E (lb PM per ton handled) = 1.18E-03

Source ID	Source Name	Process Rate (ton/hour)	Uncontrolled Emissions (lb PM_{10}/hr)	Uncontrolled Emissions (lb PM/hr)	Control %	Controlled Emissions (lb PM_{10}/hr)	Controlled PM_{10} Emissions (g/s)	Controlled Emissions (lb PM/hr)	Controlled PM_{10} Emissions (tpy)	Controlled PM Emissions (tpy)	Control System and Comments
EP-106	Emissions from dust collection system exhaust fan - Crusher Building 1 (related to Unit 3 only)	1200	0.67	1.41	99	0.007	0.001	0.014	0.011	0.024	Transfers associated with this source are TP-75 and TP-76. 600 TPH for each transfer. Fabric Filter used for dust collection.
EP-127	Emissions from dust collection system exhaust fan - Transfer Building #5	1200	0.67	1.41	99	0.007	0.001	0.014	0.011	0.024	Transfers associated with this source are TP-77 and TP-78. 600 TPH for each transfer. Fabric Filter used for dust collection.
EP-128	Emissions from dust collection system exhaust fan - Unit 3 East Silo Bay	3000	1.67	3.54	99	0.017	0.002	0.035	0.011	0.024	Transfers associated with this source are TP-79, TP-80, TP-81, TP-82, TP-83, TP-84, TP-85, TP-86, TP-87 and TP-88. 600 TPH for each transfer. Only 5 of 10 of the transfers operate at the same time. Fabric Filter used for dust collection.
EP-129	Emissions from dust collection system exhaust fan - Unit 3 West Silo Bay	2400	1.34	2.83	99	0.013	0.002	0.028	0.011	0.024	Transfers associated with this source are TP-89, TP-90, TP-91, TP-92, TP-93, TP-94, TP-95, and TP-96. 600 TPH for each transfer. Only 4 of 8 of the transfers operate at the same time. Fabric Filter used for dust collection.

Notes:
1) Control Efficiencies from Table 4 (*Summary of Control Alternatives and Their Control Efficiencies*), pg 694 of Air & Waste Management Association *Air Pollution Engineering Manual* (2000)
2) Annual PM and PM10 tpy emissions determined by using the ratio of the (maximum coal storage per year for Unit 3)/(hourly process rate x 8760). Maximum coal storage for Unit 3 = 4,000,000 tons.
3) Sample calculations (EP106):
Uncontrolled emissions (lb PM_{10} per hour): hourly process rate (1200 tons/hour) x emission factor (5.57E-04 lb/ton) = 0.669 lb/hr
Controlled emissions (lb PM_{10} per hour): uncontrolled emissions (0.67 lb/hr) x control efficiency [1-(control%/100)] = 0.67 x .01 = 0.007 lb/hr

	A	B	C	K	L	M	N
1		**Permit Basis Proposed Limits** **NO_X = 0.07 lb/mmBtu** **SO_2 =0.10lb/mmBtu** **Fuel Sulfur @ 0.75%**		**Western Bituminous Design Coal**			
2	NAME	**TECHNOLOGY:** **950 MW(Gross) PC Unit**	**UNITS**	**"Worst-Case" Fuel 105% Utah-Bit**	**"Worst-Case" Fuel 100% Utah-Bit**	**"Worst-Case" Fuel 75% Utah-Bit**	**"Worst-Case" Fuel 50% Utah-Bit**
3		**PLANT CONFIGURATION:**					
4	No_SG	NO. OF STEAM GENERATORS		1 Boiler	1 Boiler	1 Boiler	1 Boiler
5	No_ST	NO. OF STEAM TURBINES per Boiler		1 ST	1 ST	1 ST	1 ST
7							
8		SOx Control Technology		Wet FGD	Wet FGD	Wet FGD	Wet FGD
9	S_Remov	Sulfur Removal percentage to achieve Permit Limit	%	92.6	92.6	92.6	92.6
10		NOx CONTROL:		SCR	SCR	SCR	SCR
11	NOX_Re	Target Permit Limit	lb/mmBtu	0.07	0.07	0.07	0.07
12		PARTICULATE CONTROL		Baghouse	Baghouse	Baghouse	Baghouse
13		COOLING		Cooling Tower	Cooling Tower	Cooling Tower	Cooling Tower
14	Load	LOAD	% MCR	100	100	100	100
15		**PLANT PERFORMANCE:**					
16	**NPHR**	**Net Plant Heat Rate, HHV**	Btu/net-kWh	9,790	9,800	10,050	10,360
17	ggo	Gross Plant Output	Gross-kW	997,500	950,000	712,500	475,000
18	NGO	Net Plant Output	Net-kW	924,314	879,748	656,341	433,296
19	GPHR	Gross Plant Heat Rate, HHV	u/gross-kWh	9,072	9,072	9,257	9,453
20	AuxPMW	Auxiliary Power	kW	73,186	70,252	56,159	41,704
21	NTHR	Net Turbine Heat Rate	Btu/net-kWh	7,936	7,936	8,098	8,267
22	Fuel_pph	Primary Fuel Feed Rate	lb/hr	808,504	770,003	589,281	401,139
23		Primary Fuel Feed Rate	Tons/hr	404	385	295	201
24		Primary Fuel Feed Rate	lb/net-MWh	875	875	898	926
25		**Full load Heat input to Boiler**	**mmBtu's/hr**	**9,050**	**8,619**	**6,596**	**4,490**
26	Fuel2_pp	Secondary Fuel Feed Rate	lb/hr	N/A	N/A	N/A	N/A
27		Secondary Fuel Feed Rate	lb/net-MWh	N/A	N/A	N/A	N/A
28	Sorb_pph	Sorbent Feed Rate	lb/hr	20,072	19,116	14,630	9,959
29		Sorbent Feed Rate	lb/net-MWh	21.7	21.7	22.3	23.0
30	NH3_pph	Ammonia Feed Rate (Anhydrous)	lb/hr	993	946	724	493
31		Ammonia Feed Rate (Aqueous, 29.4%)	lb/hr	3,378	3,217	2,462	1,676
32		Ammonia Feed Rate (Anhydrous)	lb/net-MWh	1.074	1.075	1.103	1.137
33		Ammonia Feed Rate (Aqueous, 29.4%)	lb/net-MWh	3.655	3.657	3.751	3.868
36							
37		**FUEL ANALYSIS:**		**Utah-Bit High Emission Case**	**Utah-Bit High Emission Case**	**Utah-Bit High Emission Case**	**Utah-Bit High Emission Case**
38		**Coal/Oil Ultimate Analysis**					
39	Fu_C	Carbon	%	64.50	64.50	64.50	64.50
40	Fu_S	Sulfur	%	0.75	0.75	0.75	0.75
41	Fu_O2	Oxygen	%	8.90	8.90	8.90	8.90
42	Fu_H2	Hydrogen	%	4.66	4.66	4.66	4.66
43	Fu_N	Nitrogen	%	1.26	1.26	1.26	1.26
44		Chlorine	%	0.03	0.03	0.03	0.03
45	Fu_Ash	Ash	%	12.00	12.00	12.00	12.00
46	Fu_H2O	Moisture	%	8.26	8.26	8.26	8.26
48		**Coal/Oil Proximate Analysis**					
49		Moisture	%	8.26	8.26	8.26	8.26
50		Volatile matter	%	37.0	37.0	37.0	37.0
51		Fixed Carbon	%	43.0	43.0	43.0	43.0
52		Ash	%	12.0	12.0	12.0	12.0
53	GHV	Gross (Higher) Heating Value	Btu/lb	11,193	11,193	11,193	11,193
54	DULONG	Gross Heating Value (Dulong)	Btu/lb	11,612	11,612	11,612	11,612
55	HGI	Hardgrove Grindability	HGI	40	40	40	40
56							
57		**Coal Ash Analysis**					
58		Silica	%	63.2	63.2	63.2	63.2
59		Ferric Oxide	%	3.3	3.3	3.3	3.3
60		Alumina	%	15.5	15.5	15.5	15.5
61		Titanic Oxide	%	0.8	0.8	0.8	0.8
62		Calcium Oxide	%	7.1	7.1	7.1	7.1
63		Magnesia	%	2.9	2.9	2.9	2.9
64		Sulfur Trioxide	%	4.2	4.2	4.2	4.2
65		Potassium Oxide	%	1.0	1.0	1.0	1.0
66		Sodium Oxide	%	2.4	2.4	2.4	2.4
67		Phosphorous Pentoxide	%	0.2	0.2	0.2	0.2
68		Undetermined	%	0.0	0.0	0.0	0.0
69							

	A	B	C	K	L	M	N
1		**Permit Basis Proposed Limits** **NO_X = 0.07 lb/mmBtu** **SO_2 =0.10lb/mmBtu** **Fuel Sulfur @ 0.75%**		**Western Bituminous Design Coal**			
2	NAME	**TECHNOLOGY:** **950 MW(Gross) PC Unit**	**UNITS**	**"Worst-Case" Fuel 105% Utah-Bit**	**"Worst-Case" Fuel 100% Utah-Bit**	**"Worst-Case" Fuel 75% Utah-Bit**	**"Worst-Case" Fuel 50% Utah-Bit**
70							
92	HHV	Gross (Higher) Heating Value	Btu/lb	N/A	N/A	N/A	N/A
93	MolWt	Fuel Molecular Weight	lb/lb-mole	N/A	N/A	N/A	N/A
94							
95		**SORBENT ANALYSIS:**					
96	SorbCaC	CaCO3	%	90	90	90	90
97	SorbMgC	MgCO3	%	3	3	3	3
98	SOrbCaO	CaO	%	0	0	0	0
99	SorbAsh	Ash	%	6.5	6.5	6.5	6.5
100	SorbMois	Moisture	%	0.5	0.5	0.5	0.5
101							
102		**PLANT EMISSION ANALYSIS:**					
103		Note: The following emissions are calculated values and are less than what would be reported by a CEM system. No adjustments have been made to emulate what the CEM values might be, due to flow margins reported utilities.					
104	SOx_Unc	SOx - Uncontrolled	lb/mmBtu	1.34	1.34	1.34	1.34
105	CASR	Calcium to Sulfur Molar Ratio		1.03	1.03	1.03	1.03
106	Dibasic_A	Dibasic Acid Feed Rate	lb/hr	0	107	82	56
107	SOx_pph	SOx - Controlled	lb/hr	905	862	660	449
108	SOxpMB	SOx - Controlled	lb/mmBtu	**0.100**	**0.100**	**0.100**	**0.100**
109		SOx - Controlled	tons/year	3964	3775	2889	1967
110		SOx - Controlled	lb/net-MWh	0.98	0.98	1.00	1.04
111	SOxppm	SOx - Controlled (Approximate)	ppmvd	51.2(3%O2)	51.2(3%O2)	51.2(3%O2)	51.2(3%O2)
112		NOx - Uncontrolled	lb/mmBtu	0.35	0.35	0.35	0.35
113		NOx - Uncontrolled	lb/net-MWh	3.43	3.43	3.52	3.63
114		NOx -Uncontrolled (Normalized)	ppmvd	250(3%O2)	250(3%O2)	250(3%O2)	250(3%O2)
115		NOx Conversion Efficiency	%	80	80	80	80
116		S(N)CR Ammonia Slip	ppmvd	2(3%O2)	2(3%O2)	2(3%O2)	2(3%O2)
117	NH3NO2	NH3/NO2 Molar Ratio		0.81	0.81	0.81	0.81
118	NOx_pph	NOx - Controlled	lb/hr	633	603	462	314
119	NOx_MB	NOx - Controlled	lb/mmBtu	**0.070**	**0.070**	**0.070**	**0.070**
120		NOx - Controlled	lb/net-MWh	0.685	0.686	0.703	0.725
121		NOx - Controlled	tons/year	2775	2642	2022	1377
122		NOx - Controlled (Approximate)	ppmvd	49.9(3%O2)	49.9(3%O2)	49.9(3%O2)	49.9(3%O2)
123							
124		CO2 Uncontrolled	lb/mmBtu	204.5	204.5	204.5	204.5
125	CO2_pph	CO2 Uncontrolled	lb/hr	1,850,602	1,762,478	1,348,819	918,176
126		CO2 Uncontrolled	ton/yr	8,105,637	7,719,652	5,907,826	4,021,611
127		CO2 Uncontrolled	lb/net-MWh	2,002	2,003	2,055	2,119
128		Particulate - Controlled	lb/mmBtu	0.015	0.015	0.015	0.015
129	Partic_pp	Particulate - (Emitted)	lb/hr	135.7	129.3	98.9	67.3
130		Particulate - (Emitted)	lb/net-MWh	0.147	0.147	0.151	0.155
131	Partic_Ef	Particulate Removal Efficiency	%	99.83	99.83	99.83	99.83
132		NH3	ppmvd	2	2	2	2
133		NH3	lb/hr	8.7	8.3	6.4	4.3
134		NH3	lb/net-MWh	0.009	0.009	0.010	0.010
135		pm10	lb/mmBtu	0.015	0.015	0.015	0.015
136		pm10	lb/hr	135.7	129.3	98.9	67.3
137		pm10	lb/net-MWh	0.147	0.147	0.151	0.155
138		CO	ppmvd	180	180	180	180
139		CO	lb/hr	1,391	1,324	1,014	690
140		CO	lb/MBtu	0.154	0.154	0.154	0.154
141		CO	lb/net-MWh	1.504	1.505	1.544	1.592
142		N2O	lb/mmBtu	0.005	0.005	0.005	0.005
143		N2O	lb/hr	45.248	43.093	32.979	22.450
144		N2O	lb/net-MWh	0.049	0.049	0.050	0.052
145		Air Toxics - Chlorine	ppmvd (wt)	500	500	500	500
146		Air Toxics - Chlorine (Uncontrolled)	lb/hr	381.31	363.15	277.92	189.19
147		Air Toxics - Chlorine (Uncontrolled)	lb/net-MWh	0.413	0.413	0.423	0.437
148		Air Toxics - Chlorine Removal Eff.	%	90	90	90	90
149		Air Toxics - Chlorine (controlled-FGD)	lb/hr	38.131	36.315	27.792	18.919
150		Air Toxics - Chlorine (controlled-FGD)	lb/MBtu	0.00421	0.00421	0.00421	0.00421
151		Air Toxics - Chlorine (controlled-FGD)	lb/net-MWh	0.041	0.041	0.042	0.044
152		Air Toxics - Fluorine	ppmvd (wt)	60	60	60	60
153		Air Toxics - Fluorine (Uncontrolled)	lb/hr	46.85	44.61	34.14	23.24
154		Air Toxics - Fluorine (Uncontrolled)	lb/net-MWh	0.051	0.051	0.052	0.054
155		Air Toxics - Fluorine Removal Eff.	%	90	90	90	90

	A	B	C	K	L	M	N
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2	NAME	**TECHNOLOGY:** **950 MW(Gross) PC Unit**	**UNITS**	**"Worst-Case" Fuel 105% Utah-Bit**	**"Worst-Case" Fuel 100% Utah-Bit**	**"Worst-Case" Fuel 75% Utah-Bit**	**"Worst-Case" Fuel 50% Utah-Bit**
156		Air Toxics - Fluorine (controlled-FGD)	lb/hr	4.685	4.461	3.414	2.324
157		Air Toxics - Fluorine (controlled-FGD)	lb/MBtu	0.00052	0.00052	0.00052	0.00052
158		Air Toxics - Fluorine (controlled-FGD)	lb/net-MWh	0.005	0.005	0.005	0.005
159		Condensables - H2SO4	Conv.%	2.2	2.2	2.2	2.2
160		Condensables - H2SO4 (Uncontrolled)	lb/hr	408.55	389.09	297.77	202.70
161		Condensables - H2SO4 (Uncontrolled)	lb/net-MWh	0.442	0.442	0.454	0.468
162		Condensables - H2SO4 Removal Eff.	%	90	90	90	90
163		Condensables - H2SO4 (controlled-FGD)	lb/hr	39.7	38.9	29.8	20.3
164		Condensables - H2SO4 (controlled-FGD)	lb/mmBtu	0.00439	0.00451	0.00451	0.00451
165		Condensables - H2SO4 (controlled-FGD)	lb/net-MWh	0.043	0.044	0.045	0.047
166		Assumed - 1.0% SO2 is converted to SO3 in boiler, 4 layers of SCR - 1.2% conversion,.					
167		Condensables - Amm. Sulfate	NH3 Conv.%	80.0	80.0	80.0	80.0
168		Condensables - (NH4)2SO4 (Uncontrolled)	lb/hr	27.08	25.79	19.74	13.43
169		Condensables - (NH4)2SO4 (Uncontrolled)	lb/net-MWh	0.029	0.029	0.030	0.031
170		Condensables - (NH4)2SO4 Removal Eff.	%	90	90	90	90
171		Condensables - (NH4)2SO4 (controlled-FGD	lb/hr	2.708	2.579	1.974	1.343
172		Condensables - (NH4)2SO4 (controlled-FGD	lb/mmBtu	0.00030	0.00030	0.00030	0.00030
173		Condensables - (NH4)2SO4 (controlled-FGD	lb/net-MWh	0.003	0.003	0.003	0.003
174		Assumed - 80% NH3 is converted to Amm. Sulfate, 90% removed in FGD					
175							
176		Air Toxics - Mercury	ppmvd (wt)	0.130	0.130	0.130	0.130
177		Air Toxics - Mercury (Uncontrolled)	lb/hr	0.096	0.092	0.070	0.048
178		Air Toxics - Mercury (Uncontrolled)	lb/net-MWh	0.00010	0.00010	0.00011	0.00011
179		Air Toxics - Mercury Removal Eff. Target (See notes section for clarification)	%	77.7	77.7	77.7	77.7
180		Air Toxics - Mercury (controlled-FGD)	lb/hr	0.02155	0.02052	0.01571	0.01069
181		Air Toxics - Mercury (controlled-FGD)	lb/yr	188.8	179.8	137.6	93.7
182		Air Toxics - Mercury (controlled-FGD)	lb/TBtu	2.38	2.38	2.38	2.38
183		Air Toxics - Mercury (controlled-FGD)	lb/net-MWh	0.000023	0.000023	0.000024	0.000025
188		VOC's(AP-42)	lb/mmBtu	0.00268	0.00268	0.00268	0.00268
189		VOC's	lb/hr	24.25511	23.10009	17.67843	12.03417
190		VOC's	lb/net-MWh	0.026	0.026	0.027	0.028
191		Waste Water (for power block only)	gal/net-MWh	0.680	0.680	0.680	0.680
192		Waste Water (for power block only)	gal/hr	629	598	446	295
193							
194		*Note: Air toxics can vary significantly based on the specific mine from which the fuel is obtained. Since the coals presented are generic, the air toxic emission values are shown only to exhibit the relative performance of the various technologies. The values shown should never be used for absolute emission rates.					
204							
205		**PLANT SOLID WASTE ANALYSIS:**					
206		Fly Ash Collected Split	%	80.00	80.00	80.00	80.00
207	FlyAsh_p	Fly Ash Collected	lb/hr	77,481	73,791	56,472	38,442
208		Fly Ash Collected	Tons/yr	339,365	323,205	247,348	168,376
209		Fly Ash Collected	lb/net-MWh	83.82	83.88	86.04	88.72
211		Bottom Ash Split	%	20.00	20.00	20.00	20.00
212	BotAsh_p	Bottom Ash	lb/hr	19,404	18,480	14,143	9,627
213		Bottom Ash	Tons/yr	84,990	80,943	61,945	42,168
214	BotAsh_l	Bottom Ash	lb/net-MWh	20.99	21.01	21.55	22.22
216	FGDWst_	FGD Waste	lb/hr	32,432	30,888	23,638	16,091
217		FGD Waste	Tons/yr	142,054	135,289	103,536	70,480
218		FGD Waste	lb/net-MWh	35.09	35.11	36.02	37.14
223							
232							
233		**STEAM GENERATOR DATA (Per Boiler):**					
234	THAIR	Theoretical Air	lb/lbfuel	8.68	8.68	8.68	8.68
235	ThDRYG	Theoretical Dry Gas	lb/lbfuel	9.07	9.07	9.07	9.07
236	DRYGAS	Actual Dry Gas	lb/lbfuel	10.80	10.80	10.80	10.80
237	XSAIR	Excess Air	%	20	20	20	20
238	Dry_Air	Total Dry Air Flow	lb/lbfuel	10.42	10.42	10.42	10.42
239	Air_Mst	Ambient Air Moisture	lb/lbair	0.012	0.012	0.012	0.012
240	TotAirFlo	Total Air Flow	lb/lbfuel	10.54	10.54	10.54	10.54
241	FGasMst	Flue Gas Moisture Flow	lb/lbfuel	0.624	0.624	0.624	0.624

	A	B	C	K	L	M	N
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2	NAME	**TECHNOLOGY:** **950 MW(Gross) PC Unit**	**UNITS**	**"Worst-Case" Fuel 105% Utah-Bit**	**"Worst-Case" Fuel 100% Utah-Bit**	**"Worst-Case" Fuel 75% Utah-Bit**	**"Worst-Case" Fuel 50% Utah-Bit**
242	CombPro	Products of Combustion	lb/lbfuel	11.43	11.43	11.43	11.43
243	AH_Leak	Air Heater Leakage	%	20	20	20	20
244	AH_InletT	Airheater Inlet Temperature	°F	100	100	100	100
245	Infilt	Infiltration	%	5	5	5	5
246	Exit_FG_	Exit Flue Gas Temperature	°F	256	256	256	256
247	FlueGas_	Flue Gas Temp. Uncorrected	°F	284	284	284	284
248		Flue Gas Flow Rate to ID Fans	lb/hr	11,631,334	11,077,457	8,477,544	5,770,885
249	FlueGas_	Flue Gas Flow Rate	acfm	3,617,117	3,444,873	2,636,350	1,794,632
250		Combustion Air Flow	lb/hr	8,525,415	8,119,440	6,213,782	4,229,883
251	CA_Flow	Combustion Air Flow	acfm	2,018,359	1,922,246	1,471,089	1,001,408
252		Stack Flue Gas Temperature	°F	135	135	135	135
253		Stack Flue Gas Flow Rate	acfm	3,244,126	3,089,643	2,364,494	1,609,573
254		T Inlet Enthalpy	Btu/lb	68.0	68.0	68.0	68.0
255		T Uncorrected Enthalpy	Btu/lb	1,175	1,175	1,175	1,175
256	RadLoss	Radiation Loss	%	0.172	0.173	0.178	0.187
257	GasLoss	Dry Gas Heat Loss	%	5.13	5.13	5.13	5.13
258	FMstLoss	Fuel Moisture Loss	%	0.82	0.82	0.82	0.82
259	H2Loss	Hydrogen in Fuel Loss	%	4.15	4.15	4.15	4.15
260	AirMstLos	Air Moisture Heat Loss	%	0.099	0.099	0.099	0.099
261	CaLoss	Calcination Loss (CaCO3)	%	N/A	N/A	N/A	N/A
262	MgLoss	Calcination Loss (MgCO3)	%	N/A	N/A	N/A	N/A
263	C_Loss	Carbon Loss	%	0.36	0.36	0.36	0.36
264	UnacLoss	Unaccounted Loss	%	0.50	0.50	0.50	0.50
265	Mfg_mrgn	Manufacturer's Margin	%	1.00	1.00	1.00	1.00
266	BlrLoss	Total Boiler Loss	%	12.22	12.22	12.23	12.24
267	SulGain	Sulfation Gain	%	N/A	N/A	N/A	N/A
268	Boiler_Ef	Boiler Efficiency	%	87.48	87.48	87.48	87.46
269	Sorb_lbf	PFB Sorbent Flow	lb/lbfuel	N/A	N/A	N/A	N/A
270	HSorb	PFB Sorbent Enthalpy	Btu/lb	N/A	N/A	N/A	N/A
271	Ash_lbf	Ash Flow	lb/lbfuel	N/A	N/A	N/A	N/A
272	HAsh	Ash Enthalpy	Btu/lb	N/A	N/A	N/A	N/A
273		HRSG Efficiency	%	N/A	N/A	N/A	N/A
274	QBlr	Total Heat Output from Boiler	mmBtu/hr	7,916.40	7,539.43	5,769.97	3,926.79
275	MS_Flow	Main Steam Flow	lb/hr	6,971,093	6,639,136	4,979,352	3,319,568
276							
277		**STEAM TURBINE/CYCLE DATA (Per Turbine):**					
278		Turbine Back Pressure	in HgA	2.5	2.5	2.5	2.5
279	STout	Steam Turbine Gross Output	kW	997,500	950,000	712,500	475,000
280	LP_Turb_	LP Turbine Exhaust to Condenser	lb/hr	4,130,996	3,934,282	2,950,711	1,967,141
281	Exh_E	Exhaust Energy	Btu/lb	1,030.00	1,030.00	1,030.00	1,030.00
282	Cond_h	Condensate Enthalpy	Btu/lb	82.9	82.9	82.9	82.9
283	LPT_Hea	Heat Rejection from LP Turbine	mmBtu/hr	3,912	3,726	2,795	1,863
284	BFPT_Flo	BFP Turbine Drive Steam Flow	lb/hr	358,925	341,833	256,375	170,917
285	BFPT_Ex	BFP Turbine Exhaust Enthalpy	Btu/lb	1,060.80	1,060.80	1,060.80	1,060.80
286	BFPT_He	Heat Rejection from BFP Turbine	mmBtu/hr	351	334	251	167
287	Heat2Con	Total Heat Rejected to Condenser	mmBtu/hr	4,263	4,060	3,045	2,030
288	CW_T_R	Circulating Water Temp. Rise	°F	27	27	27	27
289	CW_Flow	Circulating Water Flow (Condenser)	gpm	347,532	330,983	248,237	165,491
290		Cooling Water Flow (Other)	gpm	3,475	3,310	2,482	1,655
291		Total Cooling Water Requirement	gpm	351,007	334,293	250,720	167,146
316			Correction factor				
317		**PLANT AUXILIARY POWER:**					
318	ID_P_Ris	Induced Draft Fan Pressure Rise	"wc	39	39	39	39
319	Air2FD	Percent Total Air to FD Fan	%	83	83	83	83
320	FD_P_Ri	Forced Draft Fan Pressure Rise	"wc	22	22	22	22
321	Air2PA	Percent Total Air to PA Fan	%	17	17	17	17
322	PA_P_Ri	Primary Air Fan Pressure Rise	"wc	50	50	50	50
323	Air2SA	Percent Total Air to SA Fan	%	0	0	0	0
324	SA_P_Ri	Secondary Air Fan Pressure Rise	"wc	17	17	17	17
325		Condensate P/P	%	0.36	0.36	0.36	0.36
326		Circulating Water P/P	%	0.64	0.64	0.64	0.64
327		Cooling Towers	%	0.55	0.58	0.78	1.16
329		Subtotal CWS	%	1.55	1.58	1.77	2.16
330		Forced Draft Fan	%	0.51	0.51	0.53	0.54
331		Induced Draft Fan	%	1.95	1.95	1.99	2.03
332		Primary Air Fan	%	0.24	0.24	0.24	0.25
333		Pulverizer Capacity Factor	%	0.80	0.80	0.80	0.80

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2	NAME	**TECHNOLOGY:** **950 MW(Gross) PC Unit**	**UNITS**	**"Worst-Case" Fuel 105% Utah-Bit**	**"Worst-Case" Fuel 100% Utah-Bit**	**"Worst-Case" Fuel 75% Utah-Bit**	**"Worst-Case" Fuel 50% Utah-Bit**
334		Pulverizer	%	0.85	0.85	0.87	0.88
335		Fuel Handling	%	0.14	0.14	0.15	0.15
336		Ash Handling	%	0.26	0.26	0.26	0.27
337		Precipitator/Baghouse	%	0.23	0.23	0.23	0.23
338	TRPwr	power	kW	895	895	895	895
339		FGD	%	0.61	0.64	0.85	1.27
340		Miscellaneous	%	1.00	1.00	1.00	1.00
341	TAuxPwr	TOTAL Auxiliary Power	%	7.34	7.39	7.88	8.78
342							
343		**STACK PARAMETERS:**					
344	No_Stack	Number of Stacks		1	1	1	1
345	Velocity	Exit Velocity	ft/sec	68	65	49	34
346		Height	ft	712	712	712	712
347		Stack diameter (top ID)	ft	31.85	31.85	31.85	31.85
348							
349		This Fossil Technology Spreadsheet is intended to provide a preliminary engineering estimate of the proposed					
350		plant's performance specifications and emission limits. Information included herein is based on engineering					
351		estimates, and if available, site-specific fuel specifications and control efficiencies provided by the client.					
352		Performance data and emission limits provided in this spreadsheet may be used for pre-construction permitt					
353		but do not constitute guaranteed performance or emission limits.					

APPENDIX D

Regulatory Compliance Checklist

TABLE D-1
Summary of Applicable Requirements – Utah Administrative Code

Citation	Description	Requirement/Standard	Applicable		Explanation/ Comments	Methods Used to Demonstrate Compliance
			Yes	No		
Utah Administrative Code						
R307-101	General Requirements	Forward and definitions regarding UAC Title R307 Environmental Quality – Air Quality.		✓	This is not an applicable standard or limitation; however, these definitions do apply when evaluating other applicable requirements within R307.	
R307-102-1	Air Pollution Prohibited Periodic Compliance Report Required	(1) "Air Pollution" is the presence in the ambient air of one or more air contaminants in such quantities and duration and under conditions and circumstances, as is or tends to be injurious to human health or welfare, animal or plant life, or property, or would unreasonably interfere with the enjoyment of life or use of property as determined by the standards, rules, and regulations adopted by the Air Quality Board is prohibited. The state statute provides for penalties up to $50,000/day for violation of state statutes, regulations, rules, or standards. (2) The owner or operator of any stationary air contaminant source in Utah shall furnish to the Air Quality Board (Board) periodic reports as required under Section 19-2-104(1)(c) and any information the Board needs to determine compliance with the state and federal regulations and standards.	✓		(1) Fines may be incurred if the facility is found in violation of state statutes, regulations, rules, or standards. (2) The facility is expected to submit information as required or requested by UDAQ.	(1) The facility shall monitor their emissions and practices to ensure that statutes, regulations, rules, or standards are not violated. (2) Representatives of the UDAQ or the Board will be allowed access to records, documents, or other sources of information as they request.
R307-102-2	Confidentiality of Information	Any person submitting information pursuant to these regulations may request that such information be treated as a trade secret or on a confidential basis.	✓		No information in the application is confidential unless requested.	
R307-102-3.	Reserved			✓	Reserved for later use by UDAQ.	

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Citation	Description	Requirement/Standard	Applicable		Explanation/ Comments	Methods Used to Demonstrate Compliance
			Yes	No		
R307-102-4	Variances Authorized	The Board may grant variance from these regulations unless prohibited by the CAA.		✓	No variances are necessary for Unit 3 at this time. If a variance is needed in the future, a variance will be applied for and the proper documentation will be retained by IPSC.	
R307-102-5	No Reduction in Pay	Owners or operators may not temporarily reduce the pay of any employee by reason of the use of a supplemental or intermittent or other dispersion dependent control system for the purposes of meeting any air pollution requirement. Adopted pursuant to the CAA.		✓	Unit 3 does not utilize dispersion-dependent control systems; therefore, this rule does not apply.	
R307-102-6	Emission Standards	Other provisions of R307 may require more stringent controls than listed herein, in which case those requirements must be met.	✓			IPSC will comply with the most stringent provisions.
R307-103	Initial Orders and Notices of Violations (NOVs)	This rule outlines procedures for initial orders and NOVs.	✓		IPP does not have any open orders or NOVs.	If IPP should ever receive a NOV or order, these rules will be followed.
R307-105	Emergency Controls	Defines the air pollution emergency episode criteria for criteria pollutants and outlines emergency actions required to be conducted by UDAQ.		✓	This requirement applies to UDAQ and is not an obligation of IPSC.	

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Summary of Applicable Requirements – Utah Administrative Code

Citation	Description	Requirement/Standard	Applicable Yes	Applicable No	Explanation/ Comments	Methods Used to Demonstrate Compliance
R307-107	Unavoidable Breakdown	(1) Meet the reporting requirements specified in R307-107-2 in the event of an unavoidable breakdown: • Report breakdown to the executive secretary with in 3 hours (or to the Environmental Health Emergency Response Coordinator at 801-536-4123 if after office hours). • Submit a written report to the executive secretary with in 7 days that includes the cause and nature of the event, the estimated quantity of pollutant(s), the time of emissions, and the steps taken to control and prevent reoccurrence. (2) The owner or operator of an installation suffering an unavoidable breakdown shall assure that emission limitations and visible emission limitations are exceeded for only as short a period of time as reasonable.	✓		Failure to meet reporting requirements can result in a violation. Immediate action must be taken to reduce emissions.	IPSC will provide all necessary reports to UDAQ in the time allotted. IPSC will take any steps to reduce emissions that do not jeopardize employee safety or equipment. Records will be retained at the plant.
R307-110	SIP	To meet requirements of the CAA, the Utah SIP must be incorporated by reference into these rules.		✓	This requirement applies to UDAQ and is not an obligation of IPSC.	
R307-115	Determining Conformity	The Utah SIP must comply with 40 CFR Part 93, Subpart B Determining Conformity of General Federal Actions to State or Federal Implementation Plans which addresses transportation plans, projects, and programs in nonattainment areas.		✓	IPSC is not located in a nonattainment area; therefore, this rule does not apply.	
R307-120	Tax Exemption for Air and Water Pollution Control Equipment	Guidelines for receiving tax exemption for having pollution control equipment.		✓	This does not pertain to the IPSC addition of Unit 3 because the equipment will be new. This rule offers tax exemptions to existing facilities to control current emissions only.	

TABLE D-1
Summary of Applicable Requirements – Utah Administrative Code

Citation	Description	Requirement/Standard	Applicable		Explanation/ Comments	Methods Used to Demonstrate Compliance
			Yes	No		
R307-121	Vehicles that use Cleaner Burning Fuels	General Requirements: Eligibility of Expenditures for Purchase of Vehicles that Use Cleaner Burning Fuels or Conversion of Vehicles and Special Fuel Mobile Equipment to Use Cleaner Burning Fuels for Corporate and Individual Income Tax Credits.		✓	IPSC has not converted vehicles or mobile equipment to cleaner burning fuel; therefore, this rule does not apply	
R307-122	Fireplaces and Wood Stoves that use Cleaner Burning Fuels	General Requirements: Eligibility of Expenditures for Purchase and Installation Costs of Fireplaces and Wood Stoves that Use Cleaner Burning Fuels.		✓	IPSC has no fireplaces or wood stoves at this facility; therefore, this rule does not apply.	
R307-130	General Penalty Policy	Provides guidance to UDAQ for negotiating penalties for noncompliance.		✓	This requirement applies to UDAQ and is not an obligation of IPSC.	
R307-135	Enforcement Response Policy for Asbestos Hazard Emergency Response Act (AHERA)	Guidelines for penalty assessment for violation of the AHERA.		✓	This applies only to educational facilities. IPSC is not an educational facility.	
R307-150	Emission Inventories – Applicability	Any Part 70 source shall submit an emission inventory report. Emission inventories are required every 3 years and are to be retained for at least 5 years.	✓		IPP is subject to the permitting requirements of R307-415 and is therefore considered a Part 70 source.	IPP will complete, submit, and retain copies of emission inventories per the guidelines in this rule.

TABLE D-1
Summary of Applicable Requirements – Utah Administrative Code

Citation	Description	Requirement/Standard	Applicable		Explanation/ Comments	Methods Used to Demonstrate Compliance
			Yes	No		
R307-155	HAP	The owner or operator of a Part 70 source that emits one or more HAPs shall submit a HAP inventory at the same time as the emission inventory and no later than April 15 of the year following.	✓		IPP will be emitting one or more HAPs and will be required to submit a HAP inventory.	IPP will complete, submit, and retain copies of HAP emission inventories per the guidelines in this rule.
R307-158	Emission Statement Inventory	Emission statement inventories are required for some stationary sources in Salt Lake, Davis, Weber, and Utah counties and non-attainment areas for ozone.		✓	IPP is not located in any of the mentioned counties nor is it located in a nonattainment area for ozone; therefore, this requirement does not apply.	
R307-165	Emission Testing	Emission testing will be required of all sources with established emission limitation at least once every 5 years. Sources that have received an approval order will be tested within 6 months of startup in accordance with R307-401.	✓		IPP is applying for an AO for the construction of Unit 3 and will need to comply with this rule.	At least 30 days prior to conducting any emission testing, the executive secretary will be notified of the date, time, and place of testing. Documentation of notifications and test results will be retained.
R307-170	Continuous Emission Monitoring Program	Any source required to install a CEMS to determine emissions to the atmosphere or to measure control equipment efficiency is subject to this rule. Section 7 of this rule provides guidance for conducting CEMS audits.	✓		Facility will install a CEMS in accordance with R307-170-5 (general requirements) and R307-170-6 (1) Fossil Fuel Fired Steam Generators. Also see 40 CFR Part 75 in this table.	Submittal to UDAQ of an electronic data report including all required information.

TABLE D-1
Summary of Applicable Requirements – Utah Administrative Code

Citation	Description	Requirement/Standard	Applicable		Explanation/ Comments	Methods Used to Demonstrate Compliance
			Yes	No		
R307-201-1	Emissions Standards	Listing of opacity requirements, compliance, and observation techniques.	✓		Emissions from any source should not have greater than 20 percent opacity. Observations of stationary sources will be conducted in accordance with EPA Method 9.	Opacity observations will be conducted and documentation retained.
R307-201-2	Automobile Emission Control Devices	Any person owning or operating any motor vehicle or motor vehicle engine registered in the State of Utah on which is installed or incorporated a system or device for the control of crankcase emissions or exhaust emissions in compliance with the federal motor vehicle rules, shall maintain the system or device in operable condition and shall use it at all times that the motor vehicle or motor vehicle engine is operated.	✓			Vehicle maintenance records.
R307-201-3	Opacity for Residential Heating	This rule outlines requirements for visible emissions from residential solid fuel burning devices and fireplaces.		✓	IPSC does not operate residential solid fuel burning devices or fireplaces at the plant; therefore, this rule does not apply.	
R307-202	Emissions Standards: General Burning	This rule describes open burning that is allowed with and without a permit in the State of Utah.	✓		IPP does have a permit to conduct open burning for fire training.	
R307-203	Emission Standards: Sulfur Content of Fuels	Any coal, oil, or mixture thereof, burned in any fuel burning or process installation not covered by NSPS for sulfur emissions shall contain no more than 1.0 pound sulfur per mmBtu heat input for any mixture of coal nor 0.85 pound sulfur per mmBtu heat input for any oil.		✓	The coal-burning equipment at IPP is covered by NSPS; therefore, this rule does not apply.	

TABLE D-1
Summary of Applicable Requirements – Utah Administrative Code

Citation	Description	Requirement/Standard	Applicable		Explanation/ Comments	Methods Used to Demonstrate Compliance
			Yes	No		
R307-204	Emission Standards: Smoke Management	This rule applies to persons using prescribed fire or wildland fire on land they own or manage.		✓	IPP does not use prescribed or wildland fire on their property; therefore, this rule does not apply.	
R307-205	Emission Standards: Fugitive Emissions and Fugitive Dust	Describes guidelines for controlling fugitive emissions and fugitive dusts but does not apply to any sources for which limitations for fugitive dust or fugitive emissions are assigned pursuant to R307-401, R307-305, or R307-307 nor to agricultural or horticultural activities.		✓	Fugitive dust emissions from the IPP plant are assigned pursuant to R307-401 (NOI and AO); therefore, this rule does not apply.	
R307-206	Emission Standards: Abrasive Blasting	Emissions standards for abrasive cleaning sources.	✓		IPSC conducts both confined and unconfined abrasive blasting on a regular basis.	
R307-210	NSPS	States that standards of performance for NSPS in 40 CFR 60 are incorporated into UAC. No description of requirements. Refer to 40 CFR 60 of this table for guidance.	✓		See section for 40 CFR 60 (NSPS).	See section for 40 CFR 60 (NSPS).
R307-214	NESHAPs	States that standards of performance for NESHAPs in 40 CFR 61 and 40 CFR 63 are incorporated into UAC. No description of requirements. Refer to 40 CFR 61 and 40 CFR 63 of this table for guidance.	✓		See sections for 40 CFR 61 and 40 CFR 63.	See sections for 40 CFR 61 and 40 CFR 63.
R307-215	Emission Standards: Acid Rain Requirements	States that standards of performance for 40 CFR 76 are incorporated into UAC. No description of requirements. Refer to 40 CFR 76 of this table for guidance.	✓		See section for 40 CFR 76.	See section for 40 CFR 76.

TABLE D-1
Summary of Applicable Requirements – Utah Administrative Code

Citation	Description	Requirement/Standard	Applicable		Explanation/ Comments	Methods Used to Demonstrate Compliance
			Yes	No		
R307-220	Emission Standards: Plan for Designated Facilities	Incorporates “designated facilities” that emit a “designated pollutant” to be subject to a standard of performance.		✓	IPP is not a designated facility; therefore, this rule does not apply.	
R307-221	Emission Standards: Emission Controls for Existing Municipal Solid Waste Landfills	Guidelines for existing municipal solid waste landfills.		✓	Specific to designated facility mentioned; therefore, does not apply to IPP.	
R307-222	Emission Standards: Existing Incinerators for Hospital, Medical, Infectious Waste	Guidelines for existing incinerators for hospital, medical, and infectious waste		✓	Specific to designated facility mentioned; therefore, does not apply to IPP.	
R307-223	Emission Standards: Existing Small Municipal Waste Combustion Units	Guidelines for existing small municipal waste combustion units.		✓	Specific to designated facility mentioned; therefore, does not apply to IPP.	

TABLE D-1
Summary of Applicable Requirements – Utah Administrative Code

Citation	Description	Requirement/Standard	Applicable		Explanation/ Comments	Methods Used to Demonstrate Compliance
			Yes	No		
R307-301 to R307-343	Standards for Davis, Salt Lake, Utah Counties, and Nonattainment areas	These rules apply only to sources in nonattainment areas and specific counties.		✓	IPP is not located in a nonattainment area or any of the counties listed; therefore, these rules do not apply	
R307-401-1 to R307-401-4	Permit: NOI and AO	Applies to any person intending to construct a new installation that will or might become an air pollution source.	✓		Unit 3 will become an air pollution source.	This NOI is being submitted pursuant to this section.
R307-401-5	AO	Whenever the executive secretary determines that the NOI is in accord with applicable requirements, the executive secretary shall issue an order permitting the proposed construction, installation, modification, relocation or establishment, with the further stipulation that all required facilities be adequately and properly maintained. To accommodate staged construction of a large source, the executive secretary may issue an order authorizing construction of an initial stage prior to receipt of detailed plans for the entire proposal provided that the proposal is determined feasible by the executive secretary.	✓		IPP can not begin construction of Unit 3 until an AO is received or authorization is received from the executive secretary.	Authorization will be retained prior to construction and plans submitted according to this rule.

TABLE D-1
Summary of Applicable Requirements – Utah Administrative Code

Citation	Description	Requirement/Standard	Applicable		Explanation/ Comments	Methods Used to Demonstrate Compliance
			Yes	No		
R307-401-6	Conditions for Issuing AO	Stipulates that the executive secretary shall issue an approval order if all applicable requirements are met: (1) The degree of pollution control for emissions is at least BACT except as otherwise provided. (2) The proposed installation will be in accord with applicable requirements of: Utah Title R307; National Standards of Performance for New Stationary Sources; National Primary and Secondary Ambient Air Quality Standards; NESHAPs; NSR criteria; maximum allowable increase and maximum allowable concentration requirements for PSD; the SIP for the area, if the area is classified as a nonattainment or maintenance area; and new source requirements for nonattainment areas under the federal CAA.	✓		Unit 3 will be constructed and operated in accordance with this section.	IPP will retain documentation of compliance on site.
R307-401-7	Temporary Relocation	The owner or operator of a source previously approved under R307-401 or in an SIP may temporarily relocate and operate the source at any site for up to 180 working days in any calendar year not to exceed 365 consecutive days, starting from the initial relocation date.		✓	No sources at IPP have been, or are planned to be, temporarily relocated; therefore, this rule does not apply.	
R307-401-8	Nonattainment and Maintenance Areas	Additional requirements for sources in nonattainment and maintenance areas.		✓	IPP is not located in a nonattainment or maintenance area; therefore, this rule does not apply.	
R307-401-9	Relaxation of Limitations	At a time that a source or modification becomes a major source or major modification because of a relaxation of any enforceable limitation ... then the pre-construction requirements shall apply to the source as though construction had not yet commenced on the source or modification.		✓	IPP is already a major source and Unit 3 will be a major modification; therefore, this section does not apply.	
R307-401-10	LNB Technology	Outlines requirements for addition of low NO_x technologies for existing sources.		✓	Unit 3 is not a pre-existing installation; therefore, this section does not apply.	

TABLE D-1
Summary of Applicable Requirements – Utah Administrative Code

Citation	Description	Requirement/Standard	Applicable		Explanation/ Comments	Methods Used to Demonstrate Compliance
			Yes	No		
R307-401-11	Eighteen Month Review	AOs shall be reviewed 18 months after the issue date to determine the status of construction, installation, modification, relocation, or establishment. If the program is not proceeding, the AO may be revoked.	✓		If construction does not proceed, the AO can be revoked.	Construction of Unit 3 is scheduled to proceed within 18 months of approval from UDAQ.
R307-403	Permits: New and Modified Sources in Nonattainment Areas and Maintenance Areas	Limitations and offset requirements for sources in nonattainment and maintenance areas.		✓	IPP is not located in a nonattainment or maintenance area; therefore, this rule does not apply.	
R307-405-1	Permits: Prevention of Significant Deterioration of Air Quality (PSD)	Forward and definitions regarding this section.	✓		This is not an applicable standard or limitation; however, these definitions do apply when evaluating other applicable requirements within R307-405.	
R307-405-2 to R307-405-5 and 7	PSD	Describes how UDAQ will designate areas as Class I, II, or III and sets maximum allowable increases in certain pollutants.		✓	These are requirements for UDAQ and do not apply to IPP.	
R307-405-6	PSD Areas – New Sources and Modifications	Every new major source or major modification must be reviewed by the executive secretary to determine the air quality impact of the source.	✓		The major modification portion of this rule does apply to fossil-fuel boilers (or combination thereof) totaling more than 250 mmBtus per hour heat input.	This NOI will be submitted to the UDAQ in compliance with this rule.

TABLE D-1
Summary of Applicable Requirements – Utah Administrative Code

Citation	Description	Requirement/Standard	Applicable Yes	Applicable No	Explanation/ Comments	Methods Used to Demonstrate Compliance
R307-405-8	PSD – Banking of Emission Offset Credits in PSD Areas	Banking of emission offset credits in PSD areas will be permitted.		✓	No credit will be banked for this project; therefore, this does not apply to IPP.	
R307-406	Visibility	R307-406-1(1) the executive secretary shall review any new major source or major modification proposed. Pre- or post-construction visibility monitoring may be required if there is an adverse impact on visibility in a mandatory Class I area.		✓	Review of major sources is a requirement for UDAQ. IPP does not have any Class I areas nearby; therefore, there should be no additional monitoring required.	
R307-410-2	Permits: Emissions Impact Analysis – Use of Dispersion Models	All estimates of ambient concentrations derived in meeting the requirements of R307 shall be based on appropriate air quality models, databases, and other requirements specified in 40 CFR Part 51, Appendix W, (Guideline on Air Quality Models). Where an EPA–approved guidance documents is inappropriate, the executive secretary may authorize the modification of the model or substitution of another model. In meeting the requirements of federal law, any modification or substitution will be made only with the written approval of the Administrator.	✓		Air quality models used should be chosen from preferred or alternative air quality models listed in 40 CFR 51, or authorization must be received from the executive secretary.	IPP used EPA Guideline air pollution dispersin models to estimate ambient concentrations. Documentation of these activities will be maintained.
R307-410-3	Permits: Emissions Impact Analysis – Modeling of Criteria Pollutant Impacts in Attainment Areas	A new source in an attainment area with a total controlled emission rate per pollutant greater than or equal to SO_2 40 tpy, NO_x 40 tpy, PM_{10} - fugitive emissions 5 tpy, and fugitive dust PM_{10} - non-fugitive emissions or non-fugitive dust 15 tpy, CO as required under R307-405-6(2), and lead 0.6 tpy shall conduct air quality modeling, as identified in R307-410-2.	✓		IPP Unit 3 is a new source in an attainment area and has an emission rate greater than the limits listed; therefore, air quality modeling is required.	Air quality modeling has been conducted in accordance with R304-410-2 (see above). Documentation will be retained.

TABLE D-1
Summary of Applicable Requirements – Utah Administrative Code

Citation	Description	Requirement/Standard	Applicable		Explanation/ Comments	Methods Used to Demonstrate Compliance
			Yes	No		
R307-410-4	Permits: Emissions Impact Analysis – Documentation of Ambient Air Impacts for HAPs	A new source shall provide documentation of increases in emission of HAPs including estimated maximum pounds per hour emission rate increase, type of release, whether the release flow is vertically restricted or unrestricted, the maximum release duration in minutes per hour, the release height measured from the ground, the height of any adjacent building or structure, the shortest distance between the release point and any area defined as "ambient air" under 40 CFR 50.1(e) for each installation for which the source proposes an emissions increase and emission threshold value	✓		IPP is required to include this information with this NOI.	Section 6.3 of this NOI includes this information
R307-410-5	Permits: Emissions Impact Analysis – Stack Heights and Dispersion Techniques	The degree of emission limitation required of any source for control of any air contaminant to include determinations made under R307-401, R307-403, and R307-405, must not be affected by so much of any source's stack height that exceeds GEP or by any other dispersion technique except for certain stacks that were in existence prior to 1970 or 1974 (see UAC section for complete exception). This does not restrict, in any manner, the actual stack height of any source.	✓		IPP, Unit 3 stack will not qualify for the exemption. GEP is expected to be approximately 750 feet (2.5 x 300 feet).	IPP will not model a stack height higher than GEP.
R307-413	Permits: Exemptions and Special Provisions	Describes exemptions to the NOI and permitting process.		✓	IPP does not meet the criteria to qualify for an exemption.	
R307-414	Permits: Fees for AOs	The owner and operator of each new major source or major modification is required to pay a fee to the department sufficient to cover the reasonable costs of reviewing and acting upon the NOI.	✓		IPP is aware of the fee process and is prepared to pay a base fee of $27,000 due with the submittal of this NOI, and additional charges of $60 per hour if the standard allotted hours are exceeded.	IPP will retain proof of payments on file.

TABLE D-1
Summary of Applicable Requirements – Utah Administrative Code

Citation	Description	Requirement/Standard	Applicable		Explanation/ Comments	Methods Used to Demonstrate Compliance
			Yes	No		
R307-415	Permits: Operating Permit Requirements	Defines requirements and process of obtaining an operating permit.	✓		IPSC obtained a Title V permit for Units 1 and 2 on January 9,1998, which was renewed on August 8, 2003. This NOI requests a reopening to include Unit 3.	Permit was received and is retained in facility files.
R307-417	Permits: Acid Rain Sources	The provisions of 40 CFR 72 for purposes of implementing an acid rain program that meets the requirements of Title IV of the CAA, are incorporated into these rules by reference.	✓		IPSC has already obtained a Title IV permit for Units 1 and 2 that is included as part of the Title V permit. IPSC will submit an acid rain permit application for Unit 3 separately.	Permit was received and is retained in facility files.
R307-420	Permits: Ozone Offset Requirements	Defines procedures for complying with standards when located in an ozone nonattainment area.		✓	Applies to Davis and Salt Lake Counties only; therefore, does not apply to IPP.	
R307-801	Asbestos	This rule establishes procedures and requirements for asbestos projects and training programs, procedures, and requirements for the certification of persons engaged in asbestos activities, and work practice standards for performing such activities.		✓	IPP does not engage in NESHAPs sized asbestos activities; therefore, this rule does not apply.	
R307-840	Lead-Based Paint	Rule R307-840 establishes procedures and requirements for the accreditation of lead-based paint activities training programs, procedures and requirements for the certification of individuals and firms engaged in lead-based paint activities, and work practice standards for performing such activities.		✓	IPP does not engage in lead-based paint activities; therefore, this rule does not apply.	

TABLE D-2
Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
Federal Requirements					
40 CFR parts 1 through 49 List various requirenments for EPA to operate their environmental programs. These sections do not apply to IPP.					
40 CFR 50, National Primary and Secondary Ambient Air Quality Standards					
40 CFR 50	This part sets forth national primary and secondary ambient air quality standards.		✓	These guidelines apply to the EPA; therefore, do not apply to IPP.	
40 CFR 51, Requirements For Preparation, Adoption, and Submittal of Implementation Plans					
40 CFR 51	This part outlines requirements for SIP.		✓	These guidelines apply to states and are not requirements of IPP; however, definitions may apply when evaluating other applicable requirements.	
40 CFR 52, Approval and Promulgation of Implementation Plans					
40 CFR 52	This part sets forth the administrator's approval and disapproval of state plans and the administrator's promulgation of such plans or portions thereof.		✓	This section is administrative and has no requirements pertaining to IPP or Unit 3.	
40 CFR 53, Ambient Air Monitoring Reference and Equivalent Methods					
40 CFR 53	This part guidelines monitoring reference and equivalent methods.		✓	Requirements in this section apply to states; therefore, do not apply to IPP.	
40 CFR 54, Prior Notice of Citizen Suits					
40 CFR 54	Guidelines for citizens to file suits.		✓	Requirements apply to citizens; therefore, do not apply to IPP.	
40 CFR 55, Outer Continental Shelf Air Regulations					
40 CFR 55	Guidelines and requirements for facilities on the outer continental shelf.		✓	IPP is not located on the outer continental shelf; therefore, these rules do not apply.	
40 CFR 56, Regional Consistency					

TABLE D-2
Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 56	This part applies to EPA employees.		✓	IPP is not an EPA employee; therefore, these rules do not apply.	
40 CFR 57, Primary Nonferrous Smelter Orders					
40 CFR 57	Guidelines and requirements for smelters.		✓	IPP does not operate a smelter; therefore, these rules do not apply.	
40 CFR 58, Ambient Air Quality Surveillance					
40 CFR 58	This part sets guidelines and requirements for PSD monitoring stations and air pollution control agencies.		✓	IPP does not operate a PSD monitoring station nor is it an air pollution control agency; therefore, these rules do not apply.	
40 CFR 59, National VOC Emission Standards for Consumer and Commercial Products					
40 CFR 59	This part sets guidelines and requirements for consumer and commercial products.		✓	IPP does not manufacture consumer or commercial products; therefore, these rules do not apply.	
40 CFR 60, Subpart A, General Provisions for Standards of Performance for New Sources					
40 CFR 60.1 – 60.4	Specifies applicability, definitions, units and abbreviations, and communication guidelines of 40 CFR 60.	✓		This is not an applicable standard or limitation; however, these definitions do apply when evaluating other applicable requirements within 40 CFR 60.	
40 CFR 60.5-60.6	Administrator determination of construction or modification.		✓	This section applies to the EPA; therefore, it does not apply to IPP.	

TABLE D-2
Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 60.7(a)	Notification, reporting and recordkeeping requirements for the affected units and the CEMS.	✓		Notification must be sent to UDEQ of: the date construction is commenced (no more than 30 days after), the date of initial startup (no more than 15 days after), physical or operational changes that may increase emission rates (no less than 60 days before), the demonstration of the continuous monitoring system performance (no less than 30 days before), the date for conducting opacity observations (no less than 30 days before), COMS data results will be used to determine compliance with the opacity standard in lieu of Method 9 (no less than 30 days before).	Send required information to UDEQ, maintain copies on file.
40 CFR 60.7(b)	Owners or operators shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative.	✓		IPP is subject to NSPS, and therefore, to this requirement.	Records of these occurrences and subsequent agency notifications will be maintained on file.

TABLE D-2
Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 60.7(c) & (d)	Owners or operators required to install a continuous monitoring device shall submit excess emissions and monitoring systems performance report and/or summary report form semiannually.	✓		Written reports shall include magnitude of excess emissions, conversion factors used, date and time of commencement process operating time, specific identification of each period of excess emissions, nature and cause of any malfunction, corrective action, dates and times when the continuous monitoring system was inoperative, or statement of no excess emissions. Reports will be sent within 30 days of the end of the 6 month period. Also see 40 CFR Part 75.	Reports should be completed and sent to UDEQ via certified mail. Copies should be maintained.
40 CFR 60.7(e)	Adjusts more frequent reporting requirements to the requirements above if the facility meets certain conditions.		✓	This can only be accomplished after a minimum of 12 months of monitoring; therefore, this rule does not apply to IPP Unit 3 at this time.	
40 CFR 60.7(f) – (h)	Owners or operators shall maintain a file of all measurements; continuous monitoring system performance evaluations, calibration checks, adjustments, and maintenance in permanent form suitable for inspection.	✓		Files shall be retained for at least 2 years. Note: 40 CFR Part 75 requires a minimum of 3 years retention.	Files shall be retained for at least 3 years.
40 CFR 60.8	Within 60 days after achieving the maximum production rate, but not later than 180 days after initial startup and at such other times as may be required by the administrator, the owner or operator shall conduct performance test(s) and furnish the administrator a written report of the results of such performance test(s)	✓		Performance tests shall be conducted and data reduced in accordance with the test methods and procedures contained in each applicable subpart or as the administrator shall specify. Notice should be sent to the administrator at least 30 days prior. Adequate performing testing facilities will be provided. Each test will consist of 3 runs unless otherwise specified.	Copies of agency notifications and testing reports will be maintained on site.

TABLE D-2
Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 60.9	Availability of information to the public regarding this source and permit.		✓	This requirement is for the Administrator; therefore, does not apply to IPP.	
40 CFR 60.10	State Authority- States maintain their authority to impose stricter requirements than the federal regulations.		✓	This is guidance for the states and does not apply directly to IPP.	IPP must comply with all applicable state regulations (see UAC sections of this table).
40 CFR 60.11	Performance tests shall determine compliance with standards in this part, except opacity standards which will be determined by conducting observations in accordance with Method 9, using an alternative method approved by the Administrator, or by implementing a COMS. Air pollution control equipment shall be maintained in a manner consistent with good air pollution control practice.	✓		Opacity observations shall be conducted concurrently with the initial performance test, or within 60 days after achieving the maximum production rate if performance tests will not be conducted.	Required tests/observations should be recorded and retained on file.
40 CFR 60.12	No owner or operator subject to the provisions of this part shall build, erect, install, or use any article, machine, equipment, or process, the use of which conceals an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous dilutents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gases discharged to the atmosphere.	✓		IPP should not use any device to conceal their emissions.	Maintain all building plans and equipment specifications to document compliance.

TABLE D-2
Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 60.13(a), Appendix B (COMS)	COMS installed will meet ASTM 6216-98 and have a certificate of conformance from the manufacturer. COMS will be located where measurements are representative of the total emissions from the facility. All tests and re-tests will be conducted as outlined in 40 CFR 60 Appendix B.	✓		Appendix B gives extensive requirements and specifications for COMS and should be referenced to verify compliance. Also see 40 CFR Part 75.	Verify and document that COMS meet ASTM 6216-98, retain certificate of conformance on file. Document all tests, re-test, and all other requirements given in Appendix B.
40 CFR 60.13(a), Appendix B (CEMS)	Procedures for measuring CEMS relative accuracy and calibration drift are outlined. CEMS installation and measurement location specifications, equipment specifications, performance specifications, and data reduction procedures are included. Conformance of the CEMS with the performance specification is determined.	✓		Appendix B gives extensive requirements and specifications for CEMS and should be referenced to verify compliance. Also see 40 CFR Part 75.	Verify and document that CEMS meets requirements of this appendix. Document all tests, re-tests, and all other requirements given in Appendix B.

TABLE D-2
Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 60.13(a), Appendix F	This procedure specifies the minimum QA requirements necessary for the control and assessment of the quality of CEMS data submitted to the EPA. Source owners and operators responsible for one or more CEMS used for compliance monitoring must meet these minimum requirements and are encouraged to develop and implement a more extensive QA program or to continue such programs where they already exist. Data collected as a result of QA and QC measures required in this procedure are to be submitted to the EPA. These data are to be used by both the EPA and the CEMS operator in assessing the effectiveness of the CEMS QC and QA procedures in the maintenance of acceptable CEMS operation and valid emission data.	✓		Each source owner or operator must develop and implement a QC program. As a minimum, each QC program must include written procedures which should describe in detail, complete, step-by-step procedures and operations for each of the following activities: 1. Calibration of CEMS. 2. CD determination and adjustment of CEMS. 3. Preventive maintenance of CEMS (including spare parts inventory). 4. Data recording, calculations, and reporting. 5. Accuracy audit procedures including sampling and analysis methods. 6. Program of corrective action for malfunctioning CEMS. These written procedures must be kept on record and available for inspection by the enforcement agency. Also see 40 CFR Part 75.	Procedures should be written, implemented, and maintained on file. Activities outlined in procedures should also be documented and records retained.
40 CFR 60.13(b)	CEMS will be installed and operational prior to performance tests. Manufacturer’s written requirements or recommendations for installation operation and calibration shall be completed, as a minimum. If COMS data will be submitted, compliance with Performance Specification 1 (see 40 CFR 60 appendix B) must be met before the performance test.	✓		Monitoring systems shall be operational and all necessary documentation completed before performance tests. Also see 40 CFR Part 75.	Document and retain records of installation and operational tests. Maintain records of manufacturer’s requirements.

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Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 60.13(c)	If the owner or operator of an affected facility elects to submit COMS data for compliance with the opacity, he shall conduct a performance evaluation of the COMS as specified in Performance Specification 1, Appendix B, of this part before the performance test required under § 60.8 is conducted. Otherwise, the owner or operator of an affected facility shall conduct a performance evaluation of the COMS or CEMS during any performance test required under § 60.8 or within 30 days thereafter in accordance with the applicable performance specification in Appendix B of this part, The owner or operator of an affected facility shall conduct COMS or CEMS performance evaluations at such other times as may be required by the administrator.	✓		If COMS data will be submitted for compliance a performance evaluation will be completed before the performance test. Otherwise, performance evaluations shall be conducted during performance tests or within 30 days of performance tests. Also see 40 CFR Part 75.	Document performance evaluations and retain records.

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Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 60.13(d)	Owners and operators of a CEMS installed in accordance with the provisions of this part, must automatically check the zero (or low level value between 0 and 20 percent of span value) and span (50 to 100 percent of span value) calibration drifts at least once daily in accordance with a written procedure. The zero and span must, as a minimum, be adjusted whenever either the 24-hour zero drift or the 24-hour span drift exceeds two times the limit of the applicable performance specification. The system must allow the amount of the excess zero and span drift to be recorded and quantified whenever specified. Owners and operators of a COMS installed in accordance with the provisions of this part, must automatically, intrinsic to the opacity monitor, check the zero and upscale (span) calibration drifts at least once daily. For continuous monitoring systems measuring opacity of emissions not using automatic zero adjustments, the optical surfaces exposed to the effluent gases shall be cleaned prior to performing the zero and span drift adjustments. For systems using automatic zero adjustments, the optical surfaces shall be cleaned when the cumulative automatic zero compensation exceeds 4 percent opacity.	✓		Owners and operators of COMS and/or CEMS must check the zero and span calibration drifts at least once daily in accordance with a written procedure. Adjustments will be made when necessary. Also see 40 CFR Part 75.	Write and implement a procedure for this requirement. Document all checks, calibrations, adjustments, and cleanings.
40 CFR 60.13(e) – (j)	Guidelines for adjustments, monitoring requirements, tests, and data requirements for CEMS and COMS are outlined in these paragraphs.	✓		These paragraphs give extensive requirements and specifications for CEMS and COMS and should be referenced to verify compliance. Also see 40 CFR Part 75.	Compliance with all required activities should be documented and records retained.

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Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 60.14	Any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification. Upon modification, an existing facility shall become an affected facility for each pollutant to which a standard applies and for which there is an increase in the emission rate to the atmosphere.	✓		Unit 3 is a new affected facility and is subject to NSPS.	This permit modification is being applied for by IPSC for the addition of Unit 3. Unit 3 will not be built until all necessary permits are obtained.
40 CFR 60.15	An existing facility, upon reconstruction, becomes an affected facility, irrespective of any change in emission rate.		✓	IPP is not planning any reconstruction at this time; therefore, this rule does not apply.	
40 CFR 60.16	Priority list for regulators.		✓	The priority list is guidance for the regulators and does not apply to IPP.	
40 CFR 60.17	Incorporations by reference.	✓		No specific requirements are presented in this section.	
40 CFR 60.18	This section contains requirements for control devices used to comply with applicable subparts of Parts 60 and 61. The requirements are placed here for administrative convenience and only apply to facilities covered by subparts referring to this section.		✓	The control devices used for Unit 3 are not covered by this section; therefore, this section does not apply to IPP.	
40 CFR 60.19	General notification and reporting requirements.	✓		Refer to this section for details of all notification and reporting requirements.	All necessary reports will be submitted to UDAQ in the appropriate timeframe.
40 CFR 60.20- 29	SIP guidance.		✓	These sections give guidance for states and does not apply to IPP.	
40 CFR 60.30 – 60.39	These sections are specific to waste combustion units, incinerators, solid waste landfills, and sulfuric acid production plants.		✓	IPP does not conduct any of the mentioned processes; therefore, these sections do not apply.	

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Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 60, Subpart D, Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971					
40 CFR 60.40-46	Each fossil-fuel-fired steam generating unit of more than 73 MW heat input rate (250 mmBtu per hour) for which construction is commenced after August 17, 1971. Excludes sources that are subject to Subpart Da.		✓	Unit 3 is covered under subpart Da; therefore, subpart D does not apply.	
40 CFR 60, Subpart Da, Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978					
40 CFR 60.40a	The affected facility to which this subpart applies is each electric utility steam generating unit that is capable of combusting more than 73 MW (250 million mmBtu per hour) heat input of fossil fuel (either alone or in combination with any other fuel); and for which construction or modification is commenced after September 18, 1978.	✓		Unit 3 meets the criteria listed and must meet the requirements in this subpart.	No requirements mentioned in this section.
40 CFR 60.41a	Definitions for 40 CFR 60, Subpart Da.	✓		This is not an applicable standard or limitation, however, these definitions do apply when evaluating other applicable requirements from Subpart Da.	

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Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 60.42a	On and after the date on which the performance test required to be conducted under § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain PM in excess of: (1) 13 ng/J (0.03 lb/mmBtu) heat input derived from the combustion of solid, liquid, or gaseous fuel; (2) 1 percent of the potential combustion concentration (99 percent reduction) when combusting solid fuel; and (3) 30 percent of potential combustion concentration (70 percent reduction) when combusting liquid fuel. (b) On and after the date the PM performance test required to be conducted under § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.	✓		Unit 3 may not discharge in amounts greater than what is listed in this section.	EPA reference Method 5 will be used to demonstrate compliance with PM emission limit. All monitoring activities and/or reports of emissions should be documented and retained on file. IPP will install, certify, and maintain a COMS.
40 CFR 60.43a	On and after the date on which the initial performance test is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts solid fuel or solid-derived fuel any gases which contain SO_2 in excess of 520 ng/J (1.20 lb/mmBtu) heat input and 10 percent of the potential combustion concentration (90 percent reduction), or 30 percent of the potential combustion concentration (70 percent reduction), when emissions are less than 260 ng/J (0.60 lb/mmBtu) heat input.	✓		Unit 3 may not discharge in amounts greater than what is listed in this section. Both scrubber inlet and outlet SO_2 concentrations will be continuously monitored to determine removal efficiency.	All monitoring activities and/or reports of emissions should be documented and retained on file. IPP will install, certify (Appendix B) and maintain (Appendix F) a CEMS for SO_2 and a diluent gas.

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Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 60.44a	On and after the date on which the initial performance test is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain nitrogen oxides (expressed as NO_2) in excess of the following emission limits, based on a 30-day rolling average: Subbituminous coal – 210 (ng/J), 0.50 (lb/mmBtu) Bituminous coal – 260 (ng/J), 0.60 (lb/mmBtu) Anthracite coal - 260 (ng/J), 0.60 (lb/mmBtu) All other fuels – 260 (ng/J), 0.60 (lb/mmBtu). Also emissions of NOx shall not exceed 1.6 pounds per megawatt hour	✓		Unit 3 may not discharge in amounts greater than what is listed in this section. Current plans call for the use of a blend of 80 percent bituminous, 20 percent subbituminous coal in Unit 3. Weighted average emission limits under this rule may require EPA approval.	All monitoring activities and/or reports of emissions should be documented and retained on file. IPP will install, certify (Appendix B) and maintain (Appendix F) a CEMS for NO_x and a diluent gas.
40 CFR 60.45a	An owner or operator of an affected facility proposing to demonstrate an emerging technology may apply to the Administrator for a commercial demonstration permit. Commercial demonstration permits may be issued only by the Administrator, and this authority will not be delegated.		✓	No emerging technologies will be used for Unit 3; therefore, this section does not apply.	
40 CFR 60.46a	Compliance with PM and NO_x limits listed in 40 CFR 60.42 and 60.44 constitutes compliance for these pollutants. During emergency conditions in the principal company, an affected facility with a malfunctioning FGD system may be operated if SO_2 emissions are minimized by operating all operable FGD system modules, and bringing back into operation any malfunctioned module as soon as repairs are completed, bypassing flue gases around only those FGD system modules that have been taken out of operation because they were incapable of any SO_2 emission reduction or which would have suffered significant physical damage if they had remained in operation, and designing, constructing, and operating a spare FGD system module for an affected facility larger than 365 MW (1,250 mmBtu per hr) heat.	✓		If compliance with 40 CFR 60.42 or 60.44 can not be maintained, refer to this section for further guidance. If desulfurization system is malfunctioning, operate only if compliance with this section can be maintained.	Maintain documents illustrating compliance with 40 CFR 60.42 and 60.44. If compliance cannot be achieved or desulfurization system is malfunctioning, maintain documentation of activities required in this section.

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Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 60.47a	The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the opacity of emissions and SO_2 and NO_x emissions discharged to the atmosphere. If the owner or operator has installed a NO_x emission rate CEMS to meet the requirements of Part 75 of this chapter and is continuing to meet the ongoing requirements of Part 75 of this chapter, that CEMS may be used to meet the requirements of this section, except that the owner or operator shall also meet the requirements of § 60.49a.	✓		IPP must have CEMS and must comply with this section.	Install CEMS and COMS and document calibration and maintenance of equipment, or comply with 40 CFR 75 and 60.49a.
40 CFR 60.48a	In conducting the performance tests required, the owner or operator shall use as reference methods and procedures in Appendix A of this part or the methods and procedures as specified in this section.	✓		IPP must use these methods to conduct performance tests.	Document methods used to conduct tests.
40 CFR 60.49a	For SO_2, NO_x, and PM emissions, the performance test data from the initial performance test and from the performance evaluation of the continuous monitors (including the transmissometer) are submitted to the administrator.	✓		IPP must submit these documents quarterly if electronic and semiannually if written, except when opacity limits are exceeded which must be submitted every quarter. Specific reporting requirements are listed in this section. Refer to section for specific requirements.	Submit required documents as outlined in this section.
40 CFR 60, Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units					
40 CFR 60.40b-end	PC-fired affected facilities having a heat input capacity greater than 29 MW (100 mmBtu/hour) and less than 73 MW (250 mmBtu/hour) and meeting the applicability requirements under Subpart D (Standards of performance for fossil-fuel-fired steam generators; § 60.40) are subject to the PM and NO_x standards under this subpart and to the SO_2 standards under Subpart D (§ 60.43).		✓	Subpart Db applies to boilers with heat input >100 mmBtu/hour and <250 mmBtu/hour; IPP Unit 3 is much larger. Therefore, this rule does not apply to Unit 3.	

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Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 61, National Emission Standards For Hazardous Air Pollutants					
40 CFR 61.01 – 61.03	Definitions and general information regarding 40 CFR 61.	✓		This is not an applicable standard or limitation; however, these definitions do apply when evaluating other applicable requirements within 40 CFR 61.	
40 CFR 61.04	All requests, reports, applications, submittals, and other communications to the administrator pursuant to this part shall be submitted in duplicate to the appropriate regional office of the EPA to: Director, Air and Waste Management Division, U.S. Environmental Protection Agency, 1860 Lincoln Street, Denver, CO 80295. A copy should also be sent to: State of Utah, Department of Health, Bureau of Air Quality, 288 North 1460 West, P.O. Box 16690, Salt Lake City, UT 84116-0690.	✓		All reports required under 40 CFR 61 shall be submitted to the listed addresses.	Maintain records of all submittals on file.
40 CFR 61.05	No owner or operator shall construct or modify any stationary source without first obtaining written approval from the administrator. No owner or operator shall operate a new stationary source in violation of standards, except under an exemption. Ninety days after the effective date of any standard, no owner or operator shall operate any existing source subject to that standard in violation of the standard, except under a waiver granted by the administrator or under an exemption granted by the President. No owner or operator subject to the provisions of this part shall fail to report, revise reports, or report source test results as required under this part.	✓		IPP may not operate in violation of any applicable standards without a waiver or exemption. All reports required under this part shall be completed and sent to the appropriate regulatory agency as required.	Maintain all reports demonstrating compliance with regulations. Periodically audit internal procedures and practices to ensure compliance.
40 CFR 61.06	Advises facilities that they can request a determination of construction or modification from the administrator.		✓	It has already been determined that Unit 3 is considered a modification; therefore, this section does not apply.	

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Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 61.07	The owner or operator shall submit to the administrator an application for approval of the construction of any new source or modification of any existing source. The application shall be submitted before the construction or modification is planned to commence, or within 30 days after the effective date if the construction or modification had commenced before the effective date and initial startup has not occurred.	✓		IPP must receive approval for the construction of Unit 3.	This NOI is being submitted for approval.
40 CFR 61.08	The administrator will notify applicant of approval.		✓	This applies to the EPA and is not a requirement of IPP.	
40 CFR 61.09	The owner or operator of each stationary source which has an initial startup after the effective date of a standard shall furnish the administrator with written notification as follows: (1) A notification of the anticipated date of initial startup of the source not more than 60 days nor less than 30 days before that date. (2) A notification of the actual date of initial startup of the source within 15 days after that date.	✓		IPP must send notification of anticipated and actual startup.	Maintain documentation that notification was sent on file.
40 CFR 61.10 – 61.11	Describes source reporting, waiver requests, and other requirements for existing sources.		✓	Unit 3 is not an existing source; therefore, these rules do not apply.	
40 CFR 61.12	The owner or operator of each stationary source shall maintain and operate the source, including associated equipment for air pollution control, in a manner consistent with good air pollution control practice for minimizing emissions.	✓		IPP must minimize emissions.	Implementation of BACT along with documentation of proper maintenance and monitoring should demonstrate compliance.
40 CFR 61.13 – 61.14	Each owner or operator shall conduct emission testing and maintain and operate each monitoring system as specified in applicable subparts.	✓		IPP must complete requirements in applicable subparts. No new requirements mentioned in this section.	Maintain documentation of compliance with subparts.

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Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 61.15	Upon modification, an existing source shall become a new source for each HAP for which the rate of emission to the atmosphere increases and to which a standard applies.	✓		Unit 3 constitutes a modification and must comply with this section.	HAPs discharged should be expressed in kg/hr. Emission factors should be from AP 42 or material balances, monitoring data, or manual emission tests if AP 42 does not satisfactorily demonstrate an increase or decrease.
40 CFR 61.20 – 61.26	Guidelines and requirements for uranium mines.		✓	IPP does not operate any uranium mines on this property; therefore, these rules do not apply.	
40 CFR 61.30 – 61.34	Guidelines and requirements for facilities that process beryllium and beryllium compounds.		✓	IPP does not process beryllium or beryllium compounds; therefore, these rules do not apply.	
40 CFR 61.40 – 61.44	Guidelines and requirements for rocket motor test sites.		✓	IPP does not test rocket motors; therefore, these rules do not apply.	
40 CFR 61.50 – 61.56	Guidelines and requirements for facilities that process mercury ore to recover mercury, use mercury chloralkali cells to produce chlorine gas and alkali metal hydroxide, and incinerate or dry wastewater treatment plant sludge.		✓	IPP does not have any processes that recover mercury or use mercury chloralkali cells, or incinerate dry sludge; therefore, these rules do not apply.	
40 CFR 61.60 – 61.71	Guidelines and requirements for facilities which produce ethylene dichloride by reaction of oxygen and hydrogen chloride with ethylene, vinyl chloride by any process, and/or one or more polymers containing any fraction of polymerized vinyl chloride.		✓	IPP does not have any of these processes; therefore, these rules do no apply.	

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Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 61.90 – 61.97	Guidelines and requirements for operations at any facility owned or operated by the Department of Energy (DOE) that emits any radionuclide other than radon-222 and radon-220 into the air.		✓	IPP is not owned or operated by the DOE; therefore, these rules do not apply.	
40 CFR 61.100 – 61.108	Guidelines and requirements for facilities owned or operated by any Federal agency other than the DOE and not licensed by the Nuclear Regulatory Commission that emits radionuclides into the air.		✓	IPP is not owned or operated by any federal agency; therefore, these rules do not apply.	
40 CFR 61.110 – 61.112	Guidelines and requirements for facilities that have possible equipment leaks of benzene.		✓	IPP does not have benzene in its processes; therefore, these rules do not apply.	
40 CFR 61.120 – 61.127	Guidelines and requirements for radionuclide emissions from elemental phosphorus plants.		✓	IPP does not have any processes with elemental phosphorus; therefore, these rules do not apply.	
40 CFR 61.130-61.139	Guidelines and requirements for furnace and foundry coke byproduct recovery plants.		✓	IPP does not recover coke byproducts; therefore, these rules do not apply.	
40 CFR 61.140 – 61.157	Guidelines and requirements for facilities that manufacture, use, or handle asbestos.		✓	IPP does not manufacture asbestos; therefore, these rules only apply to the handling of ACBM (if any) in the existing facility.	
40 CFR 61.160 – 61.165	Guidelines and requirements for glass manufacturing plants.		✓	IPP does not manufacture glass; therefore, these rules do not apply.	
40 CFR 61.170 – 61.177	Guidelines and requirements for primary copper smelters.		✓	IPP is not a copper smelter; therefore, these rules do not apply	

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Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 61.180 – 61.186	Guidelines and requirements for arsenic production facilities.		✓	IPP is not a arsenic production facility; therefore, these rules do not apply.	
40 CFR 61.190 – 61.193	Guidelines and requirements for DOE facilities.		✓	IPP is not a DOE facility; therefore, these rules do not apply.	
40 CFR 61.200 – 61.210	Guidelines and requirements for facilities with a phosphogypsum stack, or that otherwise use any quantity of phosphogypsum which is produced as a result of wet acid phosphorus production or is removed from any existing phosphogypsum stack.		✓	IPP does not use phosphogypsum; therefore, these rules do not apply.	
40 CFR 61.220 – 61.226	Guidelines and requirements for sites that are used for the disposal of tailings, and that managed residual radioactive material during and following the processing of uranium ores.		✓	IPP does not manage uranium or use its property for tailing disposal; therefore, these rules do not apply.	
40 CFR 61.240 – 61.247	Guidelines and requirements for sources that are intended to operate in volatile hazardous air pollutant (VHAP) service.		✓	IPP does not have any sources intended to operate in (VHAP) service; therefore, these rules do not apply.	
40 CFR 61.250 – 61.256	Guidelines and requirements for facilities licensed to manage uranium byproduct materials during and following the processing of uranium ores, commonly referred to as uranium mills and their associated tailings. This subpart does not apply to the disposal of tailings.		✓	IPP does not manage any uranium materials; therefore, these rules do not apply.	
40 CFR 61.270 – 61.277	Guidelines and requirements for facilities that store benzene.		✓	IPP does not store benzene; therefore, these rules do not apply.	
40 CFR 61.300 – 61.306	Guidelines and requirements for benzene transfer operations.		✓	IPP does not have any benzene transfer operations; therefore, these rules do not apply.	

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Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 61.340 – 61.358	Guidelines and requirements for chemical manufacturing plants, coke byproduct recovery plants, petroleum refineries or hazardous waste treatment, storage, and disposal facilities (TSDFs) that accept wastes from the previously mentioned plants.		✓	IPP does not apply as any of the plants listed; therefore, these rules do not apply.	
40 CFR 62, Approval and Promulgation of State Plans for Designated Facilities and Pollutants					
40 CFR 62	This part sets forth the administrator's approval and disapproval of state plans for the control of pollutants and facilities.		✓	This is the responsibility of the states and the administrator and does not apply to IPP.	
40 CFR 63, National Emission Standards for Hazardous Air Pollutants for Source Categories					
40 CFR 63.1 - 63.3	Definitions and general information regarding 40 CFR 63.	✓		This is not an applicable standard or limitation; however, these definitions do apply when evaluating other applicable requirements within 40 CFR 63.	
40 CFR 63.4	No owner or operator subject to the provisions of this part may operate any affected source in violation of the requirements of this part. No owner or operator subject to the provisions of this part shall fail to keep records, notify, report, or revise reports as required under this part.	✓		IPP will not operate in violation of this part and will maintain records as required.	Record activities showing compliance and maintain on file.
40 CFR 63.5	No person may, without obtaining written approval in advance from the administrator do any of the following: construct a new affected source that is major-emitting and subject to such standard; reconstruct an affected source that is major-emitting and subject to such standard; or reconstruct a major source such that the source becomes an affected source that is major-emitting and subject to the standard	✓		IPSC must receive approval before constructing Unit 3.	This NOI is being submitted in compliance with this rule.

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Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 63.6	The owner or operator of an affected source must develop and implement a written startup, shutdown, and malfunction plan that describes, in detail, procedures for operating and maintaining the source during periods of startup, shutdown, and malfunction; a program of corrective actions for malfunctioning process; and air pollution control and monitoring equipment used to comply with the relevant standard. This plan must be developed by the source's compliance date for that relevant standard.	✓		IPSC must implement a startup, shutdown, and malfunction plan as described in this rule.	Maintain a copy of this plan on file.
40 CFR 63.7	If required to do performance testing by a relevant standard, and a waiver of performance testing is not obtained, the owner or operator of the affected source must perform such tests within 180 days of the compliance date for such source.	✓		IPSC must complete all required performance testing within 180 days of the compliance date.	Document the date all applicable tests are conducted and maintain on file.

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Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 63.8	The owner or operator of an affected source shall maintain and operate each continuing monitoring system (CMS) in a manner consistent with good air pollution control practices. All CMS must be installed such that representative measures of emissions or process parameters from the affected source are obtained. In addition, CEMS must be located according to procedures contained in the applicable performance specification(s). All CMS shall be installed, operational, and the data verified as specified in the relevant standard either prior to or in conjunction with conducting performance tests. Verification of operational status shall, at a minimum, include completion of the manufacturer's written specifications or recommendations for installation, operation, and calibration of the system. Except for system breakdowns, out-of-control periods, repairs, maintenance periods, calibration checks, and zero (low-level) and high-level calibration drift adjustments, all CMS, including COMS and CEMS, shall be in continuous operation and shall meet minimum frequency of operation requirements.		✓	Although Unit 3 will be equipped with a COMS and a CEMS, pursuant to the federal NSPS and acid rain programs, continuous monitoring is not required under NESHAP.	
470 CFR 63.9	The owner or operator of a source shall notify the administrator of the designated state authority if emissions increase, if a source will be constructed or reconstructed, and other notifications regarding CMS mentioned in 40 CFR 75.	✓		This NOI is being submitted in accordance with this rule. IPSC will need to notify the state if changes are made to operations that affect emissions.	This NOI is being submitted in accordance with this rule.

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Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 63.10	The owner or operator of an affected shall submit reports to the delegated state authority. In addition, if the delegated authority is the state, the owner or operator shall send a copy of each report submitted to the state to the appropriate regional office of the EPA, as specified in paragraph (a)(4)(i) of this section. The regional office may waive this requirement for any reports at its discretion.	✓		Records shall be maintained of the occurrence and duration of each startup, shutdown, or malfunction of operation; the occurrence and duration of each malfunction of the required air pollution control and monitoring equipment; all required maintenance performed on the air pollution control and monitoring equipment; actions taken during periods of startup, shutdown, and malfunction when such actions are different from the procedures specified in the affected source's startup, shutdown, and malfunction plan; all information necessary to demonstrate conformance with the affected source's startup, shutdown, and malfunction plan when all actions taken during periods of startup, shutdown, and malfunction are consistent with the procedures specified in such plan; each period during which a CMS is malfunctioning or inoperative; and all required measurements needed to demonstrate compliance with a relevant standard.	These records will be created and maintained on file.
40 CFR 63.11	Owners or operators using flares to comply with the provisions of this part shall monitor these control devices to assure that they are operated and maintained in conformance with their designs. Applicable subparts will provide provisions stating how owners or operators using flares shall monitor these control devices.		✓	Flares will not be used as control devices; therefore, this rule does not apply.	

TABLE D-2
Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 63.12 – 63.15	General information, authority delegation, and addresses pertaining to 40 CFR 63.	✓		These are not applicable standards or limitations; however, these sections do apply when evaluating other applicable requirements within 40 CFR 63.40 – 63.44.	
40 CFR 63.40	The requirements of this subpart apply to any owner or operator who constructs or reconstructs a major source of HAPs after the effective date of Section 112(g)(2)(B) and the effective date of a Title V permit program in the state or local jurisdiction in which the major source is located unless the major source in question has been specifically regulated or exempted from regulation, or the owner or operator of such major source has received all necessary air quality permits for such construction or reconstruction.	✓		Coal and oil fired power plants have been included in the 112(c) listing of source categories since December, 2000; therefore, this section does apply to Unit 3.	
40 CFR 63.41	Definitions applicable to 40 CFR 63.40 – 63.44.	✓		This is not an applicable standard or limitation; however, this section will apply when evaluating other applicable requirements within 40 CFR 63.40 – 63.44.	
40 CFR 63.42	Program requirements governing construction or reconstruction of major sources. The anticipated promulgation date for a MACT standard for PC-fired power plants is December 2004; therefore, a case-by-case MACT standard must be proposed and implemented by UDAQ.	✓		This rule applies to UDAQ and is not an obligation of IPP. However, IPP must comply with standards required by UDAQ.	
40 CFR 63.43	The requirements of this section apply to an owner or operator who constructs or reconstructs a major source of HAP subject to a case-by-case determination of MACT.	✓		IPP must request approval of case-by-case MACT determinations.	This NOI contains Section 6, its tables and/or appendices that requests a MACT determination and provides all necessary documents.

TABLE D-2
Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3 Yes	Applicable to Unit 3 No	Comments	Methods Used to Demonstrate Compliance[a]
40 CFR 63.44	Requirements for constructed or reconstructed major sources subject to a subsequently promulgated MACT standard or MACT requirement.		✓	There are no promulgated MACT standards or requirements for coal fired power plants at this time; therefore, this section does not apply.	
40 CFR 63.50 – 63.56	This section implements Section 112(j) of the CAA and includes the "MACT Hammer". In general, permitting authorities must issue or reopen Title V permits when a source becomes subject to Section 112(j).	✓		IPP already has a Title V permit, which does not address the Section 112(j) requirements and the plant became subject to Section 112(j) in December, 2000. Therefore, the provisions of 40 CFR 63.52 (b) apply to Unit 3.	Request for case-by-case MACT determination included in Section 6 of this NOI
40 CFR 63.60 – 63.62	Deletion and redefinition of specific chemicals on the HAPs list.		✓	This is not an applicable standard or limitation.	
40 CFR 63.70 – 63.5779	MACT regulations pertaining to specific industries.		✓	PC-fired boilers are not included in these sections; therefore, these rules do not apply to IPP or Unit 3.	
40 CFR 64, Compliance Assurance Monitoring					
40 CFR 64	Compliance Assurance Monitoring.	✓		IPP is subject to federal acid rain program and is thus exempt from Part 64, pursuant to 40 CFR 64.2(b)(1)(iii) for the acid rain requirements only. A CAM plan will be required for particulate.	The CAM Plan for Unit 3 is contained in Section 9 of the NOI text.
40 CFR 65, Consolidated Federal Air Rule					
40 CFR 65	The provisions of this subpart apply to owners or operators expressly referenced to this part from a subpart of 40 CFR Parts 60, 61, or 63 for which the owner or operator has chosen to comply with the provisions of this part as an alternative to the provisions in the referencing subpart.		✓	IPP is not seeking alternate compliance provisions in accordance with this rule; therefore, these rules do not apply.	

TABLE D-2
Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 66, Assessment and Collection of NonCompliance Penalties by EPA					
40 CFR 66	Applies to all proceedings for the assessment by EPA of noncompliance penalties.		✓	Requirements for the EPA, not an obligation of IPP.	
40 CFR 67, EPA Approval of State NonCompliance Program					
40 CFR 67	Standards and procedures under which EPA will approve state programs for administering the noncompliance penalty program.		✓	EPA's requirements for states to implement a noncompliance penalty program, not an obligation of IPP.	
40 CFR 68, Chemical Accident Prevention Provisions					
40 CFR 68	This part sets forth the list of regulated substances and thresholds, gives the petition process for adding or deleting substances to the list of regulated substances, outlines who need a Risk Management Plan (RMP), and sets requirements for RMPs.	✓		IPSC does not currently have any chemicals onsite in excess of their threshold quantity listed in 40 CFR 68.130. IPSC will evaluate the ammonia storage requirements associated with the SCR system on Unit 3 to determine whether the RMP program is triggered.	To be determined (TBD)
40 CFR 69, Special Exemptions From the Requirements of the Clean Air Act					
40 CFR 69	Lists special exemptions		✓	IPP is not eligible for any special exemptions for the CAA.	
40 CFR 70, State Operating Permit Program					
40 CFR 70	The regulations in this part provide for the establishment of comprehensive state air quality permitting systems consistent with the requirements of Title V of the CAA. These regulations define the minimum elements required by the CAA for state operating permit programs and the corresponding standards and procedures by which the administrator will approve, oversee, and withdraw approval of state operating permit programs.	✓		IPP already has a Title V permit, which will need to be revised to add the applicable requirements for Unit 3.	This NOI is being submitted as required for modifications.

TABLE D-2
Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 71, Federal Operating Permit Programs					
40 CFR 71.1 – 71.23	Specifies applicability, definitions, units and abbreviations, and general guidelines of 40 CFR 71.	✓		The State of Utah has been delegated authority to implement a federal operating permit pursuant to 40 CFR 70. Therefore, 40 CFR 71 requirements are not applicable requirements for this facility.	
40 CFR 71.24	Identifies where a permit application should be filed and outlines the following information that a permit application should contain to be complete: Identifying information, All information required in § 63.74 A statement of the proposed alternative emission limitation for HAPs from the early reductions source on an annual basis, reflecting the emission reductions required to qualify the early reductions source for a compliance extension Additional emission limiting requirements which are necessary to assure proper operation of installed control equipment and compliance with the annual alternative emission limitation for the early reductions source; Information necessary to define alternative operating scenarios for the early reductions source or permit terms and conditions for trading hazardous air pollutant increases and decreases. Statements related to compliance.	✓		This NOI must comply with the requirements in this section.	This NOI was written in compliance with this section (see Completeness Checklist following Executive Summary).
40 CFR 71.25 – 71.27	Administrative guidelines on what a permit should contain; issuance, reopenings, and revisions; and public comment periods	✓		These rules apply to the permitting authority and are not an obligation of IPP.	

TABLE D-2
Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 72 Permits Regulation					
40 CFR 72.1-72.5	General provisions of the acid rain program. 40 CFR 72.9 specifies the standard permitting, monitoring, SO_2, NO_x, excess emissions, recordkeeping and reporting, and liability requirements for affected sources.	✓		These sections do not include applicable standards or limitations; however, these definitions do apply when evaluating other applicable requirements in 40 CFR 72.	Maintenance of records.
40 CFR 72.6	Defines facilities and units to which 40 CFR 72 apply.	✓		Unit 3 is a new utility unit; therefore, these rules do apply.	
40 CFR 72.7 & 72.8	Outlines exemptions from these rules.		✓	IPP does not qualify for any exemptions.	
40 CFR 72.9	Specifies that all facilities to which these rules apply must have an acid rain permit.	✓		Separate EPA forms should be downloaded, filled out, and submitted to the EPA. The first step is to get an ORIS number assigned. Then the complete package of forms, which identify the DR and the ORIS number goes to the EPA.	Copies of IPSC's acid rain permit revision application will be submitted to EPA and UDAQ; a copy will be kept on file at the IPP.
40 CFR 72.10 - 72.13	Definitions and general information regarding 40 CFR 72.	✓		These are not applicable standards or limitations; however, these definitions do apply when evaluating other applicable requirements within 40 CFR 72.	
40 CFR 72.20	Each affected source, including all affected units at the source, shall have one and only one designated representative, with regard to all matters under the acid rain program concerning the source or any affected unit at the source.	✓		IPP must have one and only one representative for issues concerning the acid rain program.	IPP will specify one representative, and maintain the certificate listing the representative on file.

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Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 72.21	In each submission required to by signed by the designated representative under the acid rain program, the designated representative shall certify, by signature: "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" and "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." The representative will provide a copy of the submission or determination to the owners and operators.	✓		The designated representative must have the quoted certifications on all documents being submitted or they will not be accepted by the regulatory agency. Owners and operators should be kept informed of submissions and other activities pertaining to these rules.	Documentation of submissions including certification should be kept on file. Documentation of updates to owners / operators should be kept on file (e.g., management review minutes).
40 CFR 72.22	The certificate of representation may designate one and only one alternate designated representative, who may act on behalf of the designated representative.	✓		One alternate representative may be chosen to act in place of the designated representative.	Procedures for choosing an alternate and certification of the alternate should be maintained.
40 CFR 72.23	The designated representative, alternate designated representative, and owners or operators may be changed at any time upon receipt by the administrator of a superseding complete certificate of representation. A superseding certificate must be received within 30 days of a change in owner or operator.	✓		When any of these individuals change, a new certificate must be received.	All representatives and owners / operators must be listed on the most current certificate and certificates retained.

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Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 72.24	Requirements for a complete certificate of representation.	✓		Specific and extensive requirements. See 40 CFR 72.24 for list of all applicable requirements.	Each certificate of representation issued will contain all required elements and will be retained on file.
40 CFR 72.25	Once a complete certificate of representation has been submitted in accordance with § 72.24, the administrator will rely on the certificate of representation unless and until a superseding complete certificate is received by the administrator.	✓		IPSC must submit a new certification to change representatives.	IPSC will wait to change representatives until a new certificate has been issued whenever possible.
40 CFR 72.30 – 72.33	The designated representative of any source with an affected unit shall submit a complete the acid rain permit application by the applicable deadline in paragraphs (b) and (c) of this section, and the owners and operators of such source and any affected unit at the source shall not operate the source or unit without a permit that states its acid rain program requirements.	✓		IPSC will need to update their current acid rain permit to accommodate the addition of Unit 3.	Current permit for the IPP facility will be retained on file. Copies of the acid rain permit application for Unit 3 will be submitted to UDAQ and will be kept on file at IPSC.
40 CFR 72.40	Outlines the requirements of a complete compliance plan.	✓		IPSC will need to create a complete compliance plan in accordance with this section.	A copy of the compliance plan will be submitted to EPA and UDAQ. IPSC will implement and maintain a compliance plan on site.
40 CFR 72.41 – 72.44	Guidelines for substitution plans, extension plans, reduced utilization plans, and repowering extensions.		✓	IPSC is not conducting any of the activities required for these plans; therefore, these rules do not apply at this time.	

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Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 72.50 – 72.74	Guidelines for obtaining a Title IV permit.		✓	IPP is not receiving a new permit, but is modifying a current permit. The provisions of 40 CFR 72.50 through 72.74 are applicable to initial permits. Modifications to existing permits are provided in 40 CFR 72.80 through 72.85.	
40 CFR 72.80	A permit revision may be submitted for approval at any time. No permit revision shall affect the term of the acid rain permit to be revised. No permit revision shall excuse any violation of an acid rain program requirement that occurred prior to the effective date of the revision.	✓		IPSC must revise its permit to accommodate Unit 3.	Copies of the acid rain permit revision application will be submitted to EPA and UDAQ; kept on file at IPSC.
40 CFR 72.81	Permits must be revised if processes are modified	✓		IPP must revise their permit to accommodate for the addition of Unit 3.	
40 CFR 72.82	The designated representative shall serve such a copy on the administrator, the permitting authority, and any person entitled to receive a written notice of a draft permit under the approved state operating permit program. Within 5 business days of serving such copies, the designated representative shall also give public notice by publication in a newspaper of general circulation in the area where the sources are located or in a state publication designed to give general public notice.	✓		If IPP submits a fast-track modification, this rule will need to be adhered to.	Copies will be submitted to EPA and UDAQ; kept on file at IPSC. Retain documentation of public notice on file.
40 CFR 72.83 – 72.85	Administrative instructions for permit amendments and re-openings.	✓		Administrative guidelines and requirements apply to permitting authority and are not an obligation of IPSC.	

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Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 72.90 – 72.96	For each calendar year in which a unit is subject to the acid rain emissions limitations, the designated representative of the source at which the unit is located shall submit to the administrator, within 60 days after the end of the calendar year, an annual compliance certification report for the unit.	✓		IPP will need to submit an annual compliance certification as long as it is required to have an acid rain permit. Specific requirements for certification are detailed in this part.	Submit certification annually, retain copies on file.
40 CFR 73, Sulfur Dioxide Allowance System					
40 CFR Part 73	SO_2 allowance system.	✓		The plant must have sufficient allowances available to account for each ton of annual SO_2 emissions. IPP already has sufficient credits to account for the increase of SO_2 emissions; therefore, no additional allowances will be needed.	CEMS and quarterly EDRs (pursuant to 40 CFR Part 75)
40 CFR 74, Sulfur Dioxide Opt-Ins					
40 CFR 74	Guidelines for Sulfur Dioxide Opt-In program.		✓	IPSC is not eligible for the Opt-In program; therefore, these rules do not apply.	
40 CFR 75 Continuous Emission Monitoring					
40 CFR 75.1 – 75.3	Definitions and general information regarding 40 CFR 75.	✓		This is not an applicable standard or limitation; however, these definitions do apply when evaluating other applicable requirements.	
40 CFR 75.4	The owner or operator of each new affected unit shall ensure that all monitoring systems required under this part for monitoring of SO_2, NO_x, CO_2 opacity, and volumetric flow are installed and all certification tests are completed no later than 90 days after the date the unit commences commercial operation.	✓		IPSC must install applicable monitoring equipment within specified time.	Retain documentation of installation and certification testing on file, suitable for agency inspection, for a minimum of 10 years.

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Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 75.5	Prohibitions – these rules clarify a variety of acts, omissions, or other events that constitute a violation of the CAA, relative to the acid rain monitoring provisions in Part 75.	✓			Quarterly EDRs, periodic inspection of CEMS Monitoring Plans.
40 CFR 75.6	Incorporates several ASTM, ASME, and other methods by reference.		✓	Not an applicable standard or limitation; however, information does apply when evaluating other applicable requirements.	
40 CFR 75.10	The owner or operator shall install, certify, operate, and maintain, in accordance with all the requirements of this part, a continuous emission monitoring system for SO_2, NO_x, and CO_2,volumetric stack flow and opacity.	✓		Specific requirements in this part. Refer to full text of rule.	Retain records of all activities specified.
40 CFR 75.11 – 75.14	Specific provisions for monitoring SO_2, NO_x and CO_2 emissions, stack diluent (O2 or CO_2), stack flow, and opacity.	✓		Specific and extensive provisions. IPSC will ensure that CEMS meet these requirements.	CEMS Monitoring Plan (required under §75.53) and CEMS certification report. Retain records of all activities specified.
40 CFR 75.15	Specific provisions for monitoring SO_2 emissions removal by qualifying Phase I technology. This generally applies to units in existence during calendar years 1997 through 1999.		✓	The SO_2 removal system planned for Unit 3 does not meet the definition of a qualifying Phase I technology. Therefore, this rule does not apply.	
40 CFR 75.16	Special provisions for monitoring SO_2 emissions from (and determining heat input for) common, bypass, and multiple stacks.		✓	The generating units at IPP (including Unit 3) have separate stacks. Therefore, this rule does not apply.	
40 CFR 75.17	Special provisions for monitoring NO_x from common, bypass, and multiple stacks.		✓	The generating units at IPP (including Unit 3) have separate stacks. Therefore, this rule does not apply.	
40 CFR 75.18	Special provisions for monitoring opacity from common and bypass stacks.		✓	The generating units at IPP (including Unit 3) have separate stacks. Therefore, this rule does not apply.	

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Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 75.19	Optional SO_2, NO_x, and CO_2 emissions calculation for low mass emission units.		✓	PC-fired boilers do not qualify as low mass emission units. Therefore, these rules do not apply.	
40 CFR 75.20	The owner or operator shall ensure that each continuous emission or opacity monitoring system required by this part meets the initial certification and recertification requirements of this section and shall ensure that all applicable initial certifications and recertifications are completed by the deadlines specified.	✓		Initial certification tests must be conducted for all CEMs, in accordance with this section and Appendix A of this Part.	Copies of initial certification and recertification testing reports will be submitted to EPA and UDAQ, retained on file at IPSC. Retain records of all certification tests and activities.
40 CFR 75.21	Details quality control and quality assurance requirements.	✓		The CEMS must be operated and maintained in accordance with this section and Appendix B of this part.	Retain records of all QA/QC activities specified.
40 CFR 75.22	Reference test methods.	✓		Identifies the EPA Reference Test Methods (provided in Appendix A of 40 CFR Part 60) that shall be used for certification tests, calibrations, and other measurements.	Certification and periodic audit reports will be retained on file at IPSC.
40 CFR 75.23	Alternatives to standards incorporated by reference.		✓	IPSC has no plans to petition the administrator for an alternative to any standard incorporated by reference, pursuant to §75.66(c).	
40 CFR 75.24	Out-of-control periods and adjustment for system bias.	✓		Out-of-control periods can be declared, based on daily calibration, quarterly audit, or linearity check results. During these periods, the data is considered not QA'd and shall not be used in calculating monitor availability.	QA/QC information transmitted with quarterly EDR.

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Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 75.30 – 75. 37	Subpart D – missing data substitution procedures.	✓		This subpart provides extensive guidance and requirements for substituting a variety of empirically-derived emissions values, which are usually much higher than actual emissions, during periods when the CEMS does not accurately measure SO_2, NO_x, CO_2, heat input, and moisture.	Substituted data are identified in the quarterly EDR.
40 CFR 75.40 – 75.48	Guidelines for using an alternative monitoring system, which must have the same or better precision, reliability, accessibility and timeliness as that provided by a CEMS meeting the requirements of this part.		✓	IPP will not use alternative monitoring system; therefore, these rules do not apply.	
40 CFR 70.53	Specific guidelines and requirements for CEMS Monitoring Plans.	✓		These provisions are very specific and extensive. Refer to full text of rule.	Monitoring plan submittal, pursuant to §75.62.
40 CFR 75.54	General recordkeeping provisions.		✓	This rule applies to facilities in existence prior to 04/01/2000. Unit 3 will be constructed after that date; therefore this rule does not apply.	
40 CFR 75.55	Recordkeeping provisions for specific situations.		✓	This rule applies to facilities in existence prior to 04/01/2000. Unit 3 will be constructed after that date; therefore this rule does not apply.	
40 CFR 75.56	Certification, QA/QC record provisions.		✓	This rule applies to facilities in existence prior to 04/01/2000. Unit 3 will be constructed after that date; therefore, this rule does not apply.	

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Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 75.57	General recordkeeping provisions.	✓		These provisions are very specific and extensive. Refer to full text of rule. All records of measurements, data, reports and other information required under Part 75 shall be maintained in a file at the plant, suitable for agency inspection, for a minimum of 3 years.	CEMS records on file at the plant, available for EPA/UDAQ inspection.
40 CFR 75.58	General recordkeeping provisions for specific situations.		✓	This section provides recordkeeping provisions for alternative or parametric monitoring allowed for gaseous or liquid fuel-fired units only. Unit 3 is PC-fired; therefore this rule does not apply.	
40 CFR 75.59	Certification, QA/QC record provisions.	✓		These provisions are very specific and extensive. Refer to full text of rule.	CEMS Monitoring Plan, quarterly EDRs, certification reports, RATA test reports, CEMS O&M records maintained at IPP.
40 CFR 75.60	Reporting requirements – general provisions.	✓		This section details the schedules and criteria for the submittal of initial certification reports, recertification reports, monitoring plans, EDRs, RATA reports and other communications. In addition, provisions governing the confidentiality of data are provided.	Copies of these submittals will be kept on file at the plant for a minimum of 3 years.

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Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 75.61	Reporting requirements – notifications.	✓		This section details the schedules and criteria for notifying the EPA and UDAQ of planned testing dates, installation of new units, retiring units, changes in fuels used, or monitoring system components.	Records of notifications will be maintained at the plant, in a file suitable for agency inspection for a minimum of 3 years.
40 CFR 75.62	Monitoring plan submittals.	✓		This section details the schedules and criteria for submittal of the electronic and hardcopy CEMS monitoring plan, including any revisions to the monitoring plan.	Records of the monitoring plan submittals will be maintained at the plant, in a file suitable for agency inspection for a minimum of 3 years.
40 CFR 75.63	Initial certification or recertification application submittals.	✓		This section details the schedules and criteria for the submittal of initial certification reports and recertification applications.	Records of the certification and recertification submittals will be maintained at the plant, in a file suitable for agency inspection for a minimum of 3 years.

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Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 75.64	Quarterly electronic data reports.	✓		This section details the content and submittal format requirements for the submission of CEMS measurements data, along with a variety of QA/QC activities and results for the preceding calendar quarter. Each EDR is due on or before the 30th calendar day following the end of the subject calendar quarter.	Electronic copies of each EDR will be maintained at the plant, in a file suitable for agency inspection for a minimum of 3 years.
40 CFR 75.65	Opacity reports.	✓		This section requires that excess opacity emissions measured by the CEMS be reported to the local APCD (in this case, UDAQ).	Copies of excess opacity reports submitted to UDAQ will be maintained at the plant, in a file suitable for agency inspection for a minimum of 3 years.
40 CFR 75.66	Petitions to the administrator.	✓		This section provides the procedures for petitioning the EPA for alternatives to the monitoring requirements of Part 75. IPSC has no current plans to petition for alternative monitoring arrangements.	
40 CFR 75.67	Retired units petitions.		✓	This section applies to combustion sources seeking to enter the Opt-in Program and then retired (creating an availability of SO2 allowances for use by other sources). IPSC has no such qualifying units; therefore this rule does not apply.	

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Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 75.70 through 75.75	Subpart H - NO_x mass emissions provisions.		✓	This section, which was added when the federal acid rain program NO_x limitations were revised, clarifies the source obligations for units subject to a state or federal NO_x mass emissions reduction program. However, the IPP plant is not subject to such a state or federal program (other than the federal acid rain NO_x limitations); therefore this rule does not apply. It is presumed that UDAQ permit limits for NO_x mass emissions (e.g., lbs/hour or tpy) do not constitute a "state reduction program".	
40 CFR 76, Nitrogen Oxides					
40 CFR 76.1 – 76.4	Definitions and general information regarding 40 CFR 76.		✓	Not an applicable standard or limitation; however, these definitions do apply when evaluating other applicable requirements.	
40 CFR 76.5 – 76.6	NO_x limitations for Group I, Phase I boilers and for Group II boilers.		✓	Unit 3 will be considered a Group I Phase II boiler; therefore, these rules do not apply.	
40 C.F.R. 76.7	The owner or operator of a Group 1, Phase II PC-fired utility unit with a tangentially fired boiler or a dry bottom wall-fired boiler shall not discharge, or allow to be discharged, emissions of NO_x to the atmosphere in excess of the following limits, except as provided in §§ 76.8, 76.10, or 76.11: (1) 0.40 lb/mmBtu of heat input on an annual average basis for tangentially fired boilers. (2) 0.46 lb/ mmBtu of heat input on an annual average basis for dry bottom wall-fired boilers (other than units applying cell burner technology).	✓		IPP may not discharge emissions greater than what is allowed.	CEMS documentation.

TABLE D-2
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Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 76.8	The owner or operator of a Phase II PC-fired utility unit with a Group 1 boiler may elect to have the unit become subject to the applicable emissions limitation for NO_x under § 76.5, starting no later than January 1, 1997.		✓	IPP Unit 3 construction missed the 1997 deadline; therefore, this rule does not apply.	
40 CFR 76.9	The designated representative of any source with an affected unit subject to this part shall submit, by the applicable deadline under paragraph (b) of this section, a complete acid rain permit application (or, if the unit is covered by an acid rain permit, a complete permit revision) that includes a complete compliance plan for NO_x emissions covering the unit.	✓		IPSC has already obtained a Title IV permit that is included as part of the Title V permit. A modification is being applied for by this NOI to account for the addition of Unit 3.	Permit was received and is retained. This NOI is being submitted to accommodate for the addition of Unit 3.
40 CFR 76.10	The designated representative of an affected unit that is not an early election unit and cannot meet the applicable emission limitation, for Group 1 boilers, either LNB technology or an alternative or, for tangentially fired boilers, separated overfire air, may petition the permitting authority for an alternative emission limitation less stringent than the applicable emission limitation.		✓	Unit 3 will be able to meet the applicable emission limitation; therefore, this rule does not apply.	
40 CFR 76.11	Details emissions averaging plan.		✓	IPP is not eligible for the emissions averaging plan; therefore, this rule does not apply	
40 CFR 76.12	Details Phase I NO_x compliance extension.		✓	Unit 3 is a Phase II boiler; therefore, this rule does not apply.	
40 CFR 76.13	Provides calculations for excess emissions of NO_x.	✓		If Unit 3 has excess emissions of NO_x, the guidelines detailed in this section must be followed.	If NO_x is ever exceeded, document actions required by this section.

TABLE D-2
Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 76.14 – 76.15	Details requirements for alternative monitoring equipment and alternative emission limitations.		✓	IPP will not have either alternative; therefore, these rules do not apply.	
40 CFR 77, Excess Emissions					
40 CFR 77.01 – 77.06	This part of the acid rain regulations specifies the requirements for addressing excess emissions of SO_2 (exceeding allowances).	✓		If IPSC has excess emissions of SO_2 in any calendar year it shall be liable to offset the amount of such excess emissions by an equal amount of allowances from the unit's Allowance Tracking System account in accordance with these rules.	If emissions are ever exceeded, the requirements set forth in these rules will be followed and documentation retained.
40 CFR 78, Appeal Procedures for Acid Rain Program					
40 CFR 78	Guidelines and requirements for acid rain program appeals		✓	IPP is not requesting an appeal to the acid rain program; therefore, this rule does not apply.	
40 CFR 79, Registration of Fuels and Fuel Additives					
40 CFR 79	Guidelines and requirements for the registration of fuels and fuel additives.		✓	IPP does not produce fuels or fuel additives; therefore, this rule does not apply.	
40 CFR 80, Regulation of Fuels and Fuel Additives					
40 CFR 80	Guidelines and requirements for the production and distribution of fuels and fuel additives.		✓	IPP does not produce fuels or fuel additives; therefore, this rule does not apply.	
40 CFR 81, Designation of Areas for Air Quality Planning Purposes					
40 CFR 81	Administrative guidelines and requirements.		✓	This rule applies to regulators, and is not an obligation of IPP.	

TABLE D-2
Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 82, Protection of Stratospheric Ozone					
40 CFR 82	Administrative guidelines and requirements.		✓	This rule applies to regulators, and is not an obligation of IPP.	
40 CFR 85, Control of Air Pollution From Mobile Sources					
40 CFR 85	Guidelines and requirements for mobile sources		✓	This rule applies to automobile manufacturers, distributors and emissions certifications; therefore, it does not apply to IPP.	
40 CFR 86, Control of Emissions From New and In-Use Highway Vehicles and Engines					
40 CFR 86	Guidelines and requirements for highway vehicles and engines.		✓	Guidelines and requirements for highway vehicles and engines.	
40 CFR 87, Control of Air Pollution From Aircraft and Aircraft Engines					
40 CFR 87	Guidelines and requirements for aircraft and engines.		✓	IPP does not own or produce aircraft or aircraft engines; therefore, these rules do not apply.	
40 CFR 88, Clean-Fuel Vehicles					
40 CFR 88	Guidelines and requirements for clean fuel vehicles.		✓	Guidelines for manufacturers of clean fuel vehicles; therefore, this rule does not apply to IPP.	
40 CFR 89, Control of Emissions From New and In-Use Nonroad Compression-Ignition Engines					
40 CFR 89	Guidelines and requirements for nonroad compression-ignition engines.		✓	IPP does not own or operate nonroad compression-ignition engines; therefore, this rule does not apply.	
40 CFR 90, Control of Emissions From Nonroad Spark-Ignition Engines					
40 CFR 90	Guidelines and requirements for nonroad spark-ignition engines.		✓	IPP does not own or operate nonroad spark-ignition engines; therefore, this rule does not apply.	

TABLE D-2
Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 91, Control of Emissions From Marine Spark-Ignition Engines					
40 CFR 91	Guidelines and requirements for marine spark-ignition engines.		✓	IPP does not own or operate marine spark-ignition engines; therefore, this rule does not apply.	
40 CFR 92, Control of Air Pollution From Locomotives and Locomotive Engines					
40 CFR 92	Guidelines and requirements for locomotives and locomotive engines.	✓		IPP does own/operate locomotive for the unit coal train operation.	
40 CFR 93, Determining Conformity of Federal Actions to State or Federal Implementation Plans					
40 CFR 93	Guidelines for determining conformity of federal actions to SIP.		✓	This rule applies to federal agencies and is not an obligation of IPP.	
40 CFR 94, Control of Air Pollution From Marine Compression-Ignition Engines					
40 CFR 94	Guidelines and requirements for marine compression-ignition engines.		✓	IPP does not own or operate marine compression-ignition engines; therefore, this rule does not apply.	
40 CFR 95, Mandatory Patent Licenses					
40 CFR 95	Guidelines and requirements for mandatory patent licenses.		✓	IPP is not required to obtain a patent; therefore, this rule does not apply.	
40 CFR 96, NO_x Budget Trading Program for State Implementation Plans					
40 CFR 96	Authorizes states to implement a NO_x trading program		✓	IPP is not trading NO_x credits; therefore, this rule does not apply.	
40 CFR 97, Federal NO_x Budget Trading Program					
40 CFR 97	Provisions for the federal NO_x Budget Trading Program		✓	IPP is not trading NO_x credits; therefore, this rule does not apply.	

[a]The summary of applicable requirements is intended to provide a summary of the portion of the applicable requirement applying to the generating units. It is not intended to replace a regulatory document. Please see the actual regulations for specific information.

APPENDIX E

Air Quality Analysis

Major Increment Consuming Source in Central and Southern Utah to be included in CALPUFF Class I Increment Analysis
(Draft - May 22, 2003)

1	Facility Name	Source	Unit Specific 2000 NO2 (tons)	Unit Specific 2001 NO2 (tons)	Unit Specific 2000 PM10 (tons)	Unit Specific 2001 PM10 (tons)	Unit Specific 2000 SO2 (tons)	Unit Specific 2001 SO2 (tons)	Average NO2 Emissions Rate (lb/hr)	Average PM10 Emissions Rate (lb/hr)	Average SO2 Emissions Rate (lb/hr)	UTM East (m)	UTM North (m)	Base Elev (m)	Stack Height (ft)	Stack Height (m)	Diameter (m)	Exit Velocity (m/s)	Exit temp (K)
2	Lisbon Plant	Incinerator	na	na	na	na	1251.7	1525.9	na	na	317.1	651,366	4,224,549	1828.7	213.2	65.0	1.83	7.35	737.0
3	Sunnyside	Unit 1	380.0	407.0	62.3	48.5	1054.2	999.7	89.8	12.6	234.5	552,358	4,377,295	1975.0	250	76.2	2.59	27.84	422.0
4	Hunter Power Plant	Unit 2	na	na	277.2	456.0	1812.6	2720.0	na	83.7	517.4	497,846	4,335,847	1719.0	600	182.9	7.31	17.82	329.3
5	Hunter Power Plant	Unit 3	7173.3	7099.7	237.4	84.3	1113.4	1213.2	1629.3	36.7	265.6	497,824	4,335,815	1719.0	600	182.9	7.31	16.63	322.0
6	Graymont (Continental Lime)	Rotary Kiln # 1&2 Composite	na	na	33.8	39.5	78.2	85.2	na	8.4	18.7	342,200	4,311,500	1466.0	100	30.5	1.52	19.17	450
7	Graymont (Continental Lime)	Rotary Kiln # 3	415.5	398.8	25.4	22.6	92.4	82.0	93.0	5.5	19.9	342,200	4,311,500	1466.0	100	30.5	2.13	11.19	450
8	Graymont (Continental Lime)	Rotary Kiln # 4	662.8	653.5	55.1	48.7	155.0	136.9	150.3	11.8	33.3	342,200	4,311,500	1466.0	213	64.9	2.13	20.34	450
9	Deseret - Bonanza Plant	Main Stack	7000.0	6452.0	295.0	468.0	1020.0	1127.0	1535.6	87.1	245.1	646,206	4,438,606	1533.1	600	182.9	7.92	16.30	322
10	Ashgrove Cement-Leamington Canyon	Main Stack	2679.3	2679.3	148.0	148.0	na	na	611.7	33.8	na	397,206	4,379,732	1492.6	98	29.9	4.88	9.14	379
10	IPP - Unit 1	Main Stack	13973.2	12849.5	223.8	83.1	1855.0	1914.1	3062.0	35.0	430.3	364,214	4,374,464	1428.6	527	160.6	8.53	25.20	319
10	IPP - Unit 2	Main Stack	12138.3	13839.9	101.0	74.4	1619.2	2286.2	2965.5	20.0	445.8	364,214	4,374,464	1428.6	527	160.6	8.53	25.20	319

Notes:

Based on 2000-2001 Emission inventories submitted to UDAQ

Applicants should not use emissions information from this table to represent their own source when modeling impacts for short-term averaging periods.

Additional sources may be added to this list after the date listed above. Contact UDAQ modeling staff prior to using this information in modeling analysis.

IPP - Glen Canyon

JD 321

YEAR	DAY	TIME	BEXT TOTAL	BEXT MODEL	BEXT BACKGN (FLAG)	%CHNG (FLAG)	RH-FAC	BEXT BACKGN (FLAG/ CANY)*	%CHNG (FLAG/CANY)	BEXT BACKGN (GRAND CANY)*	UTME	UTMN
1996	321	100	31.151	10.783	20.368	68.298	9.779	608	1.8	675	506.5	4161.9
1996	321	200	33.277	12.909	20.368	82.765	9.779	608	2.1	94	506.5	4161.9
1996	321	300	34.365	13.997	20.368	92.387	9.779	608	2.3		506.5	4161.9
1996	321	400	33.362	12.994	20.368	89.954	9.779	608	2.1		506.5	4161.9
1996	321	500	28.594	8.226	20.368	60.795	9.779	416	2.0		506.5	4161.9
1996	321	600	22.395	2.872	19.523	24.313	8.371	19.523	14.7		506.5	4161.9
1996	321	700	19.102	1.037	18.065	10.413	5.941	18.065	5.7		506.5	4161.9
1996	321	800	18.192	0.889	17.303	9.142	4.672	17.303	5.1		506.5	4161.9
1996	321	900	17.046	0.695	16.351	7.132	3.085	16.351	4.3		506.5	4161.9
1996	321	1000	16.719	0.658	16.061	6.642	2.601	16.061	4.1		506.5	4161.9
1996	321	1100	16.429	0.66	15.769	6.594	2.115	15.769	4.2		506.5	4161.9
1996	321	1200	16.153	0.574	15.579	5.566	1.798	15.579	3.7		506.5	4161.9
1996	321	1300	15.99	0.53	15.46	5.029	1.599	15.46	3.4		506.5	4161.9
1996	321	1400	15.873	0.472	15.401	4.415	1.501	15.401	3.1		506.5	4161.9
1996	321	1500	15.722	0.415	15.307	3.861	1.345	15.307	2.7		506.5	4161.9
1996	321	1600	15.539	0.268	15.271	2.474	1.284	15.271	1.8		506.5	4161.9
1996	321	1700	15.476	0.205	15.271	1.878	1.284	15.271	1.3		506.5	4161.9
1996	321	1800	15.557	0.156	15.401	1.407	1.501	15.401	1.0		506.5	4161.9
1996	321	1900	15.746	0.099	15.647	0.88	1.911	15.647	0.6		506.5	4161.9
1996	321	2000	15.716	0.04	15.676	0.354	1.96	15.676	0.3		506.5	4161.9
1996	321	2100	15.687	0.011	15.676	0.102	1.96	15.676	0.1		506.5	4161.9
1996	321	2200	15.678	0.002	15.676	0.021	1.96	15.676	0.0		506.5	4161.9
1996	321	2300	15.705	0	15.705	0.002	2.008	15.705	0.0		506.5	4161.9
1996	322	0	15.705	0	15.705	0	2.008	15.705	0		506.5	4161.9
			averages:	2.854	16.945	16.8	4.075	141.884	2.0			

* Includes extinction measured at Canyonlands NP IMPROVE station for hours that reflect pronounced natural obscuration; FLAG background for remaining hours.

IPP - Glen Canyon

JD 320

YEAR	DAY	TIME	BEXT TOTAL	BEXT MODEL	BEXT BACKGN (FLAG)	%CHNG (FLAG)	RH-FAC	BEXT BACKGN (FLAG/ CANY)*	%CHNG (FLAG/CANY)	BEXT BACKGN (GRAND CANY)*	UTME	UTMN
1996	320	100	15.225	0	15.225	0	1.209	15.225	0.0		486.6	4172.9
1996	320	200	15.242	0	15.242	0	1.237	15.242	0.0		486.6	4172.9
1996	320	300	15.271	0	15.271	0	1.284	15.271	0.0		486.6	4172.9
1996	320	400	15.281	0	15.281	0	1.302	15.281	0.0		486.6	4172.9
1996	320	500	15.281	0	15.281	0	1.302	15.281	0.0		486.6	4172.9
1996	320	600	15.281	0	15.281	0	1.302	15.281	0.0		486.6	4172.9
1996	320	700	15.294	0	15.294	0	1.323	15.294	0.0		486.6	4172.9
1996	320	800	15.294	0	15.294	0.004	1.323	15.294	0.0		486.6	4172.9
1996	320	900	15.297	0.003	15.294	0.028	1.323	15.294	0.0		486.6	4172.9
1996	320	1000	15.383	0.005	15.378	0.054	1.463	15.378	0.0		486.6	4172.9
1996	320	1100	15.993	0.011	15.982	0.106	2.469	608	0.0		486.6	4172.9
1996	320	1200	16.78	0.009	16.771	0.083	3.785	608	0.0	236	486.6	4172.9
1996	320	1300	18.065	0	18.065	0	5.941	608	0.0	397	486.6	4172.9
1996	320	1400	19.567	0.044	19.523	0.309	8.371	608	0.0	393	486.6	4172.9
1996	320	1500	20.422	0.054	20.368	0.346	9.779	608	0.0	260	486.6	4172.9
1996	320	1600	20.41	0.042	20.368	0.261	9.779	608	0.0	86	486.6	4172.9
1996	320	1700	22.038	0.081	21.957	0.46	12.429	608	0.0	188	486.6	4172.9
1996	320	1800	22.128	0.171	21.957	0.977	12.429	608	0.0	675	486.6	4172.9
1996	320	1900	22.387	0.43	21.957	2.482	12.429	608	0.1	60	486.6	4172.9
1996	320	2000	23.177	1.22	21.957	7.105	12.429	608	0.2		486.6	4172.9
1996	320	2100	25.016	3.059	21.957	17.898	12.429	608	0.5	675	486.6	4172.9
1996	320	2200	25.375	5.007	20.368	31.621	9.779	608	0.8	675	486.6	4172.9
1996	320	2300	28.976	8.608	20.368	54.439	9.779	608	1.4	326	486.6	4172.9
1996	321	0	31.861	11.493	20.368	72.904	9.779	608	1.9	540	486.6	4172.9
			averages:	1.260	18.117	6.95	6.028	361.035	0.3			

* Includes extinction measured at Canyonlands NP IMPROVE station for hours that reflect pronounced natural obscuration; FLAG background for remaining hours.

IPP - Glen Canyon

JD 299

YEAR	DAY	TIME	BEXT TOTAL	BEXT MODEL	BEXT BACKGN (FLAG)	%CHNG (FLAG)	RH-FAC	BEXT BACKGN (FLAG/ CANY)*	%CHNG (FLAG/CANY)	BEXT BACKGN (GRAND CANY)*	UTME	UTMN
1996	299	100	15.115	0	15.115	0	1.025	15.115	0.0		550.5	4210
1996	299	200	15.175	0	15.175	0	1.125	15.175	0.0		550.5	4210
1996	299	300	15.191	0	15.191	0	1.153	15.191	0.0		550.5	4210
1996	299	400	15.169	0	15.169	0	1.115	15.169	0.0		550.5	4210
1996	299	500	15.378	0	15.378	0	1.463	320	0.0		550.5	4210
1996	299	600	15.858	0	15.858	0	2.263	15.858	0.0		550.5	4210
1996	299	700	16.061	0	16.061	0	2.601	440	0.0		550.5	4210
1996	299	800	16.276	0	16.276	0	2.959	608	0.0		550.5	4210
1996	299	900	17.116	0	17.116	0	4.359	377	0.0	675	550.5	4210
1996	299	1000	17.684	0	17.684	0	5.307	263	0.0	210	550.5	4210
1996	299	1100	18.678	0	18.678	0	6.963	608	0.0		550.5	4210
1996	299	1200	20.368	0	20.368	0	9.779	608	0.0		550.5	4210
1996	299	1300	23.546	0	23.546	0	15.077	608	0.0		550.5	4210
1996	299	1400	25.335	0	25.335	0	18.059	608	0.0		550.5	4210
1996	299	1500	25.335	0	25.335	0	18.059	118	0.0	69	550.5	4210
1996	299	1600	27.436	2.101	25.335	10.464	18.059	608	0.3		550.5	4210
1996	299	1700	36.657	11.322	25.335	56.658	18.059	608	1.9		550.5	4210
1996	299	1800	35.103	9.768	25.335	50.72	18.059	83	11.8	67	550.5	4210
1996	299	1900	20.337	1.659	18.678	12.654	6.963	18.678	8.9		550.5	4210
1996	299	2000	17.817	0.514	17.303	4.569	4.672	17.303	3.0		550.5	4210
1996	299	2100	17.026	0.098	16.928	0.954	4.047	16.928	0.6		550.5	4210
1996	299	2200	16.928	0	16.928	0	4.047	16.928	0.0		550.5	4210
1996	299	2300	16.276	0	16.276	0	2.959	126	0.0		550.5	4210
1996	300	0	15.982	0	15.982	0	2.469	15.982	0.0		550.5	4210
			averages:	1.061	18.766	5.65	7.110	256.055	0.4			

* Includes extinction measured at Canyonlands NP IMPROVE station for hours that reflect pronounced natural obscuration; FLAG background for remaining hours.

IPP: Great Basin

JD 74

YEAR	DAY	TIME	BEXT TOTAL	BEXT MODEL	BEXT BACKGN (FLAG)	%CHNG (FLAG)	RH-FAC	BEXT BACKGN (FLAG/ GR BASIN)*	%CHNG (FLAG/CA NY)	UTME	UTMN
1996	74	100	16.922	0.404	16.518	2.9	3.364	16.518	2.45	218.70	4326.5
1996	74	200	19.392	1.327	18.065	9.0	5.941	18.065	7.35	218.70	4326.5
1996	74	300	32.501	7.166	25.335	35.613	18.059	25.335	28.28	218.7	4326.5
1996	74	400	21.891	3.826	18.065	27.28	5.941	18.065	21.18	218.7	4326.5
1996	74	500	23.163	5.098	18.065	36.832	5.941	18.065	28.22	218.7	4326.5
1996	74	600	23.136	5.071	18.065	36.955	5.941	18.065	28.07	218.7	4326.5
1996	74	700	37.248	11.913	25.335	61.831	18.059	25.335	47.02	218.7	4326.5
1996	74	800	20.846	2.781	18.065	19.7	5.941	96	2.90	218.70	4326.5
1996	74	900	16.424	0.688	15.736	5.5	2.06	727	0.09	218.70	4326.5
1996	74	1000	15.785	0.294	15.491	2.4	1.652	469	0.06	218.70	4326.5
1996	74	1100	15.425	0.131	15.294	1.058	1.323	125	0.10	218.7	4326.5
1996	74	1200	15.291	0.058	15.233	0.459	1.222	15.233	0.38	218.7	4326.5
1996	74	1300	15.289	0.018	15.271	0.141	1.284	15.271	0.12	218.7	4326.5
1996	74	1400	15.277	0.006	15.271	0.046	1.284	15.271	0.04	218.7	4326.5
1996	74	1500	15.236	0.003	15.233	0.021	1.222	15.233	0.02	218.7	4326.5
1996	74	1600	15.252	0.001	15.251	0.009	1.251	15.251	0.01	218.7	4326.5
1996	74	1700	15.234	0.001	15.233	0.004	1.222	15.233	0.01	218.7	4326.5
1996	74	1800	15.294	0	15.294	0.002	1.323	15.294	0.00	218.7	4326.5
1996	74	1900	15.378	0	15.378	0	1.463	15.378	0.00	218.7	4326.5
1996	74	2000	15.355	0	15.355	0	1.424	15.355	0.00	218.7	4326.5
1996	74	2100	15.491	0	15.491	0.0	1.652	15.491	0.00	218.7	4326.5
1996	74	2200	15.858	0	15.858	0.0	2.263	15.858	0.00	218.70	4326.5
1996	74	2300	16.061	0	16.061	0.0	2.601	16.061	0.00	218.70	4326.5
1996	75	0	16.276	0	16.276	0.0	2.959	16.276	0.00	218.70	4326.5
			averages:	1.616	16.885	9.57	3.975	75.712	2.1		

* Includes extinction measured at Great Basin IMPROVE station for hours that reflect pronounced natural obscuration; FLAG background for remaining hours.
Data for hours 1-7 were flagged as missing data in IMPROVE file

24-Hour Visibility			BEXT (Model)	EXT(BKG)	%CHNG	RH-FAC	bxSO4	bxNO3	bxPMF
1996	75	0	2.088	16.885	12.37	3.975	1.113	0.96	0.015

IPP: Great Basin

JD 42

YEAR	DAY	TIME	BEXT TOTAL	BEXT MODEL	BEXT BACKGN (FLAG)	%CHNG (FLAG)	RH-FAC	BEXT BACKGN (FLAG/ GR BASIN)*	%CHNG (FLAG/CANY)	BACKGN (GrCANY)	UTME	UTMN	DELTA DV
1996	42	100	16.408	0.347	16.061	3.086	2.601	no natural obscuration			220.2	4301	0.304
1996	42	200	16.705	0.429	16.276	3.835	2.959				220.2	4301	0.376
1996	42	300	17.828	0.712	17.116	6.3	4.359				220.20	4301	0.61
1996	42	400	18.069	0.953	17.116	8.821	4.359				220.2	4301	0.845
1996	42	500	17.561	1.043	16.518	10.3	3.364				220.20	4301	0.98
1996	42	600	18.848	1.732	17.116	16.664	4.359				220.2	4301	1.541
1996	42	700	17.955	1.437	16.518	14.272	3.364				220.2	4301	1.334
1996	42	800	17.987	1.469	16.518	14.56	3.364				220.2	4301	1.359
1996	42	900	17.215	1.154	16.061	11.5	2.601				220.20	4301	1.086
1996	42	1000	16.532	0.885	15.647	8.652	1.911				220.2	4301	0.83
1996	42	1100	16.39	0.811	15.579	7.783	1.798				220.2	4301	0.749
1996	42	1200	15.971	0.616	15.355	5.939	1.424				220.2	4301	0.577
1996	42	1300	15.929	0.658	15.271	6.345	1.284				220.2	4301	0.615
1996	42	1400	16.042	0.809	15.233	7.803	1.222				220.2	4301	0.751
1996	42	1500	16.258	1.061	15.197	10.28	1.161				220.2	4301	0.979
1996	42	1600	16.547	1.361	15.186	13.166	1.144				220.2	4301	1.237
1996	42	1700	16.722	1.547	15.175	14.9	1.125				220.2	4301	1.385
1996	42	1800	16.985	1.768	15.217	16.6	1.196				220.20	4301	1.54
1996	42	1900	17.523	2.201	15.322	20.379	1.37				220.2	4301	1.855
1996	42	2000	16.783	1.614	15.169	15.0	1.115				220.20	4301	1.401
1996	42	2100	17.507	1.959	15.548	18.3	1.747				220.20	4301	1.677
1996	42	2200	17.416	1.558	15.858	14.4	2.263				220.20	4301	1.345
1996	42	2300	17.201	0.925	16.276	8.4	2.959				220.20	4301	0.81
1996	43	0	16.411	0.35	16.061	3.305	2.601				220.2	4301	0.325
			averages:	1.142	15.891	7.18	2.306						

* Includes extinction measured at Great Basin IMPROVE station for hours that reflect pronounced natural obscuration; FLAG background for remaining hours.

IPP: Canyonlands NP

JD 262

YEAR	DAY	TIME	BEXT TOTAL	BEXT MODEL	BEXT BACKGN (FLAG)	%CHNG (FLAG)	RH-FAC	BEXT BACKGN (FLAG/ CANY)*	%CHNG (FLAG/CANY)	UTME	UTMN
1996	262	100	17.684	0.568	17.116	4.0	4.359	17.116	3.3	566.5	4254.1
1996	262	200	18.021	0.718	17.303	5.1	4.672	17.303	4.1	566.5	4254.1
1996	262	300	19.104	1.039	18.065	7.0	5.941	18.065	5.8	566.5	4254.1
1996	262	400	21.183	1.66	19.523	10.4	8.371	19.523	8.5	566.5	4254.1
1996	262	500	20.28	1.602	18.678	10.6	6.963	18.678	8.6	566.5	4254.1
1996	262	600	19.639	1.574	18.065	10.9	5.941	18.065	8.7	566.5	4254.1
1996	262	700	18.742	1.439	17.303	10.4	4.672	17.303	8.3	566.5	4254.1
1996	262	800	18.799	1.683	17.116	12.1	4.359	17.116	9.8	566.5	4254.1
1996	262	900	19.038	1.922	17.116	13.7	4.359	80	2.4	566.5	4254.1
1996	262	1000	17.575	1.367	16.208	10.2	2.846	62	2.2	566.5	4254.1
1996	262	1100	17.363	1.302	16.061	9.7	2.601	16.061	8.1	566.5	4254.1
1996	262	1200	17.939	1.588	16.351	11.5	3.085	160	1.0	566.5	4254.1
1996	262	1300	17.178	1.264	15.914	9.2	2.356	15.914	7.9	566.5	4254.1
1996	262	1400	16.444	0.896	15.548	6.7	1.747	15.548	5.8	566.5	4254.1
1996	262	1500	15.981	0.626	15.355	4.7	1.424	15.355	4.1	566.5	4254.1
1996	262	1600	15.843	0.549	15.294	4.1	1.323	15.294	3.6	566.5	4254.1
1996	262	1700	15.894	0.539	15.355	4.0	1.424	15.355	3.5	566.5	4254.1
1996	262	1800	16.144	0.565	15.579	4.1	1.798	15.579	3.6	566.5	4254.1
1996	262	1900	16.088	0.441	15.647	3.2	1.911	15.647	2.8	566.5	4254.1
1996	262	2000	15.979	0.303	15.676	2.2	1.96	15.676	1.9	566.5	4254.1
1996	262	2100	15.853	0.177	15.676	1.3	1.96	15.676	1.1	566.5	4254.1
1996	262	2200	15.772	0.096	15.676	0.7	1.96	15.676	0.6	566.5	4254.1
1996	262	2300	15.788	0.052	15.736	0.4	2.06	15.736	0.3	566.5	4254.1
1996	263	0	15.828	0.026	15.802	0.2	2.17	15.802	0.2	566.5	4254.1
			averages:	0.917	16.507	5.55	3.344	27.020	3.4		

* Includes extinction measured at Canyonlands NP IMPROVE station for hours that reflect pronounced natural obscuration; FLAG background for remaining hours.

24-Hour Visibility			BEXT (Model)	EXT(BKG)	%CHNG	RH-FAC	bxSO4	bxNO3	bxPMF
1996	263	0	0.917	16.507	5.55	3.344	0.575	0.324	0.018

IPP: Bryce Canyon NP

JD 334

YEAR	DAY	TIME	BEXT TOTAL	BEXT MODEL	BEXT BACKGN (FLAG)	%CHNG (FLAG)	RH-FAC	BEXT BACKGN (FLAG/ CANY)*	%CHNG (FLAG/CANY)	BEXT GRAND CANY
1996	334	100	15.294	0	15.294	0	1.323	15.294		
1996	334	200	15.613	0	15.613	0	1.855	608		
1996	334	300	16.351	0	16.351	0	3.085	608		129
1996	334	400	16.771	0	16.771	0	3.785	608		675
1996	334	500	16.928	0	16.928	0	4.047	608		675
1996	334	600	16.932	0.004	16.928	0.023	4.047	608		675
1996	334	700	17.731	0.803	16.928	4.743	4.047	608		675
1996	334	800	19.166	2.238	16.928	13.22	4.047	608		675
1996	334	900	18.547	1.619	16.928	9.564	4.047	608		675
1996	334	1000	17.746	0.975	16.771	5.815	3.785	608		675
1996	334	1100	18.281	1.51	16.771	9.001	3.785	608		675
1996	334	1200	18.922	1.994	16.928	11.782	4.047	608		675
1996	334	1300	19.45	2.334	17.116	13.636	4.359	608		675
1996	334	1400	19.305	2.189	17.116	12.794	4.359	608		675
1996	334	1500	19.567	2.264	17.303	13.086	4.672	608		675
1996	334	1600	19.337	2.034	17.303	11.751	4.672	332		143
1996	334	1700	19.104	1.801	17.303	10.404	4.672	183		475
1996	334	1800	19.157	1.473	17.684	8.328	5.307	608		610
1996	334	1900	19.195	1.13	18.065	6.258	5.941	340		
1996	334	2000	19.736	1.671	18.065	9.254	5.941	18.065		
1996	334	2100	18.465	0.781	17.684	4.418	5.307	17.684		
1996	334	2200	17.829	0.145	17.684	0.821	5.307	17.684		
1996	334	2300	17.433	0.13	17.303	0.75	4.672	17.303		
1996	335	0	17.422	0.306	17.116	1.791	4.359	17.116		
			averages:	1.058	17.037	6.21	4.228	419.923	0.252	

* Includes extinction measured at Canyonlands NP IMPROVE station for hours that reflect pronounced natural obscuration; FLAG background for remaining hours.

24-Hour Visibility			BEXT (Model)	EXT(BKG)	%CHNG	RH-FAC	bxSO4	bxNO3	bxPMF
1996	335	0	1.058	17.037	6.21	4.228	0.557	0.462	0.039

IPP: Capital Reef NP

JD 320

YEAR	DAY	TIME	BEXT TOTAL	BEXT MODEL	BEXT BACKGN (FLAG)	%CHNG (FLAG)	RH-FAC	BEXT BACKGN (FLAG/ CANY)*	%CHNG (FLAG/CANY)	UTME	UTMN	BEXT GRAND CANYON
1996	320	100	15.226	0.001	15.225	0.00	1.209	15.225	0.01	462.9	4252.5	
1996	320	200	15.244	0.002	15.242	0.03	1.237	15.242	0.01	462.9	4252.5	
1996	320	300	15.274	0.003	15.271	0.04	1.284	15.271	0.02	462.9	4252.5	
1996	320	400	15.297	0.016	15.281	0.19	1.302	15.281	0.10	462.9	4252.5	
1996	320	500	15.345	0.064	15.281	0.73	1.302	15.281	0.42	462.9	4252.5	
1996	320	600	15.425	0.144	15.281	1.61	1.302	15.281	0.94	462.9	4252.5	
1996	320	700	15.519	0.225	15.294	2.51	1.323	15.294	1.47	462.9	4252.5	
1996	320	800	15.517	0.223	15.294	2.43	1.323	15.294	1.46	462.9	4252.5	
1996	320	900	15.445	0.151	15.294	1.61	1.323	15.294	0.99	462.9	4252.5	
1996	320	1000	15.471	0.093	15.378	0.97	1.463	15.378	0.60	462.9	4252.5	
1996	320	1100	16.077	0.095	15.982	0.94	2.469	608	0.02	462.9	4252.5	
1996	320	1200	17.003	0.232	16.771	2.11	3.785	608	0.04	462.9	4252.5	236
1996	320	1300	18.85	0.785	18.065	6.36	5.941	608	0.13	462.9	4252.5	397
1996	320	1400	21.515	1.992	19.523	14.39	8.371	608	0.33	462.9	4252.5	393
1996	320	1500	23.807	3.439	20.368	23.07	9.779	608	0.57	462.9	4252.5	260
1996	320	1600	25.31	4.942	20.368	32.35	9.779	608	0.81	462.9	4252.5	86
1996	320	1700	31.301	9.344	21.957	55.57	12.429	608	1.54	462.9	4252.5	188
1996	320	1800	36.492	14.535	21.957	85.65	12.429	608	2.39	462.9	4252.5	675
1996	320	1900	40.808	18.851	21.957	111.06	12.429	608	3.10	462.9	4252.5	60
1996	320	2000	39.333	17.376	21.957	102.30	12.429	608	2.86	462.9	4252.5	
1996	320	2100	34.565	12.608	21.957	74.51	12.429	608	2.07	462.9	4252.5	675
1996	320	2200	27.282	6.914	20.368	44.89	9.779	608	1.14	462.9	4252.5	675
1996	320	2300	25.841	5.473	20.368	36.75	9.779	608	0.90	462.9	4252.5	326
1996	321	0	24.531	4.163	20.368	29.05	9.779	608	0.68	462.9	4252.5	540
			averages:	4.236	18.117	23.38	6.028	361.035	1.173			

* Includes extinction measured at Canyonlands NP IMPROVE station for hours that reflect pronounced natural obscuration; FLAG background for remaining hours.

IPP: Capital Reef NP

JD 321

YEAR	DAY	TIME	BEXT TOTAL	BEXT MODEL	BEXT BACKGN (FLAG)	%CHNG (FLAG)	RH-FAC	BEXT BACKGN (FLAG/ CANY)*	%CHNG (FLAG/CANY)	UTME	UTMN	BEXT GRAND CANYON
1996	321	100	30.768	10.4	20.368	69.31	9.779	608	1.71	507.3	4163.2	675
1996	321	200	33.038	12.67	20.368	83.48	9.779	608	2.08	507.3	4163.2	94
1996	321	300	34.294	13.926	20.368	92.78	9.779	608	2.29	507.3	4163.2	
1996	321	400	33.561	13.193	20.368	89.74	9.779	608	2.17	507.3	4163.2	
1996	321	500	29.066	8.698	20.368	60.15	9.779	416	2.09	507.3	4163.2	
1996	321	600	22.624	3.101	19.523	24.04	8.371	19.523	15.88	507.3	4163.2	
1996	321	700	19.12	1.055	18.065	10.27	5.941	18.065	5.84	507.3	4163.2	
1996	321	800	18.153	0.85	17.303	8.86	4.672	17.303	4.91	507.3	4163.2	
1996	321	900	16.999	0.648	16.351	6.66	3.085	16.351	3.96	507.3	4163.2	
1996	321	1000	16.658	0.597	16.061	6.16	2.601	16.061	3.72	507.3	4163.2	
1996	321	1100	16.382	0.613	15.769	6.20	2.115	15.769	3.89	507.3	4163.2	
1996	321	1200	16.124	0.545	15.579	5.33	1.798	15.579	3.50	507.3	4163.2	
1996	321	1300	15.983	0.523	15.46	4.91	1.599	15.46	3.38	507.3	4163.2	
1996	321	1400	15.871	0.47	15.401	4.37	1.501	15.401	3.05	507.3	4163.2	
1996	321	1500	15.728	0.421	15.307	3.91	1.345	15.307	2.75	507.3	4163.2	
1996	321	1600	15.556	0.285	15.271	2.60	1.284	15.271	1.87	507.3	4163.2	
1996	321	1700	15.488	0.217	15.271	1.98	1.284	15.271	1.42	507.3	4163.2	
1996	321	1800	15.57	0.169	15.401	1.52	1.501	15.401	1.10	507.3	4163.2	
1996	321	1900	15.756	0.109	15.647	0.96	1.911	15.647	0.70	507.3	4163.2	
1996	321	2000	15.72	0.044	15.676	0.39	1.96	15.676	0.28	507.3	4163.2	
1996	321	2100	15.689	0.013	15.676	0.12	1.96	15.676	0.08	507.3	4163.2	
1996	321	2200	15.678	0.002	15.676	0.02	1.96	15.676	0.01	507.3	4163.2	
1996	321	2300	15.705	0	15.705	0.00	2.008	15.705	0.00	507.3	4163.2	
1996	322	0	15.705	0	15.705	0.00	2.008	15.705	0.00	507.3	4163.2	
			averages:	2.856	16.945	16.86	4.075	131.369	2.174			

* Includes extinction measured at Canyonlands NP IMPROVE station for hours that reflect pronounced natural obscuration; FLAG background for remaining hours.

IPP: Capital Reef NP

JD 299

YEAR	DAY	TIME	BEXT TOTAL	BEXT MODEL	BEXT BACKGN (FLAG)	%CHNG (FLAG)	RH-FAC	BEXT BACKGN (FLAG/ CANY)*	%CHNG (FLAG/CANY)	UTME	UTMN	BEXT GRAND CANYON
1996	299	100	15.115	0	15.115	0	1.025	15.115	0	472.6	4264.5	
1996	299	200	15.175	0	15.175	0	1.125	15.175	0	472.6	4264.5	
1996	299	300	15.191	0	15.191	0	1.153	15.191	0	472.6	4264.5	
1996	299	400	15.169	0	15.169	0	1.115	15.169	0	472.6	4264.5	
1996	299	500	15.378	0	15.378	0	1.463	15.378	0	472.6	4264.5	
1996	299	600	15.858	0	15.858	0	2.263	15.858	0	472.6	4264.5	
1996	299	700	16.061	0	16.061	0	2.601	16.061	0	472.6	4264.5	
1996	299	800	16.276	0	16.276	0	2.959	608	0	472.6	4264.5	
1996	299	900	17.116	0	17.116	0	4.359	377	0	472.6	4264.5	675
1996	299	1000	17.684	0	17.684	0	5.307	263	0	472.6	4264.5	210
1996	299	1100	18.678	0	18.678	0	6.963	608	0	472.6	4264.5	
1996	299	1200	20.621	0.253	20.368	2.541	9.779	608	0.042	472.6	4264.5	
1996	299	1300	26.492	2.946	23.546	20.167	15.077	608	0.485	472.6	4264.5	
1996	299	1400	32.615	7.28	25.335	39.585	18.059	608	1.197	472.6	4264.5	
1996	299	1500	33.398	8.063	25.335	40.816	18.059	118	6.833	472.6	4264.5	69
1996	299	1600	34	8.665	25.335	48.238	18.059	608	1.425	472.6	4264.5	
1996	299	1700	35.5	10.165	25.335	60.868	18.059	608	1.672	472.6	4264.5	
1996	299	1800	38.47	13.135	25.335	84.707	18.059	25.335	51.845	472.6	4264.5	67
1996	299	1900	23.827	5.149	18.678	49.004	6.963	18.678	27.567	472.6	4264.5	
1996	299	2000	19.522	2.219	17.303	28.564	4.672	17.303	12.824	472.6	4264.5	
1996	299	2100	17.534	0.606	16.928	9.982	4.047	16.928	3.580	472.6	4264.5	
1996	299	2200	16.946	0.018	16.928	0.485	4.047	16.928	0.106	472.6	4264.5	
1996	299	2300	16.276	0	16.276	0	2.959	16.276	0	472.6	4264.5	
1996	300	0	15.982	0	15.982	0	2.469	15.982	0	472.6	4264.5	
			averages:	2.437	18.766	12.99	7.11	218.724	1.11			

* Includes extinction measured at Canyonlands NP IMPROVE station for hours that reflect pronounced natural obscuration; FLAG background for remaining hours.

IPP: Capital Reef NP

JD 262

YEAR	DAY	TIME	BEXT TOTAL	BEXT MODEL	BEXT BACKGN (FLAG)	%CHNG (FLAG)	RH-FAC	BEXT BACKGN (FLAG/ CANY)*	%CHNG (FLAG/CANY)	UTME	UTMN
1996	262	100	18.383	1.267	17.116	9.25	4.359	17.116	7.40	483.1	4256.6
1996	262	200	18.846	1.543	17.303	11.24	4.672	17.303	8.92	483.1	4256.6
1996	262	300	20.254	2.189	18.065	15.46	5.941	18.065	12.12	483.1	4256.6
1996	262	400	22.921	3.398	19.523	22.52	8.371	19.523	17.41	483.1	4256.6
1996	262	500	21.613	2.935	18.678	20.63	6.963	18.678	15.71	483.1	4256.6
1996	262	600	20.597	2.532	18.065	18.70	5.941	18.065	14.02	483.1	4256.6
1996	262	700	19.367	2.064	17.303	15.94	4.672	17.303	11.93	483.1	4256.6
1996	262	800	19.148	2.032	17.116	15.56	4.359	17.116	11.87	483.1	4256.6
1996	262	900	18.905	1.789	17.116	13.42	4.359	80	2.24	483.1	4256.6
1996	262	1000	17.096	0.888	16.208	6.92	2.846	62	1.43	483.1	4256.6
1996	262	1100	16.648	0.587	16.061	4.52	2.601	16.061	3.65	483.1	4256.6
1996	262	1200	16.866	0.515	16.351	3.79	3.085	160	0.32	483.1	4256.6
1996	262	1300	16.141	0.227	15.914	1.67	2.356	15.914	1.43	483.1	4256.6
1996	262	1400	15.637	0.089	15.548	0.67	1.747	15.548	0.57	483.1	4256.6
1996	262	1500	15.432	0.077	15.355	0.60	1.424	15.355	0.50	483.1	4256.6
1996	262	1600	15.405	0.111	15.294	0.84	1.323	15.294	0.73	483.1	4256.6
1996	262	1700	15.529	0.174	15.355	1.31	1.424	15.355	1.13	483.1	4256.6
1996	262	1800	15.784	0.205	15.579	1.50	1.798	15.579	1.32	483.1	4256.6
1996	262	1900	15.794	0.147	15.647	1.07	1.911	15.647	0.94	483.1	4256.6
1996	262	2000	15.76	0.084	15.676	0.61	1.96	15.676	0.54	483.1	4256.6
1996	262	2100	15.721	0.045	15.676	0.34	1.96	15.676	0.29	483.1	4256.6
1996	262	2200	15.867	0.191	15.676	1.80	1.96	15.676	1.22	483.1	4256.6
1996	262	2300	16.025	0.289	15.736	2.85	2.06	15.736	1.84	483.1	4256.6
1996	263	0	16.112	0.31	15.802	3.19	2.17	15.802	1.96	483.1	4256.6
				0.987	16.507	5.98	3.344	27.020	3.65		

* Includes extinction measured at Canyonlands NP IMPROVE station for hours that reflect pronounced natural obscuration; FLAG background for remaining hours.

IPP Project	
BPIP and ISCST3 Input/Output Files	
DISK #1	
/ISCST3	
Unit 3 Load Analysis	[Steamboat \D\AIR\NALL\IPP\LOAD]
IPP_LOAD_CO	ISCST3 input (.DTA) and output (.LST) files for CO load analysis (100%, 75%, 50% loads) with 50-m meteorological data
IPP_LOAD_SO2	ISCST3 input (.DTA) and output (.LST) files for SO2 load analysis (100%, 75%, 50% loads) with 50-m meteorological data
IPP_LOAD_PM	ISCST3 input (.DTA) and output (.LST) files for PM-10 load analysis (100%, 75%, 50% loads) with 50-m meteorological data
Unit 3 Preliminary Analysis	[Steamboat \D\AIR\NALL\IPP\PRELIM]
IPP_PRE_1_CO	ISCST3 input (.DTA) and output (.LST) files for CO prelim analysis with 50-m meteorological data
IPP_PRE_1_NOX	ISCST3 input (.DTA) and output (.LST) files for NOX prelim analysis with 50-m meteorological data
IPP_PRE_1_SO2	ISCST3 input (.DTA) and output (.LST) files for so2 prelim analysis with 50-m meteorological data
IPP_PRE_FINE_1_NOX	ISCST3 input (.DTA) and output (.LST) files for nox prelim analysis with 50-m meteorological data for a fine grid around max impact
IPP_PRE_FINE_1_SO2	ISCST3 input (.DTA) and output (.LST) files for so2 prelim analysis with 50-m meteorological data for a fine grid around max impact
IPP_PRE1_1_LEAD	ISCST3 input (.DTA) and output (.LST) files for lead prelim analysis with 50-m meteorological data 1st quarter
IPP_PRE2_1_LEAD	ISCST3 input (.DTA) and output (.LST) files for lead prelim analysis with 50-m meteorological data 2nd quarter
IPP_PRE3_1_LEAD	ISCST3 input (.DTA) and output (.LST) files for lead prelim analysis with 50-m meteorological data 3rd quarter
IPP_PRE4_1_LEAD	ISCST3 input (.DTA) and output (.LST) files for lead prelim analysis with 50-m meteorological data 4th quarter
	[Steamboat \D\AIR\NALL\IPP\PRELIMPM_HIGH]
IPP3_PMHIGH_1_[PM10]	ISCST3 input (.DTA) and output (.LST) files for PM10 prelim analysis with 50-m meteorological data
IPP_PM_ROI.XLS	Xcel spreadsheet used to determine ROI for PM-10
	[Steamboat \D\AIR\NALL\IPP\PRELIMPM_LOW]
IPP3_PMLOW_1_[PM10]	ISCST3 input (.DTA) and output (.LST) files for PM10 prelim analysis with 10-m meteorological data
NAAQS & PSD Increment Analysis	
	[Steamboat \D\AIR\NALL\IPP\SO2_FULL]
IPP_NAAQS_SO2	ISCST3 input (.DTA) and output (.LST) files for 3-hour and 24-hour SO2 NAAQS analysis (50-m met data)
IPP_INC_SO2	ISCST3 input (.DTA) and output (.LST) files for 3-hour and 24-hour SO2 increment analysis (50-m met data)
IPP_INC_SO2.GRF	XYZ file used to produce plots for increment analysis
IPP_INC_SO2_FINE	ISCST3 input (.DTA) and output (.LST) files for 3-hour and 24-hour SO2 NAAQS analysis with fine receptor grid (50-m met data)
IPP_NAAQS_LOW_1_[PM10]	ISCST3 input (.DTA) and output (.LST) files for 24-hour and annual PM-10 NAAQS and increment analysis (10-m met data)
IPP_NAAQS_HIGH_1_[PM10]	ISCST3 input (.DTA) and output (.LST) files for 24-hour and annual PM-10 NAAQS and increment analysis (50-m met data)
IPP_PM_NAAQS-INC.XLS	Xcel spreadsheet used to sum low- and high-level PM-10 source impact for NAAQS and increment
HAPs Analysis	
	[Steamboat \D\AIR\NALL\IPP\HAP]
IPP_HAP_1_HAP	ISCST3 input (.DTA) and output (.LST) files for 1-hour and 24-hour HAP impacts

/ISCMet_BPIP	
	[Steamboat \D\AIR\NALL\IPP\METDATA]
IPP10m.met	Meteorological input file for ISCST3 (IPP 10-m data for 8/1/01 through 7/31/02)
IPP50m.met	Meteorological input file for ISCST3 (IPP 50-m data for 8/1/01 through 7/31/02)
IPP3.PIP	BPIP input file for IPP structures
/MetProcessing	
Upper-Air (Mixing Height) Processing	
7/19/01 through 3/19/02	[Somerset\D\PROJECTS\IPP\ONSITE\MIXHTS]
MIXHTS.INP	Mixing heights program input file
SLC2001.RAO	Raw RAOB data for SLC
SLC2002.RAO	Raw RAOB data for SLC
12345.DAT	Surface Observations
SLC2001.MH	Mixing heights for 7/19/01 - 12/31/01
SLC2002.MH	Mixing heights for 1/1/02 - 3/19/02
3/1/02 through 8/1/02	[Somerset\D\PROJECTS\IPP\ONSITE\MIXHTS\AUG02]
SLC24127.RAO	Raw RAOB data for SLC
NEWSAM.DAT	Surface Observations
24127.MIX	Mixing heights for 3/1/02 - 8/1/02
MPRM Files	
7/19/01 through 3/19/02	[Somerset\D\PROJECTS\IPP\ONSITE\MPRM]
50MPRM.XLS (.PRN)	Spreadsheet (ACSII file) of raw surface met data
IPPOS1.INP	Stage1 runstream for OS data
SLCMH.TXT	Mixing height input file
IPPUA1.INP	Stage1 runstream for UA data
IPP2.INP	Stage2 runstream merging OS and UA
IPP3-10m.INP	Stage3 runstream for ISC-ready file w/ 10m winds
IPP3-50m.INP	Stage3 runstream for ISC-ready file w/ 50m winds
3/1/02 through 8/1/02	[Somerset\D\PROJECTS\IPP\ONSITE\MPRM\AUG02]
MARJUL.NEW	ACSII file of raw surface met data

IPP3 Project	
ISCST3 and CALPUFF Input/Output Files	
ISCST3: Revised SO2 Impacts	
IPP_PRE_3H_SO2	Input (.DTA), output (.LST), and graphics (.GRF) files for 3-hour preliminary SO2
IPP_PRE_24H_SO2	Input (.DTA), output (.LST), and graphics (.GRF) files for 24-hour preliminary SO2
IPP_NAAQS_3H_SO2	Input (.DTA), output (.LST), and graphics (.GRF) files for 3-hour NAAQS for SO2
IPP_NAAQS_24H_SO2	Input (.DTA), output (.LST), and graphics (.GRF) files for 24-hour NAAQS for SO2
IPP_INC_3H_SO2	Input (.DTA), output (.LST), and graphics (.GRF) files for 3-hour PSD increment for SO2
IPP_INC_24H_SO2	Input (.DTA), output (.LST), and graphics (.GRF) files for 24-hour PSD increment for SO2
IPP_INC_24H_FINE_SO2	Input (.DTA), output (.LST), and graphics (.GRF) files for 24-hour PSD increment for SO2 (fine grid)
CALPUFF	
VIS_AdjBackGround.xls	Summary of visibility impacts adjusted for natural background
/CALPUFF_POSTUTIL	
24HRUnit3.INP	CALPUFF input (.DTA) and list (.LST) files for Unit 3 only (24-hr emission rates)
3HRUnit3.INP	CALPUFF input (.DTA) and list (.LST) files for Unit 3 only (3-hr emission rates)
AnUnit3.INP	CALPUFF input (.DTA) and list (.LST) files for Unit 3 only (annual emission rates)
3HRInc.INP	CALPUFF input (.DTA) and list (.LST) files for cumulative PSD increment (3-hr emission rates for IPP)
DEP	POSTUTIL input (.DTA) and list (.LST) files used to sum S and N deposition
/CALPOST_ARCHES	
ARCH3SO2	CALPOST input (.DTA) and list (.LST) files for Arches NP 3-hour SO2 (IPP Unit 3 only)
ARCH24SO2	CALPOST input (.DTA) and list (.LST) files for Arches NP 24-hour SO2 (IPP Unit 3 only)
ARCHvis	CALPOST input (.DTA) and list (.LST) files for Arches NP visibility (IPP Unit 3 only)
ARCH_SDEP	CALPOST list (.LST) file for Arches NP sulfur deposition (IPP Unit 3 only)
/CALPOST_BRYCE CANYON	
BRYC3SO2	CALPOST input (.DTA) and list (.LST) files for Bryce Canyon NP 3-hour SO2 (IPP Unit 3 only)
BRYC24SO2	CALPOST input (.DTA) and list (.LST) files for Bryce Canyon NP 24-hour SO2 (IPP Unit 3 only)
BRYCvis	CALPOST input (.DTA) and list (.LST) files for Bryce Canyon visibility (IPP Unit 3 only)
BRYC_SDEP	CALPOST list (.LST) file for Bryce Canyon NP sulfur deposition (IPP Unit 3 only)
BRYC3SO2_C	CALPOST input (.DTA) and list (.LST) files for 3-hour and 24-hour SO2 (cumulative PSD increment)
/CALPOST_CANYONLANDS	
CANY3SO2	CALPOST input (.DTA) and list (.LST) files for Canyonands NP 3-hour SO2 (IPP Unit 3 only)
CANY24SO2	CALPOST input (.DTA) and list (.LST) files for Canyonlands NP 24-hour SO2 (IPP Unit 3 only)
CANYvis	CALPOST input (.DTA) and list (.LST) files for Canyonlands NP visibility (IPP Unit 3 only)
CANY_SDEP	CALPOST list (.LST) file for Canyonlands NP for sulfur deposition (IPP Unit 3 only)
/CALPOST_CAPITOL REEF	
CR3SO2	CALPOST input (.DTA) and list (.LST) files for Capitol Reef NP 3-hour SO2 (IPP Unit 3 only)
CR24SO2	CALPOST input (.DTA) and list (.LST) files for Capitol Reef NP 24-hour SO2 (IPP Unit 3 only)
CRvis	CALPOST input (.DTA) and list (.LST) files for Capitol Reef NP visibility (IPP Unit 3 only)
CR_SDEP	CALPOST list (.LST) file for Capitol Reef NP sulfur deposition (IPP Unit 3 only)
CR3SO2_C	CALPOST input (.DTA) and list (.LST) files for 3-hour and 24-hour SO2 (cumulative PSD increment)

IPP3 Project	
ISCST3 and CALPUFF Input/Output Files	
/CALPOST_GREAT BASIN	
GRTB3SO2	CALPOST input (.DTA) and list (.LST) files for Great Basin NP 3-hour SO2 (IPP Unit 3 only)
GRTB24SO2	CALPOST input (.DTA) and list (.LST) files for Great Basin NP 24-hour SO2 (IPP Unit 3 only)
GRTBvis	CALPOST input (.DTA) and list (.LST) files for Great Basin NP visibility (IPP Unit 3 only)
GRTB_SDEP	CALPOST list (.LST) file for Great Basin NP sulfur deposition (IPP Unit 3 only)
GRTB3SO2_C	CALPOST input (.DTA) and list (.LST) files for 3-hour and 24-hour SO2 (cumulative PSD increment)
/CALPOST_GLEN CANYON	
GLEN3SO2	CALPOST input (.DTA) and list (.LST) files for Glen Canyon NRA 3-hour SO2 (IPP Unit 3 only)
GLEN24SO2	CALPOST input (.DTA) and list (.LST) files for Glen Canyon NRA 24-hour SO2 (IPP Unit 3 only)
GLENvis	CALPOST input (.DTA) and list (.LST) files for Glen Canyon NRA visibility (IPP Unit 3 only)
GLEN_SDEP	CALPOST list (.LST) file for Glen Canyon NP sulfur deposition (IPP Unit 3 only)
GLEN3SO2_C	CALPOST input (.DTA) and list (.LST) files for 3-hour and 24-hour SO2 (cumulative PSD increment)
/CALPOST_ZION	
ZION3SO2	CALPOST input (.DTA) and list (.LST) files for Zion NP 3-hour SO2 (IPP Unit 3 only)
ZION24SO2	CALPOST input (.DTA) and list (.LST) files for Zion NP 24-hour SO2 (IPP Unit 3 only)
ZIONvis	CALPOST input (.DTA) and list (.LST) files for Zion NP visibility (IPP Unit 3 only)
ZION_SDEP	CALPOST list (.LST) file for Zion NP sulfur deposition (IPP Unit 3 only)
ZION3SO2_C	CALPOST input (.DTA) and list (.LST) files for 3-hour and 24-hour SO2 (cumulative PSD increment)

Visual Effects Screening Analysis for
Source: IPP3
Class I Area: Cap Reef NP

*** User-selected Screening Scenario Results ***

Input Emissions for

Particulates	178.40	LB /HR
NOx (as NO2)	633.50	LB /HR
Primary NO2	.00	LB /HR
Soot	.00	LB /HR
Primary SO4	42.40	LB /HR

PARTICLE CHARACTERISTICS

	Density	Diameter
Primary Part.	2.5	6
Soot	2.0	1
Sulfate	1.5	4

Transport Scenario Specifications:

Background Ozone:	.04 ppm
Background Visual Range:	170.00 km
Source-Observer Distance:	149.00 km
Min. Source-Class I Distance:	149.00 km
Max. Source-Class I Distance:	149.00 km
Plume-Source-Observer Angle:	11.25 degrees
Stability:	3
Wind Speed:	6.00 m/s

R E S U L T S

Asterisks (*) indicate plume impacts that exceed screening criteria

Maximum Visual Impacts INSIDE Class I Area
Screening Criteria ARE NOT Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	84.	149.0	84.	12.01	.021	.24	.000
SKY	140.	84.	149.0	84.	6.06	.009	.24	-.000
TERRAIN	10.	84.	149.0	84.	10.82	.024	.24	.000
TERRAIN	140.	84.	149.0	84.	5.63	.004	.24	.000

Visual Effects Screening Analysis for
Source: IPP
Class I Area: Delta, UT

*** Level-1 Screening ***

Input Emissions for

Particulates	178.40	LB /HR
NOx (as NO2)	633.50	LB /HR
Primary NO2	.00	LB /HR
Soot	.00	LB /HR
Primary SO4	42.40	LB /HR

**** Default Particle Characteristics Assumed

Transport Scenario Specifications:

Background Ozone:	.04 ppm
Background Visual Range:	170.00 km
Source-Observer Distance:	20.90 km
Min. Source-Class I Distance:	20.90 km
Max. Source-Class I Distance:	20.90 km
Plume-Source-Observer Angle:	11.25 degrees
Stability:	6
Wind Speed:	1.00 m/s

R E S U L T S

Asterisks (*) indicate plume impacts that exceed screening criteria

Maximum Visual Impacts INSIDE Class I Area
Screening Criteria ARE Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	84.	20.9	84.	2.00	14.168*	.05	.284*
SKY	140.	84.	20.9	84.	2.00	11.987*	.05	-.234*
TERRAIN	10.	84.	20.9	84.	2.00	43.994*	.05	.387*
TERRAIN	140.	84.	20.9	84.	2.00	7.076*	.05	.090*

Maximum Visual Impacts OUTSIDE Class I Area
Screening Criteria ARE Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	1.	1.0	168.	2.00	37.675*	.05	.884*
SKY	140.	1.	1.0	168.	2.00	16.677*	.05	-.486*
TERRAIN	10.	1.	1.0	168.	2.00	53.891*	.05	.625*
TERRAIN	140.	1.	1.0	168.	2.00	24.624*	.05	.624*

APPENDIX F

RBLC Database Tables

TABLE F-1
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for CO
Coal Fired Boilers

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit		Permit Date and Permit No.
MO-0050	Kansas City Power & Light Co. Hawthorn Station Kansas City, Missouri	1	Coal Fired Boiler 384 TPH	Good Combustion Practices	not given	0.16	lb/MMBTU	8/17/1999 No. 888
WY-0039	Two Elk Generation Partners, LTD Wright, Wyoming	1	Pulverized Coal Fired Boiler 250 MW	No Controls Feasible	not given	0.15	lb/MMBTU	2/27/1998 No. CT-1352
WY-0047	ENCOAL Corporation North Rochelle Facility 15 miles SE Wright, Wyoming	1	Pulverized Coal Fired Boiler 3960 MMBTU/HR 240 MW	Combustion Technology	not given	0.15	lb/MMBTU	10/10/1997 No. CT-1324
WY-0048	Black Hills Power and Light Company Wygen Plant Gillette, Wyoming	1	Pulverized Coal Fired Boiler 80 MW	No Controls Feasible	not given	0.15	lb/MMBTU	9/6/1996 No. CT-1236
PA-0133	Mon Valley Energy LTD Poland Mines, Pennsylvania	1	Pulverized Coal Fired Boiler 966 MMBTU/hr 80 MW Cogen	No Controls Feasible	not given	Primary = .20 lb/MMBTU	Secondary = 847 TPY	8/8/1995 No. 30-306-001
NJ-0019	Crown/Vista Energy Project (CVEP) West Deptford, New Jersey	2	Pulverized Coal Fired Boilers 1789 MMBTU/hr each 181 MW each	Good Combustion Practice	not given	Primary = .11 lb/MMBTU	Secondary = 100 ppmvd @ 7%O_2	10/1/1993 No. 01-92-0857
VA-0213	SEI Birchwood King George, Virginia SIC Code: 4931	1	Pulverized Coal Fired Boiler 2200 MMBTU/hr	Combustion Technology	not given	Primary = 440 lb/hr	Secondary = 1927 TPY	8/23/1993 No.40809
WY-0046	Black Hills Power and Light Company Neil Simpson Plant Gillette, Wyoming	1	Pulverized Coal Fired Boiler Steam Electric Power 80 MW	Combustion Control	not given	Primary = .15 lb/MMBTU	Secondary = 152.0 lb/hr	4/14/1993 No. CT-1028
MI-0228	INDELK Energy Services of Otsego Michigan	1	Coal Fired Boiler 778 MMBTU/HR	Combustion Control	not given	0.10	lb/MMBTU	3/16/1993 No. 143-90
NC-0057	Roanoke Valley Project II Weldon Township, North Carolina	1	Pulverized Coal Fired Boiler 517 MMBTU/hr	Combustion Technology	not given	0.20	lb/MMBTU	11/20/1992 No. 6964R2
SC-0027	South Carolina Electric and Gas Company Cope, South Carolina	3	Pulverized Coal Fired Boiler Units 1, 2 and 3 385 MW each	Combustion Efficiency	not given	0.15	lb/MMBTU	7/15/1992 No. 1860-0044
FL-0044	Orlando Utilities Commission Stanton Energy Center, Unit 2 Orlando, Florida	1	Pulverized Coal Fired Boiler 4286 MMBTU/HR	Combustion Control	not given	0.15	lb/MMBTU	12/23/1991

TABLE F-1
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for CO
Coal Fired Boilers

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit		Permit Date and Permit No.
NJ-0015	Keystone Cogeneration Systems, Inc. New Jersey	1	Pulverized Coal Fired Boiler 2116 MMBTU/hr	Advanced Combustion Control	not given	0.11	lb/MMBTU	9/6/1991 No.01-89-3983
VA-0181	Old Dominion Electric Cooperative Clover, Virginia	1	Coal Fired Boiler 4085 MMBTU/hr (≈ 400 MW)	Boiler Design	not given	0.10	lb/MMBTU	4/29/1991 No. 30867
NC-0054	Roanoke Valley Project Weldon, North Carolina	1	Pulverized Coal Fired Boiler 1700 MMBTU/HR	Combustion Control	not given	0.20	lb/MMBTU	1/24/1991 No. 6964
NJ-0014	Chambers Cogeneration Limited Partnership Carneys Point, New Jersey	2	Pulverized Coal Fired Boiler 1389 MMBTU/hr each	Advanced Combustion Control	not given	0.11	lb/MMBTU	12/26/1990 No. 01-89-3086
SC-0028	Santee Cooper Public Service Authority Moncks Corner, South Carolina	1	Pulverized Coal Fired Boiler Cross Unit No. 1 5200 MMBTU/hr (500 MW)	Combustion Efficiency	not given	0.10	lb/MMBTU	11/28/1990 No. 0420-0030
VA-0171	Mecklenburg Cogeneration Limited Mecklenburg, Virginia	4	Pulverized Coal Fired Boiler 834.5 MMBTU/hr each	Good Combustion Practices	not given	Primary = .20 lb/MMBTU	Secondary = 166.9 lb/hr	5/9/1990 No. 30861

Notes:
NSR RACT/BACT/LAER Clearinghouse database (http://www.epa.gov/ttn/catc) was queried for the following:
- RBLC Determinations added during or after January 1990
- SIC Code: 4911
- Process Type Code: 11.002 - Coal Combustion
- BACT-PSD

TABLE F-2
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for VOC
Coal Fired Boilers

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit		Permit Date and Permit No.
MO-0050	Kansas City Power & Light Co. Hawthorn Station Kansas City, Missouri	1	Coal Fired Boiler 384 TPH	Good Combustion Practices	not given	0.0036	lb/MMBTU	8/17/1999 No. 888
WY-0039	Two Elk Generation Partners, LTD Wright, Wyoming	1	Pulverized Coal Fired Boiler 250 MW	No Controls Feasible	not given	0.015	lb/MMBTU	2/27/1998 No. CT-1352
WY-0047	ENCOAL Corporation North Rochelle Facility 15 miles SE Wright, Wyoming	1	Pulverized Coal Fired Boiler 3960 MMBTU/HR 240 MW	Combustion Technology	not given	0.05	lb/MMBTU	10/10/1997 No. CT-1324
WY-0048	Black Hills Power and Light Company Wygen Plant Gillette, Wyoming	1	Pulverized Coal Fired Boiler 80 MW	No Controls Feasible	not given	0.015	lb/MMBTU	9/6/1996 No. CT-1236
PA-0133	Mon Valley Energy LTD Poland Mines, Pennsylvania	1	Pulverized Coal Fired Boiler 966 MMBTU/hr 80 MW Cogen	No Controls Feasible	not given	Primary = 0.01 lb/MMBTU	Secondary = 42.3 TPY	8/8/1995 No. 30-306-001
NJ-0019	Crown/Vista Energy Project (CVEP) West Deptford, New Jersey	2	Pulverized Coal Fired Boilers 1789 MMBTU/hr each 181 MW each	Good Combustion Practice	not given	Primary = .0031 lb/MMBTU	Secondary = 4.5 ppmvd @ 7%O_2	10/1/1993 No. 01-92-0857 Methane
VA-0213	SEI Birchwood King George, Virginia SIC Code: 4931	1	Pulverized Coal Fired Boiler 2200 MMBTU/hr	Combustion Technology	not given	Primary = 22 lb/hr	Secondary = 96.4 TPY	8/23/1993 No.40809
WY-0046	Black Hills Power and Light Company Neil Simpson Plant Gillette, Wyoming	1	Pulverized Coal Fired Boiler 80 MW	Combustion Control	not given	Primary = 0.015 lb/MMBTU	Secondary = 15.0 lb/hr	4/14/1993 No. CT-1028
MI-0228	INDELK Energy Services of Otsego Michigan	1	Coal Fired Boiler 778 MMBTU/HR	Combustion Control	not given	0.01	lb/MMBTU	3/16/1993 No. 143-90
NC-0057	Roanoke Valley Project II Weldon Township, North Carolina	1	Pulverized Coal Fired Boiler 517 MMBTU/hr	Combustion Technology	not given	0.03	lb/MMBTU	11/20/1992 No. 6964R2
SC-0027	South Carolina Electric and Gas Company Cope, South Carolina	3	Pulverized Coal Fired Boiler Units 1, 2 and 3 385 MW each	Combustion Efficiency	not given	0.01	lb/MMBTU	7/15/1992 No. 1860-0044
FL-0044	Orlando Utilities Commission Stanton Energy Center, Unit 2 Orlando, Florida	1	Pulverized Coal Fired Boiler 4286 MMBTU/HR	Combustion Control	not given	0.015	lb/MMBTU	12/23/1991
NJ-0015	Keystone Cogeneration Systems, Inc. New Jersey	1	Coal Fired Boiler 2116 MMBTU/hr	Advanced Combustion Control	not given	0.0036	lb/MMBTU	9/6/1991 No.01-89-3983

TABLE F-2
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for VOC
Coal Fired Boilers

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit		Permit Date and Permit No.
VA-0181	Old Dominion Electric Cooperative Clover, Virginia	1	Coal Fired Boiler 4085 MMBTU/hr (≈ 400 MW)	Boiler Design	not given	0.01	lb/MMBTU	4/29/1991 No. 30867
NC-0054	Roanoke Valley Project Weldon, North Carolina	1	Pulverized Coal Fired Boiler 1700 MMBTU/HR	Combustion Control	not given	0.03	lb/MMBTU	1/24/1991 No. 6964
NJ-0014	Chambers Cogeneration Limited Partnership Carneys Point, New Jersey	2	Pulverized Coal Fired Boiler 1389 MMBTU/hr each	Advanced Combustion Control	not given	0.0036	lb/MMBTU	12/26/1990 No. 01-89-3086
SC-0028	Santee Cooper Public Service Authority Moncks Corner, South Carolina	1	Pulverized Coal Fired Boiler Cross Unit No. 1 5200 MMBTU/hr (500 MW)	Combustion Efficiency	not given	0.012	lb/MMBTU	11/28/1990 No. 0420-0030
VA-0171	Mecklenburg Cogeneration Limited Mecklenburg, Virginia	4	Pulverized Coal Fired Boiler 834.5 MMBTU/hr each	Good Combustion Practices	not given	Primary = 0.0027 lb/MMBTU	Secondary = 2.3 lb/hr	5/9/1990 No. 30861

Notes:
NSR RACT/BACT/LAER Clearinghouse database (http://www.epa.gov/ttn/catc) was queried for the following:
• RBLC Determinations added during or after January 1990
• SIC Code: 4911
• Process Type Code: 11.002 - Coal Combustion
• BACT-PSD

TABLE F-3
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for PM
Coal Fired Boilers

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit		Permit Date and Permit No.
WY-0039	Two Elk Generation Partners, LTD Wright, Wyoming	1	Pulverized Coal Fired Boiler 250 MW	Fabric Filter	99.50%	0.02	lb/MMBTU	2/27/1998 No. CT-1352
WY-0047	ENCOAL Corporation North Rochelle Facility 15 miles SE Wright, Wyoming	1	Pulverized Coal Fired Boiler 3960 MMBTU/HR 240 MW	Fabric Filter	99%	0.02	lb/MMBTU	10/10/1997 No. CT-1324
WY-0048	Black Hills Power and Light Company Wygen Plant Gillette, Wyoming	1	Pulverized Coal Fired Boiler 80 MW	Electrostatic Precipitator	99%	0.02	lb/MMBTU	9/6/1996 No. CT-1236
NJ-0019	Crown/Vista Energy Project (CVEP) West Deptford, NJ	2	Pulverized Coal Fired Boilers 1789 MMBTU/hr each 181 MW each	Fabric Filters	99.9%	Primary = 32.2 lb/hr	Secondary = 0.018 lb/MMBTU	10/1/1993 No. 01-92-0857
VA-0213	SEI Birchwood King George, VA SIC Code: 4931	1	Pulverized Coal Fired Boiler 2200 MMBTU/hr	Fabric Filter	99.9%	Primary = 44 lb/hr	Secondary = 192.7 TPY	8/23/1993 No.40809
WY-0046	Black Hills Power and Light Company Neil Simpson Plant Gillette, Wyoming	1	Pulverized Coal Fired Boiler 80 MW	Electrostatic Precipitator	99%	Primary = .02 lb/MMBTU	Secondary = 20.0 lb/hr	4/14/1993 No. CT-1028
MI-0228	INDELK Energy Services of Otsego Michigan	1	Coal Fired Boiler 778 MMBTU/HR	Fabric Filter	99.9%	0.03	lb/MMBTU	3/16/1993 No. 143-90
NC-0057	Roanoke Valley Project II Weldon Township, NC	1	Pulverized Coal Fired Boiler 517 MMBTU/hr	Fabric Filter	99.75%	0.02	lb/MMBTU	11/20/1992 No. 6964R2
SC-0027	South Carolina Electric and Gas Company Cope, South Carolina	3	Pulverized Coal Fired Boiler 385 MW each	Fabric Filters	99.5%	0.02	lb/MMBTU	7/15/1992 No. 1860-0044
FL-0044	Orlando Utilities Commission Stanton Energy Center, Unit 2 Orlando, Florida	1	Pulverized Coal Fired Boiler 4286 MMBTU/HR	Electrostatic Precipitator	not given	0.02	lb/MMBTU	12/23/1991
VA-0181	Old Dominion Electric Cooperative Clover, Virginia	1	Coal Fired Boiler 4085 MMBTU/hr (400 MW)	Fabric Filter	99.9%	0.02	lb/MMBTU	4/29/1991 No. 30867
NC-0054	Roanoke Valley Project Weldon, North Carolina	1	Pulverized Coal Fired Boiler 1700 MMBTU/HR	Fabric Filter	99%	0.02	lb/MMBTU	1/24/1991 No. 6964

TABLE F-3
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for PM
Coal Fired Boilers

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit		Permit Date and Permit No.
SC-0028	Santee Cooper Public Service Authority Moncks Corner, South Carolina	1	Pulverized Coal Fired Boiler Cross Unit No. 1 5200 MMBTU/hr (500 MW)	Electrostatic Precipitator	99.5%	0.03	lb/MMBTU[1]	11/28/1990 No. 0420-0030
VA-0171	Mecklenburg Cogeneration Limited, Mecklenburg, VA	4	Pulverized Coal Fired Boiler 834.5 MMBTU/hr each	Fabric Filters	99.9%	Primary = .02 lb/MMBTU	Secondary = 16.7 lb/hr	5/9/1990 No. 30861

Notes:
[1] - Listed in database as 0.25 lb/MMBTU, changed to 0.03 lb/MMBTU per phone conversation with Joe Eller and Larry Ragsdale, South Carolina Department of Health and Environmental Control on April 4, 2001.

NSR RACT/BACT/LAER Clearinghouse database (http://www.epa.gov/ttn/catc/) was queried for the following:
- RBLC Determinations added during or after January 1990
- SIC Code: 4911
- Process Type Code: 11.002 - Coal Combustion
- BACT-PSD

TABLE F-4
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for PM_{10}
Coal Fired Boilers

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit		Permit Date and Permit No.
MO-0050	Kansas City Power & Light Co. Hawthorn Station Kansas City, Missouri	1	Coal Fired Boiler 384 TPH	Fabric Filter	not given	0.018	lb/MMBTU	8/17/1999 No. 888
FL-0178	JEA Northside Generating Station Jacksonville, Florida	1	Coal Fired Boiler 2764 MMBTU/hr	Fabric Filter or Electrostatic Precipitator	not given	0.011	lb/MMBTU	7/14/1999 No.PSD-FL-265
UT-0053	Deseret Generation and Transmission Company Near Bonanza, Utah	1	Coal Fired Boiler 500 MW	Fabric Filter	99.8%	0.0286	lb/MMBTU[1]	3/16/1998 No. DAQE-186-98
PA-0133	Mon Valley Energy LTD Poland Mines, Pennsylvania	1	Pulverized Coal Fired Boiler (Unit 2) 966 MMBTU/hr (97 MW)	Fabric Filter	99.95%	Primary = 0.15 lb/MMBTU	Secondary = 63.5 TPY	8/8/1995 No. 30-306-001
NJ-0019	Crown/Vista Energy Project (CVEP) West Deptford, New Jersey	2	Pulverized Coal Fired Boilers 1789 MMBTU/hr each 181 MW each	Fabric Filters	99.9%	Primary = 32.2 lb/hr	Secondary = 0.018 lb/MMBTU	10/1/1993 No. 01-92-0857
VA-0213	SEI Birchwood King George, Virginia SIC Code: 4931	1	Pulverized Coal Fired Boiler 2200 MMBTU/hr	Fabric Filter	99.9%	Primary = 39.6 lb/hr	Secondary = 173.5 TPY	8/23/1993 No.40809
NC-0057	Roanoke Valley Project II Weldon Township, North Carolina	1	Pulverized Coal Fired Boiler 517 MMBTU/hr	Fabric Filter	99.75%	0.018	lb/MMBTU	11/20/1992 No. 6964R2
SC-0027	South Carolina Electric and Gas Company Cope, South Carolina	3	Pulverized Coal Fired Boiler 385 MW each	Fabric Filters	99.5%	0.018	lb/MMBTU	7/15/1992 No. 1860-0044
FL-0044	Orlando Utilities Commission Stanton Energy Center, Unit 2 Orlando, Florida	1	Pulverized Coal Fired Boiler 4286 MMBTU/HR	Electrostatic Precipitator	not given	0.02	lb/MMBTU	12/23/1991
NJ-0015	Keystone Cogeneration Systems, Inc. New Jersey	1	Coal Fired Utility Boiler 2116 MMBTU/hr	Fabric Filter	99.9%	0.018	lb/MMBTU	9/6/1991 No.01-89-3983
VA-0181	Old Dominion Electric Cooperative Clover, Virginia	1	Coal Fired Boiler 4085 MMBTU/hr (400 MW)	Fabric Filter	99.9%	0.018	lb/MMBTU	4/29/1991 No. 30867
NC-0054	Roanoke Valley Project Weldon, North Carolina	1	Pulverized Coal Fired Boiler 1700 MMBTU/HR	Fabric Filter	99%	0.018	lb/MMBTU	1/24/1991 No. 6964
NJ-0014	Chambers Cogeneration Limited Partnership Carneys Point, New Jersey	2	Pulverized Coal Fired Boiler 1389 MMBTU/hr each	Fabric Filters	99.9%	0.018	lb/MMBTU	12/26/1990 No. 01-89-3086

TABLE F-4
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for PM_{10}
Coal Fired Boilers

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit		Permit Date and Permit No.
SC-0028	Santee Cooper Public Service Authority Moncks Corner, South Carolina	1	Pulverized Coal Fired Boiler Cross Unit No. 1 5200 MMBTU/hr (500 MW)	Electrostatic Precipitator	99.5%	0.023	lb/MMBTU	11/28/1990 No. 0420-0030
VA-0171	Mecklenburg Cogeneration Limited Mecklenburg, Virginia	4	Pulverized Coal Fired Boiler 834.5 MMBTU/hr each	Fabric Filters	99.9%	Primary = 0.018 lb/MMBTU	Secondary = 15.0 lb/hr	5/9/1990 No. 30861

Notes:
[1] - Listed in database as 0.286 lb/MMBTU, changed to 0.0286 lb/MMBTU per conversation with Tim Blanchard, Utah Department of Environmental Quality on April 4, 2001.

NSR RACT/BACT/LAER Clearinghouse database (http://www.epa.gov/ttn/catc) was queried for the following:
- RBLC Determinations added during or after January 1990
- SIC Code: 4911
- Process Type Code: 11.002 - Coal Combustion
- BACT-PSD

TABLE F-5
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for PM
Cooling Towers

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit		Permit Date and Permit No.
NJ-0019	Crown/Vista Energy Project (CVEP) West Deptford, New Jersey	2	Pulverized Coal Fired Boilers 1789 MMBTU/hr each 181 MW each	Drift Eliminator	0.001% of Circulation Water	5.9	lb/hr	10/1/1993 No. 01-92-0857
FL-0050	Florida Power Corporation Crystal River, Florida	4	735,000 gallons/hour Salt Water	Drift Eliminator	0.004% of Circulation Water	0.0040%	of Circulation Water	8/30/1990 No. PSD-FL-139

Notes:
NSR RACT/BACT/LAER Clearinghouse database (http://www.epa.gov/ttn/catc/) was queried for the following:
• RBLC Determinations added during or after January 1990
• SIC Code: 4931
• Process Type Code: 99.009 - Cooling Tower
• BACT-PSD

TABLE F-6
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for Lead
Coal Fired Boilers

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit		Permit Date and Permit No.
NJ-0019	Crown/Vista Energy Project (CVEP) West Deptford, New Jersey	2	Pulverized Coal Fired Boilers 1789 MMBTU/hr each 181 MW each	Spray Dryer Absorber and Fabric Filter	93.0%	0.03	lb/hr	10/1/1993 No. 01-92-0857
VA-0213	SEI Birchwood, Inc. King George, Virginia	1	Pulverized Coal Fired Boiler 2,200 MMBTU/HR	Lime Spray Dryer Absorber and Fabric Filter	95.0%	Primary = 0.2 lb/hr	Secondary = 0.9 TPY	8/23/1993 No. 40809
VA-0181	Old Dominion Electric Cooperative Clover, Virginia	1	Coal Fired Boiler 4085 MMBTU/hr (400 MW)	FGD and Fabric Filter	99.9%*	Primary = 0.00042 lb/mmbtu	Secondary = 7.5 TPY	4/29/1991 No. 30867
SC-0028	Santee Cooper Public Service Authority Moncks Corner, South Carolina	1	Pulverized Coal Fired Boiler Cross Unit No. 1 5200 MMBTU/hr (500 MW)	Limestone FGD and Electrostatic Precipitator	75.0%	0.00033	lb/MMBTU	11/28/1990 No. 0420-0030

Notes:
* Control Efficiency for Fabric Filter

NSR RACT/BACT/LAER Clearinghouse database (http://www.epa.gov/ttn/catc/) was queried for the following:
• RBLC Determinations added during or after January 1990
• Pollutant name - Pb
• Process Name Contains Coal

TABLE F-7
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for Fluorides
Coal Fired Boilers

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit		Permit Date and Permit No.
NJ-0019	Crown/Vista Energy Project (CVEP) West Deptford, New Jersey	2	Pulverized Coal Fired Boilers 1789 MMBTU/hr each 181 MW each	Spray Dryer Absorber and Fabric Filter	93%	4.31	lb/hr	10/1/1993 No. 01-92-0857
VA-0213	SEI Birchwood, Inc. King George, Virginia	1	Pulverized Coal Fired Boiler 2,200 MMBTU/HR	Lime Spray Dryer Absorber and Fabric Filter	94%*	3.6	lb/hr	8/23/1993 No. 40809
SC-0027	South Carolina Electric and Gas Company Cope, South Carolina	3	Pulverized Coal Fired Boiler 385 MW each	Spray Dryer Absorber and Fabric Filter	93%*	0.01	lb/MMBTU	7/15/1992 No. 1860-0044
NC-0054	Roanoke Valley Project Weldon, North Carolina	1	Pulverized Coal Fired Boiler 1700 MMBTU/HR	Lime Spray Dryer Absorber and Fabric Filter	90%	0.000538	lb/MMBTU	1/24/1991 No. 6964
SC-0028	Santee Cooper Public Service Authority Moncks Corner, South Carolina	1	Pulverized Coal Fired Boiler Cross Unit No. 1 5200 MMBTU/hr (500 MW)	Limestone FGD and Electrostatic Precipitator	82%	0.01	lb/MMBTU	11/28/1990 No. 0420-0030
VA-0165	Hadson Power II Southampton, Virginia	2	Coal Fired Boiler 379 MMBTU/HR each	Spray Dryer Absorber and Fabric Filter	92%*	9.7	lb/day	1/1/1990 No. 61093

Notes:
* Control Efficiency for SO_2 FGD System

NSR RACT/BACT/LAER Clearinghouse database (http://www.epa.gov/ttn/catc/) was queried for the following:
• RBLC Determinations added during or after January 1990
• Pollutant name - Fluoride
• Process Name Contains Coal

TABLE F-8
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for SO_2
Coal Fired Boilers

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit		Permit Date and Permit No.
MO-0050	Kansas City Power & Light Co. Hawthorn Station Kansas City, Missouri	1	Coal Fired Boiler 384 TPH	Dry FGD and Low Sulfur Coal	not given	0.12	lb/MMBTU 30-day average	8/17/1999 No. 888
FL-0178	JEA Northside Generating Station Jacksonville, Florida	1	Coal Fired Boiler 2764 MMBTU/hr	Circulating Fluidized Bed Scrubber or Spray Dryer Absorber	not given	0.20	lb/MMBTU	7/14/1999 No.PSD-FL-265
PA-0162	Edison Mission Energy Homer City, Pennsylvania	1	Pulverized Coal Fired Boiler Unit 3 6600 MMBTU/hr	Wet Limestone FGD	92%	0.40	lb/MMBTU	5/25/1999 No. 32-0055C
UT-0053	Deseret Generation and Transmission Company Near Bonanza, Utah	1	Coal Fired Boiler 500 MW	Wet Limestone FGD	90%	0.0976	lb/MMBTU 12-month average	3/16/1998 No. DAQE-186-98
WY-0039	Two Elk Generation Partners, LTD Wright, Wyoming	1	Pulverized Coal Fired Boiler 250 MW	Lime Spray Dryer	91%	0.20	lb/MMBTU 2-hour fixed	2/27/1998 No. CT-1352
WY-0047	ENCOAL Corporation North Rochelle Facility 15 miles SE Wright, Wyoming	1	Pulverized Coal Fired Boiler 3960 MMBTU/HR 240 MW	Lime Spray Dryer	73%	0.20	lb/MMBTU 2-hour fixed	10/10/1997 No. CT-1324
WY-0048	Black Hills Power and Light Company Wygen Plant Gillette, Wyoming	1	Pulverized Coal Fired Boiler 80 MW	Circulating Dry Scrubber	80% **	0.20	lb/MMBTU 2-hour rolling	9/6/1996 No. CT-1236
PA-0133	Mon Valley Energy LTD Poland Mines, Pennsylvania	1	Pulverized Coal Fired Boiler 966 MMBTU/hr 80 MW Cogen	Spray Dryer Absorber	92%	0.25	lb/MMBTU	8/8/1995 No. 30-306-001
NJ-0019	Crown/Vista Energy Project (CVEP) West Deptford, New Jersey	2	Pulverized Coal Fired Boilers 1789 MMBTU/hr each 181 MW each	Spray Dryer Absorber	93%	0.18	lb/MMBTU	10/1/1993 No. 01-92-0857
VA-0213	SEI Birchwood King George, Virginia SIC Code: 4931	1	Pulverized Coal Fired Boiler 2200 MMBTU/hr	Lime Spray Dryer	94%	220	lb/hr	8/23/1993 No.40809
WY-0046	Black Hills Power and Light Company Neil Simpson Plant Gillette, Wyoming	1	Pulverized Coal Fired Boiler Steam Electric Power 80 MW	Circulating Dry Scrubber	80% **	0.20	lb/MMBTU 2-hour rolling	4/14/1993 No. CT-1028
MI-0228	INDELK Energy Services of Otsego Michigan	1	Coal Fired Boiler 778 MMBTU/HR	Dry Scrubber	90%	0.32	lb/MMBTU	3/16/1993 No. 143-90
NC-0057	Roanoke Valley Project II Weldon Township, North Carolina	1	Pulverized Coal Fired Boiler 517 MMBTU/hr	Dry Lime Scrubber	93%	0.187	lb/MMBTU	11/20/1992 No. 6964R2

TABLE F-8
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for SO_2
Coal Fired Boilers

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit		Permit Date and Permit No.
SC-0027	South Carolina Electric and Gas Company Cope, South Carolina	2	Pulverized Coal Fired Boiler Units 2 and 3 385 MW each	Spray Dryer Absorber	93%	0.17	lb/MMBTU	7/15/1992 No. 1860-0044
SC-0027	South Carolina Electric and Gas Company Cope, South Carolina	1	Pulverized Coal Fired Boiler Unit 1 385 MW each	Spray Dryer Absorber	93%	0.25	lb/MMBTU	7/15/1992 No. 1860-0044
FL-0044	Orlando Utilities Commission Stanton Energy Center, Unit 2 Orlando, Florida	1	Pulverized Coal Fired Boiler 4286 MMBTU/HR	Wet Lime FGD	92%	0.25	lb/MMBTU	12/23/1991
NJ-0015	Keystone Cogeneration Systems, Inc. New Jersey	1	Pulverized Coal Fired Boiler 2116 MMBTU/hr	Spray Dryer Absorber	93%	0.16	lb/MMBTU	9/6/1991 No.01-89-3983
VA-0181	Old Dominion Electric Cooperative Clover, Virginia	1	Coal Fired Boiler 4085 MMBTU/hr (≈ 400 MW)	FGD and 1.0-1.3% Bituminous Sulfur Coal	94%	0.10	lb/MMBTU	4/29/1991 No. 30867
NC-0054	Roanoke Valley Project Weldon, North Carolina	1	Pulverized Coal Fired Boiler 1700 MMBTU/HR	Dry Lime FGD	92%	0.213	lb/MMBTU	1/24/1991 No. 6964
NJ-0014	Chambers Cogeneration Limited Partnership Carneys Point, New Jersey	2	Pulverized Coal Fired Boiler 1389 MMBTU/hr each	Spray Dryer Absorber	93%	0.22	lb/MMBTU	12/26/1990 No. 01-89-3086
SC-0028	Santee Cooper Public Service Authority Moncks Corner, South Carolina	1	Pulverized Coal Fired Boiler Cross Unit No. 1 5200 MMBTU/hr (500 MW)	Promoted Limestone FGD	95%	0.34	lb/MMBTU	11/28/1990 No. 0420-0030
VA-0171	Mecklenburg Cogeneration Limited Mecklenburg, Virginia	4	Pulverized Coal Fired Boiler 834.5 MMBTU/hr each	Spray Dryer Absorber	92%	0.172	lb/MMBTU	5/9/1990 No. 30861

Notes:
NSR RACT/BACT/LAER Clearinghouse database (http://www.epa.gov/ttn/catc) was queried for the following:
• RBLC Determinations added during or after January 1990
• SIC Code: 4911
• Process Type Code: 11.002 - Coal Combustion
• BACT-PSD

** Control efficiency in RBLC is incorrect. Correct data suuplied by Fred Carl, Black Hills Corporation.

TABLE F-9
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for NO_x
Coal Fired Boilers

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit		Permit Date and Permit No.
MO-0050	Kansas City Power & Light Co. Hawthorn Station Kansas City, Missouri	1	Coal Fired Boiler 384 TPH	SCR and Good Combustion	not given	0.08	lb/MMBTU 30-day average	8/17/1999 No. 888
FL-0178	JEA Northside Generating Station Jacksonville, Florida	1	Coal Fired Boiler 2764 MMBTU/hr	SNCR	not given	0.09	lb/MMBTU 30-day rolling average	7/14/1999 No.PSD-FL-265
PA-0162	Edison Mission Energy Homer City, Pennsylvania	3	Pulverized Coal Fired Boiler Units 1 & 2 (5700 MMBTU/hr each) Unit 3 (6600 MMBTU/hr)	SCR	70%	0.15	lb/MMBTU	5/25/1999 No. 32-0055C
UT-0053	Deseret Generation and Transmission Company Near Bonanza, Utah	1	Coal Fired Boiler 500 MW	Boiler Design	99.6%	0.55	lb/MMBTU 30-day average	3/16/1998 No. DAQE-186-98
WY-0039	Two Elk Generation Partners, LTD Wright, Wyoming	1	Pulverized Coal Fired Boiler 250 MW	Low-NOx Burners, Overfire Air and SCR	75%	0.15	lb/MMBTU 30-day rolling average	2/27/1998 No. CT-1352
WY-0047	ENCOAL Corporation North Rochelle Facility 15 miles SE Wright, Wyoming	1	Pulverized Coal Fired Boiler 3960 MMBTU/HR 240 MW	Low NOx Burners with Flue Gas Recirculation	not given	0.16	lb/MMBTU	10/10/1997 No. CT-1324
WY-0048	Black Hills Power and Light Company Wygen Plant Gillette, Wyoming	1	Pulverized Coal Fired Boiler 80 MW	Low NOx Burners with Overfire Air	56%	0.22	lb/MMBTU	9/6/1996 No. CT-1236
PA-0133	Mon Valley Energy LTD Poland Mines, Pennsylvania	1	Pulverized Coal Fired Boiler 966 MMBTU/hr 80 MW Cogen	Low NOx Burners and SCR	50%	0.15	lb/MMBTU	8/8/1995 No. 30-306-001
NJ-0019	Crown/Vista Energy Project (CVEP) West Deptford, New Jersey	2	Pulverized Coal Fired Boilers 1789 MMBTU/hr each 181 MW each	Low NOx Burners and SCR	48%	0.17	lb/MMBTU	10/1/1993 No. 01-92-0857
VA-0213	SEI Birchwood King George, Virginia SIC Code: 4931	1	Pulverized Coal Fired Boiler 2200 MMBTU/hr	SCR	80%	330	lb/hr	8/23/1993 No.40809
WY-0046	Black Hills Power and Light Company Neil Simpson Plant Gillette, Wyoming	1	Pulverized Coal Fired Boiler Steam Electric Power 80 MW	Combustion Control	not given	0.23	lb/MMBTU 30-day rolling average	4/14/1993 No. CT-1028
MI-0228	INDELK Energy Services of Otsego Michigan	1	Coal Fired Boiler 778 MMBTU/HR	SNCR/Dry Control	50%	0.25	lb/MMBTU	3/16/1993 No. 143-90

TABLE F-9

NSR RACT/BACT/LAER Clearinghouse Database

BACT-PSD Sources for NO_x

Coal Fired Boilers

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit		Permit Date and Permit No.
NC-0057	Roanoke Valley Project II Weldon Township, North Carolina	1	Pulverized Coal Fired Boiler 517 MMBTU/hr	Low NOx Burners, Advanced Overfire Air and SNCR	not given	0.17	lb/MMBTU	11/20/1992 No. 6964R2
SC-0027	South Carolina Electric and Gas Company Cope, South Carolina	3	Pulverized Coal Fired Boiler Units 1, 2 and 3 385 MW each	Low NOx Burners with Overfire Air	not given	0.32	lb/MMBTU	7/15/1992 No. 1860-0044
FL-0044	Orlando Utilities Commission Stanton Energy Center, Unit 2 Orlando, Florida	1	Pulverized Coal Fired Boiler 4286 MMBTU/HR	Low NOx Burners and SCR	70%	0.17	lb/MMBTU	12/23/1991
NJ-0015	Keystone Cogeneration Systems, Inc. New Jersey	1	Pulverized Coal Fired Boiler 2116 MMBTU/hr	SNCR or SCR	37%	0.17	lb/MMBTU	9/6/1991 No.01-89-3983
VA-0181	Old Dominion Electric Cooperative Clover, Virginia	1	Coal Fired Boiler 4085 MMBTU/hr (≈ 400 MW)	Low NOx Burners and Advanced Overfire Air	50%	0.30	lb/MMBTU	4/29/1991 No. 30867
NC-0054	Roanoke Valley Project Weldon, North Carolina	1	Pulverized Coal Fired Boiler 1700 MMBTU/HR	Low NOx Burners and Advanced Overfire Air	not given	0.33	lb/MMBTU	1/24/1991 No. 6964
NJ-0014	Chambers Cogeneration Limited Partnership Carneys Point, New Jersey	2	Pulverized Coal Fired Boiler 1389 MMBTU/hr each	SCR	37%	0.17	lb/MMBTU	12/26/1990 No. 01-89-3086
SC-0028	Santee Cooper Public Service Authority Moncks Corner, South Carolina	1	Pulverized Coal Fired Boiler Cross Unit No. 1 5200 MMBTU/hr (500 MW)	Low NOx Burners	not given	0.39	lb/MMBTU	11/28/1990 No. 0420-0030
VA-0171	Mecklenburg Cogeneration Limited Mecklenburg, Virginia	4	Pulverized Coal Fired Boiler 834.5 MMBTU/hr each	Low NOx Burners and Advanced Overfire Air	45%	0.33	lb/MMBTU	5/9/1990 No. 30861

Notes:

NSR RACT/BACT/LAER Clearinghouse database (http://www.epa.gov/ttn/catc) was queried for the following:

- RBLC Determinations added during or after January 1990
- SIC Code: 4911
- Process Type Code: 11.002 - Coal Combustion
- BACT-PSD

TABLE F-10
NSR RACT/BACT/LAER Clearinghouse Database **Sheet added 05-08-03**
BACT-PSD Sources for H_2SO_4
Coal Fired Boilers

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit		Permit Date and Permit No.
TX-0275	Reliant Energy Parish Unit 8 Thompson, Texas	1	Coal Fired Boiler 6700 MMBtu/hr Retrofit 590 MW to 650 MW	FGD/Fabric Filter	Not Listed	0.0015	lb/MMBtu	12/21/2000 No. PSD-TX-234
MO-0050	Kansas City Power & Light Co. Hawthorn Station Kansas City, Missouri	1	Coal Fired Boiler 384 TPH	Dry FGD and Low Sulfur Coal		No Limit		8/17/1999 No. 888
FL-0178	JEA Northside Generating Station Jacksonville, Florida	1	Coal Fired Boiler 2764 MMBTU/hr	Circulating Fluidized Bed Scrubber or Spray Dryer Absorber		No Limit		7/14/1999 No.PSD-FL-265
PA-0162	Edison Mission Energy Homer City, Pennsylvania	1	Pulverized Coal Fired Boiler Unit 3 6600 MMBTU/hr	Wet Limestone FGD		No Limit		5/25/1999 No. 32-0055C
UT-0053	Deseret Generation and Transmission Company Near Bonanza, Utah	1	Coal Fired Boiler 500 MW	Wet Limestone FGD		No Limit		3/16/1998 No. DAQE-186-98
WY-0039	Two Elk Generation Partners, LTD Wright, Wyoming	1	Pulverized Coal Fired Boiler 250 MW	Lime Spray Dryer		No Limit		2/27/1998 No. CT-1352
WY-0047	ENCOAL Corporation North Rochelle Facility 15 miles SE Wright, Wyoming	1	Pulverized Coal Fired Boiler 3960 MMBTU/HR 240 MW	Lime Spray Dryer		No Limit		10/10/1997 No. CT-1324
WY-0048	Black Hills Power and Light Company Wygen Plant Unit 1 Gillette, Wyoming	1	Pulverized Coal Fired Boiler 80 MW	Circulating Dry Scrubber		No Limit		9/6/1996 No. CT-1236
PA-0133	Mon Valley Energy LTD Poland Mines, Pennsylvania	1	Pulverized Coal Fired Boiler 966 MMBTU/hr 80 MW Cogen	Spray Dryer Absorber		No Limit		8/8/1995 No. 30-306-001
NJ-0019	Crown/Vista Energy Project (CVEP) West Deptford, New Jersey	2	Pulverized Coal Fired Boilers 1789 MMBTU/hr each 181 MW each	Spray Dryer Absorber		No Limit		10/1/1993 No. 01-92-0857
VA-0213	SEI Birchwood King George, Virginia SIC Code: 4931	1	Pulverized Coal Fired Boiler 2200 MMBTU/hr	Lime Spray Dryer	Not Listed	4.8	lb/hr (6.4 tpy)	8/23/1993 No.40809
WY-0046	Black Hills Power and Light Company Neil Simpson Plant Gillette, Wyoming	1	Pulverized Coal Fired Boiler Steam Electric Power 80 MW	Circulating Dry Scrubber		No Limit		4/14/1993 No. CT-1028
MI-0228	INDELK Energy Services of Otsego Michigan	1	Coal Fired Boiler 778 MMBTU/HR	Dry Scrubber		No Limit		3/16/1993 No. 143-90
NC-0057	Roanoke Valley Project II Weldon Township, North Carolina	1	Pulverized Coal Fired Boiler 517 MMBTU/hr	Dry Lime Scrubber		No Limit		11/20/1992 No. 6964R2

TABLE F-10
NSR RACT/BACT/LAER Clearinghouse Database **Sheet added 05-08-03**
BACT-PSD Sources for H_2SO_4
Coal Fired Boilers

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit		Permit Date and Permit No.
SC-0027	South Carolina Electric and Gas Company Cope, South Carolina	2	Pulverized Coal Fired Boiler Units 2 and 3 385 MW each	Spray Dryer Absorber	Not Listed	0.011	lb/MMBTU	7/15/1992 No. 1860-0044
SC-0027	South Carolina Electric and Gas Company Cope, South Carolina	1	Pulverized Coal Fired Boiler Unit 1 385 MW each	Spray Dryer Absorber	Not Listed	0.011	lb/MMBTU	7/15/1992 No. 1860-0044
FL-0044	Orlando Utilities Commission Stanton Energy Center, Unit 2 Orlando, Florida	1	Pulverized Coal Fired Boiler 4286 MMBTU/HR	Wet Lime FGD		No Limit		12/23/1991
NJ-0015	Keystone Cogeneration Systems, Inc. New Jersey	1	Pulverized Coal Fired Boiler 2116 MMBTU/hr	Spray Dryer Absorber		No Limit		9/6/1991 No.01-89-3983
VA-0181	Old Dominion Electric Cooperative Clover, Virginia	1	Coal Fired Boiler 4085 MMBTU/hr (≈ 400 MW)	FGD and 1.0-1.3% Bituminous Sulfur Coal		No Limit		4/29/1991 No. 30867
NC-0054	Roanoke Valley Project Weldon, North Carolina	1	Pulverized Coal Fired Boiler 1700 MMBTU/HR	Dry Lime FGD		No Limit		1/24/1991 No. 6964
NJ-0038	Chambers Cogeneration Limited Partnership Carneys Point, New Jersey	2	Pulverized Coal Fired Boiler 1389 MMBTU/hr each	Spray Dryer Absorber	Not Listed	1.12	lb/hr (both units)	12/26/1990 No. 01-89-3086
SC-0028	Santee Cooper Public Service Authority Moncks Corner, South Carolina	1	Pulverized Coal Fired Boiler Cross Unit No. 1 5200 MMBTU/hr (500 MW)	Promoted Limestone FGD	50%	0.04	lb/MMBTU	11/28/1990 No. 0420-0030
VA-0171	Mecklenburg Cogeneration Limited Mecklenburg, Virginia	4	Pulverized Coal Fired Boiler 834.5 MMBTU/hr each	Spray Dryer Absorber		No Limit		5/9/1990 No. 30861
VA-0165	Hadson Power II Southampton, Virginia	2	Coal Fired Boiler 379 MMBTU/HR each	Spray Dryer Absorber and Fabric Filter	Not Listed	149.2	lb/day	1/1/1990 No. 61093

Notes:
NSR RACT/BACT/LAER Clearinghouse database (http://www.epa.gov/ttn/catc) was queried for the following:
• RBLC Determinations added during or after January 1990
• SIC Code: 4911
• Process Type Code: 11.110 - Coal Combustion
• BACT-PSD

APPENDIX G

BACT Cost Analysis

IPP Unit No. 3
Selective Catalytic Reduction
Cost Estimate

Capital Cost Factors

DIRECT COSTS	**Cost Factors**					
(1) Purchased Equipment						
(a) Basic Equipment and auxiliaries						
Capital Cost of SCR System				=	$	34,125,000
Capital Cost of Spare Catalyst	(Spare Catalyst not included)					
Total Capital Cost				=	$	34,125,000
(b) Instruments and controls [0.1 * (a)]	(Included in Purchased Equipment Costs)					
(c) Taxes [0.03(a)]	0.03	*	(a)	=	$	1,023,750
Total Equipment Cost (TEC)				=	$	35,148,750
(2) Construction Costs						
(a) Foundations and supports	(Included in Total Construction Costs)					
(b) Handling and Erection	(Included in Total Construction Costs)					
(c) Electrical	(Included in Total Construction Costs)					
(d) Piping	(Included in Total Construction Costs)					
(e) Insulation	(Included in Total Construction Costs)					
(f) Painting	(Included in Total Construction Costs)					
Total Construction Costs (TCC)				=	$	34,295,625
Total Direct Costs (TDC)	(TEC)	+	(TCC)	=	$	69,444,375
INDIRECT COSTS						
(3) Engineering and supervision	(Included in Total Indirect Costs)					
(4) Construction and field expenses	(Included in Total Indirect Costs)					
(5) Construction fee	(Included in Total Indirect Costs)					
(6) Start-up	(Included in Total Indirect Costs)					
(7) Performance test	(Included in Total Indirect Costs)					
TOTAL INDIRECT COSTS (TIC)				=	$	25,999,838
TOTAL DIRECT AND INDIRECT COSTS (TDIC)	(TDC)	+	(TIC)	=	$	95,444,213
(8) Contingency	(Included in Total Indirect Costs)					
(9) Site Preparation					$	200,000
TOTAL INSTALLED CAPITAL COSTS (TICC)				=	$	95,644,213

IPP Unit No. 3
Selective Catalytic Reduction
Cost Estimate (continued)

Annualized Cost Factors

DIRECT COSTS		**Cost Factors**				
Fixed O&M Costs						
(1) Operating Labor:	(Included in Total Fixed O&M Costs)					
(2) Supervisory Labor	(Included in Total Fixed O&M Costs)					
(3) Maintenance Labor:	(Included in Total Fixed O&M Costs)					
(4) Parts and Materials	(Included in Total Fixed O&M Costs)					
Total Fixed O&M Costs				=	$	281,000
Variable O&M Costs						
(5) Ammonia	(Included in Total Variable O&M Costs)					
(6) Utilities	(Included in Total Variable O&M Costs)					
(7) Replacement Catalyst	(Included in Total Variable O&M Costs)					
Total Variable O&M Costs					$	3,828,120
TOTAL DIRECT COSTS (TDAC)				=	$	4,109,120
INDIRECT COSTS						
(8) Overhead	60%	of	Fixed O&M Costs	=	$	168,600
(9) Property Tax	1%	of	(TICC)	=	$	956,442
(10) Insurance	1%	of	(TICC)	=	$	956,442
(11) G&A Charges	2%	of	(TICC)	=	$	1,912,884
(12) Capital Recovery	0.110	*	(TICC - Catalyst Cost)	=	$	10,080,913
TOTAL INDIRECT COSTS (TIAC)				=	$	14,075,282
TOTAL ANNUALIZED COSTS		TDAC + TIAC		=	$	18,184,402
TOTAL TONS REMOVED PER YEAR (NO_x)				=		11,099
COST EFFECTIVENESS ($ per ton of pollutant removed)				=	$	1,638

Notes:

1) Cost factors from OAQPS Control Cost Manual, Chapter 3

2) Capital Recovery Factor for System - Based on a 15-year equipment life and 7% interest rate, base cost excludes cost of catalyst because equipment life will be less than 15 years. Catalyst replacement included as an operating and maintenance cost.

3) Sargent & Lundy provided SCR purchased equipment cost, direct installation cost, indirect installation cost and annual fixed and variable O&M costs.

4) Cost effectiveness, $ per ton of NOx removed, based on SCR only. Does not include removal by Low NOx burners.

IPP Unit No. 3
SCR NO_x Removal Calculation

Gross Unit Output (MW gross)	950	MW	Provided by IPP
Net Unit Output (MW net)	880	MW	Provided by Sargent & Lundy
Average Coal Heating Value =	11,193	Btu/lb	Provided by Sargent & Lundy
Unit Capacity Factor =	100	%	Provided by Sargent & Lundy
Annual Heat Input (at 100% CF) =	79,278,000	MMBtu/year	9,050 MMBtu/hr x 8760 hours
Annual Coal Use (at 100% CF) =	3,541,410	tons/year	Calculated
SCR Design Collection Efficiency =	80	%	Provided by Sargent & Lundy
NO_x Emission rate after Low Nox Burners =	0.35	lb/MMBtu	Provided by Sargent & Lundy
NO_x Emission rate after SCR (stack) =	0.07	lb/MMBtu	Provided by Sargent & Lundy
NO_x annual tons before SCR =	13,874	tons/year	Calculated
NO_x annual tons after SCR =	2,775	tons/year	Calculated
NO_x annual tons removed by SCR =	11,099	tons/year	Calculated

IPP Unit No. 3
Wet Limestone Flue Gas Desulfurization System
Cost Estimate

Capital Cost Factors

DIRECT COSTS	**Cost Factors**					
(1) Purchased Equipment						
(a) Basic Equipment and auxiliaries						
Capital Cost of Wet Scrubber System				=	$	69,871,000
Total Capital Cost				=	$	69,871,000
(b) Instruments and controls [0.1 * (a)]	(Included in Purchased Equipment Costs)					
(c) Taxes [0.03(a)]	0.03	*	(a)	=	$	2,096,130
(d) Freight [0.05(a)]	(Included in Purchased Equipment Costs)					
Total Equipment Cost (TEC)				=	$	71,967,130
(2) Construction Costs						
(a) Foundations and supports	(Included in Total Construction Costs)					
(b) Handling and Erection	(Included in Total Construction Costs)					
(c) Electrical	(Included in Total Construction Costs)					
(d) Piping	(Included in Total Construction Costs)					
(e) Insulation	(Included in Total Construction Costs)					
(f) Painting	(Included in Total Construction Costs)					
Total Construction Costs (TCC)				=	$	89,420,000
Total Direct Costs (TDC)	(TEC)	+	(TCC)	=	$	161,387,130
INDIRECT COSTS						
(3) Engineering and supervision	(Included in Total Indirect Costs)					
(4) Construction and field expenses	(Included in Total Indirect Costs)					
(5) Construction fee	(Included in Total Indirect Costs)					
(6) Start-up	(Included in Total Indirect Costs)					
(7) Performance test	(Included in Total Indirect Costs)					
TOTAL INDIRECT COSTS (TIC)				=	$	60,530,580
TOTAL DIRECT AND INDIRECT COSTS (TDIC)	(TDC)	+	(TIC)	=	$	221,917,710
(8) Contingency	(Included in Total Indirect Costs)					
(9) Site Preparation				=	$	350,000
TOTAL INSTALLED CAPITAL COSTS (TICC)				=	$	222,267,710

IPP Unit No. 3
Wet Limestone Flue Gas Desulfurization System
Cost Estimate (continued)

Annualized Cost Factors

DIRECT COSTS		**Cost Factors**				
Fixed O&M Costs						
(1) Operating Labor:		(Included in Total Fixed O&M Costs)				
(2) Supervisory Labor		(Included in Total Fixed O&M Costs)				
(3) Maintenance Labor:		(Included in Total Fixed O&M Costs)				
(4) Parts and Materials		(Included in Total Fixed O&M Costs)				
Total Fixed O&M Costs				=	$	469,000
Variable O&M Costs						
(5) Lime		(Included in Total Variable O&M Costs)				
(6) Utilities		(Included in Total Variable O&M Costs)				
Total Variable O&M Costs				=	$	5,326,080
TOTAL DIRECT COSTS (TDAC)				=	$	5,795,080
INDIRECT COSTS						
(7) Overhead	60%	of	Fixed O&M Costs	=	$	281,400
(8) Property Tax	1%	of	(TICC)	=	$	2,222,677
(9) Insurance	1%	of	(TICC)	=	$	2,222,677
(10) G&A Charges	2%	of	(TICC)	=	$	4,445,354
(11) Capital Recovery	0.110	*	(TICC)	=	$	24,403,800
TOTAL INDIRECT COSTS (TIAC)				=	$	33,575,908
TOTAL ANNUALIZED COSTS		TDAC + TIAC		=	$	39,370,988
TOTAL TONS REMOVED PER YEAR (SO2)				=		49,152
COST EFFECTIVENESS ($ per ton of pollutant removed)				=	$	801

Notes:

1) Cost factors - from OAQPS Control Cost Manual, Chapter 3

2) Capital Recovery Factor for System - Based on a 15-year equipment life and 7% interest rate

3) No costs are included for the handling and disposal of the sludge produced by the wet limestone scrubber. However, even with the addition of this cost, the use of wet limestone scrubbing is likely to remain cost effective on a cost per ton removed basis. Therefore, the inclusion of this cost is not likely to change the outcome of this BACT analysis.

4) Sargent & Lundy provided FGD purchased equipment cost, direct installation cost, indirect installation cost and annual fixed and variable O&M costs.

IPP Unit No. 3
Wet Limestone FGD SO_2 Removal Calculation

Gross Unit Output (MW gross)	950	MW	Provided by IPP
Net Unit Output (MW net)	880	MW	Provided by Sargent & Lundy
Average Coal Heating Value =	11,193	Btu/lb	Provided by IPP
Unit Capacity Factor =	100%		Provided by IPP
Annual Heat Input (at 100% CF) =	79,278,000	MMBtu/year	9,050 MMBtu/hr x 8760 hours
Annual Coal Use (at 100% CF) =	3,541,410	tons/year	Calculated
Design Coal Sulfur Content =	0.75	%	Provided by IPP
Wet Limestone FGD Design Collection Efficiency =	92.5	%	Provided by Sargent & Lundy
SO_2 emission rate before FGD =	1.34	lb/MMBtu	Provided by Sargent & Lundy
SO_2 annual tons before FGD =	53,116	tons/year	Calculated
SO_2 emission rate after FGD =	0.10	lb/MMBtu	Provided by Sargent & Lundy
SO_2 annual tons after FGD =	3,964	tons/year	Calculated
SO_2 annual tons removed by FGD =	49,152	tons/year	Calculated

APPENDIX H

BACT Supporting Information

IPP has reviewed all potential control technologies for the Unit 3 project. A review of each technology by applicable BACT pollutant is below.

Potential NOx Control Technologies:

Technology	**Brief Description**	**Applicability to Coal-Fired Boiler**
Low NOx Burners	Burner design – designed to combust fuel in a sub-stoichiometric mode (i.e., air: fuel ratio <1.0). Designed to minimize the NOx generation rate.	Low NOx burners and Low NOx burners with overfire air were evaluated in Section 6 of the IPP Unit 3 permit application. Applicable to most boiler designs. Adverse effects can include an increase in the CO and VOC emission rates, increase in fly ash LOI, increased furnace corrosion and slagging, and loss of steam production and temperature. Low NOx burners will be installed on IPP Unit 3.
Ultra Low NOx Burners	Ultra low NOx could be classified as the next generation of low NOx burners to further reduce NOx levels.	This technology is still in the developmental phase and would not be considered applicable to power plant boilers at this time. This technology has been partially successful in laboratory testing. Adverse effects identified for low NOx burners would be greatly intensified.
Staged Reburn	Staged reburn, on coal-fired boilers, consists of injection of a portion of the total fuel (typically as natural gas, but also possible with coal or oil) into the furnace after the primary burner. The primary burner continues to operate at the design stoichiometry while the reburn fuel is conveyed into the furnace with cooled flue gas. This creates a reducing zone in the reburn zone of the furnace that reduces the NOx formed in the primary combustion back to nitrogen. Overfire air is then used to complete combustion in the upper furnace.	Applicable to coal-fired power plants but only marginally more effective at reducing NOx than low NOx burners. The marginal improvement in NOx reduction is more than offset by the higher capital cost and the higher differential fuel costs.

Technology	Brief Description	Applicability to Coal-Fired Boiler
Enviroscrub	The Enviroscrub process uses a proprietary reagent (Pahlmanite) in a scrubbing process that results in the oxidation of both SO2 and NOx into sulfate and nitrate compounds. The process claims to be able to recover the nitrates and sulfates in a form suitable for fertilizer or chemical processing use.	An Enviroscrub unit has been tested in a 1000 SCFM (1/2 MW equivalent) test at Ameren's Hutsonville Power Station and in a 2000 SCFM (1 MW equivalent) slipstream at Minnesota Power's Boswell Unit 1 plant. To date, sorbent regeneration has only been performed at an off-site facility by the developer and has never been proven in the field during a test. The process has not been demonstrated on a larger scale basis, and is not commercially viable nor available for power plant application.
Oxidation/ Reduction (O/R)	These reaction mechanisms are part of all the evaluated technologies and therefore are not a "stand alone" technology for evaluation.	Not applicable
Low Temperature Selective Catalytic Reduction (SCR)	Standard SCR system but with a noble metal catalyst designed to achieve high NOx removals at flue gas temperatures in the 200-400 F range. Could be employed after an air heater.	Not yet demonstrated beyond bench scale in the laboratory with simulated flue gas. Currently not commercially available for a large pulverized coal-fired unit.
Standard SCR (Medium Temperature SCR)	Catalyst bed installed between economizer and combustion air preheater in a conventional power plant. The temperature range of the flue gas at this point is between 650-750F. Ammonia is injected into the flue gas stream and catalytically reduces the NOx to nitrogen and water.	SCR was evaluated in Section 6 of the IPP Unit 3 permit application. SCR was selected as BACT for IPP Unit 3. Commercially viable and demonstrated at full scale on most boiler designs and most coal types. Currently the standard in the industry for high levels of NOx reduction to levels less than 0.1 lb/MMBtu. Medium temperature SCR will be installed in IPP Unit 3.
High Temperature SCR	Catalyst bed is installed in a high temperature regime of the flue gas (1000-1200F). Similar to a standard SCR in that ammonia is used in the catalytic reduction of NOx to N2 and H2O.	To date, this technology has not been applied to coal-fired boilers. The catalyst is sensitive to high levels of dust in the treated gas and therefore not currently applicable to coal-fired power plants. All applications in the utility industry, to date, have been at the exit of gas-fired combustion turbines.

Technology	Brief Description	Applicability to Coal-Fired Boiler
Catalytic Scrubbing (Airborne Process)	This technology uses sodium bicarbonate / carbonate to remove SOx and NOx. This removal takes place through a combination of duct injection of sodium carbonate / bicarbonate to oxidize the NO to NO2 and perform the first stage of scrubbing of SO2. This is followed by a wet scrubber where the injected salts and reaction products are collected and used in the second stage of scrubbing SO2 and NO2. The scrubber is followed by an ammonia based carbonate regeneration process that converts the sodium sulfates and nitrates, formed in the removal of the SO2 and NOx, back into sodium carbonate, while producing fertilizer coproducts (ammonium sulfate and nitrate).	To date results have been laboratory only, with no application at a utility system. A slipstream pilot of this technology is under construction with start-up in mid 2003.
Powerspan (Electro-Catalytic Oxidation)	Powerspan is an electro-catalytic oxidation process. It oxidizes NOx, SO2 (to some extent), and mercury. It is coupled with an ammonia scrubber to remove the oxidized materials from the gas stream and produce saleable byproducts. The four main pieces of equipment comprising the ECO technology are: Stage 1: ECO Reactor — oxidizes pollutants Stage 2: Absorber Vessel — collects SO2 and NO2 Stage 3: Wet ESP — collects acid aerosols and fine particles Stage 4: Byproduct Recovery System — produces commercial-grade fertilizer	Not applicable for full-scale power plant installation. At present a pilot test facility processes 1,500–3,000 scfm of coal-combustion flue gas, taken as a slipstream from one of the R.E. Burger Plant's 156-megawatt (MW) vertically-fired coal-fired units.

Technology	Brief Description	Applicability to Coal-Fired Boiler
Ozone Injection	The LoTOx System uses oxygen to produce ozone as the primary reagent. An ozone generator is used to produce the ozone. The ozone is injected into the flue gas stream where it reacts with relatively insoluble NO and NO2 to form N2O3 and N2O5, which are highly water soluble, and are easily and efficiently removed and neutralized in a wet scrubbing system.	Only demonstrated on 25 MW stoker boiler to date. Not proven in utility service.
Selective Non-Catalytic Reduction (SNCR)	This technology thermally reduces NOx into nitrogen and water, without catalyst, by injection of urea or ammonia into the appropriate temperature zone in the furnace (typically between 1800-2100 deg. F). The reduction efficiency and reagent utilization of this process depends upon the injection of the ammonia into the proper temperature zone in the furnace.	SNCR was evaluated in Section 6 of the IPP Unit 3 permit application. Has been applied to many coal-fired boilers. However, NOx reduction efficiency is reliably limited to a range of 25-35%. Because the rapid mixing of reagent in the gas is required within a relatively small temperature range, the size of the furnace is critical to the success of this technology. To date, long term successful operation has been principally limited to less than, or equal to 300 MW size furnaces.
Non-Selective Catalytic Reduction (NSCR) (NOxTech)	A controlled amount of hydrocarbon (a liquid or gaseous fuel) is introduced into the flue gas where, at elevated temperatures (1400-1700F) it auto ignites forming a plasma of free radicals. Ammonia is introduced into this environment where the free radicals auto catalyze its reaction with NOx, to produce nitrogen and water. The hydrocarbon and ammonia are added through banks of nozzles in the superheat or reheat sections of the boiler. The injection location is determined by the location of the temperature windows for the "plasma creation zone" as well as the reaction zone for the ammonia.	Not yet commercially available for coal-fired power plants. A short demonstration test was completed at TVA Kingston Unit #9. Application to power plants will depend upon boiler configuration. The hydrocarbon distribution grid may present a problem with large boilers. Booster fan motor requirements may be about 1/2% of gross generation. Reporting on test work to date has been silent on ammonia consumption.

Technology	Brief Description	Applicability to Coal-Fired Boiler
Flue Gas Recirculation	Flue gas is recirculated from the furnace exit back to the burners. This reduces the air / fuel ratio at the burners and produces a lower level of NOx emissions.	Applicable to most new boilers, however, NOx emission rates have not been reported as achievable lower than 0.32 lb / MMBtu. Due to severe operational problems with coal-fired plants, this technology has typically been applied to gas and oil units only.
SCONOx	The SCONOx emission control system utilizes a single catalyst for the reduction of CO and NOx. The SCONOx catalyst works by simultaneously oxidizing CO to CO2 and NO to NO2. The NO2 is then absorbed on the surface of the catalyst through the use of a potassium carbonate coating to form potassium nitrites and nitrates. The regeneration cycle of the SCONOx catalyst is accomplished by passing a controlled mixture of regeneration gases across the surface of the catalyst in the absence of oxygen. The regeneration gases react with nitrites and nitrates to form water vapor and elemental nitrogen which are emitted with the regeneration exhaust.	Not applicable for coal-fired power plants. The SCONOx system has been demonstrated on a couple of smaller natural gas fired combined cycle combustion units. The SCONOx system is located within the HRSG at a temperature suitable for conventional SCR catalysts. The systems are designed with a series of isolatable compartments with one compartment in the regeneration mode at any time. The unit uses dampers for compartment isolation during regeneration. The SCONOx catalyst is highly sensitive to sulfur compounds and therefore is not applicable in its present form to coal-fired plants.
Proper Design & Good Combustion Practices (Combustion Controls)		Combustion Controls was evaluated in Section 6 of the IPP Unit 3 permit application. Applicable to new boilers. Choice of a qualified boiler supplier, with state-of-the-art combustion technology (LNB's, OFA, etc.) will ensure that this is accomplished. Proper design and good combustion controls will be used on IPP Unit 3.

Potential SO2 Control Technologies:

Technology	Brief Description	Applicability to Coal-Fired Boiler
Enviroscrub	The Enviroscrub process uses a proprietary reagent (Pahlmanite) in a scrubbing process that results in the oxidation of both SO2 and NOx into sulfate and nitrate compounds. The process claims to be able to recover the nitrates and sulfates in a form suitable for fertilizer or chemical processing use.	An Enviroscrub unit has been tested in a 1000 SCFM (1/2 MW equivalent) test at Ameren's Hutsonville Power Station and in a 2000 SCFM (1 MW equivalent) slipstream at Minnesota Power's Boswell Unit 1 plant. To date, sorbent regeneration has only been performed at an off-site facility by the developer and has never been proven in the field during a test. The process has not been demonstrated on a larger scale basis, and is not commercially viable nor available for power plant application.
Wet Scrubber	In the wet scrubbing process, the flue gas is contacted with an alkaline solution or slurry (typically lime or limestone). The temperature of the flue gas is reduced to its adiabatic saturation temperature and the sulfur dioxide is removed from the flue gas by reaction with the alkaline medium.	Wet Limestone and Lime FGD were evaluated in Section 6 of the IPP Unit 3 permit application. Applicable to all boiler types and coals. Wet Limestone FGD was selected as BACT for IPP Unit 3 and will be installed on IPP Unit 3.
Slaked Lime Slurry Injection	The dry scrubbing process is similar to a wet scrubber, in that the hot flue gas is contacted with an alkaline solution or slurry (typically lime). In the dry scrubbing process a sufficient amount of slurry is injected to only lower the temperature of the flue gas to 30-40 deg. F above the adiabatic saturation temperature. Evaporation of the water produces a dry waste product containing flyash, reacted and unreacted alkaline materials. Particulate collection is usually done with a fabric filter, although an electrostatic precipitator could also be used.	Lime Spray Dryer was evaluated in Section 6 IPP Unit 3 permit application. Applicable to all boiler types and coals with a sulfur content typically less than 2 lb/MMBtu. Water consumption is lower than a wet scrubber.

Technology	Brief Description	Applicability to Coal-Fired Boiler
Dry Slaked Lime Injection	Hydrated lime is injected, with some humidification, into the hot flue gas upstream of the particulate collection device. The lime reacts with some of the sulfur dioxide to remove it from the gas stream. Particulate collection is usually done with a fabric filter although an electrostatic precipitator could be used.	Applicable to all boiler types and coals, although only capable of achieving 20-40% reduction in SO2.
Low Sulfur Materials (i.e., fuel)	Switch to lower sulfur coals will reduce overall sulfur emissions	A new boiler can be designed to use low sulfur coal as its primary fuel. For existing boilers, not designed for low sulfur fuels, the change to low sulfur fuels can result in a number of adverse impacts including reduced steam production and increased slagging depending upon the characteristics of the low sulfur fuel. IPP Unit 3 is planning on burning low-sulfur bituminous coals that are among the lowest sulfur coals available.
SCOSOx™	The SCOSOx™ sulfur removal catalyst works as a guard bed to protect the SCONOx catalyst from the masking effect that sulfur compounds have on the SCONOx catalyst. The SCOSOx catalyst is placed upstream of the SCONOx catalyst and selectively removes sulfur compounds from the exhaust stream. The SCOSOx catalyst utilizes the same oxidation / absorption cycle and a regeneration cycle as the SCONOx system.	The SCOSOx catalyst is only capable of addressing a fairly small concentration of sulfur compounds in the flue gas. This concentration is well below the lowest level from coal combustion making this technology not applicable to coal-fired plant application.
DeSOx	This is a generic term for all SO2 removal processes and does not refer to a specific process.	Not Applicable

Potential PM/PM_{10} Control Technologies:

Technology	**Brief Description**	**Applicability to Coal-Fired Boiler**
HEPA Filter	High efficiency particulate filtration system	Not intended for use, nor applicable to, filtering heated flue gas from coal-fired power plants. HEPA filters have a very high pressure drop and are commonly employed in filtering essentially room temperature air from pharmaceutical, nuclear, and clean room applications
Baghouse (fabric filters)	Flue gas, containing fly ash, is filtered by cloth bags to separate out the flyash from the gas.	Fabric Filters were evaluated in IPP Unit 3 permit application. A fabric filter was selected as BACT for IPP Unit 3. Applicable to coal fired boilers. A fabric filter will be installed on IPP Unit 3.
Ceramic Filters	Gas containing particulates is filtered out by passing through rigid porous ceramic tubes.	This technology has not been applied to coal-fired boilers to date. This technology is being developed for very hot gas de-dusting applications that are not typical in a conventional coal-fired boiler. Ceramic filters have been tested on coal gasification demonstration projects to de-dust the syngas prior to combustion in the gas turbine.
Electrostatic Precipitator (ESP)	Electrical field imparts a charge to the fly ash. Charged fly ash is collected on grounded plates and removed from the gas stream.	ESP was evaluated in Section 6 of IPP Unit 3 permit application. Applicable to coal fired boilers.
Wet ESP	Electrical field imparts a charge to the fly ash and any aerosols in the flue gas. Charged particles are collected on grounded plates and removed from the gas stream. Typically the particles are removed from the plates by sluicing with water.	Wet ESP systems are not intended or applied as the primary particulate collection device at a power plant.
Wet Particulate Scrubber	Wet scrubbers remove particles from gas by capturing the particles in liquid (usually water) droplets and separating the droplets from the gas stream. The droplets act as conveyors of the particulate out of the gas stream.	Wet particulate scrubbers have been used on older generation coal-fired boilers, however, collection efficiencies (especially of PM_{10}) do not compare with newer fabric filter and ESP designs.
Technology	**Brief Description**	**Applicability to Coal-Fired Boiler**

Mechanical Collector (i.e., cyclone)	Separates flyash from the flue gas by centrifugal force	This technology is not intended for, nor can it achieve, the high efficiency required for outlet emissions from a power plant.
Paint Filter	Filtering technology used to filter paint mist from paint booth exhaust.	Not intended for, nor applicable to, filtering particulate matter from coal-fired power plant flue gas.
Gravity Collector	Separates flyash from the flue gas by gravity settling. Successful operation requires that the flue gas have a very low velocity.	Gravity collectors have a very low separation efficiency, and cannot achieve the high efficiency required for outlet emissions from a power plant.
Partial Enclosure (fugitives)	The use of partial enclosures for fugitive dust control was evaluated in the Section 6 BACT Analysis subsection related to coal, ash, and limestone material handling systems of the IPP Unit 3 permit application.	For coal-fired plant material handling and fugitive emission sources only.
Total Enclosure (fugitives)	The use of total enclosures for fugitive dust control was evaluated in the Section 6 BACT Analysis subsection related to coal, ash, and limestone material handling systems of the IPP Unit 3 permit application.	For coal-fired plant material handling and fugitive emission sources only.
Water Application (fugitives)	The use of water sprays for fugitive dust control was evaluated in the Section 6 BACT Analysis subsection related to coal, ash, and limestone material handling systems of the IPP Unit 3 permit application.	For coal-fired plant material handling and fugitive emission sources only.
Chemical Suppressants (fugitives)	The use of chemical suppressants for fugitive dust control was evaluated in the Section 6 BACT Analysis subsection related to coal, ash, and limestone material handling systems of the IPP Unit 3 permit application.	For coal-fired plant material handling and fugitive emission sources only.

Potential VOC Control Technologies:

Technology	**Brief Description**	**Applicability to Coal-Fired Boiler**
Thermal Incineration	Destroys VOC's by passing the VOC laden gas through a flame or high temperature region	Not intended for, nor applicable to, coal-fired power plants. This technique is only applicable to gas streams with relatively high concentrations of VOC's, and not the low VOC concentrations exiting a well operated boiler.

Technology	Brief Description	Applicability to Coal-Fired Boiler
Catalytic Incineration	Destroys VOC's by passing through a catalyst bed at a lower temperature than that used for thermal incineration.	Not intended for, nor applicable to, coal-fired power plants. This technique is only applicable to gas streams with relatively high concentrations of VOC's, and not the low VOC concentrations exiting a well operated boiler.
Cryogenic Condensation	Separates organic compounds from gas streams by cooling the flue gas until the VOC's condense out. Usually involves the atomization of a cryogenic liquid into the gas stream.	Not intended for, nor applicable to, coal-fired power plants. This technique is very energy intensive and not suitable for the extremely low levels of VOC's found in the flue gas from a well operated boiler.
Condensation	Separates out organics from gas streams by cooling the flue gas until the VOC's condense out. Similar to cryogenic condensation but may not utilize a cryogenic liquid to cool the gas stream.	Not intended for, nor applicable to, coal-fired power plants. This technique is very energy intensive and not suitable for the extremely low levels of VOC's found in the flue gas from a well operated boiler.
Carbon Adsorption	Separates VOC's from flue gas streams by adsorption into beds of activated carbon granules. VOC's are separated from the carbon through thermal regeneration or steam stripping, followed by condensation of the concentrated stream.	Not intended for, nor applicable to, coal-fired power plants. This technique would require extremely large adsorption towers due to the low VOC concentration and large flue gas volumes from a power plant.
Polyad™ System	The Polyad™ system extracts VOCs from the air stream by passing them through trays of adsorbent. The air flows through the trays and fluidizes the adsorbent on the trays. The Polyad™ fluidized bed systems consist of a series of trays containing polymeric adsorbent or other media, which flow downward through multiple trays and are conveyed into a microwave desorption chamber.	Not intended for, nor applicable to, coal-fired plants. The Polyad™ system is designed for vapor treatment in conjunction with air discharges from industrial operations, such as the control of fugitive emissions and solvent recovery, as well as soil vapor extraction or air stripping at remediation sites.
Flares	Destroys VOC's by passing the gas stream through a flame zone while mixing in large amounts of excess air.	Not intended for, nor applicable to, coal-fired power plants. The uncontrolled flame of the flare would produce more VOCs (through incomplete combustion of the flare fuel) than would be destroyed from the extremely low levels of VOCs in the power plant flue gas.

Technology	Brief Description	Applicability to Coal-Fired Boiler
ESP	Electrical field imparts a charge to aerosol VOC's. The charged aerosols are collected on grounded plates and removed from the gas stream. Collected organic liquids are removed from the plates by sluicing with water.	Not intended for, nor applicable to, coal-fired power plants. VOCs in power plant flue gas are at a much lower concentration then VOCs in the industrial process streams where ESPs been applied. Wet electrostatic precipitators have been used in the wood products industry to remove "condensable" VOCs (e.g., pinenes, terpenes, cymene, toluene, etc.) from wood product dryer exhausts.
Adsorption	See Carbon Adsorption	See Carbon Adsorption
Volume Concentrators	See Rotary Concentrator	See Rotary Concentrator
Rotary Concentrator	The rotary concentrator places removable adsorbent media blocks (activated carbon or zeolite honeycomb block) in a vertically mounted, rotating cylinder. Optional filters may be located upstream of the adsorbent media to remove particles and even out the flow of pollutants. Regeneration of media is accomplished by either steam or a hot gas stream, followed by concentration of the stripped VOC's.	Not intended for, nor applicable to, coal-fired power plants. This technique has not been tested or demonstrated on flue gas from a power plant. Besides major technological obstacles to success of this technology, the size of the equipment and its associated capital and operating costs result in unfavorable economics for VOC removal.
Biofiltration	Biological organisms destroy VOC's as they pass through filter beds containing the biological media.	Not intended for, nor applicable to, coal-fired power plants. This technique has been used for odor control and VOC control from wastewater treatment plants, however, it has never been applied to a flue gas stream from a power plant.
Membrane Technology	This technology uses a high pressure membrane separation system to treat streams that contain dilute concentrations of VOCs. The organic vapor/air separation technology involves the preferential transport of organic vapors through a nonporous gas separation membrane. In this system, the feedstream is compressed and sent to a condenser where the liquid solvent is recovered.	Not intended for, nor applicable to, coal-fired power plants. This method was developed to treat VOC laden gas streams from waste remediation processes. This process has never been applied to gas streams from power plants, which have much lower VOC concentrations and much higher gas flows than remediation process gas streams.

Technology	Brief Description	Applicability to Coal-Fired Boiler
Ultraviolet Oxidation	VOC's are destroyed by exposure to high levels of UV radiation.	Ultraviolet oxidation is an extremely energy intensive process. It is not intended for, nor applicable to, coal-fired power plants, and it has not been tested or demonstrated on flue gas from a power plant.
Plasma Technology	Electrically generated plasma field destroys VOC's and converts them into carbon dioxide and water vapor.	Not intended for, nor applicable to, coal-fired power plants. Previous applications for this technology include the treatment of gas streams from remediation processes. This technology has never been applied to gas streams of the size found at a power plant.
Low VOC Materials	Low VOC materials is a technique which replaces raw material streams in a industrial manufacturing process with those containing little or no VOC's in their formulation. This generally results in the replacement of materials having a hydrocarbon carrier with those having an aqueous carrier.	Not intended for, nor applicable to, coal-fired power plants. The volatile organics are those contained within the nature of the coal being used as fuel.
Catalytic Oxidation	Catalytic oxidation has been used to control CO and VOC on combustion turbines firing natural gas. Has not been applied to coal fired units.	Catalytic oxidation was evaluated in Section 6 of IPP Unit 3 permit application. Catalytic oxidation has not been demonstrated on coal-fired boilers.
Combustion Control		Combustion Control was evaluated in Section 6 of IPP Unit 3 permit application. Combustion Control was selected as BACT for IPP Unit 3 and will be installed on IPP Unit 3.

Potential CO Control Technologies:

Technology	Brief Description	Applicability to Coal-Fired Boiler
Regenerative Thermal Oxidation	Destroys CO by passing gas stream through a flame or high temperature region. A Regenerative Oxidizer is also a Direct Fired oxidizer that employs integral primary heat recovery. However, the RTO operates in a periodic, repetitive cycle rather than a continuous mode. Instead of conventional heat exchangers which indirectly transfer heat from the hot side to the cold side across exchanger walls, RTOs use a store and release mechanism. The nature of an RTO heat recovery process requires it to have at least two beds of appropriate heat recovery media.	Not intended for, nor applicable to, coal-fired power plants. This technique is only applicable to gas streams with high levels of CO, and not the low CO concentrations exiting a well operated boiler. If a flame type oxidizer is used, the CO exiting the unit may be higher than the low levels of CO in a power plant flue gas.
Recuperative Thermal Oxidation	Destroys CO by passing gas stream through a flame or high temperature region. A recuperative oxidizer consists of a combustion chamber, a burner, and a heat exchanger / shell that pre-heats the incoming air.	Not intended for, nor applicable to, coal-fired power plants. This technique is only applicable to gas streams with high levels of CO, and not the low CO concentrations exiting a well operated boiler.
Flares	A flare is a direct combustion device in which air and all combustible gases react at the burner with the objective of complete and instantaneous oxidation of the combustible gases. Flares are used either continuously or intermittently and are not equipped with devices for fuel-air mix control or for temperature control.	Not intended for, nor applicable to, coal-fired power plants. This technique is only applicable to gas streams with high levels of CO, and not the low CO concentrations exiting a well operated boiler. If a flare is used, CO exiting the unit will be higher than the low levels of CO in the power plant flue gas.

Technology	Brief Description	Applicability to Coal-Fired Boiler
Afterburners	The simplest Thermal Oxidizer is a Direct Fired unit (sometimes referred to as an After-Burner) that employs no heat recovery. In this system, a fuel burner (mostly natural gas fired) raises the temperature of the pollutant laden air to a predetermined combustion temperature. In order to achieve a high level of hydrocarbon destruction, the heated air is kept at the combustion chamber setpoint for a predetermined minimum residence (or dwell time).	Not intended for, nor applicable to, coal-fired power plants. This technique is only applicable to gas streams with high levels of CO, and not the low CO concentrations exiting a well operated boiler. If a flame type oxidizer is used, CO exiting the unit may be higher than the low levels of CO in a power plant flue gas.
Catalytic Oxidation	Catalytic oxidation has been used to control CO and VOC on combustion turbines firing natural gas. Has not been applied to coal fired units.	Catalytic oxidation was evaluated in Section 6 of IPP Unit 3 permit application. Catalytic oxidation has not been demonstrated on coal-fired boilers.
Combustion Control		Combustion Control was evaluated in Section 6 of IPP Unit 3 permit application. Combustion Control was selected as BACT for IPP Unit 3 and will be installed on IPP Unit 3.

Potential Lead Control Technologies:

Technology	Brief Description	Applicability to Coal-Fired Boiler
HEPA Filter	Discussed above	Not Applicable
Baghouse	Discussed above	A fabric filter was evaluated in Section 6 of the IPP Unit 3 permit application. A fabric filter was selected as BACT for IPP Unit 3 and will be installed on IPP Unit 3.
ESP	Discussed above	ESP was evaluated in Section 6 of the IPP Unit 3 permit application.
Wet Scrubber	Discussed above	Applicable
Mechanical Collector (i.e., cyclone)	Discussed above	Applicable
Paint Filter	Discussed above	Not Applicable
Gravity Collector	Discussed above	Not Applicable

Potential Fluorides Control Technologies:

Technology	Brief Description	Applicability to Coal-Fired Boiler
HEPA Filter	Discussed above	Not Applicable
Baghouse	Discussed above	Fabric filters were evaluated in Section 6 of the IPP Unit 3 permit application.
ESP	Discussed above	Applicable
Wet Scrubber	Discussed above	Wet scrubbers were evaluated in Section 6 of the IPP Unit 3 permit application. The use of a fabric filter followed by wet limestone FGD was selected as BACT for IPP Unit 3 and will be installed on IPP Unit 3.
Dry Scrubber	Discussed above	Dry scrubbers were evaluated in Section 6 of the IPP Unit 3 permit application.
Mechanical Collector (i.e., cyclone)	Discussed above	Not Applicable
Paint Filter	Discussed above	Not Applicable
Gravity Collector	Discussed above	Not Applicable

Potential Sulfuric Acid Mist Control Technologies:

Technology	Brief Description	Applicability to Coal-Fired Boiler
Wet Scrubber	Discussed above	Wet scrubbers were evaluated in Section 6 of the IPP Unit 3 permit application. The use of a fabric filter followed by wet limestone FGD was selected as BACT for IPP Unit 3 and will be installed on IPP Unit 3.
Biofiltration	Discussed above	Not Applicable
Dry Scrubber	Discussed above	Dry scrubbers were evaluated in Section 6 of the IPP Unit 3 permit application.
Wet ESP	Electrical field imparts a charge to the fly ash and any aerosols in the flue gas. Charged particles are collected on grounded plates and removed from the gas stream. Typically the particles are removed from the plates by sluicing with water.	The use of a Wet ESP for additional control of H2SO4 mist is evaluated in a technical paper in Appendix I.

Potential Total Reduced Sulfur Control Technologies:

Technology	Brief Description	Applicability to Coal-Fired Boiler
Flares	Discussed above	Not Applicable
Wet Scrubber	Discussed above	Wet scrubbers were evaluated in Section 6 of the IPP Unit 3 permit application. The use of wet limestone FGD was selected as BACT for IPP Unit 3 and will be installed on IPP Unit 3.
Thermal Oxidation	See Thermal Oxidation (Recuperative & Regenerative)	Not Applicable
Biofiltration	Discussed above	Not Applicable
Dry Scrubber	Discussed above	Dry scrubbers were evaluated in Section 6 of the IPP Unit 3 permit application.

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TECHNICAL SUPPORT DOCUMENTATION

In December 2002, Intermountain Power Agency (IPA) submitted a Notice of Intent (NOI) to permit and construct a new nominal 950-gross MW (900-net MW) pulverized coal-fired unit at the Intermountain Power Project station near Delta, Utah. On May 14, 2003, IPA submitted an Addendum to the NOI, which included Appendix I, Technical Discussion. Since that time, supplemental technical documentation to the NOI has been developed. A summary of technical support documentation is presented here as follows:

1. Coal Supply

- Intermountain Power Project (IPP) Unit 3 Coal Supply

2. Modeling

- Replacement Graphics for IPP NOI Addendum submitted on May 14, 2003
- Replacement Sections and Files for the IPP NOI Addendum submitted on May 14, 2003
- IPP Unit 3 Start-Up & Shut-Down Modeling
- White Paper: PM10 Impacts in Utah County
- Replacement Sections and Files for the IPP NOI Addendum submitted on May 14, 2003
- IPP3 Project CALPUFF: Observed Weather Conditions for Days with Natural Obscuration
- IPP3: Revised Cumulative Class I Increment Modeling

3. PM_{10} BACT

- PM_{10} Emissions and Fabric Filter Control Efficiency
- IPP Unit 3—PM_{10} BACT Cost Estimate
- IPP Unit 3—PM_{10} BACT Questions
- IPP Unit 3—PM_{10} BACT Questions
- PM_{10} BACT Cost Analysis

4. NO_X BACT

- Nitrogen Oxide Emissions and Control

5. SO_2 BACT

- Flue Gas Desulfurization – Control Efficiency
- SO_2 Control - Effect of Averaging Time on Wet FGD System Performance and Design
- Wet Flue Gas Desulfurization Control Efficiency
- IPP Unit 3 – SO2 BACT Questions

6. Sulfuric Acid Mist

- Evaluation of Wet Electrostatic Precipitation to control Sulfuric Acid Mist Emissions

7. CO/VOC BACT

- IPP Unit 3 Air Permit Application: Review of CO and VOC Permit Limits (revised)

8. Response to UDAQ BACT Questions

- Generating Technology BACT Evaluation
- Intermountain Power Project Unit 3 Permit Application: Response to UDAQ Questions

9. Mercury MACT

- IPP Unit 3 Air Permit Application: Review of Mercury Permit Conditions (revised)

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Coal Supply

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Intermountain Power Project (IPP) Unit 3 Coal Supply

Background and Summary

In December 2002, Intermountain Power Authority (IPA) submitted a Notice of Intent (NOI) to permit and construct a new nominal 950-gross MW (900-net MW) pulverized coal-fired unit at the Intermountain Power Project Station near Delta, Utah. In the NOI, IPA proposed a worst-case design coal based primarily on Utah produced coal with a sulfur content of 0.75% by weight and a heat content of 11,193 Btu/lb. During subsequent NOI Technical Review Meetings between IPA and the Utah Department of Environmental Quality – Division of Air Quality (UDAQ), representatives of UDAQ inquired why IPP didn't specify a lower sulfur coal for Unit 3, similar to coals historically received at IPP Units 1 & 2 (i.e., approximately 0.5% sulfur by weight); or why IPP didn't specify a Power River Basin (PRB) coal for Unit 3, which appears to have a sulfur content in the range of 0.4%.

IPA is providing the following explanation in response to UDAQ's request. Due to the inherent risk in coal mining, increasing decline in coal quality of Utah coals, anticipated quality of future Utah coal reserves, and the long-term flexibility required in coal supply, IPA believes that a 0.75% worst-case design coal sulfur content is reasonable and prudent. Although IPA may purchase PRB coal for a number of reasons, the resulting reduction in the controlled SO_2 emission rate would be minimal, and would cost approximately $148,000/ton. Limiting Unit 3 to purchase PRB coal, strictly due to an apparent lower sulfur content, is not technically viable or economically prudent.

Technical Discussion

The following provides background and feedback as to the sulfur content of the coal selected for IPP Unit 3's worst-case design scenario. IPP gave careful consideration to many factors in establishing this specification, including the general trend of coal quality, current and future coal resources, and the overall economics of purchasing coal from non-Utah sources.

Design Coal

It is vitally important to establish design coal characteristics early in the planning stage of any new coal-fired electricity-generating unit. Not only are coal characteristics needed to properly design the boiler and pollution control equipment, but the availability of a reliable long-term supply of fuel is fundamental to the economic feasibility of any project. Because of the

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tremendous capital investment needed to construct a new electricity-generating unit, it is necessary to specify coal characteristics that will ensure that the unit is designed for reliable long-term operation. Design coal specifications should be developed based on a comprehensive review of:

- currently available coal reserves;
- anticipated life of existing coal reserves;
- potential availability of future coal reserves;
- coal quality and characteristics at each reserve, and
- the economics, including the delivered fuel cost, associated with each coal reserve.

The term "worst-case design coal" is used to describe a coal that exhibits characteristics (i.e., heating value, sulfur content, ash content, moisture, etc.) that envelop the characteristics described above. Worst-case design coal will generate the highest pollutant emission rates, and is used, therefore, to ensure that emission control systems are designed to ensure compliance with permitted emission limits recognizing the potential variability in the fuel. It is also important that the worst-case design coal is not specified with unrealistic or unreasonable characteristics. Specifying a unreasonable worst-case design coal could lead to inefficient boiler design, over-sized emission control equipment, and a project that is not economically viable.

Coals used in IPP Units 1 & 2 have historically exhibited a fuel sulfur content of approximately 0.5 weight percent. However, as with all coal-fired electricity generating units, Units 1 & 2 were designed to utilize a variety of coals that may reasonably be expected to be available over the life of the units. At the time Units 1 & 2 were designed, IPP considered specifications of seven potential coal sources, including some coals with a sulfur content up to 1%. Likewise, Unit 3 will be designed based on a similar worst-case design coal, and the characteristics of the worst-case design coal must be established based on careful consideration of potential fuel sources.

Fuel costs represent over 40% of the cost of power generation, therefore, it is simply good public policy for utilities to evaluate the delivered fuel cost, including the cost of transporting fuels over long distances, along with the cost of pollution control equipment. Currently, Utah coals are economic for the proposed IPP Unit 3. In accordance with the Utah legislature's intent to support the economic viability of the Utah coal market, as well as the Governor's desire for IPP Unit 3 to use Utah coal as much as practical, IPA has designed Unit 3 to burn primarily Utah coals. However, IPA also understands that in the future the availability of Utah coals may be limited, and it may be economically necessary to burn out-of-state coals. Therefore, IPA must allow for fuel flexibility in developing the design for Unit 3. This flexibility impacts the selection of all equipment associated with burning coal.

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Coal Characteristics

It is often helpful to distinguish coals by their coal quality characteristics. Coal has many quality characteristics with the most commonly evaluated being moisture, sulfur, ash, and heat content. Other quality characteristics commonly watched are ash fusion temperatures, sodium content, calcium content, coal hardness, spontaneous combustion characteristics, and coal fineness. For discussion regarding emission considerations, specifically sulfur dioxide emissions, we will concentrate on the coals' sulfur content (typically measured by the weight percent of sulfur in the coal or described in post combustion content as lb-SO_2/mmBtu), and heat content (typically measured in Btu/lb).

Coal characteristics will vary within a particular region or basin, or even within a particular coal seam. Coal produced in the United States is generally characterized by region or basin. In the West there is: the PRB (Eastern Wyoming and Southern Montana); the Uinta Basin (Eastern Utah and Western Colorado); the Green River Basin (Southwest Wyoming and Northwest Colorado); the San Juan Basin (Northwest New Mexico and Southwest Colorado); and a few other lesser coal producing areas. In the mid-west there is the Interior Coal Province where Illinois Basin Coals are produced (Illinois, Indiana, and Western Kentucky), and further east are the Appalachian coal-producing states (Pennsylvania, Ohio, Virginia, West Virginia, Western Kentucky, Tennessee and Alabama).

When it comes to coal characteristics, Utah coals have some of the highest heat content and lowest sulfur content in the country. In fact when the Clean Air Act Amendments of 1990 (CAA) were passed, it was generally believed that Utah and other Western Region coals would benefit due to their relatively low sulfur content. The CAA required utilities to either reduce their SO_2 emissions to 1.5 lb/mmBtu by 1995 and 1.2 lb/mmBtu by 2000, or purchase emission allowances to offset excess SO_2 emissions. Although some Eastern utilities opted to add SO_2 scrubbers to their coal fired units, many have decided to either burn Western coals or burn a blend of Western coal and their native coal to meet their emission limits. Over the past several years, approximately 10% of Utah's total 26 million ton per year production was sold to eastern customers (Tennessee, Wisconsin, Florida, Texas, and others). Many of these users purchased Utah coal to reduce sulfur emissions, and meet their SO_2 emissions limit, without using post-combustion scrubbing. It should be noted that not only will IPP Unit 3 primarily burn low sulfur Utah coal, but a flue gas desulfurization system will also be provided to remove approximately 90% of the post-combustion SO_2.

Comparison of Utah to PRB Coals

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Both Utah coals and PRB coals are considered low sulfur coals in that a large majority have a sulfur content less than 0.7 % by weight, although a few mines produce coal with a sulfur content above 1.0%. The larger difference between Utah coals and PRB coals is that PRB coals are mostly sub-bituminous by coal ranking (i.e., PRB coal heat contents range from 8,400 to 8,800 Btu/lb, as received basis), compared to Utah coals which are bituminous (i.e., Utah coal heat contents range from 11,100 to 13,100 btu/lb, as received basis). The higher heat content of Utah coals has a significant effect on post-combustion SO_2 concentration. Therefore, the post-combustion SO_2 concentration for a typical Utah coal is comparable to a typical PRB fuel, as shown in Table 1 below:

Table 1
Comparison of Sulfur Content in Coal vs. Design Basis

	Utah Typical	PRB Typical	Unit 3 Design Basis	Typical PRB Design Basis	Design Basis Used at Wygen 2[1]
Higher heating Value (Btu/lb)	11,800	8,800	11,193	8,000	7,950
Sulfur by weight (%)	0.6	0.4	0.75	0.51	1.0
Uncontrolled SO_2 rate into Wet-FGD system (lb/mmBtu)	1.02	0.91	1.34	1.275	2.52
Percent difference	12.1% above typical PRB	Base	5.1% above design PRB	Base	87.7% higher than IPA Unit 3 Design Basis

A comparison of PRB coal with Utah coal must include a comparison of the design range that must be allowed for permitting and designing of a coal-fired plant. The uncontrolled SO_2 emission rates to the FGD control system will be essentially the same, therefore, overall economics of the coal must be taken into consideration.

On an economic basis, a typical Utah coal can be delivered to IPP Units 1&2 for approximately $0.39/mmBtu less than a typical PRB coal. If we assume, for comparison purposes, Utah coal with a sulfur content of 0.6 % (approximately equal to IPA's current coal supply) and a Unit 3

[1] Information on the Wygen 2 permit application was obtained from the Wyoming Department of Environmental Quality – Division of Air Quality, Permit Application Analysis, NSR-AP-C92, April 24, 2002, and "In the Matter of a Permit Application (AP-C92) From Black Hills Corporation to Construct a 500 MW Pulverized Coal Fired Electric Generating Facility to be Known as Wygen 2," Wyoming DEQ Decision paper, September 26, 2002.

scrubber efficiency of 92.6% compared to the PRB coal at 0.4% sulfur and a Unit 3 scrubber efficiency of 92.6%[2], the cost/ton of SO_2 reduction using a typical PRB coal instead of a Utah coal would be approximately $148,000/ton (Table 2).

Table 2
PRB Coal Cost Effectiveness Compared to Utah Coal Due to Lower Sulfur

Scrubber Efficiency	Total Annual Cost ($/year)	Annual Emission Reduction, (tpy)	Ave Annual Cost Effectiveness, ($/ton)
92.6 %	$47,800,000	323	$148,000

Utah Mining History

Based on IPA's current estimates, Utah has approximately 800 million tons of reserves remaining (this excludes the Kaiparowits Plateau coal fields which has an estimated 20 Billion tons but is part of the Grand Staircase - Escalante National Monument Declaration). The 800 million tons of reserves remaining could increase depending on market economics and advancements in mining technologies, or decrease due to unforeseen geological conditions and/or future preservation designations.

Over the years, the easily obtained high quality coals have been mined, or are currently being mined. Utah is just beginning to see mines with less than ideal geological conditions or coal qualities. Three such examples are the last three large-scale mines to open; the Willow Creek Mine, the Dugout Canyon Mine, and the West Ridge Mine.

The Willow Creek Mine had very challenging geology with many coal seams and partings combined with being a very gassy mine (high methane gas liberation). The Willow Creek Mine ceased operation in August of 2000.

The Dugout Canyon Mine began operation in 1999 and was projected to have higher than normal sulfur as well as higher than typical ash in the upper coal seam (first 4-5 years of operation). The coal quality is projected to improve, but potential issues still exist with high ash once they move to a lower coal seam. Due to maximum coal recovery requirements, the upper seam of coal must be removed before an underlying coal seam can be mined.

[2] The control efficiencies listed above are for illustrative purposes only, and may not be achievable in practice. As described in detail in IPA's FGD Control Efficiency write-up (submitted to UDAQ under separate cover), FGD control efficiency is a function of several operating variables, including SO_2 inlet concentration. As the inlet SO_2 concentration goes down, it becomes more and more difficult to maintain a high control efficiency. Therefore, with PRB coal at a sulfur content of 0.4%, a control efficiency of approximately 90% is probably more realistic.

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The West Ridge Mine began development in early 2000 and began full-scale production in mid-2001. The mine was projected to have an average sulfur content over 1.0%. Due to the higher than normal sulfur, West Ridge segregates and blends its coal based on sulfur content and markets the coal accordingly. IPA is 50% owner in the West Ridge Project.

Regardless of the closure of the Willow Creek mine and decline of the export market, Utah's total coal production has stabilized at around 26 million ton per year. Except for the building of IPP Unit 3, which would burn about 2.7 million tons per year and has an estimated in-service date in 2008, there doesn't appear to be any new large-scale demand for Utah coal.

Utah's future coal outlook continues the trend of higher quality coal mines depleting their reserves and being replaced with coal mines of lesser coal quality and/or more difficult geological conditions.

Historical Utah Sulfur Quality

Historically, Utah coal is considered low-sulfur coal. The standard Utah coal agreement will normally specify a maximum sulfur limit of 0.8% by weight even though Utah mines will typically produce coal averaging 0.45% to 0.7%. In fact, with the exception of the West Ridge mine (which began producing substantial quantities of coal in the early 2000's), coal producers in Utah rarely segregate and blend their production based on sulfur content. The West Ridge mine is the exception, and was opened knowing that the average sulfur content would be above 1.0%. Understanding the normal Utah markets, West Ridge decided to segregate and blend its product based on sulfur. If a producer segregates their products, they will typically segregate their coal products based on ash content (usually relates to heat content) or sodium content (usually relates to ash fusion temperatures).

Each year IPP Units 1&2's average coal quality will change slightly depending on quantity of coal purchased from a variety of coal sources. The average coal quality for coal received at IPP Units 1&2 during the period 1998 through 2002 is shown in Table 3.

Table 3
IPP Units 1&2 Average Coal Quality
(1998 –2002)

Coal Characteristic	Average (1998-2002)	12 Month Average High	12 Month Average Low
Heat Content, (btu/lb)	11,857	N/A	N/A
Sulfur Content (% weight)	0.54	0.61	0.50

SO_2 (SO_2/mmBtu)	0.915	1.031	0.836

During this period, the highest twelve month average occurred for the period of calendar year 2002 with the lowest twelve-month average occurring between June 1999 and May 2000. This trend is higher due to the burning of more West Ridge coal.

Proposed Worst-Case Sulfur Content

As mentioned above, there is a continual shift from mining the easily obtained high quality coal to mining either the less than ideal coal quality, or mining under more difficult geological conditions, or a combination of the two.

From a coal purchaser's perspective, it would be unwise to rely on only a few sources for its total coal supply. As seen with the unexpected closure of the Willow Creek Mine, any given source can be removed for either a short period or indefinitely. Coal mining still possesses a certain level of uncertainty and risk. In order to effectively manage that risk, as well as do our best to remain economically competitive, coal purchasers are always looking to maintain a diverse purchasing portfolio. It is that uncertainty, and need to keep a diverse purchasing portfolio, that drives IPA to use a worst-case design coal sulfur limit of 0.75% based on 11,193 lb/btu (1.34 lb-SO_2/mmBtu). It is not our intent to purchase coals with higher sulfur contents than the past, but the uncertainty of what source will be available, not in the near future but 15 to 25 years from now. Although a 0.75% worst-case design coal specification is slightly higher than the sulfur content of coals that are currently available, 0.75% sulfur content in coal is still considered low sulfur coal.

SUMMARY

The long-term planning of a coal-fired power plant requires the owners to look far into the future for their coal supply. Although we try to anticipate how the future coal market will unfold, mining is an inherently risky business. One factor is certain, much of the high quality, easily mineable coal has been, or is currently being, mined. Future mines will face increasingly difficult mining conditions and/or less than ideal coal qualities. With these factors in mind, IPA feels it is prudent to permit IPP Unit 3 with a worst-case design coal sulfur content that will allow enough flexibility to operate economically during the life of the IPP Unit 3. IPA believes that using a sulfur content of 0.75% by weight (1.34 lb-SO_2/mmBtu) is reasonable. This will allow for a fuel flexibility to strive for low-cost, reliable, and emission-compliant power generation.

In summary:

IPA Unit 3 NOI
Appendix I
Technology Discussions

- PRB fuel is more costly to use at this site, and not consistent with the Utah governor's or legislature's intent to use Utah coal.
- The uncontrolled SO_2 emission rate is not significantly improved by using PRB over Utah coal.
- The controlled SO_2 emission rate would be essentially identical with either PRB or Utah coal.
- Worst-case design coal characteristics are appropriate for designing the unit's emission control equipment.
- IPA is being prudent in the development of the specified fuel design range for the equipment. This will support the long-range competitive position of IPP Unit 3 while meeting one of the lowest permitted SO_2 emission rates.

APPENDIX I-2

Modeling

Replacement Graphics for IPP NOI Addendum
Submitted on May 14, 2003

Utah Department of Environmental Quality
Division of Air Quality
Rick Sprott, Dirrector
168 North 1950 West
P.O. Box 144810
Salt Lake City, UT 84114-4810

May 27, 2003
Via Hand Delivery

RE: Replacement Graphics for IPP NOI Addendum submitted on May 14, 2003

Dear Rick:

On May 27, 2003, CH2M HILL submitted replacement graphics for the IPP NOI Addendum that was submitted on May 14, 2003. The replacement graphics were submitted to provide higher quality (resolution) to the graphics that were submitted on May 14, 2003. Please note that there were no substantive changes to any of the figures or NOI addendum text; only quality improvements to the printed figures. The following figures were updated to provide higher quality graphics for the NOI Addendum:

Figure 2-1	General Location Map
Figure 2-3	Existing Coal Handling
Figure 2-4	Modified Coal Handling Systems for Units 1, 2, and 3
Figure 2-5	Schematic Flow Diagram
Figure 2-6	Fly Ash Handling
Figure 7-1	NPS Class I and Class II Areas
Figure 7-2	CALMET Modeling Domain
Figure 7-3	Surface and Upper-Air Stations
Figure 8-1	Terrain Adjacent to the IPP
Figure 8-5	Ambient Boundary for IPP

CH2M HILL assisted DAQ in replacing the figures in the six (6) clean copies and the six (6) redline copies of the NOI Addendum submitted to DAQ on May 14, 2003. With these graphic page replacements, the NOI Addendum is ready for distribution to the FLMs and EPA. As discussed with DAQ staff, IPA/IPSC is anticipating that the DAQ preliminary review of the NOI Addendum will be sufficiently complete this week and DAQ can forward the NOI Addendum to the FLMs and EPA prior to the end of the month so that a draft permit can be developed and issued to public comment prior to the August Utah Air Quality Board Meeting.

Please call me directly with any questions or concerns, or have your staff call Lance Lee.

Sincerely,

Reed Searle
General Manager
Intermountain Power Agency

Cc: Milka Radulovic
Lance Lee

Replacement Section and Files for the IPP NOI Addendum Submitted on May 14, 2003

Intermountain Power Agency

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Utah Department of Environmental Quality
Division of Air Quality
Rick Sprott, Director
150 North 1950 West
P.O. Box 144820
Salt Lake City, UT 84114-4820

June 18, 2003
Via Hand Delivery

RE: Replacement Sections and Files for the IPP NOI Addendum submitted on May 14, 2003

Dear Rick:

On May 14, 2003, CH2M HILL submitted the IPP NOI Addendum. Modifications have been made to Sections 7 and 8, the modeling files, and an additional table added to the end of Appendix E.

The following are provided in hard copy to replace the pages in the IPP NOI dated May 14, 2003, and electronically on the enclosed CD:

- Table of Contents in its native Word file; replace the entire section in hard copy
- Section 7 in its native Word file; replace the entire section in hard copy
- Section 8 in its native Word file; replace the entire section in hard copy
- Appendix E table in PDF format; add to the end of Appendix E in hard copy

The CD also contains additional modeling files in their native software format, a complete clean version of the NOI in PDF format, and a complete redline version of the NOI in PDF format. The redline version contains both redline changes to Sections 7 and 8 from the original December 16, 2002, NOI and redline changes to Sections 7 and 8 from the May 14, 2003, NOI submission.

If you have any questions, please contact me at (801) 938-1315.

Sincerely,

Lance C. Lee

Lance C. Lee
IPP Unit 3 Feasibility Manager

c: Milka Radulovic (UDAQ)
Stephen C. Sands (CH2MHILL)
Reed Searle

10653 South River Front Parkway, Suite 120, South Jordan, Utah 84095
(801) 938-1333 Fax (801) 938-1330

IPP Uni 3 Start-Up & Shut-Down Modeling

IPA
Intermountain Power Agency

July 28, 2003

Utah Department Of Environmental Quality
Division of Air Quality
Brock LeBaron - Manager, Technical Analysis Section
150 North 1950 West
P.O. Box 144820
Salt Lake City, Utah 84114-4820

Re: IPP Unit 3 Start-Up & Shut-Down Modeling

Dear Brock:

This letter presents a summary of start-up/shut-down dispersion modeling that was conducted by CH2M HILL for the IPP Unit 3 Project (IPP3) in response to a request made by UDAQ. The modeling was requested by UDAQ to determine if National Ambient Air Quality Standards (NAAQS) would be protected during periods of start-up and shutdown.

__Cold Start-Up Emission Characteristics__

To model the potential impacts of start-up/shut-down periods, Intermountain Power Agency (IPA) developed a scenario reflective of the emission characteristics expected for a typical cold start-up. A cold start-up scenario would represent a worst-case modeling profile (i.e., worse than a warm re-start, shutdown, maintenance/planned outage or malfunction scenario) in terms of resulting exit velocity, exit temperature, and emission rates. Attachment 1 presents a summary for each hour of the cold start-up sequence, including the exit velocity, exit temperature, and the emission rates for carbon monoxide (CO), sulfur dioxide (SO_2), nitrogen oxides (NOx), and particulate matter (PM_{10}). As shown in Attachment 1, the cold start-up was assumed to be in place for the first 19 hours of a given day, with base load conditions in place for the remaining hours. The assumed base load emission rate for SO_2 (1,357.5 lb/hr) is an estimate of the maximum emission rate from Unit 3 for normal operation over a 3-hour period. This emission rate has been used to represent 3-hour conditions for previous near-field SO_2 modeling for the Unit 3 source.

For input to the model, we created hourly emissions files for CO, SO_2, NOx, and PM_{10} that repeated the start-up sequence for each day of the one-year period of meteorological input. In this way, the cold start-up sequence was conservatively assumed to occur for each day of an annual period. As you well know, startup and shutdown will not occur every day of the year, so this assumption makes our modeling exercise drastically overpredict IPP Unit impacts during startup and shutdown. However, as you will see, even with this drastic

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overprediction assumption, IPP Unit 3 will never cause an exceedance of the health based NAAQS. Other inputs to the EPA ISCST3 or ISC-PRIME models included the base receptor grid and the 50-meter meteorological input file that were used for previous analyses for the project.

For CO, the impacts from the start-up sequence for IPP Unit 3 were compared to the Class II modeling significance levels. Only the Unit 3 source was modeled because the impacts were expected to be well below the modeling significance levels and therefore well below the NAAQS for CO. For a 1-hour averaging period, the maximum predicted impact from the EPA ISCST3 model was 103.7 $\mu g/m^3$. The maximum impact occurred several hundred meters to the north of the IPP ambient boundary (fenceline). This maximum predicted impact represents only 5 percent of the Class II modeling significance level of 2,000 $\mu g/m^3$. The maximum 8-hour impact of 31.6 $\mu g/m^3$ also occurred several hundred meters to the north of the IPP ambient boundary, and represents only 6 percent of the modeling significance level of 500 $\mu g/m^3$.

To assess the short-term impacts of SO_2, CH2M HILL repeated the initial NAAQS analysis for normal operation of IPP3, with the substitution of an hourly SO_2 emission file for the Unit 3 source. As with the NAAQS analysis for SO_2 under normal operation, we used the latest version of the ISC-PRIME model (01228) to predict the maximum impacts. Our analysis included other sources of SO_2 at IPP as well as outside sources that were provided by UDAQ. The predicted high second-high 3-hour impact was 192.4 $\mu g/m^3$, and the high second-high 24-hour impact was 41.1 $\mu g/m^3$. With the addition of the appropriate background concentrations, the total predicted impacts are well below the NAAQS, as shown in Table 1. For both averaging periods, the predicted maximum impacts occurred at the IPP ambient boundary to the south of Unit 3. In both cases, the maximum impacts were driven primarily by the auxiliary boiler at IPP rather than Unit 3, and the predicted impacts were identical to those for the NAAQS analysis for normal operation.

Short-term (24-hour) impacts of PM_{10} were estimated with the ISCST3 model by repeating the NAAQS analysis that was conducted for normal operation of Unit 3, with the substitution of an hourly emission file for the Unit 3 source. All other PM_{10} sources at IPP, including material handling sources, were included in the analysis. Outside sources were provided by UDAQ. The predicted high second-high 24-hour impact was 37.6 $\mu g/m^3$. With the addition of the background concentration of 56 $\mu g/m^3$, the total predicted impact of 93.6 $\mu g/m^3$ is well below the NAAQS of 150 $\mu g/m^3$.

Impacts for NOx were estimated with ISCST3 by modeling all NOx sources at the IPP facility along with outside sources of NOx that UDAQ provided to CH2M HILL. Although start-up/shut-down of Unit 3 is expected to occur infrequently, the cold start-up sequence was input as if the start-up occurred every day in order to conservatively estimate annual impacts since the NAAQS for NOx is based on an annual averaging period. The highest predicted annual impact occurred at a receptor near the Ashgrove facility, approximately 25 kilometers to the east of IPP in an area of 1000-m receptor spacing. A fine grid (100-meter spacing) was constructed around the maximum receptor and the analysis was repeated to further refine the predicted impact. The maximum predicted impact with the fine grid was 57.9 μg/m³. With the addition of the background concentration of 10 μg/m³, the total predicted impact of 67.9 μg/m³ is well below the NAAQS of 100 μg/m³. The maximum concentration that was predicted for all of the IPP sources alone was no higher than 7.5 μg/m³ at any place on the base receptor grid.

TABLE 1 – RESULTS OF CONSERVATIVE START-UP MODELING ANALYSIS

Pollutant /Period	Maximum Predicted Impact for Unit 3 Only: Start-Up (μg/m³)	Maximum Predicted NAAQS Impact (μg/m³)	Total Predicted NAAQS Impact Including Background (μg/m³)	Class II Area Modeling Significance Level (μg/m³)	Class II Area NAAQS (μg/m³)	Percentage of Class II Area Modeling Significance Level	Percentage of NAAQS for Unit 3 Only: Start-Up
1-Hour CO	103.7	N/A	N/A	2,000	40,000	5%	0.3%
8-hour CO	31.6	N/A	N/A	500	10,000	6%	0.3%
3-hour SO_2	54.7	192.4	220.4*	N/A	1300	N/A	4.2%
24-hour SO_2	6.8	41.1	52.6*	N/A	365	N/A	1.9%
24-hour PM_{10}	25.2	37.6	93.6*	N/A	150	N/A	16.8%
Annual NOx	0.93	57.9	67.9	N/A	100	N/A	0.9%

* Background concentrations for SO_2 and PM_{10} are taken from monitoring data at IPP, and therefore include influence from existing units at the facility. Because these units were also included in the modeling, the background concentrations conservatively "double-count" the impacts from the existing units.

The results of the conservative modeling demonstrate that the NAAQS will be fully protected during periods of IPP Unit 3 start-up/shut-down.

Proposed Alternate Start-Up, Shut-Down, and Malfunction Limits

DAQ has suggested that if the impacts are below the NAAQS, emissions from startup, shutdown, maintenance/planned outage (SS&M) or malfunction could be reported as excess emissions. IPSC has evaluated the modeling and concluded that it would be their preference to develop alternate permit limits that would apply during periods of startup, shutdown, maintenance/planned outage or malfunction. Such alternate SS&M emission limits would be representative of emissions anticipated during periods of startup, shutdown, maintenance/planned outage or malfunction, would ensure protection of the NAAQS, and only report such emissions as excess emissions if these alternate SS&M permit limits are exceeded.

Emissions during periods of startup, shutdown, maintenance/planned outage or malfunction would become permitted emissions subject to the alternate SS&M permit limits instead of the permit limits applicable during normal operation. The remainder of this section describes the analysis that was performed to define appropriate alternate SS&M emission limits that should apply during periods of startup, shutdown, maintenance/planned outage or malfunction.

The following emission rates represent the highest hourly emissions that were modeled for the 24-hour start-up sequence, including the actual 19-hour start-up period and normal operation for the final five hours of each day. These hourly emission rates are proposed as limits for the Unit 3 source during periods of startup, shutdown, maintenance/planned outage or malfunction. These proposed alternate SS&M emission limits would supplement the normal operation emission limits we previously submitted in the NOI (attached to this letter for your reference).

- SO_2 1,357.5 lb/hr
- PM_{10} 2,999.4 lb/hr
- CO 1,390.6 lb/hr
- NOx 1,229.8 lb/hr

To verify that these proposed alternate SS&M emission limits would be protective of the NAAQS for the duration of any startup, shutdown, maintenance/planned outage or malfunction period, the analyses described above were repeated with revised hourly emission files that reflected the proposed alternate SS&M emission limit for every hour of each day. For example, the 24-hour start-up sequence for PM_{10} was revised so that the emission rate for each hour was 2,999.4 lb/hr. The exit velocity and exhaust temperature fluctuated during the start-up sequence as before, but the emission rate was held constant at this proposed alternate SS&M emission limit, and the entire sequence was repeated for each day of meteorological input. The results of this "worst-case" start-up analysis are summarized in Table 2. As before, the predicted results were less than the NAAQS for each pollutant.

TABLE 2 – RESULTS OF CONSERVATIVE START-UP MODELING ANALYSIS (PROPOSED ALTERNATE SS&M EMISSION LIMITS)

Pollutant/ Period	Maximum Predicted Impact for Unit 3 Only: Start-Up (μg/m^3)	Maximum Predicted NAAQS Impact (μg/m^3)	Total Predicted NAAQS Impact Including Background (μg/m^3)	Class II Area Modeling Significance Level (μg/m^3)	Class II Area NAAQS (μg/m^3)	Percentage of Class II Area Modeling Significance Level	Percentage of NAAQS for Unit 3 Only: Start-Up
1-Hour CO	268.3	N/A	N/A	2,000	40,000	13%	0.7%
8-hour CO	54.9	N/A	N/A	500	10,000	11%	0.6%
3-hour SO_2	95.1	193.7	221.7*	N/A	1300	N/A	7.3%
24-hour SO_2	16.3	41.1	52.6*	N/A	365	N/A	4.5%
24-hour PM_{10}	34.9	52.8	108.8*	N/A	150	N/A	23.2%
Annual NOx	1.4	57.9	67.9	N/A	100	N/A	1.4%

* Background concentrations for SO_2 and PM_{10} are taken from monitoring data at IPP, and therefore include influence from existing units at the facility. Because these units were also included in the modeling, the background concentrations conservatively "double-count" the impacts from the existing units.

We have proposed alternate SS&M permit limits that would apply during periods of startup, shutdown, maintenance/planned outage or malfunction. Our overly conservative modeling analysis shows that our proposed permit limits would be protective of the NAAQS during these SS&M periods.

If you have any questions, please contact me at 801-938-1315.

Sincerely,

Lance C. Lee

Lance C. Lee
Unit 3 Feasibility Manager

c: Mr. Stephen Sands (CH2M HILL)
Mr. Reed T. Searle

ATTACHMENT 1: IPP3 Cold Start-Up

Hour	Unit Load	Exhaust T (F)	Exhaust T (K)	Exhaust Flow (SCFH)	Exhaust Flow (ACFM)	Exit Velocity (ft/s)	Exit Velocity (m/s)	NOx (lb/hr)	NOx (g/s)	SO_2 (lb/hr)	SO_2 (g/s)	PM_{10} (lb/hr)	PM_{10} (g/s)	CO (lb/hr)	CO (g/s)
1	10	90	305.4	75,000,000	1,650,174	34.2	10.4	409.9	51.6	40	5.0	32.0	4.0	399.9	50.4
2	10	90	305.4	75,000,000	1,650,174	34.2	10.4	409.9	51.6	40	5.0	32.0	4.0	399.9	50.4
3	10	90	305.4	75,000,000	1,650,174	34.2	10.4	409.9	51.6	40	5.0	32.0	4.0	399.9	50.4
4	10	90	305.4	75,000,000	1,650,174	34.2	10.4	409.9	51.6	40	5.0	32.0	4.0	399.9	50.4
5	10	90	305.4	75,000,000	1,650,174	34.2	10.4	409.9	51.6	40	5.0	32.0	4.0	399.9	50.4
6	10	90	305.4	75,000,000	1,650,174	34.2	10.4	409.9	51.6	40	5.0	32.0	4.0	399.9	50.4
7	20	100	310.9	75,000,000	1,680,195	34.8	10.6	819.8	103.3	200	25.2	1999.6	251.9	799.8	100.8
8	20	100	310.9	75,000,000	1,680,195	34.8	10.6	819.8	103.3	200	25.2	1999.6	251.9	799.8	100.8
9	20	100	310.9	75,000,000	1,680,195	34.8	10.6	819.8	103.3	200	25.2	1999.6	251.9	799.8	100.8
10	20	100	310.9	75,000,000	1,680,195	34.8	10.6	819.8	103.3	200	25.2	1999.6	251.9	799.8	100.8
11	20	100	310.9	75,000,000	1,680,195	34.8	10.6	819.8	103.3	200	25.2	1999.6	251.9	799.8	100.8
12	20	100	310.9	75,000,000	1,680,195	34.8	10.6	819.8	103.3	200	25.2	1999.6	251.9	799.8	100.8
13	20	100	310.9	75,000,000	1,680,195	34.8	10.6	819.8	103.3	200	25.2	1999.6	251.9	799.8	100.8
14	20	100	310.9	75,000,000	1,680,195	34.8	10.6	819.8	103.3	200	25.2	1999.6	251.9	799.8	100.8
15	20	100	310.9	75,000,000	1,680,195	34.8	10.6	819.8	103.3	200	25.2	1999.6	251.9	799.8	100.8
16	20	100	310.9	75,000,000	1,680,195	34.8	10.6	819.8	103.3	200	25.2	1999.6	251.9	799.8	100.8
17	20	100	310.9	75,000,000	1,680,195	34.8	10.6	819.8	103.3	200	25.2	1999.6	251.9	799.8	100.8
18	30	100	310.9	75,000,000	1,680,195	34.8	10.6	1,229.8	155.0	299	37.7	2999.4	377.9	1199.8	151.2
19	30	100	310.9	75,000,000	1,680,195	34.8	10.6	210.0	26.5	299	37.7	45.0	5.7	461.9	58.2
20	100	135	330.4	--	--	65.0	19.8	633.5	79.8	1357.5	171.0	221.0	27.8	1390.6	175.2
21	100	135	330.4	--	--	65.0	19.8	633.5	79.8	1357.5	171.0	221.0	27.8	1390.6	175.2
22	100	135	330.4	--	--	65.0	19.8	633.5	79.8	1357.5	171.0	221.0	27.8	1390.6	175.2
23	100	135	330.4	--	--	65.0	19.8	633.5	79.8	1357.5	171.0	221.0	27.8	1390.6	175.2
24	100	135	330.4	--	--	65.0	19.8	633.5	79.8	1357.5	171.0	221.0	27.8	1390.6	175.2

SCFM to ACFM Conversion

Start-Up Flow: 75,000,000 SCFH
1,250,000 SCFM

$$\text{Volume (ACFM)} = \frac{PsVsTa}{TsPa}$$

where:
- Ps = 14.70 psi (pressure at STP)
- Vs = SCFM
- Ts = 273 K (temperature of ideal gas at STP)
- Pa = 12.46 psi (pressure at 4,676.5 ft. msl)
- Ta = temperature of exhaust (K)

Hours 1-6 flow (ACFM) = 1,650,174
Hours 7-19 flow (ACFM) = 1,680,195

Stack Diameter: 32.0 ft
9.75 m

Stack Area: 804.25 ft^2

White Paper: PM_{10} Impacts in Utah County

IPA
Intermountain Power Agency

October 16, 2003

Utah Department of Environmental Quality
Division of Air Quality
Brock LeBaron, Modeling Section Manager
150 North 1950 West
P.O. Box 144820
Salt Lake City, UT 84114-4820

RE: **Intermountain Power Project Unit 3 Permit Application**
White Paper: PM_{10} Impacts in Utah County

Dear Brock:

Please find four copies of the enclosed white paper entitled *PM_{10} IMPACTS IN THE UTAH COUNTY PM_{10} NONATTAINMENT AREA USING CALPUFF AND NO CHEMICAL TRANSFORMATION*. This white paper describes the modeling approach used by CH2MHILL to demonstrate that the impacts from the IPP Unit 3 project on the Utah County PM10 nonattainment area are comfortably below the 3 $\mu g/m^3$ "maximum allowable impact" threshold. An electronic copy of the enclosed white paper was sent to you yesterday via e-mail, and electronic modeling files were sent to you via e-mail on Friday, October 10, 2003.

If you have any questions or require any additional information, please call me directly at (801) 938-1315.

Sincerely,

Lance C. Lee

Lance C. Lee

IPP Unit 3 Feasibility Manager

Enclosure

c: w/o enclosure
Mr. Stephen Sands (CH2M HILL)
Mr. Reed T. Searle

10653 South River Front Parkway, Suite 120, South Jordan, Utah 84095
(801) 938-1333 Fax (801) 938-1330

PM_{10} IMPACTS IN THE UTAH COUNTY PM_{10} NONATTAINMENT AREA USING CALPUFF AND NO CHEMICAL TRANSFORMATION

October 16, 2003

Introduction

The Utah Department of Air Quality (UDAQ) has asked the Intermountain Power Plant (IPP) to evaluate the impact that the Unit 3 project will have on the particulate matter less than 10 microns (PM_{10}) nonattainment area in Utah County. The nonattainment area is located approximately 57 kilometers (km) to the northeast of IPP. For the plume from IPP to enter into the southwestern portion of Utah County, it must first cross the Tintic mountain range, the crest of which forms the county boundary in this area. The evaluation was performed using the CALPUFF model, which is the Environmental Protection Agency (EPA)-preferred model for transport distances of greater than 50 km. The modeling was conducted without using the chemical transformation capability of CALPUFF, resulting in a very conservative estimate of PM_{10} impacts in Utah County. Although the use of the chemical transformation capability in CALPUFF is considered a "regulatory default" technical option within the model, UDAQ has directed that chemical transformation not be used for the analyses described here.

The modeling was conducted with two general approaches . One approach utilized all but one of the regulatory default settings (other than chemical transformation) within the model, and the results of that modeling are discussed in detail below. The other approach was to use technical settings within the model that would produce a more accurate estimate of pollutant dispersion and ground-level concentrations in Utah County. These modeling results, also discussed below, demonstrate that the Unit 3 project will have an insignificant impact on Utah County, i.e. that the impact is less than the "maximum allowable impact" allowed under Utah rules, and far below the "significance level" allowed under the federal rules.

Requirements of Federal and Utah Air Quality Statutes and Rules

The Utah Administrative Code (UAC) R307-403 requires that, to determine whether a source proposed to be located outside of a PM_{10} nonattainment area is required to obtain offsets, the proposed source is modeled to see if the new source impact (Unit 3) exceeds the "maximum allowable impact" on any PM_{10} nonattainment area. Under Utah rules, the "maximum allowable impact" for PM_{10} is 1.0 microgram per cubic meter ($\mu g/m^3$) on an annual average or 3.0 $\mu g/m^3$ on a 24-hour average.[1]

[1] R307-403-5(1)(a). It is worth noting that Utah's "maximum allowable impact" 24-hour standard is considerably more stringent than the Federal rules require. The corresponding EPA rule is at 40 C.F.R 51.165(b)(2)—and the federal 24-hour significance level is 5 $\mu g/m^3$. It is also worth noting that IPP disagrees with UDAQ's direction to run CALPUFF without all of the default regulatory settings; specifically, IPP disagrees that the chemical transformation setting should be turned off. See the white paper submitted to UDAQ entitled, "The Chemical Transformation Capabilities of CALPUFF in Modeling Impact Nonattainment Areas is the Best Informational and Analytical Technique Available."

Preliminary Modeling

The Utah County modeling was performed with the EPA CALPUFF model, which is a long-range air quality dispersion model that has been formally adopted into the EPA's *Guideline on Air Quality Models* (GAQM), Appendix W of 40 CFR Part 51. With its adoption into Appendix W on April 15, 2003 (68 Federal Register 18439), CALPUFF is now the EPA-preferred model for assessing long-range (> 50 km) transport of pollutants.

For meteorological input to CALPUFF, IPP applied the same three-dimensional meteorological windfield that was developed (and approved by UDAQ) for the Class I area analysis for the Unit 3 project. Receptors were placed at 1-km spacing along the boundary and interior of the southern one-half of Utah County, as shown in Figure 1.

The preliminary analysis made use of the current regulatory default option within CALPUFF for the determination of plume growth, which employs the same dispersion coefficients used with the EPA's Industrial Source Complex Short-Term (ISCST3) model. Specifically, the current default option uses Pasquill-Gifford coefficients in rural areas and McElroy-Pooler coefficients in urban areas. Hereafter these will collectively be referred to as the either the PG method of calculating dispersion coefficients or simply PG dispersion.

Emissions of primary PM_{10} and gaseous nitrogen oxides and sulfur dioxide from the proposed Unit 3 stack were modeled, as well as PM_{10} emissions from fugitive sources associated with the handling of coal and ash for the Unit 3 project. To arrive at an estimate of total PM_{10} impacts which consisted of primary PM_{10} , gaseous sulfur dioxide, and gaseous nitrogen dioxide, the POSTUTIL routine was used to sum these components at each receptor. Nitrogen oxide impacts were multiplied by 0.75 within POSTUTIL to arrive at impacts of nitrogen dioxide. The factor of 0.75 is the national default ratio of ambient nitrogen oxide to nitrogen dioxide as listed in the GAQM.

The results of the preliminary conservative modeling yielded 4 days for which the 24-hour impacts exceeded the Utah "maximum allowable impact" level of 3.0 $\mu g/m^3$ for 24-hour impacts, yet all 4 days were below the federal significance level of 5.0 μg/m3. Annual impacts were well below the significance level of 1.0 $\mu g/m^3$.

Detailed Examination of Preliminary Results

The details of the meteorology and dispersion for the four periods with 24-hour PM_{10} concentrations above Utah's 3 $\mu g/m^3$ threshold were examined. Specifically the following were examined: the wind fields, the vertical thermal profiles, and the 1-hour PM_{10} concentrations. Furthermore, contour plots of the maximum 24-hour PM_{10} concentrations were made for each of the 4 days (see Appendix A).

Analysis of the 1-hour PM_{10} concentrations that occurred during the four maximum 24-hour periods showed that high values of PM_{10} were occurring during nighttime hours (see Appendix B). Examining the wind fields during those hours showed winds at elevations of 500 meters above ground level (AGL) blowing in a north to northeastern direction; therefore, nearly straight-line winds from the IPP to the southwest border of Utah County where the maximums occur (see Appendix C). The result of this can be seen in the four contour plots in Appendix A.

For the hours with high PM_{10} concentrations, the vertical thermal profiles were examined for points along the path from IPP to the area of the maximum impacts on the border of Utah County. This was done using the third-party software, CalDesk™. As expected for the nighttime atmosphere, stable thermal profiles were found. Furthermore, ground level inversions were also found (see Appendix D).

Under these physical conditions (i.e., stable nighttime atmosphere, ground level inversion, and nearly straight-line winds) a plume that stabilized at several hundred meters above the ground is expected to "fan out" over the top of the inversion. That is, the amount of turbulence-driven dispersion in the vertical direction should be very small relative to the turbulence-driven dispersion in the horizontal direction. The preliminary modeling, using PG dispersion, failed to capture this behavior. If the CALPUFF model with PG dispersion was accurately representing this behavior, then ground level concentrations should be quite low — the opposite of what is seen in the preliminary modeling results.

The "DEBUG" option within CALPUFF was used to examine the evolution and relative sizes of the horizontal and vertical dispersion coefficients for a puff on one of the days in question. It was found that the vertical dispersion coefficient grew more quickly than was expected (see Appendix E). This indicated that the PG dispersion approach used in the preliminary modeling was not doing a good job of capturing the very small vertical turbulence in nighttime stable air over a ground-level inversion.

Selection of Appropriate Refinement

The preliminary results were performed using the current regulatory default method of calculating the atmospheric turbulence component of the dispersion coefficients, namely, the PG dispersion coefficients for rural areas. Using this method, the dispersion coefficients are functions of the distance from the source and six discrete stability classes. The PG formulation was developed in the early 1960s to enable the calculation of the dispersion coefficients based on ambient data that were readily available at that time.

Within the CALPUFF dispersion modeling system, the stability class for each modeling grid cell is determined in the CALMET meteorological preprocessor. It should be noted that the stability class is a two-dimensional array within the CALMET.DAT file (that is, PG stability class is only calculated for the surface layer).

More refined methods of estimating dispersion coefficients are available within CALPUFF. As suggested in the CALPUFF User's Manual[2], the most desirable approach is to relate the dispersion coefficients directly to measured turbulence velocity variances or intensity components. CALPUFF does have an option to use measured values of turbulence; however, it

[2] Earth Tech, Inc., 2000. *A User's Guide for the CALPUFF Dispersion Model* (Version 5), January.

is important that the quality of the observational data be considered in the selection of the method of computing the dispersion coefficients. The User's Manual provides the example that inaccurate observations of the vertical intensity of turbulence, which is difficult to measure, would lead to less accurate modeling results than predictions based on more routine data. Consequently, the User's Manual recommends that the default selection be the use of similarity theory and micrometeorological variables derived from routinely available meteorological observations and surface characteristics.[3] This is CALPUFF's "Option 2" for calculating dispersion.

CALPUFF's Option 2 for dispersion coefficients is based on a continuous treatment for characterizing dispersion based on similarity theory. A variable called the Monin-Obukhov length is used as the stability parameter.[4] The other variables used in the similarity-based calculation of dispersion are the surface friction velocity, the convective velocity scale, and the mixing height. The meteorological preprocessor, CALMET, computes the values for each of these values for every grid cell.

The similarity-based method for calculation dispersion is the one recommended in the CALPUFF User's Manual because it has the advantages of using a fully established theory for surface layer meteorology while using variables derived from routinely available meteorological observations and surface characteristics. Furthermore, the performance of CALPUFF using similarity-based dispersion was found to be superior to CALPUFF using PG-based dispersion in comparison to data from several field studies.[5] Finally, it should be noted that a method that includes the use of similarity-based dispersion is advocated by John Irwin for regulatory applications of CALPUFF.[6]

Based on the detailed examination of the preliminary results obtained when using CALPUFF with PG-based dispersion, it was decided that the use of similarity-based dispersion would more accurately represent the behavior expected for conditions of plumes occurring in very stable air over a ground-based inversion. This is because with the similarity-based dispersion the coefficients include effects of a continuous range of stability, height above ground, and time. This is in contrast to the PG approach where only six discrete classes of stability and distance are used (equations showing the dispersion calculations used in the two approaches are given in Appendix F).

As was done for the PG-based CALPUFF modeling, the “DEBUG” option within CALPUFF was used to examine the evolution and relative sizes of the horizontal and vertical dispersion coefficients for a puff with the use of similarity-based dispersion coefficients. It was found that

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[3] "It is recommended that the default selection be Dispersion Option 2, which uses similarity theory and micrometeorological variables derived from routinely available meteorological observations and surface characteristics." Earth Tech, Inc., 2000. *A User's Guide for the CALPUFF Dispersion Model* (Version 5), January. Page 2-25.

[4] It should be noted that use of Monin-Obukhov similarity theory is one of the significant improvements in AERMOD’s formulation as compared to the ISCST3 model (EPA, *Compendium of Reports from the Peer Review Process for AERMOD*, February 2002).

[5] U.S. Environmental Protection Agency. 1998. *Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts.* Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina. December 1998.

[6] Irwin, 2001. *E-mail correspondence from John Irwin (NOAA Meteorologist, EPA Office of Air Quality Planning and Standards, Air Quality Modeling Group) to Dennis Atkinson (EPA) and Mark Bennett (CH2M HILL)*, August 10, 2001. (See Appendix I)

the vertical dispersion coefficient grew far more slowly than the horizontal dispersion coefficient, as is expected for these meteorological conditions (see Appendix G). This indicates that this approach does a much better job of capturing the very small vertical turbulence in nighttime stable air over a ground-level inversion. Hereafter this approach, as defined by John Irwin[7], is referred to as the turbulence-based approach. Details of the CALPUFF options used in this approach are provided below.

Refined Modeling

Turbulence-based dispersion was initiated in CALPUFF with the following refinements to the regulatory default technical options:

- MDISP = 2, to select dispersion coefficients from internally-calculated sigmas using micrometeorological variables
- MPDF = 1, to select the Probability Distribution Function method for dispersion in the convective boundary layer

With these refinements to the CALPUFF setup, the maximum 24-hour impact in Utah County was 1.94 μg/m^3 , as shown in Figure 2. A concentration contour plot for this day is provided in Appendix H. For the purpose of comparison, four additional 24-hour concentration contours from the turbulence-based dispersion approach are also presented. These correspond to the same 24-hour periods shown in Appendix A.

Conclusion

Use of a Turbulence-based approach (as defined above) for CALPUFF air dispersion modeling generally represents a technological advancement over the PG-based approach, and has been shown previously to yield superior results when comparing to field studies. For the specific case examined here, the Turbulence-based approach yields results that better represent the expected behavior of the plume for the stable nighttime meteorological conditions that have been examined in detail. Consequently, we conclude that CALPUFF modeling with the Turbulence-based approach for the PM_{10} impacts in the Utah County PM_{10} nonattainment area provides a more realistic result. Therefore, Unit 3's PM_{10} impacts to Utah County are comfortably below Utah's 3 μg/m^3 "maximum allowable impact" threshold, and well below EPA's 5 μg/m^3 "significance level."comfortably below Utah's 3 μg/m^3 "maximum allowable impact" threshold, and well below EPA's 5 μg/m^3 "significance level."

[7] *Id*

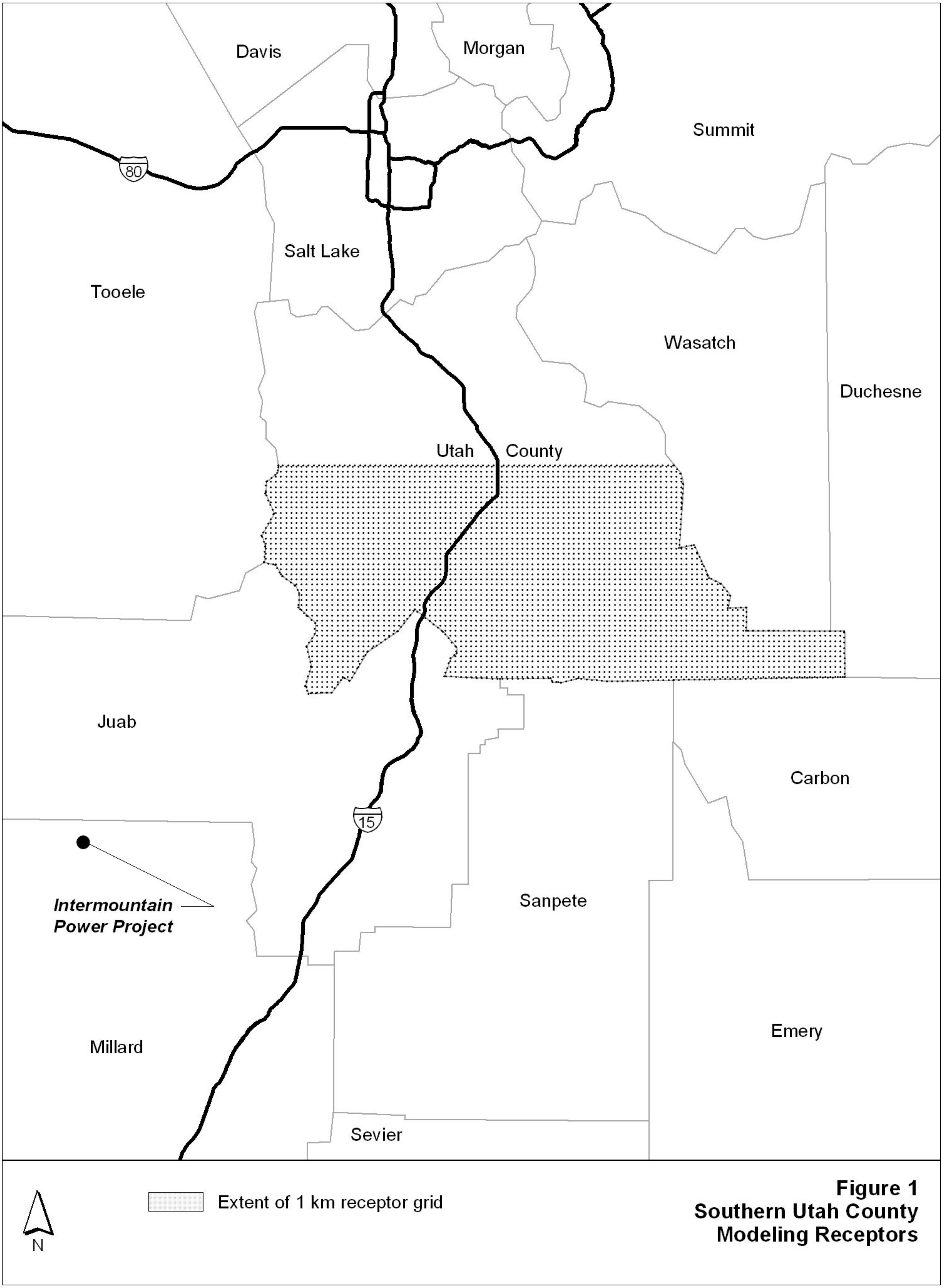
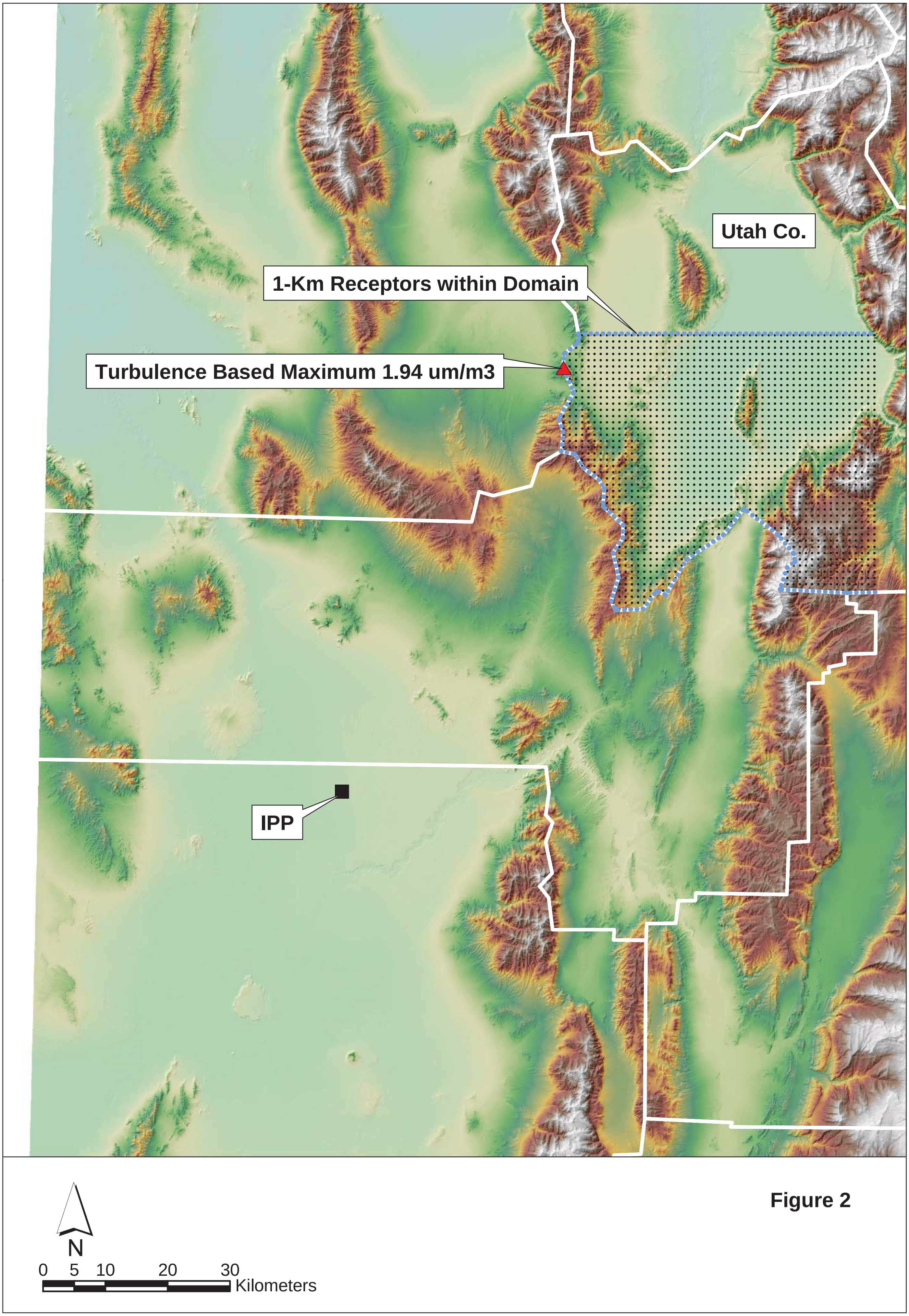


Figure 1
Southern Utah County
Modeling Receptors



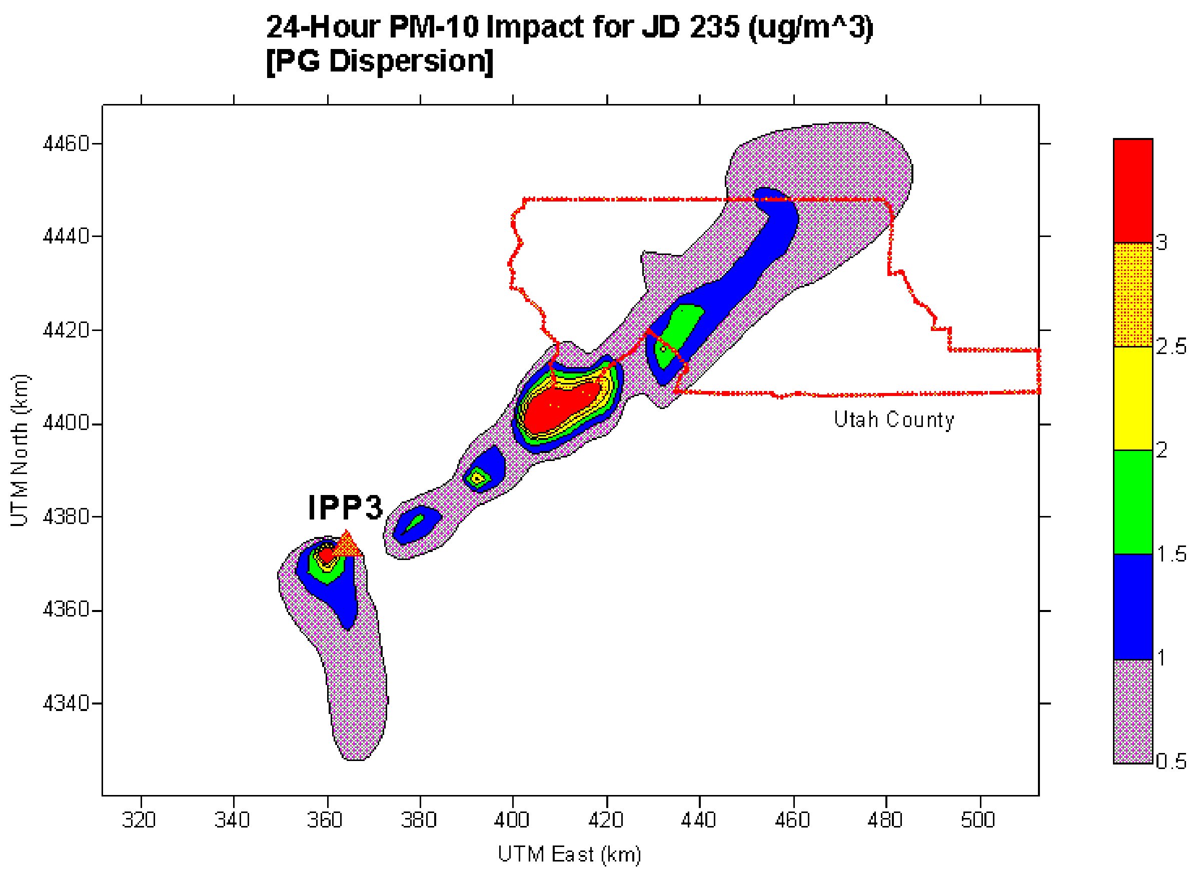
Utah Co.
1-Km Receptors within Domain
Turbulence Based Maximum 1.94 um/m3
IPP
N
0 5 10 20 30
Kilometers

Figure 2

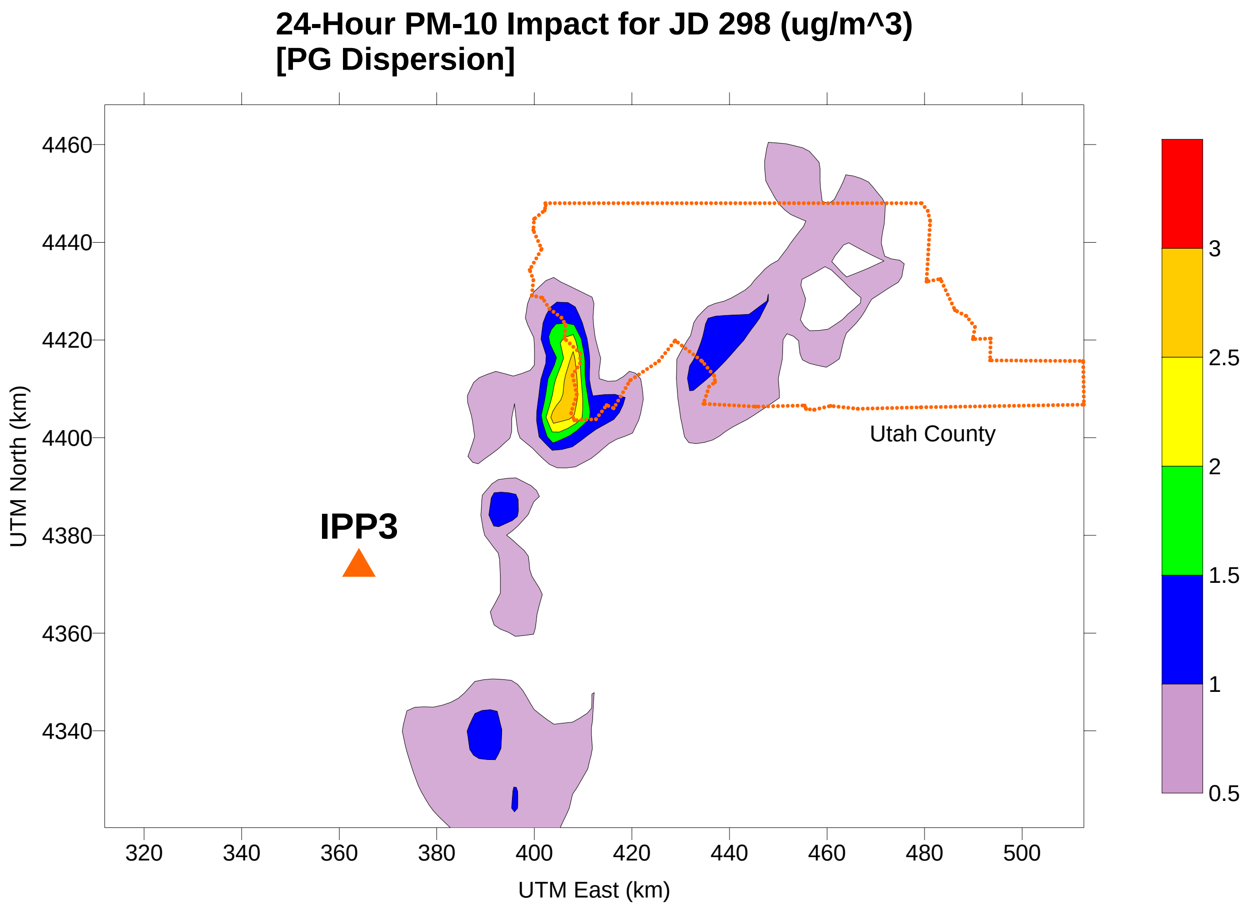
APPENDIX A

PM_{10} Concentration Contours for PG Dispersion

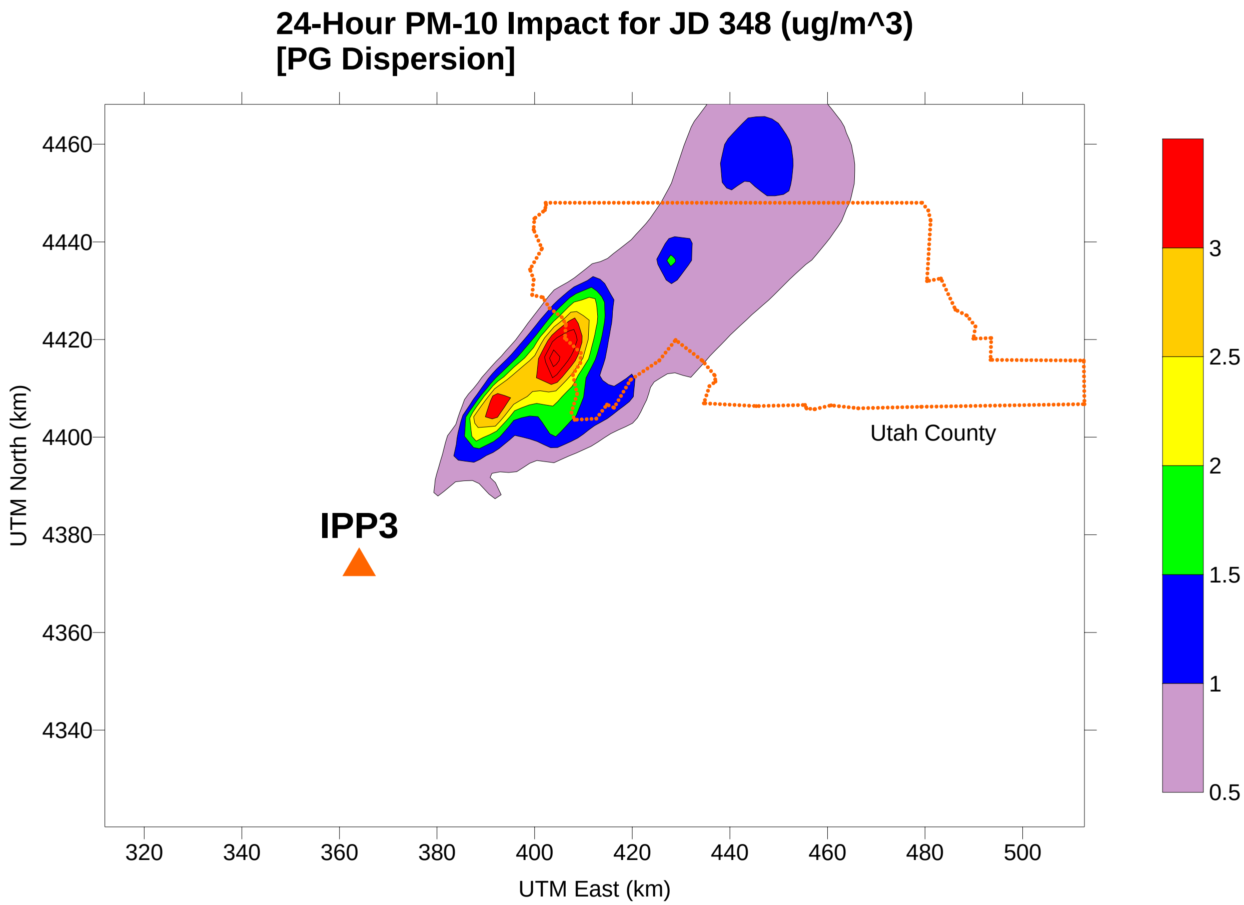
PG DISPERSION



PG DISPERSION



PG DISPERSION



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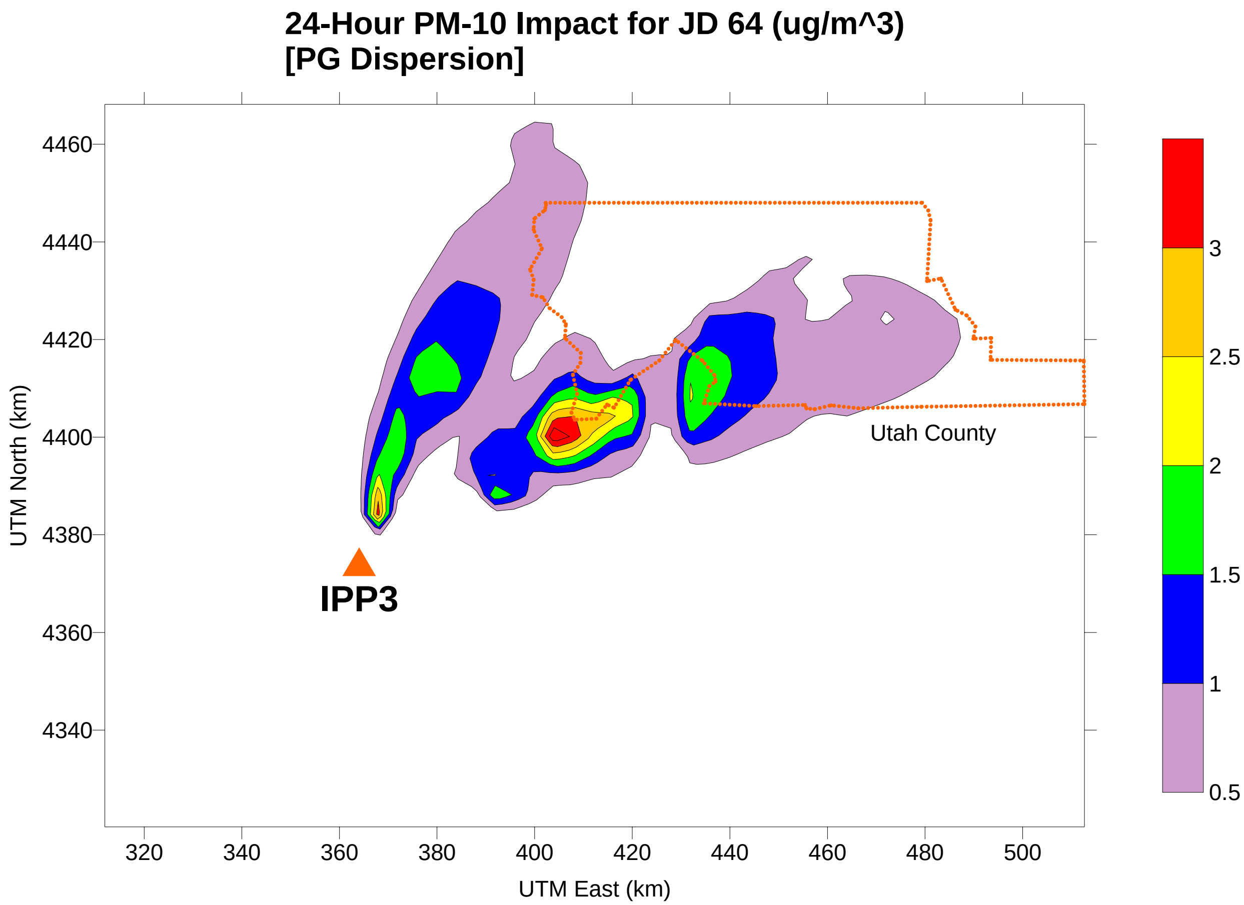


APPENDIX B

Resolution of Maximum 24-Hour PM_{10} Concentrations into 1-Hour Components (PG Dispersion)

HOURLY RESOLUTION OF JULIAN DAY 235
Maximum Concentrations at Receptor 228 Located at 408.204 4403.562

Year	Day	Hour	Receptor	Concentration (µg/m³)
Maximum 1-Hour Averages				
1996	234	0100	228	1.5413E+01
1996	234	0300	228	1.3347E+01
1996	234	0200	228	1.3250E+01
1996	234	0500	228	1.3076E+01
1996	234	0400	228	1.2983E+01
1996	234	0600	228	1.1848E+01
1996	234	0800	228	6.9362E+00
1996	234	0900	228	5.5119E+00
1996	234	0700	228	5.2080E+00
1996	234	1000	228	4.4662E+00
1996	234	1100	228	2.2755E+00
1996	234	1200	228	1.2688E+00
1996	234	1300	228	5.5146E-01
1996	234	1400	228	4.9933E-01
1996	234	1500	228	3.3933E-01
1996	234	1600	228	2.5280E-01
1996	234	1700	228	1.5715E-01
1996	234	1800	228	7.9274E-02
1996	234	1900	228	3.3136E-02
1996	234	2000	228	7.8806E-03
1996	234	2100	228	3.1092E-03
1996	234	2200	228	1.4211E-03
1996	234	2300	228	3.2724E-04
1996	235	0000	228	3.1077E-05
Maximum 24-Hour Average				
1996	235	0000	228	4.4796E+00

HOURLY RESOLUTION OF JULIAN DAY 298
Maximum Concentrations at Receptor 239 Located at 408.070 4411.723

Year	Day	Hour	Receptor	Concentration (μg/m³)
Maximum 1-Hour Averages				
1996	297	0400	239	8.7618E+00
1996	297	0500	239	8.6409E+00
1996	297	0200	239	8.5618E+00
1996	297	0300	239	8.5581E+00
1996	297	0600	239	7.9941E+00
1996	297	0100	239	7.9403E+00
1996	297	0700	239	7.6058E+00
1996	297	0800	239	4.0820E+00
1996	297	0900	239	3.8928E+00
1996	297	1000	239	3.1381E+00
1996	297	1100	239	1.7405E+00
1996	297	1200	239	7.3031E-01
1996	297	1300	239	3.1778E-01
1996	297	1400	239	1.0582E-01
1996	297	1500	239	3.0255E-02
1996	297	1600	239	7.5059E-03
1996	297	1700	239	6.4968E-03
1996	297	1900	239	3.1710E-03
1996	297	1800	239	3.0451E-03
1996	297	2000	239	1.5598E-03
1996	297	2100	239	1.0479E-03
1996	297	2200	239	1.0289E-03
1996	297	2300	239	8.5623E-04
1996	298	0000	239	3.5747E-04
Maximum 24-Hour Average				
1996	298	0000	239	3.0052E+00

HOURLY RESOLUTION OF DAY 348
Maximum Concentrations at Receptor 1506 Located at 406.859 4419.785

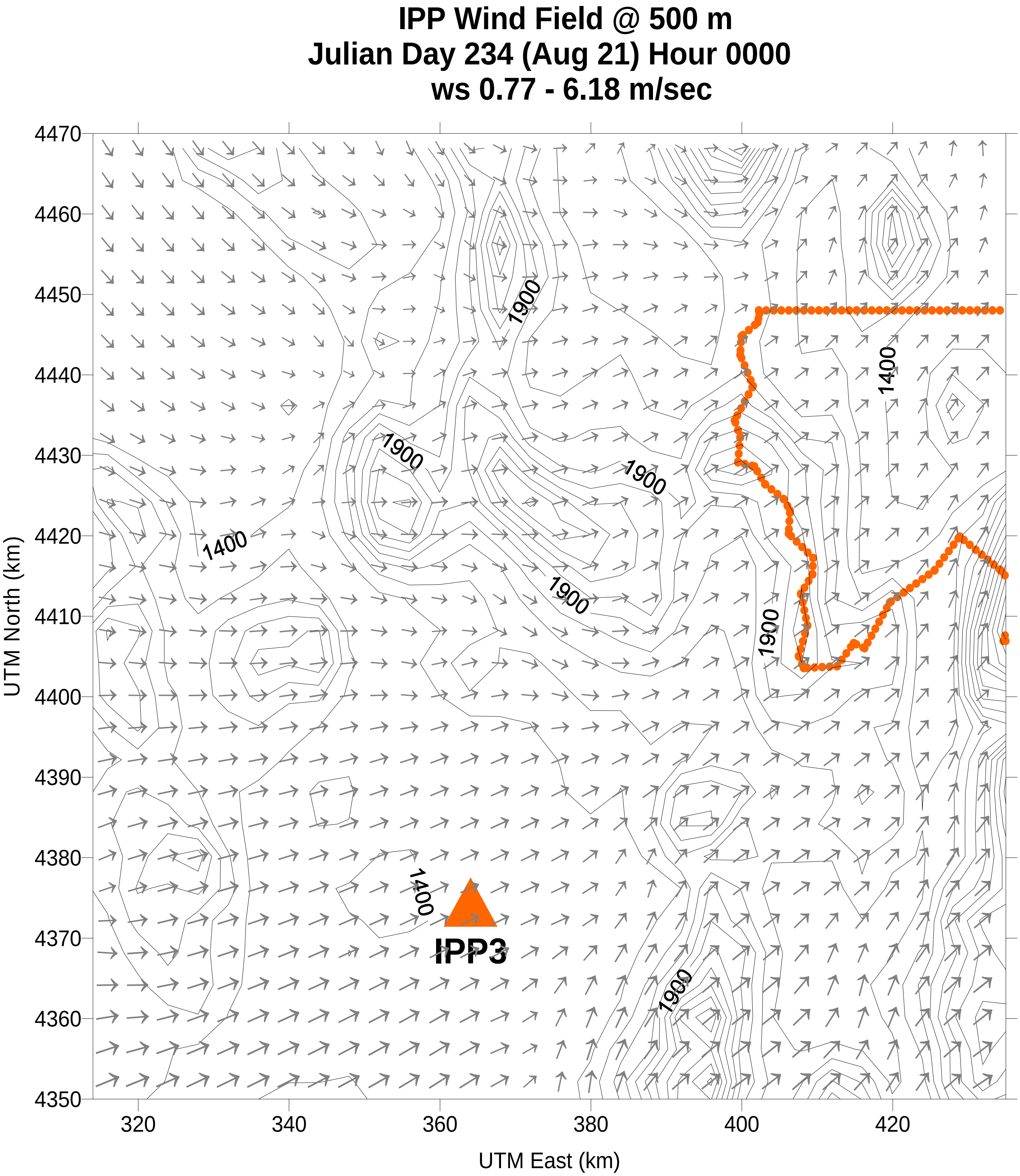
Year	Day	Hour	Receptor	Concentration (µg/m³)
Maximum 1-Hour Averages				
1996	347	0500	1506	1.0004E+01
1996	347	0400	1506	9.2848E+00
1996	347	0800	1506	8.6414E+00
1996	347	0200	1506	8.5973E+00
1996	347	0600	1506	6.7898E+00
1996	347	0700	1506	6.6112E+00
1996	347	1000	1506	6.5368E+00
1996	347	0100	1506	6.4324E+00
1996	347	1100	1506	6.4106E+00
1996	347	0900	1506	6.3032E+00
1996	347	0300	1506	6.1161E+00
1996	347	1200	1506	4.8939E+00
1996	347	1300	1506	3.2973E+00
1996	347	1400	1506	2.8711E+00
1996	347	1500	1506	1.0937E+00
1996	347	2200	1506	6.5675E-01
1996	347	1600	1506	6.0492E-01
1996	347	2100	1506	2.1084E-01
1996	347	1700	1506	1.5410E-01
1996	347	2300	1506	1.9543E-02
1996	347	2000	1506	3.8014E-03
1996	348	0000	1506	0.0000E+00
1996	347	1800	1506	0.0000E+00
1996	347	1900	1506	0.0000E+00
Maximum 24-Hour Average				
1996	348	0	1506	3.9806E+00

HOURLY RESOLUTION OF JULIAN DAY 64
Maximum Concentrations at Receptor 228 Located at 408.204 4403.562

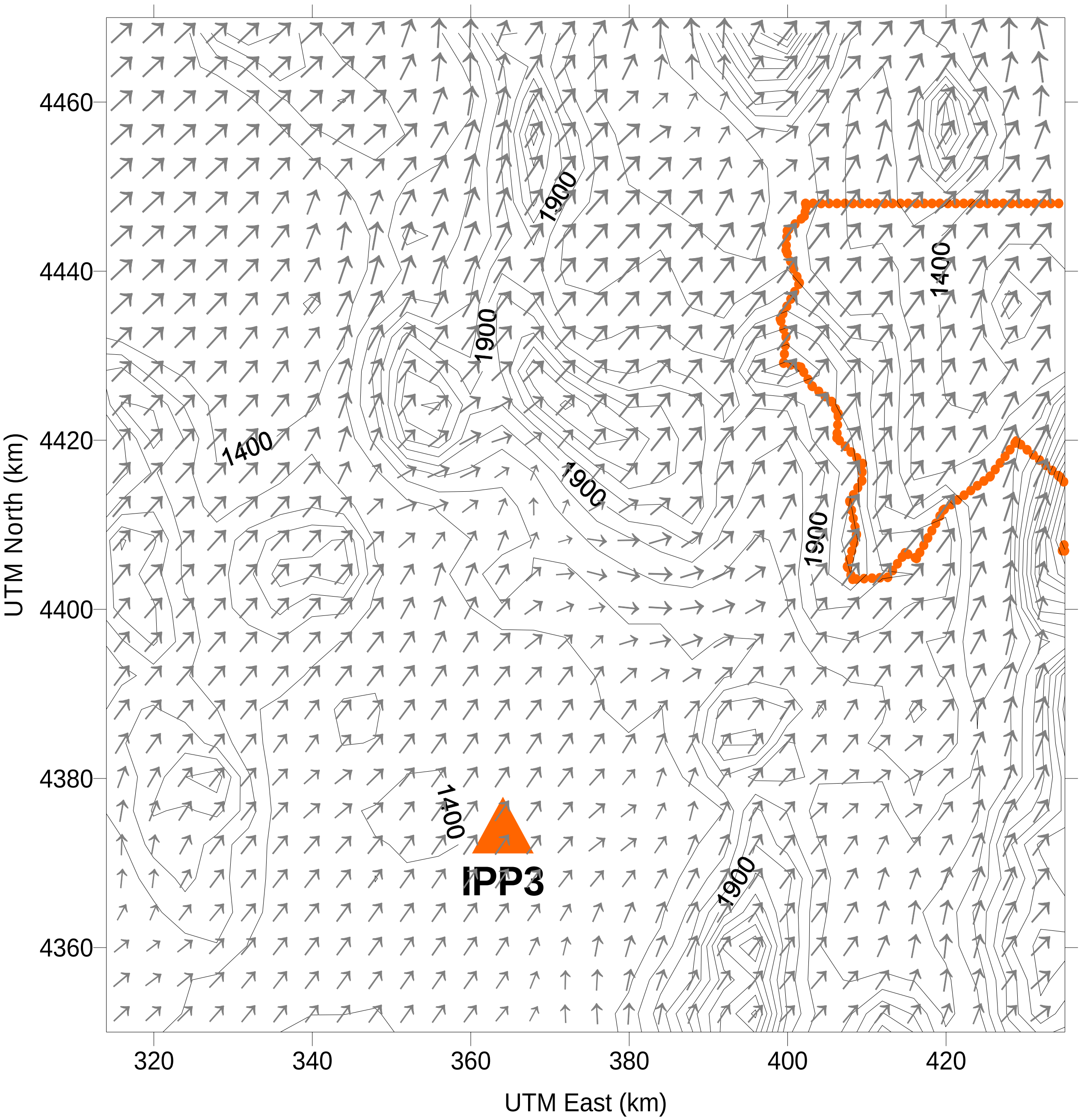
Year	Day	Hour	Receptor	Concentration ($\mu g/m^3$)
Maximum 1-Hour Averages				
1996	63	0100	228	8.9713E+00
1996	63	0900	228	8.3260E+00
1996	63	0700	228	8.0061E+00
1996	63	0500	228	7.8129E+00
1996	63	0600	228	7.7382E+00
1996	63	1000	228	7.4928E+00
1996	63	0800	228	6.9248E+00
1996	63	0200	228	6.7502E+00
1996	63	0400	228	6.7131E+00
1996	63	0300	228	6.2243E+00
1996	63	1100	228	1.2962E+00
1996	63	1200	228	1.2026E-02
1996	63	1800	228	0.0000E+00
1996	63	1700	228	0.0000E+00
1996	63	1600	228	0.0000E+00
1996	63	1500	228	0.0000E+00
1996	63	1400	228	0.0000E+00
1996	63	1300	228	0.0000E+00
1996	64	0000	228	0.0000E+00
1996	63	2300	228	0.0000E+00
1996	63	2200	228	0.0000E+00
1996	63	2100	228	0.0000E+00
1996	63	2000	228	0.0000E+00
1996	63	1900	228	0.0000E+00
Maximum 24-Hour Average				
1996	64	0000	228	3.1778E+00

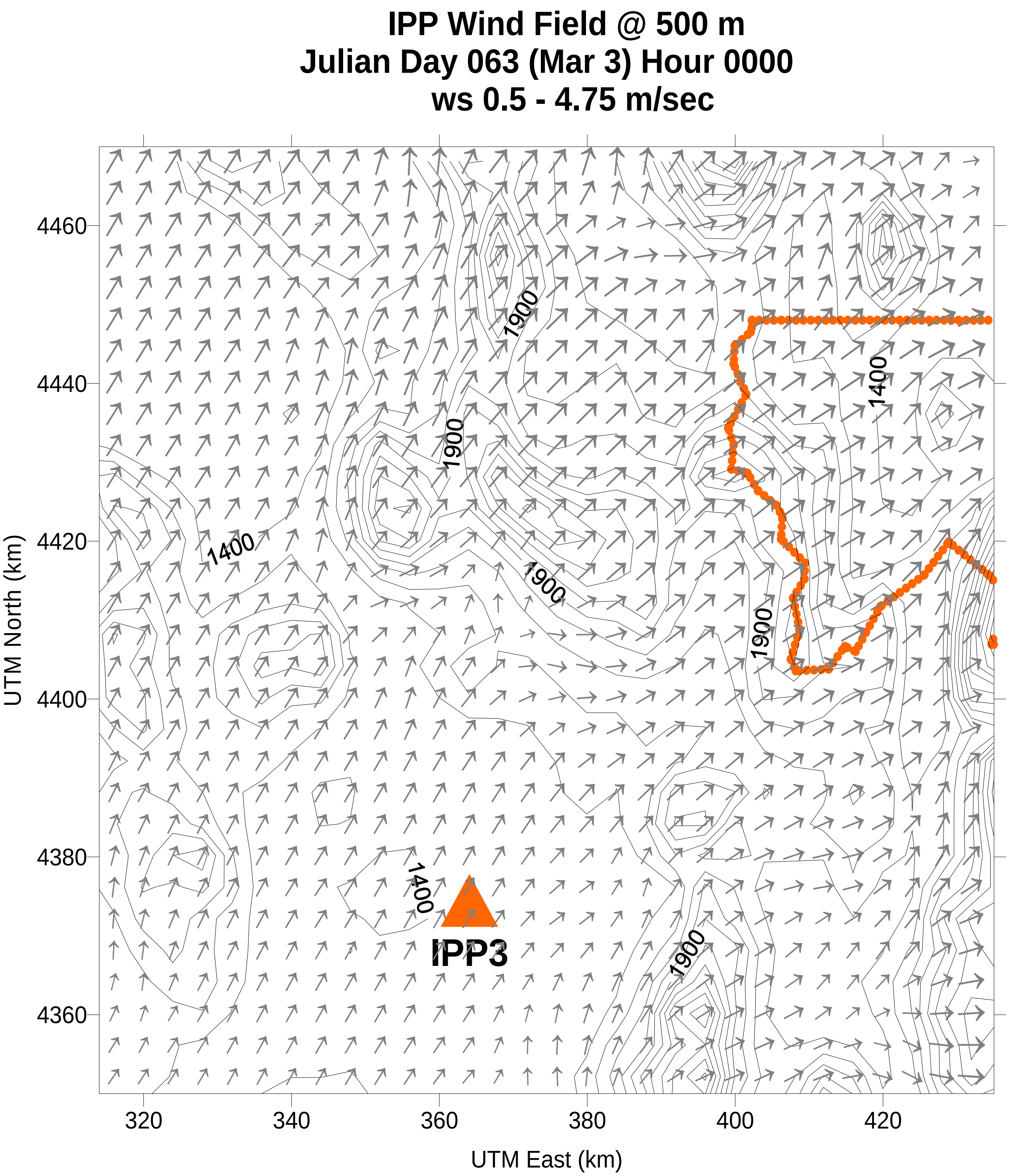
APPENDIX C

Representative Windfields

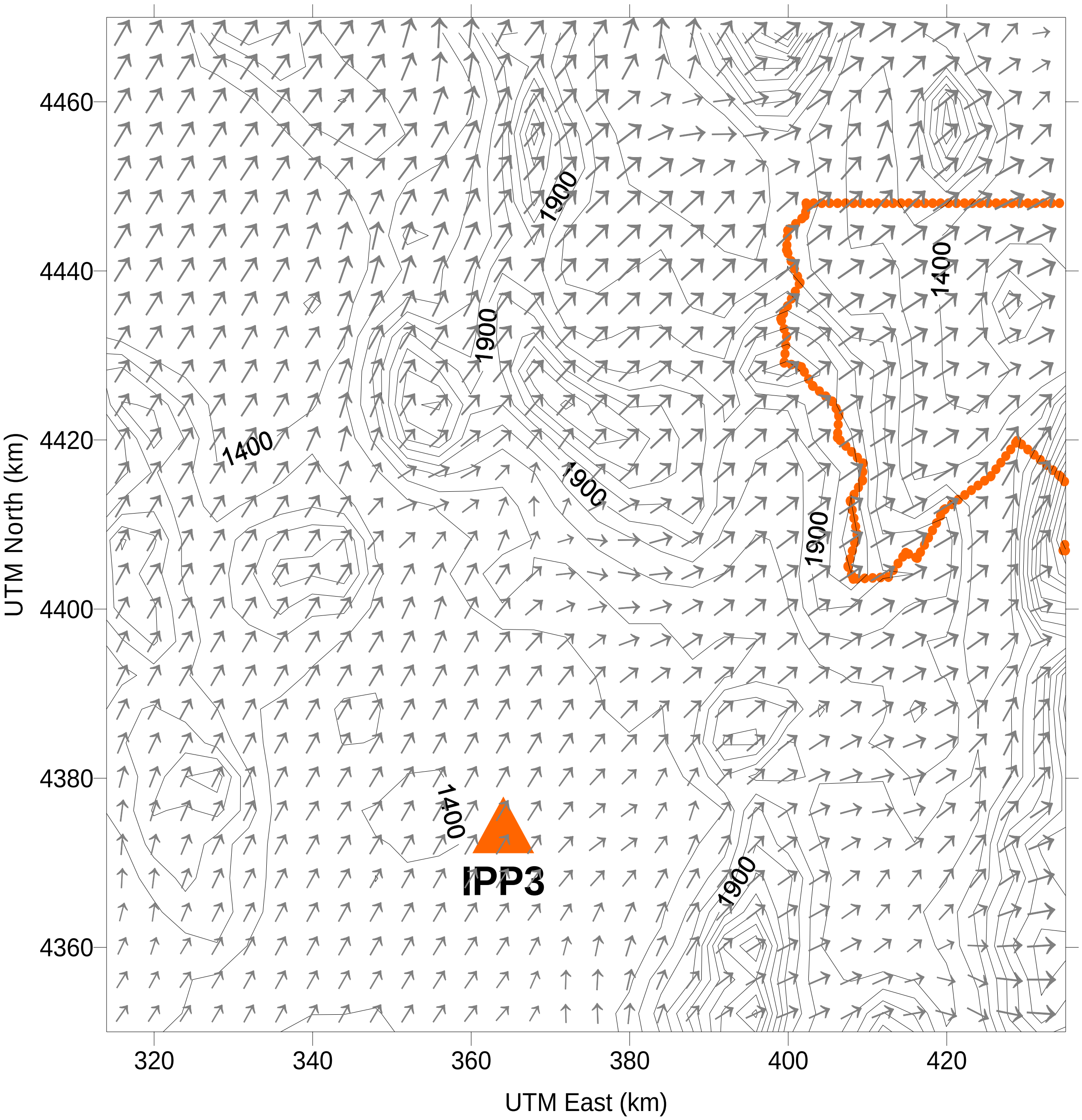

IPP Wind Field @ 500 m
Julian Day 234 (Aug 21) Hour 0000
ws 0.77 - 6.18 m/sec
4470
4460
4450
4440
4430
4420
4410
4400
4390
4380
4370
4360
4350
UTM North (km)
320
340
360
380
400
420
UTM East (km)
1900
1400
IPP3

IPP Wind Field @ 500 m
Julian Day 297 (Oct 23) Hour 0300
ws 0.68 - 2.68 m/sec




IPP Wind Field @ 500 m
Julian Day 063 (Mar 3) Hour 0000
ws 0.5 - 4.75 m/sec
UTM North (km)
4460
4440
4420
4400
4380
4360
UTM East (km)
320
340
360
380
400
420
1900
1400
IPP3

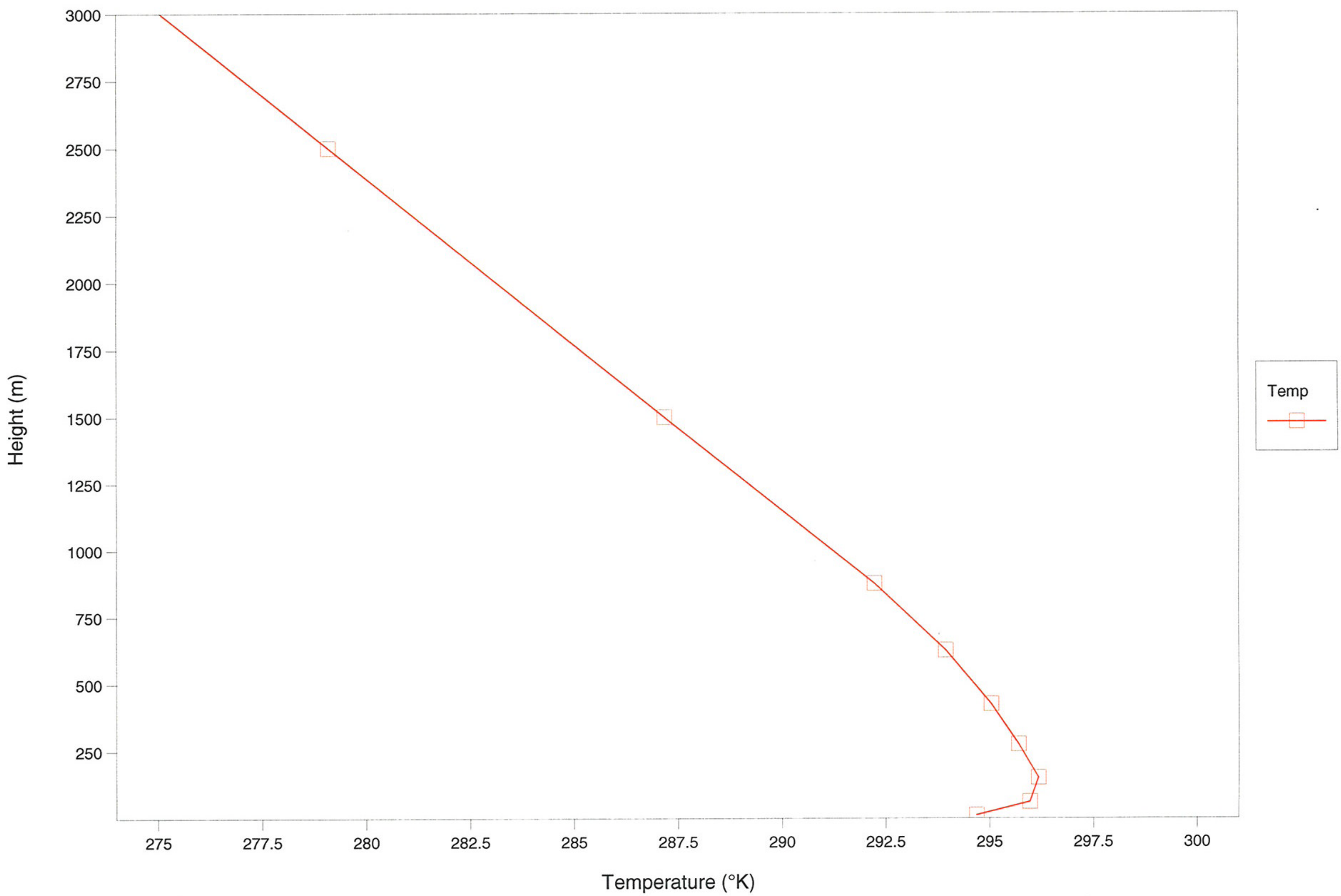
IPP Wind Field @ 500 m
Julian Day 063 (Mar 3) Hour 0000
ws 0.5 - 4.75 m/sec

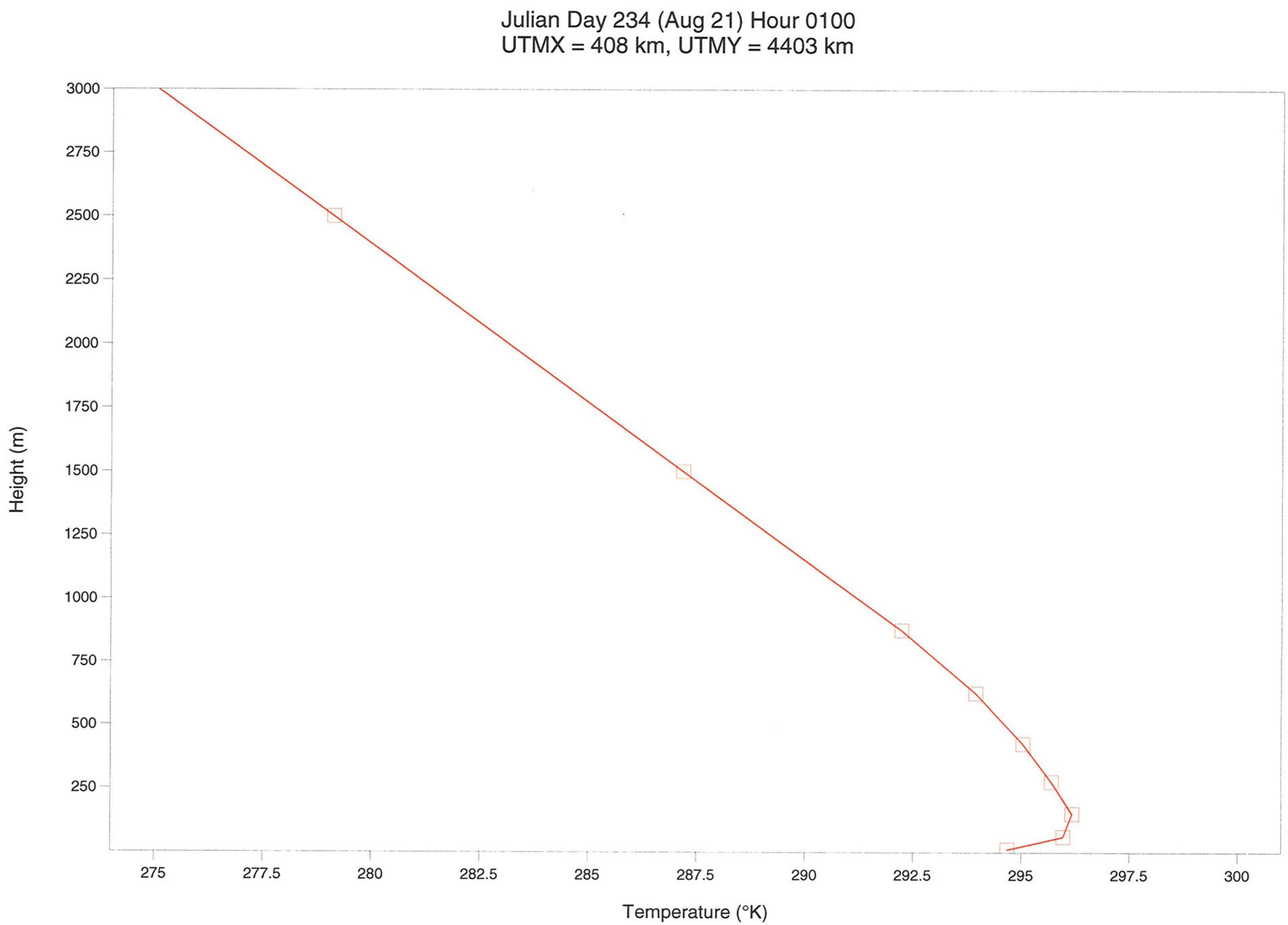


APPENDIX D

Representative Thermal Profiles

Julian Day 234 (Aug 21) Hour 0100
UTMX = 371 km, UTMY = 4378 km




Julian Day 234 (Aug 21) Hour 0100
UTMX = 408 km, UTMY = 4403 km
Height (m)
3000
2750
2500
2250
2000
1750
1500
1250
1000
750
500
250
275
277.5
280
282.5
285
287.5
290
292.5
295
297.5
300
Temperature (°K)

APPENDIX E

Representative Growth of σ_y and σ_z (PG Dispersion)

REPRESENTATIVE GROWTH OF σY AND σZ

PG Dispersion

YYYYJJJHH[1]	ipnum	Cd	zfnl	x(metG)	y(metG)	UTMX	UTMY	sigyB	sigzB	QM	QU	zimax	rflctn	dpbl	jdstab
199623322	1	1	444.1	52.4	78.5	367.5	4376.1	115.2	30.4	1.23E+05	0.0E+0	10000	10000	50.0	6
199623322	1	1	444.1	53.3	78.9	371.0	4377.8	213.8	42.6	1.23E+05	0.0E+0	10000	10000	50.0	6
199623322	1	1	444.1	54.1	79.3	374.4	4379.4	305.7	52.1	1.23E+05	0.0E+0	10000	10000	50.0	6
199623322	1	1	444.1	54.9	79.7	377.6	4380.9	388.1	59.3	1.23E+05	0.0E+0	10000	10000	50.0	6
199623323	1	1	444.1	55.6	80.0	380.5	4382.3	462.0	68.1	1.23E+05	0.0E+0	10000	10000	57.2	6
199623323	1	1	444.1	56.3	80.4	383.1	4383.8	528.0	76.3	1.23E+05	0.0E+0	10000	10000	66.0	6
199623323	1	1	444.1	56.9	80.8	385.5	4385.3	840.4	83.6	1.23E+05	0.0E+0	10000	10000	105.6	6
199623323	1	1	444.1	57.5	81.2	387.9	4386.9	1290.4	91.0	1.23E+05	0.0E+0	10000	10000	117.2	6
199623400	1	1	444.1	58.1	81.6	390.4	4388.5	1740.4	94.8	1.23E+05	0.0E+0	10000	10000	143.2	6
199623400	1	1	444.1	58.7	82.0	392.8	4390.1	2190.4	96.7	1.23E+05	0.0E+0	10000	10000	193.6	6
199623400	1	1	444.1	59.3	82.4	395.3	4391.8	2640.4	106.4	1.23E+05	0.0E+0	10000	10000	159.0	5
199623400	1	1	444.1	60.0	82.8	397.8	4393.4	3090.4	114.4	1.23E+05	0.0E+0	10000	10000	159.0	5
199623401	1	1	444.1	60.6	83.3	400.4	4395.2	3540.4	116.3	1.22E+05	0.0E+0	10000	10000	148.2	6
199623401	1	1	444.1	61.3	83.7	403.0	4397.0	3990.4	117.0	1.22E+05	0.0E+0	10000	10000	148.2	6
199623401	1	1	444.1	61.9	84.2	405.6	4398.9	4440.4	117.3	1.22E+05	0.0E+0	10000	10000	149.4	6
199623401	1	1	444.1	62.5	84.6	408.1	4400.7	4890.4	117.6	1.21E+05	0.0E+0	10000	10000	108.7	6
199623402	1	1	444.1	63.2	85.1	410.9	4402.7	5340.4	117.9	1.20E+05	0.0E+0	10000	10000	106.7	6
199623402	1	1	444.1	64.0	85.7	413.7	4404.8	5790.4	118.2	1.19E+05	0.0E+0	10000	10000	92.4	6
199623402	1	1	444.1	64.7	86.2	416.6	4406.9	6240.4	120.7	1.19E+05	0.0E+0	10000	10000	113.1	6
199623402	1	1	444.1	65.4	86.7	419.4	4409.0	6690.4	131.5	1.18E+05	0.0E+0	10000	10000	202.9	6
199623403	1	1	444.1	66.0	87.2	421.8	4410.9	7050.4	141.9	1.17E+05	0.0E+0	10000	10000	153.1	6
199623403	1	1	444.1	66.5	87.7	424.1	4412.9	7410.4	160.3	1.17E+05	0.0E+0	10000	10000	107.3	6
199623403	1	1	444.1	67.0	88.2	425.9	4415.1	7770.4	181.0	1.17E+05	0.0E+0	10000	10000	107.3	6

REPRESENTATIVE GROWTH OF σY AND σZ

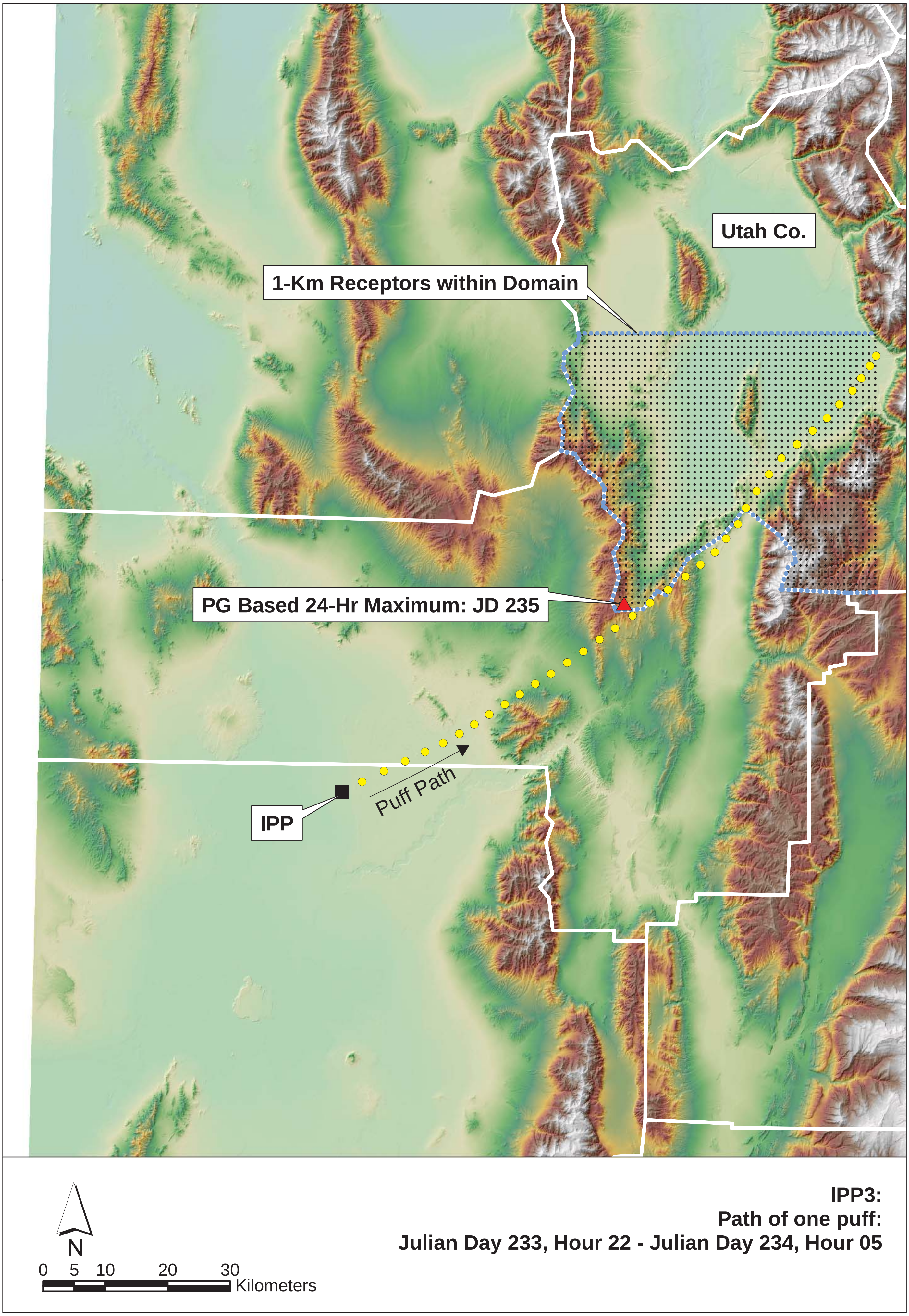
PG Dispersion

YYYYJJJHH[1]	ipnum	Cd	zfnl	x(metG)	y(metG)	UTMX	UTMY	sigyB	sigzB	QM	QU	zimax	rflctn	dpbl	jdstab
199623403	1	1	444.1	67.5	88.8	427.8	4417.4	8130.4	203.9	1.17E+05	0.0E+0	10000	10000	183.9	5
199623403	1	1	444.1	67.8	89.5	429.1	4420.0	8490.4	216.9	1.16E+05	0.0E+0	10000	10000	221.5	5
199623404	1	1	444.1	68.2	90.1	430.8	4422.7	8850.4	230.4	1.16E+05	0.0E+0	10000	10000	60.4	6
199623404	1	1	444.1	68.7	90.8	432.8	4425.4	9210.4	230.4	1.16E+05	0.0E+0	10000	10000	67.4	6
199623404	1	1	444.1	69.2	91.4	434.8	4428.0	9570.4	230.4	1.16E+05	0.0E+0	10000	10000	54.8	6
199623404	1	1	444.1	69.8	92.0	437.3	4430.2	9930.4	230.4	1.16E+05	0.0E+0	10000	10000	52.2	6
199623404	1	1	444.1	70.5	92.6	439.8	4432.4	10290.	230.6	1.16E+05	0.0E+0	10000	10000	50.0	6
199623405	1	1	444.1	71.0	93.1	442.1	4434.4	10590.	234.4	1.16E+05	0.0E+0	10000	10000	50.0	6
199623405	1	1	444.1	71.5	93.6	444.1	4436.6	10890.	238.3	1.16E+05	0.0E+0	10000	10000	50.0	6
199623405	1	1	444.1	72.1	94.2	446.2	4438.8	11190.	247.7	1.16E+05	0.0E+0	10000	10000	50.0	6
199623405	1	1	444.1	72.4	94.7	447.6	4440.8	11490.	257.5	1.16E+05	0.0E+0	10000	10000	50.0	6
199623405	1	1	444.1	72.8	95.2	449.0	4442.8	11790.	267.6	1.16E+05	0.0E+0	10000	10000	50.0	6
199623405	1	1	444.1	73.0	95.6	450.0	4444.4	12090.	267.6	1.15E+05	0.0E+0	10000	10000	50.0	6

[1] Refer to table on the following page for explanation of column headings

EXPLANATION OF COLUMN HEADINGS

Column Heading	Description
YYYYJJJHH	Year-Julian Day-Hour for modeling period
IPNUM	Puff ID number
CD	Puff Code (1 = Puff within mixed layer & Gaussian)
ZNFL	Puff height (m) at final rise
X	X-coordinate of puff or old slug-end (Met Grid Units)
Y	Y-coordinate of puff or old slug end (Met Grid Units)
UTMX	X-coordinate in UTM (km)
UTMY	Y-coordinate in UTM (km)
SIGYB	Sigma-y of puff or old slug-end (m)
SIGZB	Sigma-z of puff or old slug-end (m)
QM	Puff mass (g) of species 1 below mixing lid
QU	Puff mass (g) of species 1 above mixing lid
ZIMAX	Largest mixing height (m) for this puff (10000m used for unlimited mixing)
RFLCTN	Reflecting lid height (m) for Gaussian distribution (10000 m used for unlimited mixing)
DPBL	Current surface boundary layer height (m)
JDSTAB	Stability Class



IPP3:
Path of one puff:
Julian Day 233, Hour 22 - Julian Day 234, Hour 05

APPENDIX F

Treatment of Dispersion in CALPUFF

TREATMENT OF DISPERSION IN CALPUFF

The technical details of the workings of the CALPUFF dispersion model are given in Chapter 2 of "A User's Guide for the CALPUFF Dispersion Model,"[1] with a specific discussion of the various options for the treatment of dispersion provided in Section 2.2. Section 2.2 is summarized here with respect to the two options used in the modeling of the PM_{10} impacts in the Utah County PM_{10} nonattainment area from IPP Unit 3. The two options used, and the two options summarized here are Option 3, Pasquill-Gifford dispersion coefficients for rural areas (computed using the ISCST multi-segment approximation) and McElroy-Pooler coefficients in urban areas (hereafter referred to collectively as the PG method), and Option 2, dispersion coefficients from internally calculated σ_V and σ_W using micrometeorological variables (u_*, w_*, L, etc.) (hereafter referred to as the turbulance-based method). The two methods represent two different approaches to correlations for the horizontal and vertical dispersion coefficients used in the Gaussian dispersion equations, σ_y and σ_z , respectively.

PG Method

In the PG method σy and σz ,are estimated based on the stability class and on the distance downwind the puff has traveled. The stability classes are determined in CALMET, the meteorological preprocessor of the CALPUFF dispersion system, and passed to CALPUFF as a two-dimensional array. The stability class is determined from standard meteorological data: wind speed at 10 meters, solar radiation, and nighttime cloud cover.

The correlations used in CALPUFF are given in Tables 2-4, 2-5, 2-6, and 2-7 of the User's Manual (which are inserted below for the reader's convenience). As can be seen, in the PG method dispersion coefficients are completely determined by the stability class of the grid cell, whether the grid cell is considered "rural" or "urban", and the distance downwind the puff has moved.

It should be noted that Pasquill introduced the concept of the stability class in 1961 due to the need for a readily usable way to define atmospheric stability based on then present-day routine observations. However, Monin-Obukhov theory (and its use of the Monin-Obukhov length to define stability) has been the well-accepted foundation of surface layer meteorology since the early 1950s.

[1] Earth Tech, Inc., 2000. *A User's Guide for the CALPUFF Dispersion Model* (Version 5). January 2000.

Table 2-4

Parameters Used to Calculate Pasquill-Gifford σ_y

	$\sigma_y = 465.11628\,(x)\tan(\theta)$** $\theta = 0.017453293\,(c - d \ln x)$	
Pasquill Stability Class	c	d
A	24.1670	2.5334
B	18.3330	1.8096
C	12.5000	1.0857
D	8.3330	0.72382
E	6.2500	0.54287
F	4.1667	0.36191

* Source: U.S. EPA (1992)

** Where σ_y is in meters and x is in kilometers

Table 2-5
Parameters Used to Calculate Pasquill-Gifford σ_z*

Pasquill Stability Class	x (km)	σ_z (meters) = a x^b	
		a	b
A**	<.10	122.800	0.94470
	0.10 - 0.15	158.080	1.05420
	0.16 - 0.20	170.220	1.09320
	0.21 - 0.25	179.520	1.12620
	0.26 - 0.30	217.410	1.26440
	0.31 - 0.40	258.890	1.40940
	0.41 - 0.50	346.750	1.72830
	0.51 - 3.11	453.850	2.11660
	> 3.11	**	**
B**	<.20	90.673	0.93198
	0.21 - 0.40	98.483	0.98332
	> 0.40	109.300	1.09710
C**	All	61.141	0.91465
D	<.30	34.459	0.86974
	0.31 - 1.00	32.093	0.81066
	1.01 - 3.00	32.093	0.64403
	3.01 - 10.00	33.504	0.60486
	10.01 - 30.00	36.650	0.56589
	> 30.00	44.053	0.51179
E	<.10	24.260	0.83660
	0.10 - 0.30	23.331	0.81956
	0.31 - 1.00	21.628	0.75660
	1.01 - 2.00	21.628	0.63077
	2.01 - 4.00	22.534	0.57154
	4.01 - 10.00	24.703	0.50527
	10.01 - 20.00	26.970	0.46713
	20.01 - 40.00	35.420	0.37615
	> 40.00	47.618	0.29592
F	<.20	15.209	0.81558
	0.21 - 0.70	14.457	0.78407
	0.70 - 1.00	13.953	0.68465
	1.01 - 2.00	13.953	0.63227
	2.01 - 3.00	14.823	0.54503
	3.01 - 7.00	16.187	0.46490
	7.01 - 15.00	17.836	0.41507
	15.01 - 30.00	22.651	0.32681
	30.01 - 60.00	27.074	0.27436
	> 60.00	34.219	0.21716

* Source: U.S. EPA (1992)
** If the calculated value of σ_z exceeds 5000 m, σ_z is set equal to 5000 m

Table 2-6

Briggs Formulas Used to Calculate McElroy-Pooler σ_{y*}

Pasquill Stability Category	σ_y (meters)**
A	$0.32 x (1.0 + 0.0004 x)^{-1/2}$
B	$0.32 x (1.0 + 0.0004 x)^{-1/2}$
C	$0.22 x (1.0 + 0.0004 x)^{-1/2}$
D	$0.16 x (1.0 + 0.0004 x)^{-1/2}$
E	$0.11 x (1.0 + 0.0004 x)^{-1/2}$
F	$0.11 x (1.0 + 0.0004 x)^{-1/2}$

* Source: U.S. EPA (1992)
** where x is in meters

Table 2-7

Briggs Formulas Used to Calculate McElroy-Pooler σ_{z*}

Pasquill Stability Category	σ_z (meters)**
A	$0.24 x (1.0 + 0.001 x)^{+1/2}$
B	$0.24 x (1.0 + 0.001 x)^{+1/2}$
C	$0.20 x$
D	$0.14 x (1.0 + 0.0003 x)^{-1/2}$
E	$0.08 x (1.0 + 0.0015 x)^{-1/2}$
F	$0.08 x (1.0 + 0.0015 x)^{-1/2}$

* Source: U.S. EPA (1992)
** where x is in meters

Turbulence-Based Method

The turbulence-based method used in CALPUFF is an implementation of the correlations for SS. A general form for a time-dependent form of the dispersion coefficients is given in Equations 2-39 and 2-40 of the User's Manual (which are inserted below for the reader's convenience).

The general forms of σ_{yt} and σ_{zt} (Hanna et al., 1977) for Dispersion Options 1, 2, and 5 are:

$$\sigma_{yt} = \sigma_v \; t \; f_y\left(t / t_{ly}\right) \tag{2-39}$$

$$\sigma_{zt} = \sigma_w \; t \; f_z\left(t / t_{lz}\right) \tag{2-40}$$

In the turbulence-based method, the σV and σW components of those equations are derived using similarity theory and micrometeorological variables derived from routinely available meteorological observations and surface characteristics. These include surface friction velocity (u*), convective velocity scale (w*), mixing height (h), and Monin-Obukhov length (L). The Monin-Obukhov length is the height above the ground at which the production of turbulence by buoyancy forces first equals the mechanical (shear) production of turbulence.

The correlations used in CALPUFF are given in Equations 2-52 through 2-64 of the User's Manual (which are inserted below for the reader's convenience). As can be seen, these range of equations address not only changes in stability, but also changes in the height of the plume with respect to the mixing height.

Surface Layer: $z \leq 0.1$ h (L ≤ 0)

$$\sigma_v = \left[4\ u_*^2\ a_n^2 + 0.35\ w_*^2\right]^{1/2} \tag{2-52}$$

$$\sigma_w = \left[1.6\ u_*^2\ a_n^2 + 2.9\ u_*^2\ (-z/L)^{2/3}\right]^{1/2} \tag{2-53}$$

$$a_n = \exp\left[-0.9\,(z/h)\right] \tag{2-54}$$

Mixed-Layer: z = 0.1-0.8 h (L ≤ 0)

$$\sigma_v = \left[4\ u_*^2\ a_n^2 + 0.35\ w_*^2\right]^{1/2} \tag{2-55}$$

$$\sigma_w = \left[1.15\ u_*^2\ a_n^2 + 0.35\ w_*^2\right]^{1/2} \tag{2-56}$$

Entrainment Layer: z > 0.8 h (L ≤ 0)

$$\sigma_v = \left[4\ u_*^2\ a_n^2 + 0.35\ w_*^2\right]^{1/2} \tag{2-57}$$

for z = 0.8 to 1.0 h

$$\sigma_w = \left[1.15\ u_*^2\ a_n^2 + a_{c1}\ 0.35\ w_*^2\right]^{1/2} \tag{2-58}$$

$$a_{c1} = \left[1/2 + (h - z)/(0.4h)\right] \tag{2-59}$$

for z = 1.0 to 1.2 h

$$\sigma_w = \left[1.15\ u_*^2\ a_n^2 + a_{c2}\ 0.35\ w_*^2\right]^{1/2} \tag{2-60}$$

$$a_{c2} = \left[1/3 + (1.2h - z)/(1.2h)\right] \tag{2-61}$$

In the neutral-stable boundary layer, the following equations can be used to interpolate vertical profiles of σ_v and σ_w as a function of stability. As with the neutral-convective equations, they provide the proper values in the appropriate stability limits.

$$\sigma_v = u_*\left[\left(1.6\ C_s\ (z/L) + 1.8\ a_n\right)/(1 + z/L)\right] \qquad (L > 0) \tag{2-62}$$

$$\sigma_w = 1.3\ u_*\ \left[\left(C_s\ (z/L) + a_n\right)/(1 + z/L)\right] \qquad (L > 0) \tag{2-63}$$

$$C_s = (1 - z/h)^{3/4} \qquad (L > 0) \tag{2-64}$$

A method developed by John Irwin is used to address the time-dependent part of Equations 2-39 and 2-40. This is given in equations 2-65 through 2-67 in the User's Manual (which are inserted below for the reader's convenience).

Irwin (1983) evaluated several schemes for determining the f_y and f_z functions. It was concluded that a parameterization suggested by Draxler (1976) performed best overall.

$$f_y = \left[1 + 0.9\ (t/1000)^{1/2}\right]^{-1} \tag{2-65}$$

$$f_z = \left[1 + 0.9\ (t/500)^{1/2}\right]^{-1} \qquad L < 0 \tag{2-66}$$

$$f_z = \left[1 + 0.945\ (t/100)^{.806}\right]^{-1} \quad L > 0 \tag{2-67}$$

P.D.F. Option for Convective Boundary Layer

It should be noted that the turbulence-based approach recommended by John Irwin also includes the use of the p.d.f. option within CALPUFF. As use of this option will have effect during unstable conditions — and the maximums addressed here occur during stable conditions, this option is not discussed. However, a full discussion may be found in the User's Manual in Section 2.2.5.

APPENDIX G

Representative Growth of σ_y and σ_z (Turbulence-based Dispersion)

REPRESENTATIVE GROWTH OF σY AND σZ

Turbulence-based Dispersion

YYYYJJJHH[1]	ipnum	Cd	zfnl	x(metG)	y(metG)	UTMX	UTMY	sigyB	sigzB	QM	QU	zimax	rflctn	dpbl	jdstab
199623322	1	1	444.1	52.4	78.5	367.5	4376.1	242.7	2.3	1.23E+05	0.0E+0	10000	10000	50.0	6
199623322	1	1	444.1	53.3	78.9	371.0	4377.8	407.7	2.8	1.23E+05	0.0E+0	10000	10000	50.0	6
199623322	1	1	444.1	54.1	79.3	374.4	4379.4	544.6	3.2	1.23E+05	0.0E+0	10000	10000	50.0	6
199623322	1	1	444.1	54.9	79.7	377.6	4380.9	980.9	3.6	1.23E+05	0.0E+0	10000	10000	50.0	6
199623323	1	1	444.1	55.6	80.0	380.5	4382.3	1430.9	4.0	1.23E+05	0.0E+0	10000	10000	57.2	6
199623323	1	1	444.1	56.3	80.4	383.1	4383.7	1880.9	4.5	1.23E+05	0.0E+0	10000	10000	66.0	6
199623323	1	1	444.1	56.9	80.8	385.4	4385.3	2330.9	4.9	1.23E+05	0.0E+0	10000	10000	105.6	6
199623323	1	1	444.1	57.4	81.2	387.7	4386.8	2780.9	5.4	1.23E+05	0.0E+0	10000	10000	117.2	6
199623400	1	1	444.1	58.0	81.6	390.1	4388.4	3230.9	5.6	1.23E+05	0.0E+0	10000	10000	143.2	6
199623400	1	1	444.1	58.6	82.0	392.5	4390.0	3680.9	5.7	1.23E+05	0.0E+0	10000	10000	193.6	6
199623400	1	1	444.1	59.2	82.4	394.9	4391.7	4130.9	5.8	1.23E+05	0.0E+0	10000	10000	152.4	6
199623400	1	1	444.1	59.9	82.8	397.4	4393.3	4580.9	6.2	1.23E+05	0.0E+0	10000	10000	159.0	5
199623401	1	1	444.1	60.5	83.2	400.0	4395.1	5030.9	6.3	1.23E+05	0.0E+0	10000	10000	148.2	6
199623401	1	1	444.1	61.2	83.7	402.6	4396.9	5480.9	6.3	1.23E+05	0.0E+0	10000	10000	148.2	6
199623401	1	1	444.1	61.8	84.1	405.1	4398.7	5930.9	6.4	1.23E+05	0.0E+0	10000	10000	149.4	6
199623401	1	1	444.1	62.4	84.6	407.7	4400.5	6380.9	6.5	1.23E+05	0.0E+0	10000	10000	108.7	6
199623402	1	1	444.1	63.1	85.1	410.5	4402.5	6830.9	6.5	1.23E+05	0.0E+0	10000	10000	106.7	6
199623402	1	1	444.1	63.8	85.6	413.3	4404.6	7280.9	6.5	1.23E+05	0.0E+0	10000	10000	92.4	6
199623402	1	1	444.1	64.5	86.1	416.1	4406.6	7730.9	6.6	1.22E+05	0.0E+0	10000	10000	113.1	6
199623402	1	1	444.1	65.2	86.6	418.9	4408.7	8180.9	7.2	1.22E+05	0.0E+0	10000	10000	220.3	6
199623403	1	1	444.1	65.8	87.1	421.2	4410.6	8540.9	7.8	1.22E+05	0.0E+0	10000	10000	153.1	6
199623403	1	1	444.1	66.4	87.6	423.6	4412.6	8900.9	8.8	1.22E+05	0.0E+0	10000	10000	107.3	6
199623403	1	1	444.1	66.9	88.2	425.4	4414.8	9260.9	10.0	1.22E+05	0.0E+0	10000	10000	107.3	6
199623403	1	1	444.1	67.3	88.7	427.3	4417.1	9620.9	11.3	1.22E+05	0.0E+0	10000	10000	183.9	5

REPRESENTATIVE GROWTH OF σY AND σZ

Turbulence-based Dispersion

YYYYJJJHH[1]	ipnum	Cd	zfnl	x(metG)	y(metG)	UTMX	UTMY	sigyB	sigzB	QM	QU	zimax	rflctn	dpbl	jdstab
199623403	1	1	444.1	67.7	89.4	428.6	4419.8	9980.9	12.0	1.22E+05	0.0E+0	10000	10000	221.5	5
199623404	1	1	444.1	68.1	90.1	430.3	4422.6	10340.	12.8	1.22E+05	0.0E+0	10000	10000	65.6	6
199623404	1	1	444.1	68.6	90.8	432.4	4425.2	10700.	12.8	1.22E+05	0.0E+0	10000	10000	67.4	6
199623404	1	1	444.1	69.1	91.4	434.4	4427.9	11060.	12.8	1.22E+05	0.0E+0	10000	10000	54.8	6
199623404	1	1	444.1	69.7	92.0	436.9	4430.2	11420.	12.8	1.22E+05	0.0E+0	10000	10000	52.2	6
199623404	1	1	444.1	70.4	92.6	439.5	4432.4	11780.	12.8	1.22E+05	0.0E+0	10000	10000	50.0	6
199623405	1	1	444.1	71.0	93.1	441.8	4434.4	12080.	13.1	1.22E+05	0.0E+0	10000	10000	50.0	6
199623405	1	1	444.1	71.5	93.6	444.1	4436.5	12380.	13.5	1.22E+05	0.0E+0	10000	10000	50.0	6
199623405	1	1	444.1	72.1	94.1	446.2	4438.8	12680.	14.0	1.22E+05	0.0E+0	10000	10000	50.0	6
199623405	1	1	444.1	72.4	94.7	447.6	4440.9	12980.	14.5	1.22E+05	0.0E+0	10000	10000	50.0	6
199623405	1	1	444.1	72.7	95.2	448.9	4443.1	13280.	15.0	1.22E+05	0.0E+0	10000	10000	50.0	6
199623405	1	1	444.1	73.0	95.7	449.8	4445.0	13580.	15.0	1.22E+05	0.0E+0	10000	10000	50.0	6

[1] Refer to table on the following page for explanation of column headings

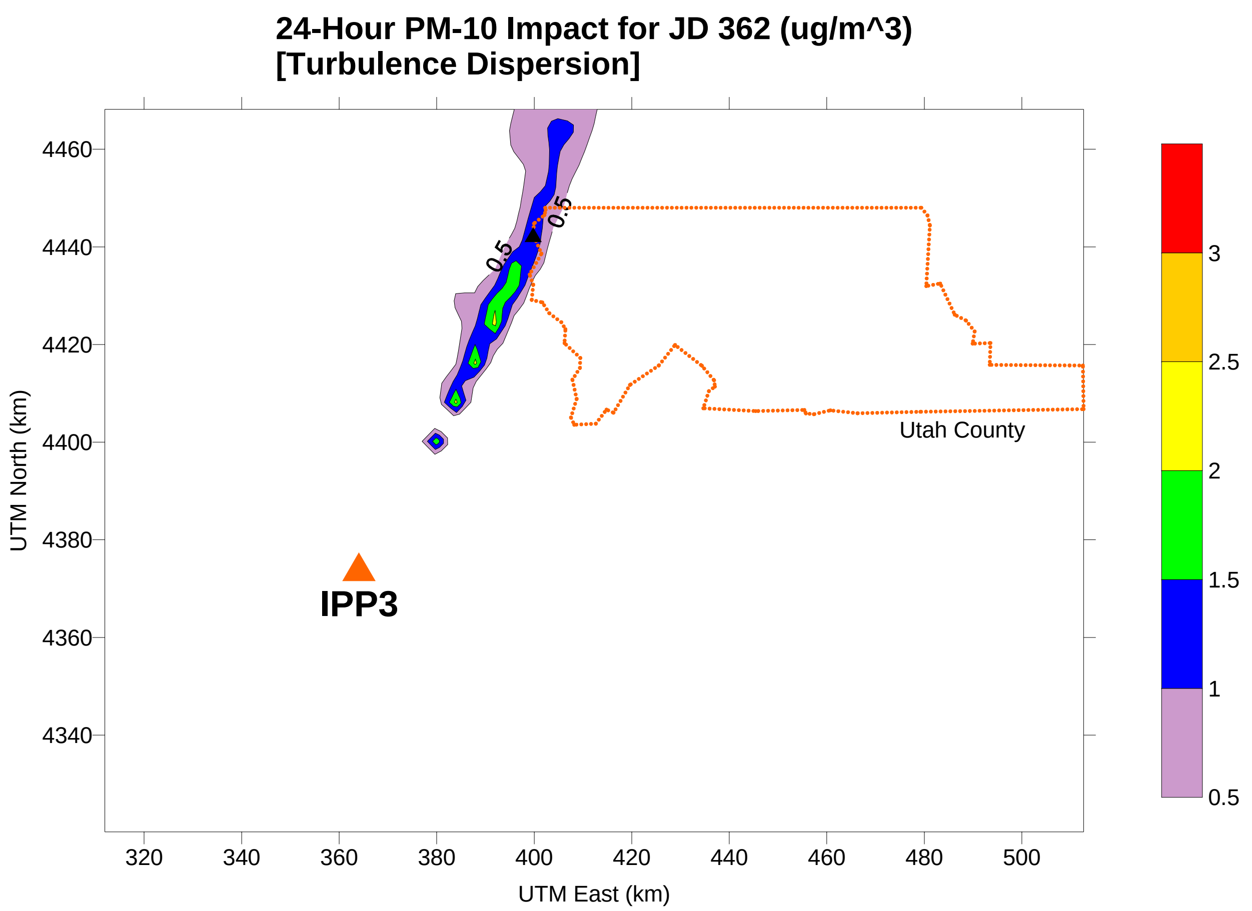
EXPLANATION OF COLUMN HEADINGS

Column Heading	Description
YYYYJJJHH	Year-Julian Day-Hour for modeling period
IPNUM	Puff ID number
CD	Puff Code (1 = Puff within mixed layer & Gaussian)
ZNFL	Puff height (m) at final rise
X	X-coordinate of puff or old slug-end (Met Grid Units)
Y	Y-coordinate of puff or old slug end (Met Grid Units)
UTMX	X-coordinate in UTM (km)
UTMY	Y-coordinate in UTM (km)
SIGYB	Sigma-y of puff or old slug-end (m)
SIGZB	Sigma-z of puff or old slug-end (m)
QM	Puff mass (g) of species 1 below mixing lid
QU	Puff mass (g) of species 1 above mixing lid
ZIMAX	Largest mixing height (m) for this puff (10000m used for unlimited mixing)
RFLCTN	Reflecting lid height (m) for Gaussian distribution (10000 m used for unlimited mixing)
DPBL	Current surface boundary layer height (m)
JDSTAB	Stability Class

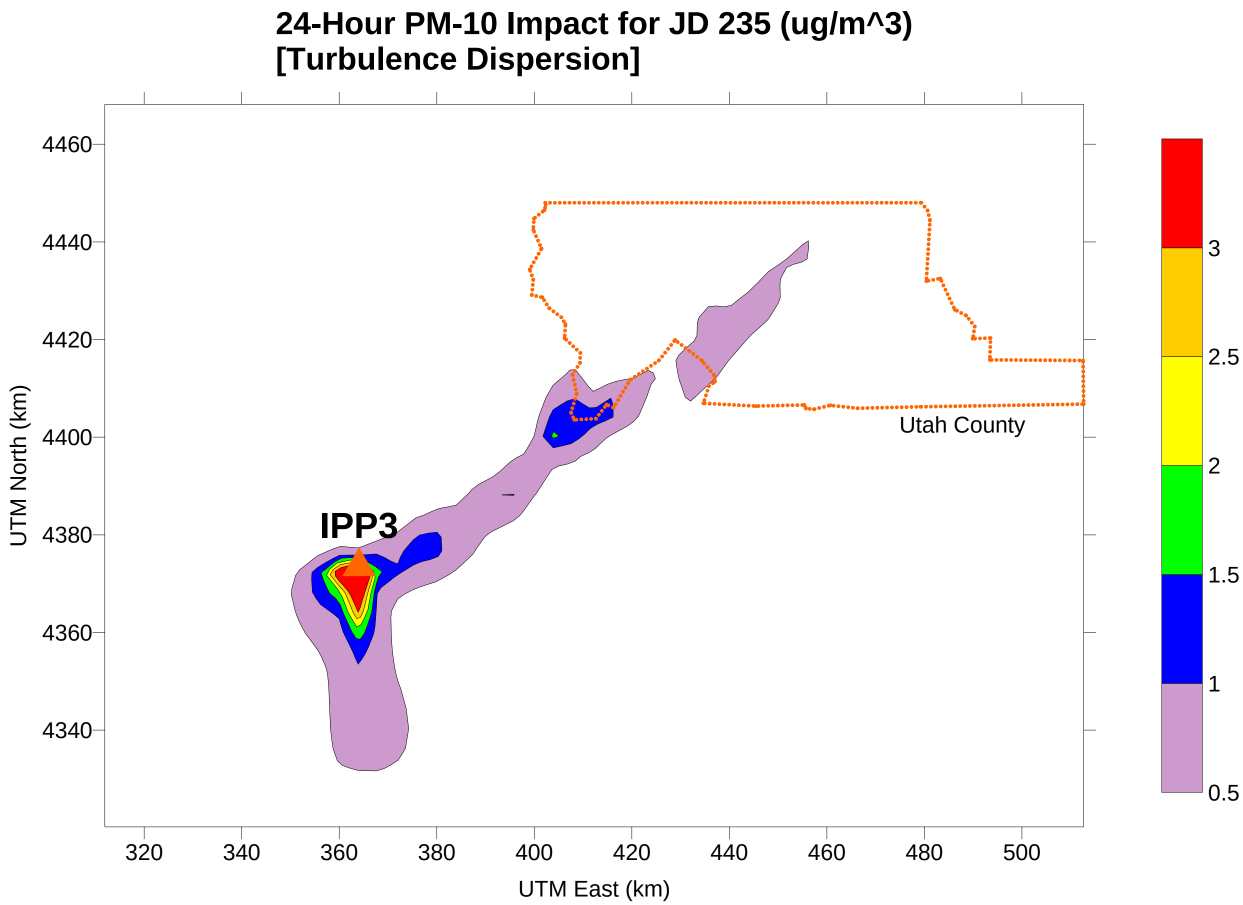
APPENDIX H

PM_{10} Concentration Contours for Turbulence-based Dispersion

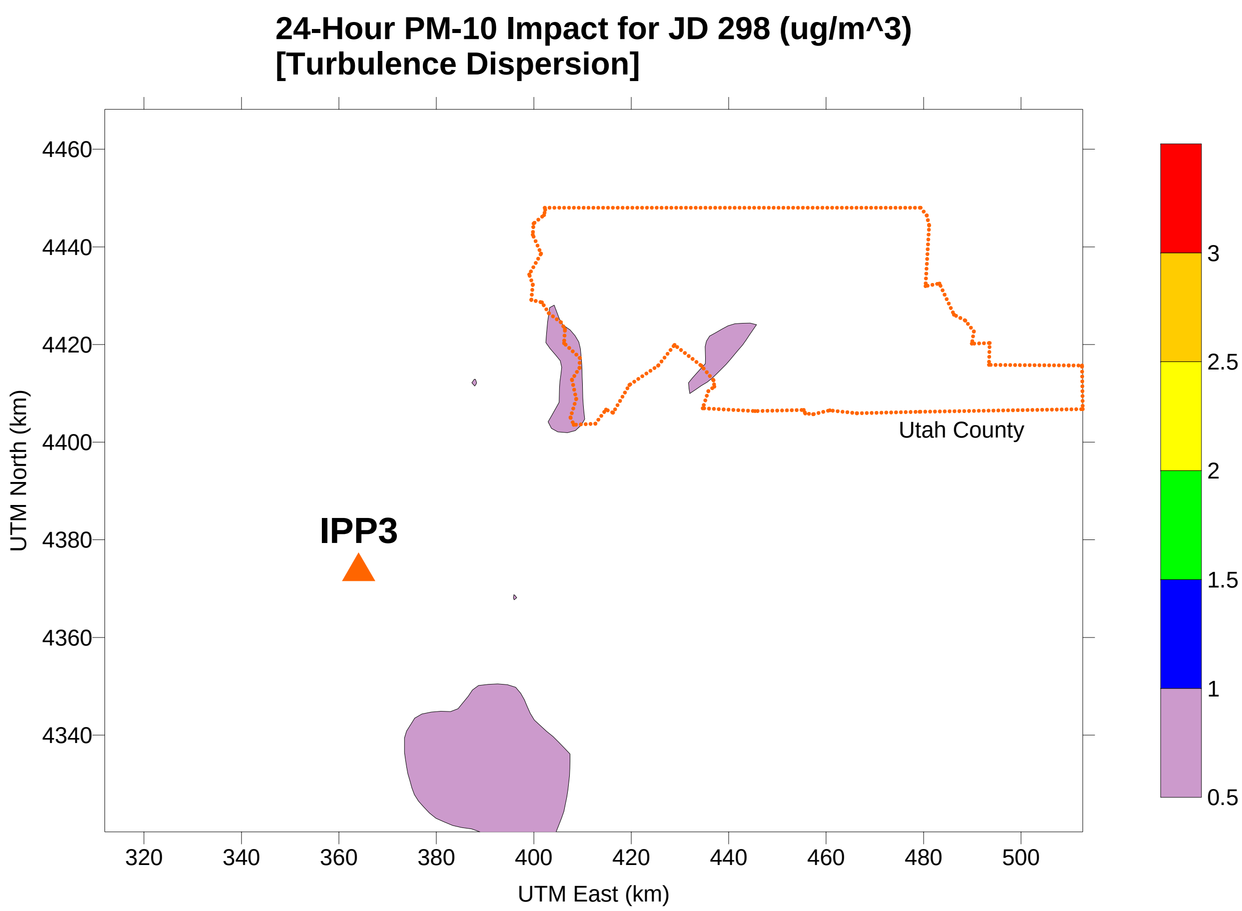
TURBULENCE DISPERSION



TURBULENCE DISPERSION



TURBULENCE DISPERSION



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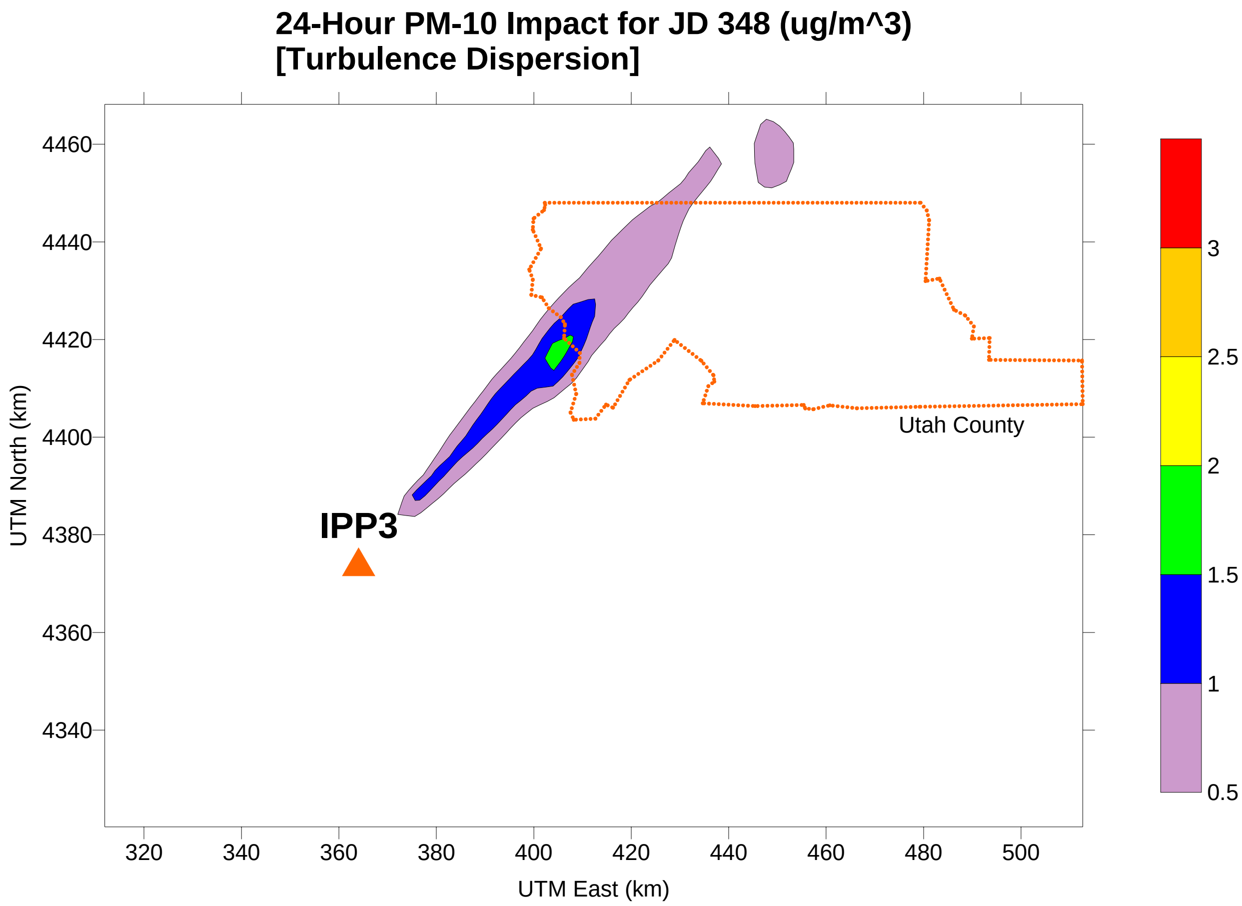

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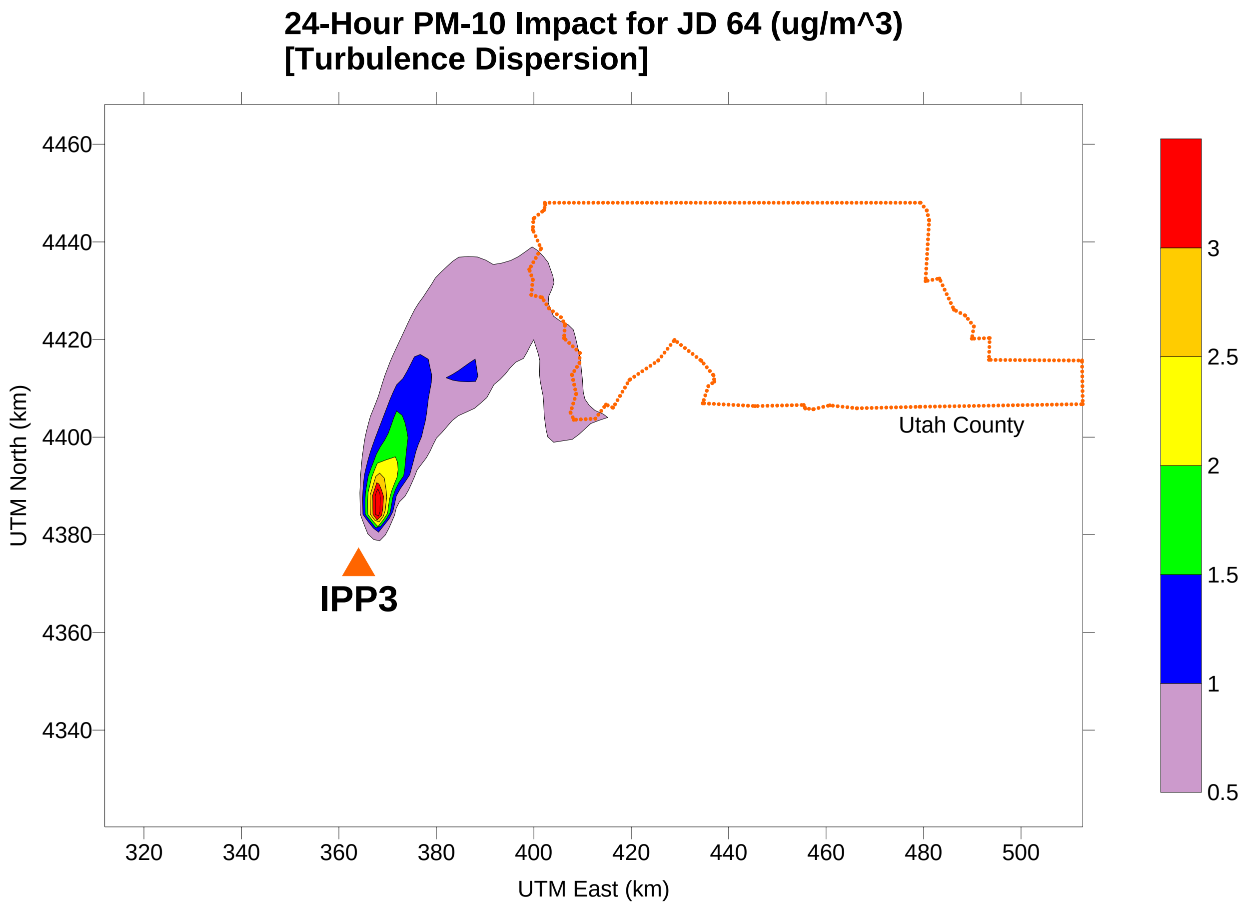

APPENDIX I

Email from John Irwin Regarding Chan ges in the Recommended Dispersion Method for CALPUFF

From: Irwin.John@epamail.epa.gov
Sent: Friday, August 10, 2001 5:59 AM
To: Bennett, Mark/SDO
Cc: Atkinson.Dennis@epamail.epa.gov; Eckhoff.Peter@epamail.epa.gov; rwbrode@mactec.com; jss@src.com
Subject: Re: Is there a plan to change recommended dispersion method for CALPUFF?

Dennis,

You are correct that we are following the advice of the public comments, and we are recommending use of "AERMOD-like" dispersion. This actually requires three switches to be considered:

NDISP = 2 (to select similarity sigmas)
MPARTL = 1 (turns on partial plume penetration effects into elevated inversions)
NPDF = 1 (turns on convective pbl dispersion)

There is also something that one must recognize, namely the increased importance of the land-use characterizations and the surface-layer associations made with each land-use type. My experiences suggest that urban land use is often under-represented, so check carefully the land use processing (not only for urban but for all the major differences, water, prairie, forest, urban). Also, make sure you are using reasonable values for roughness length, bowen ratio, albedo, etc. for each land use type. Selecting "AERMOD-like" sigmas makes Calpuff more dependent on proper characterization of the land use and the surface-layer associations as well.

There may be other "worries" that I've forgotten to mention, so I'm cc-ing this reply to Roger Brode and Joe Scire, just in case.

jsi

Bennett, Mark/MGM <MBennet2@CH2 M.com>
To: John Irwin/RTP/USEPA/US@EPA
cc: Dennis Atkinson/RTP/USEPA/US@EPA, Peter Eckhoff/RTP/USEPA/US@EPA
Subject: Is there a plan to change recommended dispersion method for CALPUFF?
08/09/2001 05:08 PM

John,

Many thanks. Since sending out my email I've been told that all NCDC data uses NAD27. I'm becoming increasingly interested in this entire subject area as we're increasingly being required to use Lambert Conformal, rather than UTMs, in our CALPUFF modeling. Just as with State Plane Coordinate Systems, the Lambert Conformal projection is not always the "best" mapping to use - for example, wrt minimizing distortion over the domain. For states, and also with domains in general, with north-south extents larger than their east-west extents, the transverse Mercator projection yields less distortion. I am particularly concerned that while Lambert Conformal is being suggested, no advise (or, in some cases, bad advice) is being given wrt to choosing standard parallels so as to minimize distortion over the domain in question. Some so-called "advice" I've received would clearly have resulted in more distortion using Lambert Conformal than using UTM. An excellent source of information on this topic is U.S. Geological Survey Professional Paper 1395, Map Projections - A Working Manual, by John Snyder. I'm thinking of doing a paper on this subject for next year's A&WMA conference.

As to the subject line of this email, I believe I've heard that for the regulatory use of CALPUFF that the recommended methodology for calculating dispersion coefficients will be changing from PGT to micrometeorologically-based. This seems quite reasonable, and in keeping with the reason for the change from ISC to AERMOD. I was hoping to get a confirmation of this, and whether or not this approach might be acceptable now (with appropriate protocol approval).

Thanks.

Mark

Mark J. Bennett, Ph.D.
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-----Original Message-----
From: Irwin.John@epamail.epa.gov [mailto:Irwin.John@epamail.epa.gov]
Sent: August 07, 2001 8:54 AM
To: Bennett, Mark/MGM
Cc: Atkinson.Dennis@epamail.epa.gov; Eckhoff.Peter@epamail.epa.gov
Subject: Re: What is datum used for LAT LONG given in station list?

Hi Mark,

Your question was posed to me. I suspect that the UA sites all reference NAD27, since these sites were defined prior to 1983. I do not know this as certain knowledge (as having a reference to cite). I have posed your question to a friend of mine at NCDC. If my friend finds out more on this, I will forward it along to you.

In any case, the most you could be off in the contiguous US is about 100 meters, which is a small uncertainty, given all the approximations and uncertainties we have in air quality modeling. However, from a philosophical and technical viewpoint, it would be nice to know which datum has been used, so that when you plot pictures of your results, the UA site
does not end up in the middle of a road. In the mean time, were you
aware of the following link (Pete Eckhoff provided me with the link and zip file)?

http://www.ngs.noaa.gov/TOOLS/Nadcon/Nadcon.html

And, were you aware of the attached program NADCOM that converts between the two datums?

best regards,
jsi

(See attached file: nadcon.zip)

Dennis Atkinson
To: John Irwin/RTP/USEPA/US@EPA
08/03/2001 02:14 PM
Subject: What is datum used for LAT LONG given in station list?

John,

Can you answer the question below?

Thanks,
Dennis

----- Forwarded by Dennis Atkinson/RTP/USEPA/US on 08/03/01 02:13 PM -----

Bennett, Mark/MGM <MBennet2@CH2M.com>
To: Dennis Atkinson/RTP/USEPA/US@EPA
Subject: What is datum used for LAT LONG given in station list?
08/03/01 12:00 PM

Dennis,

What datum (for example, North American Datum 1927 = NAD27, or NAD83, or
WGS72) was used in providing the decimal degrees latitudes and longitudes of the surface and upper air stations? We need this because we're working in Lambert Conformal projection for CALPUFF modeling. Just incase you don't know (I didn't) the dataum has to do with the specific approximation used to map the world onto an oblate spheroid (different values for the semi-major axis and the flattening).

Thanks.

Mark

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Replacement Sections and Files for the IPP NOI Addendum Sumbitted on May 14, 2003

Intermountain Power Agency

Utah Department of Environmental Quality
Division of Air Quality
Brock LeBaron, Modeling Section Manager
150 North 1950 West
P.O. Box 144820
Salt Lake City, UT 84114-4820

October 31, 2003
Via Hand Delivery

RE: Replacement Sections and Files for the IPP NOI Addendum submitted on May 14, 2003

Dear Brock:

On May 14, 2003, CH2M HILL submitted the IPP NOI Addendum. Modifications were subsequently made to Sections 7 and 9 on June 18, 2003. Additional modifications have been made to Section 7 and additional modeling files have been developed.

The following are provided in hard copy (and electronically on the enclosed CD) to replace the pages in the IPP NOI dated May 14, 2003:

- Table of Contents in its native Word file; replace the entire section in hard copy
- Section 7 in its native Word file; replace from Page 7-25 through end of section in hard copy

The CD also contains the additional modeling files for the Utah County Nonattainment Area Impact Analysis in their native software format, a complete clean version of the NOI in PDF format, and a complete redline version of the NOI. The redline version contains both redline changes to Sections 7 and 8 from the original NOI (December 16, 2002) to reflect changes made in the NOI Addendum on May 14, 2003, redline changes to Sections 7 and 8 from the NOI Addendum (May 14, 2003) to reflect changes made in the NOI update on June 18, 2003, and redline changes to Section 7 from the NOI update (June 18, 2003) to reflect the current change.

If you have any questions, please contact me at (801) 938-1315.

Sincerely,

Lance C. Lee

Lance Lee
IPP Unit 3 Feasibility Manager

c: Dave Prey
Milka Radulovic
Steve Sands (CH2M HILL)
Reed T. Searle (IPA)

IPP3 Project CALPUFF: Observed Weather Conditions for Days with Natural Obscuration

IPP3 Project CALPUFF: Observed Weather Conditions for Days with Natural Obscuration

PREPARED FOR: UDAQ

PREPARED BY: Josh Nall, Bob Pearson/CH2M HILL/DEN

COPIES: Steve Sands/CH2M HILL/SLC

DATE: November 6, 2003

IPP Unit 3 assessed the impact of the source on nearby Class I areas. Federal Land Managers, in their consultative role under the Clean Air Act, have developed a guidance document to assist states in providing certainty to this assessment process. The FLAG Guidance document establishes the procedure for assessing impact on visibility, and requires the use of a "natural background" value that is the same for all the Class I areas throughout the Western US. The only adjustment that is allowed in FLAG is for relative humidity. FLAG provides no ability to recognize the occasional obscuration of views in a Class I area by precipitation, snow, clouds or fog. It is well known that this is a flaw in the FLAG Guidance document.

The Department of the Interior (DOI) has this concern and further defined natural background conditions in one case. In a letter DOI sent to the State of Montana Department of Environmental Quality dated January 16, 2003, it is the position of the Department of Interior "that 'natural conditions' include significant meteorological events such as fog, precipitation or naturally occurring haze". IPP has asked us to further assess this issue as it relates to Unit 3, in order to be protective of visibility.

Accordingly, CH2M HILL has used verified and actual visibility monitoring data collected by the National Park Service at Canyonlands and Great Basin National Parks as part of the IMPROVE monitoring network to determine natural background conditions on certain days when precipitation or fog is present in the areas of concern in Nevada and Southern Utah. CH2M HILL has also revised the CALPUFF visibility modeling for the IPP3 Project using a measured sulfate emission rate taken from stack tests conducted at IPP in April 2003 rather than engineering projections that were used previously. The results of the visibility modeling, performed using only the FLAG guidance are summarized in the table below. Each 24-hour period that yielded a visibility impact of 5% or greater is shown. Also shown (in parenthesis) are the 24-hour visibility impacts after adjustment for natural obscuration, in recognition of the Department of Interior statement “that ‘natural conditions’ include significant meteorological events such as fog, precipitation or naturally occurring haze.”

TABLE 1 – SUMMARY OF CALPUFF VISIBILITY RESULTS (FLAG VS. ADJUSTED FOR OBSCURATION)

Day	Capitol Reef NP	Bryce Canyon NP	Canyonlands NP	Great Basin NP (CLASS II)	Glen Canyon (CLASS II)
JD 42 / 10 Feb				7.2%*	
JD 74 / 14 Mar				9.6% (2.1%)	
JD 262 / 18 Sep	6.0% (3.7%)		5.6% (3.4%)		
JD 299 / 25 Oct	13.0% (1.1%)				5.7% (0.4%)
JD 320 / 15 Nov	23.4% (1.2%)				7.0% (0.3%)
JD 321 / 16 Nov	16.9% (2.2%)				16.8% (2.0%)
JD 334 / 29 Nov		6.2% (0.3%)			

* natural obscuration did not occur on this day

Natural obscuration due to precipitation, clouds, or fog, for purposes of adjusting the CALPUFF results was determined from hourly transmissometer data collected at Canyonlands and Great Basin National Parks. A transmissometer measures the attenuation of a light beam as it travels through the atmosphere over a path length that is several kilometers long. Hourly transmissometer readings that are elevated (> 50 MM^{-1}) indicate that natural obscuration is occurring. Transmissometer readings less than 50 Mm^{-1} indicate that natural obscuration is not occurring in that hour. This is particularly important in the West since the dry atmosphere usually allows long distance views through a clear atmosphere. Precipitation events more dramatically affect visibility in the West than in similar views in the East where higher ambient humidity continuously obscures visibility to some extent.

As described in the document *Transmissometer Data Reduction And Validation* (Air Resource Specialists, January 1994), the intensity of light measured by the IMPROVE transmissometers can be decreased through "interference" with, among other factors, condensed water vapor in the forms of fog, clouds, and precipitation along the sight path. A given measurement is flagged if it "indicates the slightest possibility of meteorological or optical interference" in one of several categories. The data that were used to demonstrate natural obscuration for the IPP3 Project analysis was flagged under one (or more) of these four interference categories:

- Relative Humidity – When relative humidity at the transmissometer is greater than 90% for a given hour, the measured extinction for that hour is flagged as having possible meteorological interference.
- Maximum Threshold – For each transmissometer, a site-specific threshold is established that corresponds to greatly reduced transmittance along the sight path. When the measured light extinction is this high, it is assumed that "meteorological or optical

interferences, not ambient aerosols, are causing the high extinction" and that hourly value is flagged for possible interference (Air Resource Specialists, 1994).

- Uncertainty Threshold – The operators of the IMPROVE transmissometers make a conservative assumption that measured extinction will remain relatively constant during the ten one-minute measurements that make up an hourly average reading. As stated by Air Resources in their 1994 document, "The presence of any meteorological or optical interferences along the sight path will lead to large standard deviations" in the optical measurements. Therefore, an uncertainty threshold is established for each site as a test for large standard deviations between measurements.
- Delta Threshold – Similar to the uncertainty threshold, the Delta threshold tests for large fluctuations in measured extinction from hour to hour that might indicate possible interference.

To further verify that natural obscuration was indeed occurring during the periods in question, CH2M HILL examined precipitation data files and Local Climatological Data (LCD) summaries for 1996 obtained from the National Climatic Data Center (NCDC) and 1996 surface data collected at Canyonlands NP. The LCD summary was taken from the nearest primary National Weather Service (NWS) station at Grand Junction, CO. The precipitation data were taken from measurement locations nearest to the areas of concern.

<u>JD 74 / 14 Mar</u>

The FLAG analysis procedure predicts a 24-hour visibility impact of 9.6% at the Class II Great Basin NP. However, actual monitoring data shows that precipitation occurred on this date. Therefore, we must adjust for the impact of natural obscuration, as allowed by the Department of Interior. We used actual IMPROVE transmissometer data from Great Basin NP, and the actual IMPROVE data more accurately changes this predicted impact to 2.1%. Precipitation, as measured at Great Basin NP, began on this day at 11:00 AM and continued until 2:00 PM for a total equivalent of 0.7 inches of rainfall, a heavy precipitation event in an arid desert such as Great Basin. The transmissometer measured obscuration of visibility above 50 Mm^{-1} from 8:00 until the precipitation began falling at 11:00. During the precipitation event, the transmissometer measured less than 50 Mm^{-1} of light scattering, so these hours were not adjusted since obscuration of visibility was not sufficiently impaired by the precipitation. Even so, the IPP3 impact on visibility for this day is actually 2.1% when the transmissometer readings are utilized for the four hours from 8:00 to 11:00 AM.

The transmissometer data used to demonstrate natural obscuration for this day were flagged for high relative humidity and for large fluctuations in consecutive readings. This is indicative of the onset of the precipitation event that was measured at the park.

<u>JD 262 / 18 Sep</u>

The FLAG protocol predicts the visibility impacts for this day to be slightly greater than 5% at Capitol Reef NP and Canyonlands NP. However, actual monitoring data shows that precipitation and other meteorological phenomena occurred on this date. Therefore we must adjust for hours of natural obscuration from 9:00 AM to 10:00 AM and then again at 12:00 PM (using the transmissometer data from Canyonlands NP). Measurable precipitation was recorded at the Canyonlands CASTNET meteorological station during the hour from 9:00 AM to 10:00 AM and again for the hour beginning at 12:00 PM. Measurable precipitation was also recorded for the hour from 9:00 AM to 10:00 AM at the cooperative climate monitoring stations (Blanding and Angle) within 50 kilometers of each park. A trace of precipitation and observations of rain and haze were also reported at the NWS station at Grand Junction during the day. The IPP3 impact on visibility for this day is actually less than 4% when the transmissometer readings are utilized for the three hours beginning 9:00 and 10:00 AM and 12:00 PM.

The three hours of transmissometer data used for this day were flagged for possible interference because the hour-by-hour fluctuation in measured light extinction was greater than the "Delta" threshold (10 Mm^{-1}). These fluctuations are indicative of the meteorological interference that was in place during the period.

JD 299 / 25 Oct

The FLAG protocol predicts visibility impacts greater than 5% for this day at Capitol Reef NP and Class II Glen Canyon NRA. However, actual monitoring data shows that precipitation and other meteorological phenomena occurred on this date. Therefore, we must adjust for a 10-hour period of natural obscuration from 8:00 AM to 5:00 PM (using transmissometer data from Canyonlands NP). Measurable precipitation was recorded at the Canyonlands CASTNET meteorological station from 5:00 AM until 3:00 PM on this day. Measurable precipitation was also recorded for one hour at 11:00 at a cooperative climate monitoring station (Blanding) within 50 kilometers of Capitol Reef. Measurable precipitation (total of 0.21 inches) and observations of rain, snow, and mist were reported at the NWS station at Grand Junction during the day. The IPP3 impact on visibility for this day is actually 1.1% at Capitol Reef and less than 1% at Glen Canyon when the transmissometer readings are utilized during the ten hours of natural obscuration. The presence of widespread natural obscuration is further confirmed by elevated IMPROVE transmissometer readings at Grand Canyon NP for the hours of 9:00 AM to 10:00 AM, 3:00 PM, and 6:00 PM.

Transmissometer data used to demonstrate natural obscuration during the period from 8:00 AM to 5:00 PM were flagged for possible interference for a combination of all four interference categories described earlier. Data were flagged for high relative humidity because the measured relative humidity during the entire period exceeded 90%. Data flagged due to high fluctuations or high absolute light extinction readings reflect the pronounced weather event that was in place at the time.

JD 320 / 15 Nov

The FLAG procedure predicts visibility impacts greater than 5% for this day at Capitol Reef NP and Class II Glen Canyon NRA. However, actual monitoring data shows that precipitation and other meteorological phenomena occurred on this date. Therefore, we must adjust the impacts for a 14-hour period of natural obscuration from 11:00 AM to the end of the day at midnight (using transmissometer data from Canyonlands NP). Measurable precipitation was recorded at the Canyonlands CASTNET meteorological station from 11:00 AM until 6:00 PM. Measurable precipitation was also recorded for several hours during the period of obscuration at cooperative climate monitoring stations (Blanding and Hanksville) within 50 kilometers of Capitol Reef. Measurable precipitation (total of 0.41 inches) and observations of rain, snow, heavy fog, ice fog, and mist were reported at the NWS station at Grand Junction during the day. The IPP3 impact on visibility for this day is actually 1.2% at Capitol Reef and less than 1% at Glen Canyon NRA when the transmissometer readings are utilized for the fourteen hours of natural obscuration. The presence of widespread natural obscuration is further confirmed by elevated IMPROVE transmissometer readings at Grand Canyon NP for the hours of 12:00 PM to 7:00 PM and 9:00 PM to midnight.

Transmissometer data used to demonstrate natural obscuration during the 14-hour period on this day were flagged for possible interference because the readings indicated less than 5% transmittance of light. This is indicative of the pronounced weather event that was in place, a point further evidenced by the measured relative humidity during the period which was 95% or higher for all but one hour.

JD 321 / 16 Nov

The FLAG procedure predicts visibility impacts greater than 5% for this day at Capitol Reef NP and Class II Glen Canyon NRA. However, actual monitoring data shows that precipitation and other meteorological phenomena occurred on this date. Therefore, we must adjust the impacts for a 5-hour period of natural obscuration from midnight through 5:00 AM (using transmissometer data from Canyonlands NP). Measurable precipitation was recorded for several hours during the day at cooperative climate monitoring stations (Blanding and Hanksville) within 50 kilometers of Capitol Reef. This is a continuation of the same precipitation event that began at 11:00 the previous day. A trace of measurable precipitation and observations of snow and mist were reported at the NWS station at Grand Junction during the day. The IPP3 impact on visibility for this day is actually 2.2% at Capitol Reef and 2.0% at Glen Canyon when the transmissometer readings are utilized for the five hours of natural obscuration. The presence of widespread natural obscuration is further confirmed by elevated IMPROVE transmissometer readings at Grand Canyon NP from midnight to 2:00 AM.

Transmissometer data used to demonstrate natural obscuration during the period from midnight through 5:00 AM were flagged for possible interference for a combination of high relative humidity, high light extinction, and hour-by-hour fluctuations greater than 10 Mm^{-1}. These interferences reflect a continuation of the weather event that began on November 15. The relative humidity for the 5-hour period of obscuration was 97% for each hour.

JD 334 / 29 Nov

The FLAG procedure predicts visibility impacts greater than 5% for this day at Bryce Canyon NP. However, actual monitoring data shows that precipitation and other meteorological phenomena occurred on this date. Therefore, we must adjust the impact for an 18-hour period of natural obscuration from 2:00 AM to 7:00 PM (using transmissometer data from Canyonlands NP). Measurable precipitation was recorded at the Canyonlands CASTNET meteorological station for seven of the nine hours from 2:00 AM until 10:00 AM that day. Measurable precipitation was also recorded for one hour at 11:00 AM during this period of obscuration at a cooperative climate monitoring station (Duck Creek Village) within 10 kilometers of Bryce Canyon. Measurable precipitation (0.12 inches) and observations of snow and mist were reported at the NWS station at Grand Junction during the day. The IPP3 impact on visibility for this day is actually 0.3% when the transmissometer readings are utilized for the eighteen hours of natural obscuration. The presence of widespread natural obscuration is further confirmed by elevated IMPROVE transmissometer readings at Grand Canyon NP from 3:00 AM through 6:00 PM.

Transmissometer data used to demonstrate natural obscuration during this period were flagged for possible interference for a combination of the four interference categories described earlier. Data were flagged for high relative humidity because the measured relative humidity during the entire period exceeded 90%. Data flagged due to high fluctuations or high absolute light extinction readings reflect the pronounced weather event that was in place.

In conclusion, the elevated light scattering measured at the IMPROVE transmissometers for each of these days coincides with measured and observed weather events at nearby weather monitoring stations. In addition, when the FLAG-only visibility impact calculations are adjusted for actual measured visibility during the periods of natural obscuration on these days, the estimated impact of IPP Unit 3 drops dramatically to levels that will not be perceptible to human observers, and below the significance thresholds for UDAQ to require cumulative modeling. In our expert opinion, the visibility impacts from Unit 3 will be insignificant, not discernable by the human eye.

IPP3: Revised Cumulative Class I Increment Modeling

CH2M HILL
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CH2MHILL

December 16, 2003

Mr. Brock LeBaron
Division of Air Quality
Utah Department Of Environmental Quality
150 North 1950 West
P.O. Box 144820
Salt Lake City, Utah 84114-4820

Subject: IPP3: Revised Cumulative Class I Increment Modeling

Dear Brock:

This letter provides a summary of revised cumulative Class I Prevention of Significant Deterioration (PSD) increment modeling for the IPP3 Project. The model used for the analysis, the EPA CALPUFF model, has been adopted as the EPA-preferred model for "particulate matter ambient air quality standards and PSD increment impact analyses" involving transport distances greater than 50 kilometers (EPA, 2003). The same modeling domain was used for this analysis as was used for the other Class I analyses for the IPP3 Project. This modeling domain includes all of central and southern Utah and extends, in a north-south direction, from near Provo, Utah into northern Arizona, and in an east-west direction from eastern Nevada into western Colorado.

The previous cumulative Class I PSD increment modeling for the IPP3 Project (submitted in the June 18, 2003 modeling section update to the May 14, 2003 NOI Addendum) was based on emission rates for sources outside of the IPP facility that were derived from annual ton per year actual emissions reported by each source in emission inventories submitted to UDAQ in 2000 and 2001 divided by total hours per year (8760 hours/year). The June 18, 2003 cumulative Class I increment modeling analysis (presented in Table 7-7 of the modeling section update) predicted the following increment consumption results:

Table 7-7 ***(from the June 18, 2003 modeling section update)***
Cumulative Increment Consumption (all reported values are in units of μg/m³)

Area	Annual NO_2	3-hour SO_2	24-Hour SO_2	Annual SO_2	24-Hour PM_{10}	Annual PM_{10}
Class I PSD Increment	2.5	25[a]	5[a]	2	8[a]	4
<u>Class I Areas</u>						
Arches NP	0.047	2.65	0.76	0.13	0.15	0.015
Bryce Canyon NP	0.029	2.42	0.83	0.04	0.14	0.009
Capitol Reef NP	0.109	3.66	0.91	0.10	0.17	0.020
Canyonlands NP	0.074	8.39	2.10	0.12	0.20	0.019
Zion NP	0.030	3.13	0.59	0.03	0.13	0.007

[a] Not to be exceeded more than once per year.

The June 18, 2003 cumulative Class I PSD increment analysis has been revised at the request of the Utah Division of Air Quality (UDAQ) as described below.

Revised Approach

For the revised analysis, the same annual ton per year emissions were used, but the actual hours of operation for each source were used to compute the annual average actual emission rates. With this adjustment, the pound per hour emission rates input to the CALPUFF model reflect annual average actual emissions for fine particulate matter (PM_{10}), sulfur dioxide (SO_2), and oxides of nitrogen (NO_x) for each source during their hours of actual operation. As before, the emissions from the proposed Unit 3 at IPP were set to potential to emit (PTE) levels. Other than the revised annual average actual emission rates for existing sources, all other stack release parameters that were used in the June 18, 2003 cumulative Class I PSD increment analysis were also used for this revised analysis. Attachment 1 lists the input parameters for each modeled source. The emissions of nitrogen oxides (NOx) from each source were conservatively assumed to convert completely to nitrogen dioxide (NO_2) for comparison to the allowable PSD increment for NO_2.

Regulatory Basis

Utah air quality rules state that a new major source such as IPP3 must be reviewed to determine if the source will cause or contribute to a violation of the maximum allowable increases (PSD increments). Such review shall take into account the cumulative effect of all sources and growth in the affected area to the extent practicable (UACR307-405-6). CH2M HILL accounted for the cumulative effect in the Class I areas in Utah by modeling the impact from the IPP facility and all large increment-consuming point sources in central and southern Utah.

As defined in Section 163 of the Clean Air Act, increment consumption is based on the increase in pollutant concentration above an established baseline level. Modeling for increment consumption is therefore based on actual emissions from increment-consuming sources. Actual emissions are explicitly defined in Utah air quality rules as follows: "In general, actual emissions as of a particular date shall equal the average rate, in tons per year, 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 operations" (UACR307-101-2). CH2M HILL used annual average actual emission rates for the two-year period from 2000-2001 as model input for all existing sources.

Results

Results of the revised cumulative Class I PSD increment analysis are shown in Table 1 (which replaces the results in Table 7-7 of the June 18, 2003 modeling section update). All predicted cumulative impacts were well below the allowable Class I PSD increments in each Class I area. These results definitively show that the IPP3 Project will not cause or contribute to a violation of the allowable Class I increments in Utah.

Table 1
Cumulative Increment Consumption (all reported values are in units of $\mu g/m^3$)

Area	Annual NO_2	3-hour SO_2	24-Hour SO_2	Annual SO_2	24-Hour PM_{10}	Annual PM_{10}
Class I PSD Increment	2.5	25[a]	5[a]	2	8[a]	4
Class I Areas						
Arches NP	0.05	2.41	0.68	0.12	0.09	0.013
Bryce Canyon NP	0.02	1.40	0.40	0.03	0.07	0.005
Capitol Reef NP	0.10	2.82	0.80	0.09	0.13	0.016
Canyonlands NP	0.07	6.95	1.56	0.12	0.14	0.016
Zion NP	0.02	1.62	0.37	0.02	0.07	0.004

Note: Reported 3-hour and 24-hour impacts are the overall high second-high impacts.

[a] Not to be exceeded more than once per year.

Conclusions

Annual average emissions are the best approximation of the actual emissions from a large group of sources. Because not every increment-consuming source uses CEMs, an annual average actual emissions approach is the only way to treat sources with and without CEMs on a consistent and equitable basis. An annual average actual emission rate approach is also a consistent way to account for emissions variability among increment consuming sources. Using annual average actual emission rates is consistent with how increment analysis have historically been performed in Utah and other western states, and meets state and federal requirements for conducting an increment analysis.

Given CEM data limitations, the low probability (due to infrequency) that increment consuming sources would simultaneously emit at annual maximum emission rates, past precedent, and current regulatory interpretation, the annual average emission rate approach summarized in this report is the only appropriate method for performing a cumulative increment analysis.

We submitted the CALPUFF input and output files to UDAQ via e-mail on December 16, 2003. Please contact me at (720) 286-5362 if you have any questions.

References

EPA, 2003. Appendix W of 40 CFR Part 51 - *Guideline On Air Quality Models (Revised)*, Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina, April 2003.

Sincerely,

James Nall

James (Josh) Nall

CH2M HILL

Attachment

ATTACHMENT 1 - IPP3: Major Increment-Consuming Sources in Central and Southern Utah to be Included in CALPUFF Class I Increment Analysis
(Dec 2003)

	Facility Name	Source	Hours of Operation for 2000	Hours of Operation for 2001	Unit Specific 2000 NO2 (tons)	Unit Specific 2001 NO2 (tons)	Unit Specific 2000 PM10 (tons)	Unit Specific 2001 PM10 (tons)	Unit Specific 2000 SO2 (tons)	Unit Specific 2001 SO2 (tons)	Average NO2 Emissions Rate (lb/hr)	Average PM10 Emissions Rate (lb/hr)	Average SO2 Emissions Rate (lb/hr)	UTM East (m)	UTM North (m)	Base Elev (m)	Stack Height (ft)	Stack Height (m)	Diameter (m)	Exit Velocity (m/s)	Exit temp (K)
1	IPP - Unit 3	Main Stack	na	na	na	na	na	na	na	na	633.5	221.0	1357.5	364,054	4,374,464	1425.4	712	217.0	9.75	20.70	330.4
2	IPP - Unit 1	Main Stack	8581	7849.5	13973.2	12849.5	223.8	83.1	1855.0	1914.1	3265.0	37.4	458.8	364,214	4,374,464	1428.6	712	217.0	8.53	25.20	319
3	IPP - Unit 2	Main Stack	7709.5	8760	12138.3	13839.9	101.0	74.4	1619.2	2286.2	3154.7	21.3	474.3	364,214	4,374.464	1428.6	712	217.0	8.53	25.20	319
4	Lisbon Plant	Incinerator	8760	8760	na	na	na	na	1251.7	1525.9	na	na	317.1	651,368	4,224,549	1828.7	213.2	65.0	1.83	7.35	737.0
5	Sunnyside	Unit 1	8760	8760	380.0	407.0	62.3	48.5	1054.2	999.7	89.8	12.6	234.5	552,358	4,377,295	1975.0	250	76.2	2.59	27.84	422.0
6	Hunter Power Plant	Unit 2	8155	7831	na	na	277.2	456.0	1812.6	2720.0	na	91.7	567.1	497,846	4,335,847	1719.0	600	182.9	7.31	17.82	329.3
7	Hunter Power Plant	Unit 3	8125	7629	7173.3	7099.7	237.4	84.3	1113.4	1213.2	1812.0	40.8	295.4	497,824	4,335,815	1719.0	600	182.9	7.31	16.63	322.0
8	Graymont (Continental Lime)	Rotary Kiln # 1&2 Composite	4485	4485	na	na	33.8	39.5	78.2	85.2	na	16.3	36.4	342,200	4,311,500	1466.0	100	30.5	1.52	19.17	450
9	Graymont (Continental Lime)	Rotary Kiln # 3	6735	6735	415.5	398.8	25.4	22.6	92.4	82.0	120.9	7.1	25.9	342,200	4,311,500	1466.0	100	30.5	2.13	11.19	450
10	Graymont (Continental Lime)	Rotary Kiln # 4	8037	8037	662.8	653.5	55.1	48.7	155.0	136.9	163.8	12.9	36.3	342,200	4,311,500	1466.0	213	64.9	2.13	20.34	450
11	Deseret - Bonanza Plant	Main Stack	7066	8695	7000.0	6452.0	295.0	468.0	1020.0	1127.0	1707.0	96.8	272.4	646,206	4,438,606	1533.1	600	182.9	7.92	16.30	322
12	Ashgrove Cement-Leamington Canyon	Main Stack	8032	8032	2679.3	2679.3	148.0	148.0	na	na	667.2	36.9	na	397,206	4,379,732	1492.6	98	29.9	4.88	9.14	379

Notes:

1) Emissions for IPP Unit 3 based on PTE. Other emissions (tons) and hours of operation are based on 2000-2001 emission inventories submitted to UDAQ

2) Hours of operation for IPP Units 1&2 and Deseret-Bonanza taken from Acid Rain Database

Sample Calculation:

Average annual SO_2 emission rate (Bonanza) = (1020 ton/yr + 1127 ton/yr) * 2000 lb/ton / (7066 hours/yr + 8695 hours/yr) = 272.4 lb/hr

APPENDIX I-3

PM_{10} BACT

PM_{10} Emissions and Fabric Filter Control Efficiency

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PM_{10} Emissions and Fabric Filter Control Efficiency

Background and Summary

In December 2002, Intermountain Power Agency (IPA) submitted a Notice of Intent (NOI) to permit and construct a new nominal 950-gross MW (900-net MW) pulverized coal-fired unit at the Intermountain Power Project station near Delta, Utah. In the NOI, IPA proposed fabric filtration as the best available control technology (BACT) for the control of particulate matter with an aerodynamic diameter less than 10 microns (PM_{10}), and recommended a controlled PM_{10} emission rate of 0.015 lb/mmBtu. During subsequent NOI Technical Review Meetings between IPA and the Utah Department of Environmental Quality – Division of Air Quality (UDAQ), representatives of UDAQ asked whether a more stringent PM_{10} emission rate was technically and economically feasible.

In response to UDAQ's request for additional information, IPA is providing a more detailed description of the information used to form the basis of our proposed PM_{10} emission rate and the BACT analysis we submitted in the NOI. The information contained herein should be considered part of IPA's BACT determination, and supplemental to Section 6.2 of the above referenced NOI.

IPA has concluded, based on the information presented herein, that a PM_{10} emission rate less than 0.015 lb/mmBtu may not be technically feasible. Furthermore, even if a more stringent PM_{10} emission rate is considered technically feasible, it must be rejected as BACT based on economic impacts. The incremental cost associated with a more stringent PM_{10} emission rate is excessive. A PM_{10} emission rate of 0.015 lb/mmBtu represents BACT as defined in UAC R307-101-2.

Technical Discussion

I. Particulate Matter

Particulate matter composition and emission levels are a complex function of boiler firing configuration, boiler operation, pollution control equipment and coal properties. Uncontrolled particulate matter (PM) emissions from coal-fired boilers include the ash from combustion of the fuel, noncombustible metals present in trace quantities and unburned carbon resulting from incomplete combustion. In pulverized coal-fired boiler systems, the emitted PM is primarily composed of inorganic ash residues. Other sources of PM include condensable organics and minerals present in the combustion air.

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Coal ash may either settle out in the boiler (bottom ash) or be entrained in the flue gas (fly ash). The distribution between bottom ash and fly ash fractions affects the PM_{10} emission rate and is a function of the boiler firing method and furnace type. With a pulverized coal-fired boiler approximately 80% of the ash will be emitted with the flue gas as fly ash, and 20% will settle out in the combustion bed as bottom ash.

II. Main Boiler PM_{10} Control Options

The principal techniques for PM_{10} control are post-combustion methods. There are two generally recognized PM_{10} control devices that are used to control PM_{10} emissions from coal-fired boilers: electrostatic precipitators (ESP) and fabric filters (or baghouses). Either of these devices, if properly designed and operated, is capable of reducing PM emissions below the 0.03 lb/mmBtu limit required by 40 CFR 60 Subpart Da (New Source Performance Standard) as well as limiting opacity to below 20%.

III. Unit 3 Best Available PM_{10} Control Technology

In its BACT analysis, IPA concluded that a fabric filter will provide the most effective control, and represents BACT for PM_{10} (Intermountain Power Project Unit 3, NOI, Section 6.2.6, December 2002). IPA proposed a controlled PM_{10} emission rate of 0.015 lb/mmBtu,[1] based on a 3-hour rolling average (NOI, Section 4.4). This supplement to the BACT analysis evaluates potential bag materials that can be used for filter bags in the fabric filter control system.

The proposed fabric filter will be located downstream of the Unit 3 air preheater and upstream of the Unit's induced draft fans and flue gas desulfurization system. The fabric filter will have a number of parallel banks of individual filter compartments. Individual filter compartments consist of a bottom collection hopper and an upper bag compartment. A tube sheet separates the hopper from the bag compartment, and tube sheet thimbles direct gas flow through the tube sheet. The bottom, or open end, of the filter bag is attached to the tube-sheet thimble, while the upper end of the bag is attached to the top of the filter compartment.

Particulate laden flue gas from the boiler will enter system compartments in the upper section of the hopper, just below the tube sheet. Flue gas will travel up through the filter bags where particulates collect on the inside of the bags. Particulate matter captured on the filter bags will form a cake. The filter cake increases both the filtration efficiency, and its resistance to gas flow.

[1] The PM_{10} emission rate of 0.015 lb/mmBtu proposed in IPA's NOI is for filterable PM_{10} only.

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The filter bags must be routinely cleaned to remove accumulated filter cake. The cleaning frequency of the individual compartments will depend, in part, upon the inlet grain loading and the resistance to gas flow of the filter cake formed. It is anticipated that the Unit 3 fabric filter system will be designed as a reverse-air type system. In a reverse-air system, gas flow through an isolated compartment is reversed, causing the filter bag to collapse fracturing the filter cake. Filter cake falls into the collection hopper for transport to the fly ash handling system.

IV. Step 1: Fabric Filter Control Options Under a BACT Analysis

Fabric filter design depends on specific items such as permeability of the filter cake, the loading and nature of the particulate matter (e.g., irregular-shaped or spherical), air/cloth ratio, particle size distribution and, to some extent, the frequency of the cleaning cycle. Although fabric filters will consistently achieve very high collection efficiencies (e.g., >99.5%), there will inevitably be some variation in collection efficiency over the operating cycle of the fabric filter. Therefore, it would be inappropriate to include a collection efficiency limit in the approval order. As can be seen in this paper, it is appropriate to require an Operations and Maintenance plan to maintain the integrity of the fabric filter. A summary of the anticipated fabric filter design parameters for IPA Unit 3 is provided in Table 1.

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Table 1
Anticipated Fabric Filter Design Parameters

Parameter	Units	Estimated Design Value	Notes
Maximum Flue Gas Flow Rate	acfm	3,617,117	
Inlet Gas Temperature	^oF	275 – 300	
Inlet Particulate Loading	lb/hr	77,620 (8.58 lb/mmBtu)	Based on ash content of 12% and fuel heating value of 11,193 Btu/lb.
Outlet Particulate Loading	lb/mmBtu	0.015	
Maximum Particulate Emission Rate	lb/hr	135.8	
Collection Efficiency	%	99.83	
Bag Diameter, Length, Number of Bags			To be determined during detailed design.
Number of modules and compartments per module			To be determined during detailed design.
Total Number of Bags		approx. 20,000 to 30,000	
Area of Filter Required	ft^2	approx. 1,808,559	
Air to Cloth Ratio	ft	2	
Pressure Drop Across Bags	in. H_2O	5 - 6 (typical)	
Cleaning Mechanism and Cycle		reverse air	

Fabric filter system design also includes the election of a suitable filter fabric and finish. The type of filter material used depends on the chemical composition of the flue gas, operating temperatures, dust loading and physical/chemical characteristics of the particulate.

In coal-fired boiler applications, synthetic fibers are generally used because they can withstand the flue gas temperatures and are more resistant to chemical attach. A synthetic fiber typically used for high temperature application is fiberglass or glass fibers. However, glass fibers can break easily and require gentle filtering and cleaning cycles that result in a larger control device to limit the maximum velocity of flue gas through the bags (air to cloth ratio). Ryton™ is a felted filter made from polyphenylene sulfide fibers

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generally attached to a woven polyfluorocarbon backing. Ryton can operate at high temperatures and has shown good resistance to acids and alkalis. Ryton-type[2] bags have been used successfully to remove PM_{10} generated from coal-fired boilers. Filter bags can also be treated with a membrane, such as Goretex™. Goretex membrane is an expanded polytetrafluoroethylene (PTFE) membrane that can be laminated over a variety of fibers. PTFE-coated bags are more expensive, but may provide some incremental additional PM_{10} control efficiency. PTFE-coated bags have not been used extensively on pulverized coal-fired boilers so they have only marginally been demonstrated in practice in this application.

V. Step 2: Eliminate Technically Infeasible Options for Fabric Filters

The particulate removal efficiency of a fabric filter is dependent on a variety of site-specific particle and operational characteristics. Particle characteristics that affect the collection efficiency include particle size distribution and particle cohesion characteristics. Operational parameters that affect fabric filter collection efficiency include air-to-cloth ratio, operating pressure loss, and cleaning method/intensity.

When assessing emission control limits of fabric filters the issue of mechanical integrity of the filter housing (e.g., welds, seams, bag hangers, and connections) is an important factor that must be taken into consideration. Improvements to fabric technology have reduced particulate emissions through the fabric bags to very low levels, making the relative importance of particulate emissions due to compromises in the integrity of the filter system much more critical.

Although the IPP Unit 3 fabric filter will be constructed in accordance with applicable engineering standards, it is necessary to consider the effect that mechanical integrity will have on short-term particulate emission rates. The IPP fabric filter will have approximately 20,000 – 30,000 filter bags,[3] each with a bag cleaning mechanism. Mechanical problems that may impact flue gas flow through the filters include:

- bags not tightly fastened to the outlet duct nozzle,
- loose bag hangers,
- bags torn during construction or improperly manufactured, and
- failed welds or cracks that occur within the extensive ducting system.

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[2] The term "Ryton-type" bags is not limited to Ryton™ bags, but is used in this document to describe fabric filters made with synthetic fibers designed to withstand high temperatures and abrasive flue gas.

[3] The actual number of bags will be vendor specific and will depend on the size of the filter bags based on the final design of the fabric filter.

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Furthermore, fabric filters are subject to deterioration and operational problems over the life of the filter bag. Operational problems that may cause an increase in fabric fiber spacing and potentially higher particulate emissions are described below.

- Occasional filter bag blinding may occur because of moisture in the flue gas, low flue gas temperatures, or other matters. Bag blinding will cause high flue gas velocity in the remaining open bag areas that can lead to erosion of the fabric fibers in these areas.

- Flue gas temperatures may, on occasion, inadvertently exceed the preferred maximum because of unit startup, shutdown, load changing conditions, or because of equipment operational problems such as an air heater problem. These high flue gas temperatures can cause deterioration of fabric, resulting in larger openings in the fabric mess through which more particulate material can pass.

- Bag cleaning is accomplished with a brief high pressure air blast. Over time the cleaning operations may cause the bag fabric to erode.

- Fly ash is abrasive and will over time erode the fabric material.

Although it is probably technically feasible to construct a fabric filter with either type of bag, it should be noted that “Goretex” or PTFE bags have not been used in large-scale utility applications, and thus subjected to the operating conditions described above. Therefore, there is no historical data and no commercial operating history upon which to base a conclusion regarding the technical feasibility of PTFE in a utility application. Even with the lack of technical data and commercial operating experience, as you will see later, PTFE bags must be eliminated as BACT based on economic impact.

Based on a maximum fuel ash content of 12%, and assuming 80% of the total ash is exhausted with the flue gas as fly ash, the maximum particulate loading to the Unit 3 fabric filter will be 8.58 lb/mmBtu heat input. At the maximum heat input of 9,050 mmBtu/hr, particulate loading to the fabric filter system will be approximately 77,620 lb/hr.

Based on the anticipated flue gas flow rate, the chemical and physical characteristics of the IPP fly ash, and information available from fabric filter vendors, it is expected that a properly sized and operated fabric filter utilizing Ryton-type bags could consistently achieve a post-control PM_{10} emission rate (including some nominal margin for normal operational variations) of 0.015 lb/mmBtu representing an overall control efficiency of 99.83%. For this BACT analysis, it will be assumed that a fabric filter using PTFE-

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coated bags may be able to achieve a controlled emission rate of 0.012 lb/mmBtu[4] representing an overall control efficiency of 99.86, or an increased collection efficiency of 0.03%.

VI. Step 3: Rank Remaining Control Technologies by Control Effectiveness

Table 2 ranks the candidate fabric filter control technologies of Rayton-type bags and PTFE bags with their annual emission rate.

Table 2
Candidate Control Technologies

Control Technology	Percent Removal	PM-10 Emissions (lb/mmBtu)	Maximum Annual Emissions (tpy)*
Fabric Filter with PTFE-Coated Bags	99.86%	0.012	476
Fabric Filter with Ryton-Type Bags	99.83%	0.015	595

VII. Step 4: Evaluate the Most Effective Controls and Document Results by Environmental Impacts, Energy Impacts and Economic Impacts

This section evaluates the economic effectiveness of PTFE-coated bags with respect to the control of PM_{10} emissions. Economic effectiveness is evaluated in terms of average annual cost effectiveness, expressed as the annual cost per ton of PM_{10} removed ($/ton). Because fabric filtration with Ryton-type bags is being proposed as BACT for the control of PM_{10}, this technology will be considered baseline for PM_{10}, and the incremental cost effectiveness of the PTFE-coated bag system will be evaluated.[5]

Summarized in Table 3 are the expected PM_{10} emission rates and maximum annual PM_{10} mass emissions associated with the baseline control technology (Ryton-type bags) and

[4] EPA NSR guidance manual at page B.7 states "…in cases where the level of control in a permit is not expected to be achieved in practice (e.g., a source has received a permit but the project was canceled, or every operating source at that permitted level has been physically unable to achieve compliance with the limit), and supporting documentation showing why such limits are not technically feasible is provided, the level of control (but not necessarily the technology) may be eliminated from further consideration."

[5] Incremental cost is the cost per ton associated with the incremental increase in pollutant removal, and is an appropriate economic consideration under a BACT analysis. See, New Source Review Workshop Manual (NSR Manual), USEPA Office of Air Quality Planning and Standards, Research Triangle Park, NC, Draft October 1990, (pp. B.31).

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with the PTFE-coated bags. Table 4 presents the difference in capital costs and annual operating costs associated with building and operating each control system.

Additional annual operating costs associated with the PTFE-coated bags were limited to bag replacement costs. Pressure drop across PTFE-bags will be essentially the same as the pressure drop across Ryton-type bags, however the PTFE-bags may need to be cleaned more frequently. Therefore, annual operating costs also include an incremental increase in operating and maintenance labor. Solid waste disposal is an operating cost associated with fabric filtration, however, because both systems will generate essentially the same amount of solid waste (e.g., fly ash), solid waste disposal costs have been disregarded.

Table 5 shows the average annual incremental cost effectiveness for the PM_{10} control provided by PTFE-coated bags. A more detailed cost estimate is provided in Attachment 1.

Table 3
Annual PM_{10} Emissions

Control Technology	PM-10 (lb/mmBtu)	Maximum Annual Emissions (tpy)*	Annual Reduction in Emissions (tpy from base case)*
Fabric Filter with Ryton-Type Bags	0.015	595	-
Fabric Filter with PTFE-Coated Bags	0.012	476	119

* Maximum annual emissions, and annual emission reductions for the BACT analysis are based on a maximum heat input of 9,050 mmBtu/hr for 8,760 hours per year (100% capacity factor).

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Table 4
PM_{10} Emission Control System
Cost Summary

Control Technology	Total Capital Investment* ($)	Total Capital Investment ($/kW)	Annual Capital Recovery Cost ($/year)	Annual Operating Costs** ($/year)	Total Annual Costs ($/year)
PTFE-Coated Bags	$6,030,000	$6.7	$757,200	$911,900	$1,669,100

* Total capital investment is the incremental increase in capital investment needed to design a fabric filter with PTFE-coated bags. The cost includes the initial cost of the bags, additional engineering, and contingencies (see Attachment 1). Based on information supplied by bag vendors, the cost of a Ryton-type bag for the Unit 3 reverse air baghouse will be approximately $125/bag, and the cost of a PTFE-coated bag will be approximately $275/bag.

** The increase in annual operating costs is generally related to the increased cost in periodic bag replacement (see Attachment 1). Note that the annual operating cost in this cost evaluation is based on a fabric filter with 20,000 bags. It is possible that the IPA Unit 3 fabric filter could have as many as 30,000 bags, which would increase annual operating costs.

Table 5
PM_{10} Emission Control System
Incremental Cost Effectiveness

Control Technology	Total Annual Cost Difference ($/year)	Annual Emission Reduction (tpy)	Average Annual Cost Effectiveness ($/ton)
PTFE-Coated Bags	$1,669,100	119	$14,036

Based on a calculation of the annual average incremental cost effectiveness, a fabric filter system with PTFE-coated bags is not considered economically feasible for the control of PM_{10} emissions from a nominal 900-MW net coal-fired boiler firing Utah bituminous coal. Although the specialty bag system may reduce overall PM_{10} emissions, the average cost effectiveness for the incremental increase in PM_{10} control is approximately $14,000/ton of PM_{10} controlled. This cost is significantly greater than the average cost for PM_{10} control (which is generally in the range of $15 - $25/ton), and exceeds the cost effectiveness guidelines used by UDAQ in prior BACT determinations. [6]

[6] To justify the elimination of a control alternative on economic grounds, the applicant must demonstrate that costs of pollutant removal for the control alternative are disproportionately high when compared to the costs of control for that particular pollutant in recent BACT determinations. (NSR Manual page B.32)

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VIII. Step 5: Determination of BACT and Conclusions

Fabric filters represent the most effective system for the control of PM_{10}. Based on site-specific design parameters, including flue gas flow rate, flue gas temperature, fly ash loading, and fly ash chemical/physical characteristics, it is concluded that a fabric filter consisting of Ryton-type bags can consistently achieve a controlled PM_{10} emission rate of 0.015 lb/mmBtu. Based on an uncontrolled PM_{10} emission rate of 8.58 lb/mmBtu, a controlled emission rate of 0.015 lb/mmBtu represents a control efficiency of 99.83%.

It is not economically feasible to increase the control efficiency to approximately 99.86%, and achieve a controlled emission rate of 0.012 lb/mmBtu by designing the fabric filter with PTFE-coated specialty bags. These specialty bags are not economically feasible. Based on information provided by fabric filter vendors, specialty bags cost approximately $275/bag compared to approximately $125/bag for Ryton-type bags. The IPP Unit 3 baghouse will have approximately 20,000 - 30,000 filter bags, and on average approximately 1/5th of the bags will require replacement annually.

It should be noted that to the best of our knowledge there are no large-scale (> 250MW's) utility baghouse applications using PTFE-coated specialty bags. Thus, there is no actual operating experience with this material on a unit similar to the proposed Unit 3. Although a fabric filter with specialty bags may represent the lowest achievable emission rate, it must be rejected as BACT, as defined in UAC R307-101-2, based on economic considerations.

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Attachment 1
Incremental Cost Effectiveness Worksheet

INTERMOUNTAIN - UNIT 3
FABRIC FILTER BACT COST EVALUATION
COMPARISON OF FABRIC FILTERS @ 0.015 lb/mmBtu
and FABRIC FILTERS @ 0.012 lb/mmBtu

Net Plant Output 900 MW

CAPITAL COSTS	**Cost [$]**		**Basis**
Direct Capital Costs			Increase in capital cost is related to the difference in bag costs, and includes the cost of bags, cages, installation and erection. Based on vendor information, the cost of a Ryton-type bag is approximately $125/bag and the cost of a PTFE-coated bag is approximately $275/bag. The Unit 3 reverse air fabric filter will have approximately 20,000 bags.
Emission Control Device	$4,500,000		
Auxiliary Equipment (e.g., ductwork, fans, etc)	$0	0%	
Instrumentation	$0	0%	
Sales Tax	$0	0%	Sales tax on pollution control equipment - N/A in Utah.
Freight	$0	0%	included in control device cost
Total Purchased Equipment Cost	$4,500,000		
Direct Installation Costs			
Foundations and Supports	$0	0.0%	included in control device cost
Handling and Mechanical Erection	$0	0.0%	included in control device cost
Electrical	$0	0.0%	included in control device cost
Piping	$0	0.0%	included in control device cost
Insulation	$0	0.0%	included in control device cost
Painting	$0	0.0%	included in control device cost
Total Direct Installation Costs	$0		
Indirect Capital Costs			
Engineering	$450,000	10.0%	of purchased equipment cost (typical order-of-magnitude value)
Construction and Field Expenses	$225,000	5.0%	of purchased equipment cost (typical order-of-magnitude value)
Contractor Fees	$0	0%	Included in purchase and direct costs
Start-Up	$90,000	2.0%	of purchased equipment cost (typical order-of-magnitude value)
Performance Testing	$90,000	2.0%	of purchased equipment cost (typical order-of-magnitude value)
Contingencies	$675,000	15.0%	of purchased equipment cost (typical order-of-magnitude value)
Total Indirect Capital Costs	$1,530,000		
Site Preparation	$0		included in control device costs
Buildings	$0		included in control device costs
Total Capital Costs			
Total Capital Investment	$6,030,000		
Total Capital Investment ($/kW)	$6.7		
Capital Recovery Factor = $i(1+i)^n / (1+i)^n - 1$	0.1256	20	life of equipment (years)
Annualized Capital Costs			
(Capital Recover Factor x Total Capital Investment)	**$757,200**	11%	pretax marginal rate of return on private investment
OPERATING COSTS			**Basis**
Operating & Maintenance Costs			
Variable O&M Costs			
Bags and Cage Replacement Costs	$600,000		difference of $150/bag ($275/bag v. $125/bag)
Ash Disposal Cost	$0		The additional disposal cost will be minimal.
Auxiliary Power Cost	$0		Pressure drop will be essentially the same with either bag, however the PTFE-coated bag may require more frequent cleaning.
Total Variable O&M Cost	$600,000		
Fixed O&M Costs			
Operating Labor	$17,500		1/4 additional operator @$70,000/operator/year added for expected more frequent cleaning of PTFE-coated bags.
Supervisory Labor	$3,500	20.0%	of Operating Labor cost
Administrative Labor	$2,000	3.0%	of Operating, Supervisory and Maintenance Labor
Maintenance Materials	$67,500	1.5%	of purchased equipment cost (typical value for fabric filters)
Maintenance Labor	$40,500	60.0%	of maintenance materials cost
Total Fixed O&M Cost	$131,000		
Indirect Operating Cost			
Property Taxes	$60,300	1%	of total capital investment (EPA Guidelines)
Insurance	$60,300	1%	of total capital investment (EPA Guidelines)
Administration	$60,300	1%	of total capital investment (EPA Guidelines)
Total Indirect Operating Cost	$180,900		
Total Annual Operating Cost	**$911,900**		
TOTAL ANNUAL COST			
Annualized Capital Cost	**$757,200**		
Annual Operating Cost	**$911,900**		
Total Annual Cost	**$1,669,100**		
TOTAL PM-10 REMOVED (tons/year)	**119**		Difference between 0.012 and 0.015 lb/mmBtu @ 100% capacity factor
COST EFFECTIVENESS ($/ton removed)	**$14,026**		

IPP Unit 3—PM_{10} BACT Cost Estimate

Technical Memorandum

To: Milka Radulovic
UDEQ Division of Air Quality

Date: November 7, 2003

cc: Steve Sands
CH2MHill

From: Ken Snell / Bill Rosenquist
Sargent & Lundy LLC

Subject: IPP Unit 3 – PM10 BACT Cost Estimate

This technical memorandum provides a response to questions raised by UDAQ regarding the BACT economic analysis prepared for PM10 control at the proposed IPP Unit 3.

Question: In the fabric filter BACT cost evaluation, what is the average cost effectiveness of each alternative, and does the average cost effectiveness support the exclusion of specialty filters as BACT?

Response: Yes, in our opinion, the average and incremental cost effectiveness of the alternatives supports exclusion of specialty filters as BACT.

IPP prepared and submitted a comprehensive top-down BACT analysis of PM10 control technologies for the proposed unit. Information to support the BACT analysis was included in IPP's original permit application (December 2002) and supplemented with additional information submitted in the NOI Addendum on May 14, 2003. Results of the first three steps in the top-down BACT analysis for PM10 (i.e., identification and ranking of technically feasible control technologies) are summarized in the following table:

Control Technology	Controlled PM10 Emission Rate (lb/mmBtu)	Maximum Annual PM10 Emissions (tpy)	Annual PM10 Emission Reductions (tpy)	Percent Reduction (%)
Fabric Filter with PTFE Coated Bags (specialty bags)	0.012	476	339,499	99.86
Fabric Filter with Ryton-type or Fiberglass Bags	0.015	595	339,380	99.83
Electrostatic Precipitator (ESP)	0.018	714	339,261	99.79
Uncontrolled PM10 Emission Rate – Baseline	8.58	339,975		

Step four in the top-down BACT analysis is an evaluation of the energy, environmental, and economic impacts of each option and the selection of the final level of control (NSR Manual page B.26). IPP concluded in its BACT analysis that installation of a fabric filter would not result in energy or environmental impacts significant enough to preclude it from being considered BACT. Therefore, IPP prepared an economic impact evaluation of the dominant control alternative. In this case, the dominant control alternative was determined to be a fabric filter control system over a range of removal efficiencies. The highest removal efficiency can be achieved using a fabric filter control system equipped with specialty coated bags. The second highest removal efficiency can be achieved using a fabric filter control system equipped with more common, and less expensive, fiberglass or Ryton-type bags.

Average and incremental cost effectiveness are the two economic criteria that are considered in the BACT analysis (NSR Manual, page B.31). Average cost effectiveness is the dollars per ton of pollutant emissions reduced. Average cost effectiveness is calculated as shown by the following formula:

$$CE_{Avg} = TAC / (ER_{baseline} - ER_{control\ option})$$

Where:

CE_{Avg} = Average Cost Effectiveness
TAC = Total Annualized Cost
$ER_{baseline}$ = Baseline Emission Rate
$ER_{control\ option}$ = Control Option Emission Rate

Average cost effectiveness is a function of both the cost of the pollution control system and the total quantity of pollutant removed from the exhaust gas stream. The result is a pollutant-specific cost effectiveness number in annualized dollars per ton of pollutant removed.

In addition to the average cost effectiveness of a control option, incremental cost effectiveness between dominant control options should be calculated (NSR Manual page B.41). A comparison of incremental costs can also be useful in evaluating the economic viability of a specific control option over a range of efficiencies (NSR Manual page B.43). The incremental cost effectiveness calculation compares the costs and emissions performance level of a control option to those of the next most stringent option, as shown in the following formula:

$$CE_{Incremental} = (TAC_{option1} - TAC_{option2}) / (ER_{option\ 2} - ER_{option\ 1})$$

Where:

$CE_{Incremental}$ = Incremental Cost Effectiveness
$TAC_{option\ 1}$ = Total Annualized Cost of more stringent control option
$TAC_{option\ 2}$ = Total Annualized Cost of next most stringent control option
$ER_{option\ 1}$ = Emission Rate of more stringent control option
$ER_{option\ 2}$ = Emission Rate of next most stringent control option

Incremental cost effectiveness should be examined in combination with the average cost effectiveness in order to justify elimination of a control option (NSR Manual page B.41).

If the cost of reducing emissions with the top control alternative, expressed in dollars per ton, is on the same order as the cost previously borne by other sources of the same type in applying that control alternative, the alternative should initially be considered economically achievable (NSR Manual page B.44). However, cost effectiveness values above the levels experienced by other sources of the same type <u>and pollutant</u>, are taken as an indication that unusual and persuasive differences exist with respect to the source under review (NSR Manual page B.31 emphasis added). To justify elimination of an alternative the applicant should demonstrate that costs of pollutant removal for the control alternative are disproportionately high when compared to the cost of control for the pollutant in recent BACT determinations.

Recent coal-fired boiler BACT determinations include very limited information regarding the cost effectiveness of PM10 control technologies. Based on a review of recently issued PSD permits for large coal-fired boilers, only one BACT analysis was identified to include a PM10 control cost evaluation. This is because most permit applicants have compared the effectiveness of fabric filters and electrostatic precipitators, and concluded that fabric filters represent the most stringent control technology. Applicants have typically not been required to evaluate the cost effectiveness of a fabric filtration over a range of control efficiencies.

The only BACT evaluation identified comparing the incremental cost effectiveness of fabric filtration over a range of control efficiencies was in the Wygen 2 permit application. A summary of the Wygen 2 PM10 cost evaluation is provided below:

	Baseline	**Ryton Bags**	**Membrane Bags**	**Membrane Bags**
Emission Rate	10.2 lb/mmBtu	0.018 lb/mmBtu	0.015 lb/mmBtu	0.012 lb/mmBtu
Annual Emissions	231,032 tpy	406 tpy	338 tpy	270 tpy
Emissions Reduction	Baseline	230,626 tpy	230,694 tpy	230,762 tpy
Total Cost Effectiveness	Baseline	$2.3 / ton	$5.8 / ton	$5.8 / ton
Incremental Reduction	--	Baseline	68 tpy	136 tpy
Incremental Annualized Cost	--	Baseline	$795,000	$795,000
Incremental Cost Effectiveness	--	Baseline	$11,691/ton	$5,846/ton

Taken from Wyoming Department of Environmental Quality Division of Air Quality, Permit Application Analysis, NSR-AP-C92, April 24, 2002, page 13.

Based on the costs presented in the Wygen 2 permit application, the average cost effectiveness of PM10 control at the Wygen 2 facility would range from $2.3/ton to $5.8/ton. This cost estimate does not appear to be consistent with the fabric filter cost estimate prepared for IPA Unit 3. For example, under Wygen's Ryton bag scenario, the total annual cost of operating the fabric filter at Wygen 2 would be approximately $530,440 per year (i.e., $2.3/ton x 230,626 ton/year). This total annual cost appears to be very low. The auxiliary power cost alone associated with a fabric filter (i.e., the cost of power required to operate the ID fans and overcome pressure drop across the filter) is typically in the range of 0.25 to 0.30 percent of the unit's gross power output. Assuming the Wygen 2 unit has a gross power output of 500 MW, the power requirement for the fabric filter would be in the range of 9,855 to 11,826 MWh per year (e.g., 500 MW x 0.0025 x 8760 x 0.9 capacity factor = 9,855 MWh). Assuming an auxiliary power cost of $30/MWh, the total annual auxiliary power cost for the fabric filter would be $295,650 to $354,780 per year. In addition to the auxiliary power cost the total annual cost should include annualized capital recovery, bag/cage replacement costs, ash disposal costs, maintenance materials, labor, and indirect operating costs. Details of the Wygen 2 cost estimate were not available for review, however, the total annual cost appears to be low, and cannot be directly compared to the cost estimate prepared for IPP Unit 3.

Cost estimates prepared to support IPP's BACT analysis were prepared in accordance with guidance provided in EPA publications, including the OAQPA Control Cost Manual, 6th ed., U.S.EPA Office of Air Quality Planning and Standards, EPA 452/B-02-001, January 2002. The fabric filter control cost estimates are summarized below, and detailed in Attachment 1 to this memorandum.

PM10 Control Technology	Total Capital Cost	Total Capital Cost ($/kW-net)	Capital Recovery Cost	Annual O&M	Total Annual Cost
Fabric Filter with PTFE Coated Bags (specialty bags)	$51,638,000	$57.4	$5,939,600	$6,536,500	$12,476,100
Fabric Filter with Ryton-type or Fiberglass Bags	$45,587,000	$50.7	$5,243,600	$5,349,800	$10,593,400

The total annual cost estimate prepared for IPP Unit 3 is significantly higher then the costs presented in the Wygen 2 permit application. However, the IPP Unit 3 costs were prepared in accordance with EPA cost estimating guidelines, and, based on engineering judgment, are in-line with actual purchased equipment costs and O&M costs observed at large coal-fired units.

To evaluate the average cost effectiveness of the fabric filter control system, IPA used an uncontrolled PM10 emission rate of 8.53 lb/mmBtu. This emission rate represents the upper bound of uncontrolled PM10 emissions from the proposed source. Assuming an uncontrolled PM10 emission rate of 8.53 lb/mmBtu, total annual PM10 emissions from the source would be approximately 339,975 ton/year. Annual emission reductions and average and incremental cost effectiveness of the fabric filter control systems are presented below:

Control Technology	PM10 Emission Rate (lb/mmBtu)	Annual PM10 Emisions (tpy)	Annual PM10 Reduction (tpy)	Percent Reduction
Fabric Filter with PTFE Coated Bags (specialty bags)	0.012	476	339,499	99.86
Fabric Filter with Ryton-type or Fiberglass Bags	0.015	595	339,380	99.83

Control Technology	Total Annual Cost ($/yr)	Average Cost Effectiveness ($/ton)	Incremental Annual Cost ($/yr)	Incremental Cost Effectiveness ($/ton)
Fabric Filter with PTFE Coated Bags (specialty bags)	$12,476,100	$37	$1,882,700	$15,800
Fabric Filter with Ryton-type or Fiberglass Bags	$10,593,400	$31		

As shown above, the incremental cost effectiveness for controlling PM10 using specialty-coated bags is substantial ($15,800/ton), and use of specialty-coated bags would increase the total annual cost of PM10 control by approximately 20% ($1.88 MM/year). Because there is very limited data regarding BACT cost evaluations for PM10 control, it is difficult to determine how this cost compares to the cost of PM10 control at similar facilities. However, IPP contends that, on an average cost effectiveness basis, an increase of 20% represents a significant increase in the control of PM10 emissions.

Although the average cost effectiveness appears to be relatively low, it is important to keep in mind that average cost effectiveness is a function of both the total annual cost and the quantity of pollutant controlled. In this case both control alternatives will remove more than 339,300 tons per year of PM10. However, the additional 119 tons of PM10 removed using specialty-coated bags would increase the total annual cost of PM10 control by more than $1.88 MM.

Given the significant increase in annual costs associated with the specialty bags, it is appropriate to evaluate the incremental cost effectiveness of the more stringent control scenario. As shown above, the incremental cost effectiveness associated with the specialty bags is $15,800/ton. This cost is significantly greater than the average cost effectiveness of either system. In other words, the cost of removing the first 339,400 tons of PM10 is approximately $31/ton, while the cost of removing the last 119 tons increases to $15,800/ton. The incremental cost increase associated with the lower emission limit is disproportionately high.

Finally, as noted in the IPP BACT analysis, to the best of our knowledge, there are no large-scale (>250 MW) utility baghouse applications currently in operation using PTFE-coated specialty bags. Thus, there is no actual operating experience with this material on a unit similar to the proposed Unit 3. For these reasons, a fabric filter with specialty bags should be rejected as BACT, as defined in UAC R307-101-2.

Attachment 1
Fabric Filter Cost Comparison

CAPITAL COSTS	0.015 Case [$]	0.012 Case [$]		Basis
Direct Capital Costs				Increased capital cost is related to the difference in bag costs. It was assumed that all other costs (e.g., ductwork, fans, instrumentation, etc.) would be constant regardless of bag material. Bag cost was based on a total required filter area of 1,989,415 ft^2, and a unit cost of \$4.355/ft^2 for specialty bags and \$2.085/ft^2 for ryton-type (or fiberglass) bags. The bag cost includes cages, installation, freight and erection.
Emission Control Device	$34,020,000	$38,536,000		
Auxiliary Equipment (e.g., ductwork, fans, etc)	$0	$0	0%	
Instrumentation	$0	$0	0%	
Sales Tax	$0	$0	0%	
Freight	$0	$0	0%	
Total Purchased Equipment Cost	$34,020,000	$38,536,000		
Direct Installation Costs				
Foundations and Supports	$0	$0	0.0%	included in control device cost
Handling and Mechanical Erection	$0	$0	0.0%	included in control device cost
Electrical	$0	$0	0.0%	included in control device cost
Piping	$0	$0	0.0%	included in control device cost
Insulation	$0	$0	0.0%	included in control device cost
Painting	$0	$0	0.0%	included in control device cost
Total Direct Installation Costs	$0	$0		
Indirect Capital Costs				
Engineering	$3,402,000	$3,853,600	10.0%	of purchased equipment cost (typical order-of-magnitude value)
Construction and Field Expenses	$1,701,000	$1,926,800	5.0%	of purchased equipment cost (typical order-of-magnitude value)
Contractor Fees	$0	$0	0%	Included in purchase and direct costs
Start-Up	$680,400	$770,720	2.0%	of purchased equipment cost (typical order-of-magnitude value)
Performance Testing	$680,400	$770,720	2.0%	of purchased equipment cost (typical order-of-magnitude value)
Contingencies	$5,103,000	$5,780,400	15.0%	of purchased equipment cost (typical order-of-magnitude value)
Total Indirect Capital Costs	$11,566,800	$13,102,240		
Site Preparation	$0	$0		included in control device costs
Buildings	$0	$0		included in control device costs
Total Capital Costs				
Total Capital Investment	$45,587,000	$51,638,000		
Total Capital Investment ($/kW)	$50.7	$57.4		
Capital Recovery Factor = $i(1+i)^n / (1+i)^n - 1$	0.1150	0.1150	30	life of equipment (years)
Annualized Capital Costs (Capital Recover Factor x Total Capital Investment)	**$5,243,600**	**$5,939,600**	11%	pretax marginal rate of return on private investment
OPERATING COSTS				**Basis**
Operating & Maintenance Costs				
Variable O&M Costs				
Bags and Cage Replacement Costs	$787,000	$1,661,000		Based on 5-year bag life, a bag size of 91ft^2/bag, a baghouse with 21,860 bags, and a bag cost \$180/bag and \$380/bag, respectively.
Ash Disposal Cost	$1,697,000	$1,697,000		\$5/ton on-site disposal of fly ash collected in the FF. Based uncontrolled PM emission rate of 339,975 tpy and a controlled emission rate of 595 tpy and 476 tpy, respectively.
Auxiliary Power Cost	$586,000	$586,000		Based on an auxiliary power requirement of 2,476 kW and an auxiliary power cost of \$30/MWh.
Total Variable O&M Cost	$3,070,000	$3,944,000		
Fixed O&M Costs				
Operating Labor	$70,000	$87,500		Assumed one additional operator for the fabric filter and 1/4 additional operator for more frequent cleanings with the specialty bags.
Supervisory Labor	$14,000	$17,500	20.0%	of Operating Labor cost
Administrative Labor	$11,700	$13,600	3.0%	of Operating, Supervisory and Maintenance Labor
Maintenance Materials	$510,300	$578,000	1.5%	of purchased equipment cost (typical Ryton-type fabric filter value)
Maintenance Labor	$306,180	$346,800	60.0%	of maintenance materials cost
Total Fixed O&M Cost	$912,180	$1,043,400		
Indirect Operating Cost				
Property Taxes	$455,870	$516,380	1%	of total capital investment (EPA Guidelines)
Insurance	$455,870	$516,380	1%	of total capital investment (EPA Guidelines)
Administration	$455,870	$516,380	1%	of total capital investment (EPA Guidelines)
Total Indirect Operating Cost	$1,367,610	$1,549,140		
Total Annual Operating Cost	**$5,349,800**	**$6,536,500**		
TOTAL ANNUAL COST				
Annualized Capital Cost	**$5,243,600**	**$5,939,600**		
Annual Operating Cost	**$5,349,800**	**$6,536,500**		
Total Annual Cost	**$10,593,400**	**$12,476,100**		
Annual Cost $/kW	**$11.77**	**$13.86**		
TOTAL PM-10 REMOVED (tons/year)	**339,380**	**339,499**		Based on an uncontrolled PM emission rate of 339,975 tpy, a controlled emission rate of 575 tpy and 476 tpy, respectively.
AVERAGE ANNUL COST EFFECTIVENESS ($/ton removed)	**$31.00**	**$37.00**		
INCREMENTAL INCREASE IN PM-10 REMOVED (TPY)		**119**		
INCREMENTAL COST EFFECTIVENESS ($/ton removed)		**$ 15,800**		

IPP Unit 3—PM_{10} BACT Questions

Technical Memorandum
(Revision 4)

To: Milka Radulovic
UDEQ Division of Air Quality

Date: November 7, 2003
Resubmitted 1-31-04

cc: Steve Sands
CH2MHill

From: Ken Snell / Bill Rosenquist
Sargent & Lundy LLC

Subject: IPP Unit 3 – PM10 BACT Questions

Provided below are responses to questions raised by UDAQ during our August 22, 2003 conference call.

1. Does S&L have information from vendors to support the fabric filter cost comparison?

Response: The fabric filter cost comparison provided in Appendix I of IPP's NOI Addendum was based on fabric costs obtained from a supplier of filters used in the electricity generating industry. A summary of the budgetary cost estimate is provided below.

Bag Description	Bag Size	Unit Price	Price per ft^2
15 oz. PTFE Membrane Laminate (Gortex-type specialty bags)	6" x 288" (37.9 ft^2)	$165.00	$4.355/ ft^2
16 oz. Felted (Ryton-type or woven fiberglass bags)	6" x 288" (37.9 ft^2)	$79.00	$2.085/ ft^2

Note that the terms "Gortex-type specialty bags" and "Ryton-type bags" have been used in IPP's NOI and in the PM-10 BACT determination. These terms are being used generically to identify bags coated with a specialty membrane (e.g., PTFE coating). There are several fabrics and bag designs that may be suitable for use in a reverse air baghouse, and new bag materials are continuously under development. By using the trade names Gortex and Ryton, IPP does not intend to limit the potential suppliers of fabric filter bags.

The budgetary costs provided by the supplier were adjusted for IPP Unit 3 based on unit-specific considerations. Based on combustion calculations and anticipated boiler design, S&L calculated the flue gas flow rate at the inlet to the Unit 3 baghouse to be 3,617,117 acfm. Assuming a net air-to-cloth ratio of 2.0 cfm/ft^2 (with a reverse air cleaning mechanism) the filter area required for the Unit 3 baghouse was estimated to be 1,808,559 ft^2.

Assuming that the baghouse will be designed to contain 20,000 to 30,000 individual bags, the filter area required of each bag was estimated to be between 60 to 90 ft^2, considerably larger than the bags used in the supplier's cost estimate. (See the response to Question 4 for a more detailed calculation of the total number of bags).

For the IPP BACT cost estimate S&L assumed a bag size of 10" x 25' (diameter x length). These bags will each have a filtering surface of approximately 66 ft^2. Based on the unit costs summarized above ($/$ft^2$), the per bag cost for IPP Unit 3 was adjusted to $275/bag for specialty bags and $125/bag for Ryton-type bags. The actual calculated costs were $287.43/bag and $135.61/bag, respectively, however, these costs were revised downward assuming some efficiencies in the manufacturing of the larger sized bags. Assuming an individual bag size of 66 ft^2, the Unit 3 baghouse will contain approximately 30,000 bags (i.e., 1,808,559 4 66).

If the bag size is increased to 10" x 35', the filter surface area of each bag will increase to approximately 91 ft^2 /bag, and the per-bag price will increase to approximately $380/bag and $180/bag, respectively (i.e., 91 ft^2 x $4.355/ ft^2 = $396.31 and 91 ft^2 x $2.085/ ft^2 = $189.75, again revising the costs downward assuming some efficiencies in the manufacturing of larger sized bags). Assuming an individual bag size of 91 ft^2, the Unit 3 baghouse will contain approximately 20,000 bags (i.e., 1,808,559 4 91).

In the original IPP BACT cost estimate, S&L assumed a bag size of 66 ft^2, and estimated annual bag replacement costs based on a baghouse containing 20,000 bags. Both estimates were considered to be conservative in order to provide a conservative estimate of the incremental annual cost effectiveness (expressed in $/ton) associated with the specialty bags. However, in order to provide a more verifiable cost estimate, S&L has revised the BACT cost estimate using a more consistent approach. See, response to Question #5.

2. How do the IPP Unit 3 fabric filter cost estimates compare to the fabric filter cost estimate provided by Black Hills Power Corporation in the Wygen 2 permit application?

Response: S&L does not have a copy of the detailed cost estimate prepared to support the Wygen 2 permit application, however, based on information available in the Wyoming DEQ Permit Application Analysis (NSR-AP-C92, dated April 24, 2002) the total annualized cost of the proposed Wygen2 baghouse increased by $759,000 with the use of specialty bags (i.e., $1,331,000/year with specialty bags vs. $536,000/year with Ryton-type bags). Based on a unit size of 500 MW (gross), the incremental annual cost increase at Wygen 2 would be approximately $1.59/kW-gross. Wygen 2 has not yet been constructed, so the Wygen 2 cost estimate was probably based on 2002 design costs.

In the IPP Unit 3 cost estimate the incremental cost increase associated with using specialty bags was calculated to be $1,669,100/year ($757,200 capital recovery cost plus $911,900 O&M). Based on a 950 MW-gross output, the cost increase per kw-gross would be $1.76/kW-gross. Although this is approximately 10% higher than the cost estimate at Wygen 2 it is well within the margin of a budgetary cost estimate.

In addition to the incremental difference in bag material cost, there are other significant differences between the Wygen 2 and IPP Unit 3 PM-10 BACT determinations. First, Wygen 2 proposed a 500 MW-gross pulverized coal fired boiler compared the IPP's 950 MW-gross boiler. Based on unit size and flue gas flow rates, the IPP Unit 3 baghouse will be significantly larger than the Wygen 2 baghouse. Second, Wygen 2 will burn a subbituminous coal and WDEQ approved a spray dry absorber (SDA) for SO_2 control. IPP Unit 3 will primarily burn a Utah bituminous coal and proposed a wet scrubber for SO_2 control; a wet scrubber provides more stringent SO_2 control than an SDA. As discussed in IPP's NOI, an SDA is typically located upstream of the baghouse while a wet scrubber is located downstream of the baghouse. Because of the location of the scrubber, the IPP Unit 3 baghouse will see higher flue gas temperatures, and there will be a corresponding slight increase in particulate emissions from dissolved solids in the wet FGD scrubber slurry. On the other hand, the IPP wet scrubber provides the most stringent SO_2 control.

Finally, in its BACT determination Wygen 2 assumed that the lowest emission rate it could achieve with Ryton-type bags was 0.018 lb/mmBtu. S&L has received information that baghouse vendors may be willing to guarantee a PM-10 emission rate of 0.015 lb/mmBtu without using specialty coated bags (based on the IPP Unit 3 design). Wygen 2 concluded that membrane bags would be required to achieve either 0.015 or 0.012

lb/mmBtu (presumably for the Wygen 2 design). Therefore, the Wygen 2 incremental cost comparison between 0.018 lb/mmBtu and 0.012 lb/mmBtu resulted in an incremental cost effectiveness of $5,846/ton. Even though this cost effectiveness is significantly greater than the cost typically associated with PM-10 control, WDEQ considered the "incremental cost effectiveness to be reasonable for 0.012 lb/mmBtu…"

BACT is an emission limitation based on a case-by-case review of emission control technologies taking into account site-specific energy, environmental and economic costs associated with each alternative technology. Based on site-specific design criteria including boiler design, flue gas flow rate, flue gas temperature, uncontrolled particulate loading, sulfur dioxide control configuration, and bag material costs, IPP concluded that an emission rate of 0.012 lb/mmBtu may be technically feasible, however the incremental cost of reducing PM-10 emissions from 0.015 to 0.012 lb/mmBtu (approximately $14,000 - $15,800/ton) exceeds the cost effectiveness guidelines used by UDAQ in prior BACT determinations.

3. Was bag size taken into consideration in the fabric filter cost evaluation?

Response: Baghouse design is based on several variables, including inlet flue gas flow rate, inlet particulate loading, flue gas temperature, filter cake cleaning mechanism, and air-to-cloth ratio. Based on preliminary design calculations, it was estimated that the IPP Unit 3 baghouse would require a filter area of approximately 1,808,559 ft^2. This overall filter area is independent of the filter bag material.

The actual bag size will be vendor-specific, and it is possible that certain bag materials will limit the size of the bag because of mechanical or physical properties. However, regardless of the bag material or the filter size, the overall filter area for IPP Unit 3 will have to be approximately 1,808,559 ft^2. Cost estimates prepared for the IPP Unit 3 BACT determination were based on this filter area.

4. What is the basis for S&L's estimate of 20,000 – 30,000 bags? Was the number of bags used consistently throughout the cost estimate?

Response: As discussed above, the total number of bags in the IPP Unit 3 baghouse will depend on the size of each individual bag. Bag size will be vendor specific, and will depend on the baghouse design and materials used. A bag size of 10" x 25' (diameter x length) will have a filter surface area of approximately 66 ft^2. Assuming an inlet flue gas flow rate of 3,617,117 ft^2, a net air-to-cloth ratio of 2.0, and assuming 10% of the bags will be off-line at any given time for cleaning, the baghouse would be designed to house approximately 30,000 bags ((1,808,559 ft^2 + 10%)466). If the bag size is increased to 10" x 35' the total number of bags will decrease to approximately 22,000 (however, the overall filter surface area will remain the same).

Bag Diameter	inches	10	10
Bag Length	feet	25	35
Filter Surface Area	ft^2 / bag	66	91
Inlet Flue Gas Flow Rate	acfm	1,808,559	1,808,559
Net Air-to-Cloth		2	2
Bags Off-Line For Cleaning	%	10%	10%
Total Filter Surface Area Required	ft^2	1,989,415	1,989,415
Total Number of Bags		30,140	21,860

5. Please explain the basis for the capital costs and annual operating costs in the fabric filter BACT cost evaluation.

In the BACT cost evaluation, capital costs were based on the total filter surface area required to control PM10 emissions, while the annual O&M costs were calculated based on replacing a specific number of bags each year.

The basis for the capital cost increase associated with using specialty bags is shown below:

Inlet Flue Gas Flowrate	acfm	3,617,117	3,617,117
Net Air-to-Cloth Ratio	cfm/ft^2	2	2
Bags Off-Line For Cleaning	%	10%	10%
Total Filter Area Required	ft^2	1,989,415	1,989,415
Bag Unit Cost	\$/ft^2	\$4.355	\$2.085
Total Cost	\$	\$8,664,000	\$4,148,000
Capital Cost Increase	\$	\$4,516,000	

For the annual bag replacement cost, S&L assumed 20,000 bags, a bag life of 5 years, and a differential of \$150/bag based on 66 ft^2 bags (\$275 - \$125/bag). Therefore, annual increase in bag replacement cost was estimated to be \$600,000/year ((20,000 4 5) x \$150). However, as discussed in the response to Question #1, both the 66 ft^2 bag size and the 20,000 bags are conservative estimates. Therefore, in order to provide a more verifiable cost estimate and to envelop potential cost increases, the BACT cost estimate was revised as follows:

Parameter	**Unit**	**Original BACT Economic Evaluation**	**Revised BACT Economic Evaluation**	**Comment**
Bag Diameter	inches	10	10	Assumed
Bag Length	feet	25	35	Assumed
Filter Surface Area	ft^2 / bag	66	91	Calculated
Cost for specialty bags Cost for non-coated bags Δ Cost per bag	\$ \$ \$	\$275 \$125 \$150	\$380 \$180 \$200	Estimated based on \$/ ft^2 costs supplied by fabric vendor.
Inlet Flue Gas Flow Rate	acfm	1,808,559	1,808,559	Engineering Calculation
Net Air-to-Cloth		2	2	Typical for reverse air cleaning mechanism
Bags Off-Line For Cleaning	%	10%	10%	Typical for reverse air cleaning mechanism
Total Filter Surface Area Required	ft^2	1,989,415	1,989,415	Calculated
Total Number of Bags		20,000	21,860	20,000 bags was a conservative estimate. 21,860 bags is based on the actual estimated flue gas flow rate.
Bag Life	years	5	5	Typical value. See also, USEPA CUECost Manual page B-7
Bags Replaced per year		4,000	4,372	20% of bags replaced each year
Baghouse Economic Life	years	20	30	See response to Question 8

6. Is a lower PM-10 emission rate (e.g., 0.011 or 0.010 lb/mmBtu) technically feasible? Does S&L have any documentation from bag vendors regarding the expected guaranteed PM-10 emission rates?

Response: Based on information provided from baghouse vendors and baghouse vendor representatives, the lowest guaranteed emission rate available for the IPP Unit 3 project is in the range of 0.012 – 0.015 lb/mmBtu. Establishing a permit limit at or below approximately 0.012 lb/mmBtu would eliminate any margin between the guaranteed emission rate and the permitted emission rate to allow for normal process fluctuations (e.g., fluctuations that may occur immediately after bag cleaning) and in our opinion is not feasible on a long-term steady state basis.

7. In the cost estimate where did S&L come up with the 15% engineering contingency?

Response: The cost estimates prepared for submittal with IPP's NOI, including percentages used to estimate engineering costs and contingencies, were based on guidance provided in EPA publications and experience S&L has gained from working on similar projects. Two EPA publications used as reference were:

OAQPS Control Cost Manual, 6^{th} ed., U.S.EPA Office of Air Quality Planning and Standards, EPA 452/B-02-001, January 2002.

Coal Utility Environmental Cost (CUECost) Workbook User's Manual, Version 1.0, Prepared for: U.S.EPA Office of Research and Development, EPA Contract No. 68-D7-0001.

Both references, and the associated CUECost worksheets, can be found at: http://www.epa.gov/ttncatc1/product.html.

S&L did not use CUECost worksheets to develop the IPP BACT evaluation. Cost estimates prepared by S&L were based on experience gained from work on similar projects. EPA guidance manuals were to double check assumptions used in the cost estimate. For example, the default input parameters for reverse air fabric filters in the CUECost worksheets include:

Maintenance	5% of installed equipment cost
Contingency	20% of installed equipment cost
General Facilities	10% of installed equipment cost
Engineering Fees	10%of installed equipment cost

Engineering and contingency costs included in the IPP BACT cost evaluation were based on:

Engineering Fees:	10% of installed equipment cost

Construction and Field Expenses:	5% of installed equipment cost
Contingencies:	15% of installed equipment cost
Startup and Performance Testing:	4% of installed equipment cost

In addition to the engineering and contingency costs, S&L assumed that the cost of maintenance materials for a reverse air baghouse would be 1.5% of installed purchased equipment cost plus maintenance and operating labor. The total cost of maintenance materials plus labor was equal to approximately 2.17% of the installed purchased equipment cost.

Although the percentages used by S&L to estimate engineering, contingency, and maintenance costs did not mirror default values included in the U.S.EPA CUECost worksheets, the percentages were within the margin of error for a budgetary cost estimate and were based on experience from similar projects.

8. What is the basis for the 20-year life of the fabric filter unit?

S&L assumed a 20-year service life for the IPP Unit 3 baghouse. This assumption was based on S&L's experience developing economic cost estimates for pollution control equipment.

The default value for a baghouse in U.S.EPA's CUECost worksheets is 30 years. In order to provide a comprehensive evaluation of the potential annual costs, the IPA BACT cost analysis has been modified to incorporate the 30-year equipment life. Copies of the original and revised cost analyses are attached to this memorandum.

9. In the fabric filter cost evaluation did S&L take into consideration other pollutants that would be controlled with the more efficient specialty filters?

In addition to the incremental reduction in PM-10 emissions, the specialty bags may reduce two additional PSD pollutants: lead and sulfuric acid mist.

The emission factor used to estimate controlled lead emissions is:

$$ER = 3.4 \text{ x } (C/A * PM)^{0.80} \quad \text{(AP-42 Table 1.1-16)}$$

Where:

ER = controlled emission rate (lb/10^{12} Btu)
C = lead concentration in the coal (ppmwt)
A = weight fraction of ash in the coal
PM = site-specific PM-10 emission rate (lb/mmBtu)

Based on a controlled PM10 emission rate of 0.015 lb/mmBtu the controlled lead emission rate at IPP Unit 3 was calculated to be 228 lb/year. If the controlled PM10 emission rate were reduced to 0.012 lb/mmBtu, the controlled lead emission rate would be reduced to 191 lb/yr (a reduction of approximately 37 lb/year or 0.0185 tpy). The reduction in lead emissions represents only a small fraction of the overall reduction in PM10 emissions (approximately 119 tpy) and would not impact the BACT economic evaluation.

Sulfuric acid mist is another PSD pollutant that may be controlled in the fabric filter. However, with respect to H_2SO_4 and other acid gases (e.g., HCl and HF) it is not expected that the type of filter used in the fabric filter will impact acid gas removal. Acid gases are removed as the flue gas passes through the alkaline filter cake that accumulates on the filter bag. Therefore, acid gas removal is a function of the thickness and alkalinity of the filter cake. Filter cake properties, including thickness and alkalinity, are not of function of the bag material. Therefore, changing to specialty coated filter bags is not expected to increase the system's acid gas removal efficiency.

Attachment
Fabric Filter - Original BACT Cost Evaluation

CAPITAL COSTS	Cost [$]		Basis
Direct Capital Costs			Increased capital cost is related to the difference in bag costs. It was assumed that all other costs (e.g., ductwork, fans, instrumentation, etc.) would be constant regardless of bag material. Bag cost was based on a total required filter area of 1,989,415 ft², and a unit cost of \$4.355/ft² for specialty bags and \$2.085/ft² for ryton-type (or fiberglass) bags. The bag cost includes cages, installation, freight and erection.
Emission Control Device	$4,500,000		
Auxiliary Equipment (e.g., ductwork, fans, etc)	$0	0%	
Instrumentation	$0	0%	
Sales Tax	$0	0%	
Freight	$0	0%	
Total Purchased Equipment Cost	$4,500,000		
Direct Installation Costs			
Foundations and Supports	$0	0.0%	included in control device cost
Handling and Mechanical Erection	$0	0.0%	included in control device cost
Electrical	$0	0.0%	included in control device cost
Piping	$0	0.0%	included in control device cost
Insulation	$0	0.0%	included in control device cost
Painting	$0	0.0%	included in control device cost
Total Direct Installation Costs	$0		
Indirect Capital Costs			
Engineering	$450,000	10.0%	of purchased equipment cost (typical order-of-magnitude value)
Construction and Field Expenses	$225,000	5.0%	of purchased equipment cost (typical order-of-magnitude value)
Contractor Fees	$0	0%	Included in purchase and direct costs
Start-Up	$90,000	2.0%	of purchased equipment cost (typical order-of-magnitude value)
Performance Testing	$90,000	2.0%	of purchased equipment cost (typical order-of-magnitude value)
Contingencies	$675,000	15.0%	of purchased equipment cost (typical order-of-magnitude value)
Total Indirect Capital Costs	$1,530,000		
Site Preparation	$0		included in control device costs
Buildings	$0		included in control device costs
Total Capital Costs			
Total Capital Investment	$6,030,000		
Total Capital Investment ($/kW)	$6.7		
Capital Recovery Factor = $i(1+i)^n / (1+i)^n - 1$	0.1256	20	life of equipment (years)
Annualized Capital Costs (Capital Recover Factor x Total Capital Investment)	**$757,200**	11%	pretax marginal rate of return on private investment
OPERATING COSTS			**Basis**
Operating & Maintenance Costs			
Variable O&M Costs			
Bags and Cage Replacement Costs	$600,000		Based on 5-year bag life, a bag size of 66 ft²/bag, a baghouse with 20,000 bags, and a bag cost differential of \$150/bag (\$275/bag v. \$125/bag).
Ash Disposal Cost	$0		The additional disposal cost will be minimal.
Auxiliary Power Cost	$0		Pressure drop will be essentially the same with either bag, however the PTFE-coated bag may require more frequent cleaning.
Total Variable O&M Cost	$600,000		
Fixed O&M Costs			
Operating Labor	$17,500		1/4 additional operator @\$70,000/operator/year added for expected more frequent cleaning of PTFE-coated bags.
Supervisory Labor	$3,500	20.0%	of Operating Labor cost
Administrative Labor	$2,000	3.0%	of Operating, Supervisory and Maintenance Labor
Maintenance Materials	$67,500	1.5%	of purchased equipment cost (typical value for fabric filters)
Maintenance Labor	$40,500	60.0%	of maintenance materials cost
Total Fixed O&M Cost	$131,000		
Indirect Operating Cost			
Property Taxes	$60,300	1%	of total capital investment (EPA Guidelines)
Insurance	$60,300	1%	of total capital investment (EPA Guidelines)
Administration	$60,300	1%	of total capital investment (EPA Guidelines)
Total Indirect Operating Cost	$180,900		
Total Annual Operating Cost	**$911,900**		
TOTAL ANNUAL COST			
Annualized Capital Cost	**$757,200**		
Annual Operating Cost	**$911,900**		
Total Annual Cost	**$1,669,100**		
TOTAL PM-10 REMOVED (tons/year)	**119**		Difference between 0.012 and 0.015 lb/mmBtu @ 100% capacity factor
COST EFFECTIVENESS ($/ton removed)	**$14,036**		

Attachment
Fabric Filter - Revised BACT Cost Evaluation

CAPITAL COSTS	Cost [$]		Basis
Direct Capital Costs			Increased capital cost is related to the difference in bag costs. It was assumed that all other costs (e.g., ductwork, fans, instrumentation, etc.) would be constant regardless of bag material. Bag cost was based on a total required filter area of 1,989,415 ft^2, and a unit cost of $4.355/$ft^2$ for specialty bags and $2.085/$ft^2$ for ryton-type (or fiberglass) bags. The bag cost includes cages, installation, freight and erection.
Emission Control Device	$4,500,000		
Auxiliary Equipment (e.g., ductwork, fans, etc)	$0	0%	
Instrumentation	$0	0%	
Sales Tax	$0	0%	
Freight	$0	0%	
Total Purchased Equipment Cost	$4,500,000		
Direct Installation Costs			
Foundations and Supports	$0	0.0%	included in control device cost
Handling and Mechanical Erection	$0	0.0%	included in control device cost
Electrical	$0	0.0%	included in control device cost
Piping	$0	0.0%	included in control device cost
Insulation	$0	0.0%	included in control device cost
Painting	$0	0.0%	included in control device cost
Total Direct Installation Costs	$0		
Indirect Capital Costs			
Engineering	$450,000	10.0%	of purchased equipment cost (typical order-of-magnitude value)
Construction and Field Expenses	$225,000	5.0%	of purchased equipment cost (typical order-of-magnitude value)
Contractor Fees	$0	0%	Included in purchase and direct costs
Start-Up	$90,000	2.0%	of purchased equipment cost (typical order-of-magnitude value)
Performance Testing	$90,000	2.0%	of purchased equipment cost (typical order-of-magnitude value)
Contingencies	$675,000	15.0%	of purchased equipment cost (typical order-of-magnitude value)
Total Indirect Capital Costs	$1,530,000		
Site Preparation	$0		included in control device costs
Buildings	$0		included in control device costs
Total Capital Costs			
Total Capital Investment	$6,030,000		
Total Capital Investment ($/kW)	$6.7		
Capital Recovery Factor = $i(1+i)^n / (1+i)^n - 1$	0.1150	30	life of equipment (years)
Annualized Capital Costs (Capital Recover Factor x Total Capital Investment)	**$693,600**	11%	pretax marginal rate of return on private investment
OPERATING COSTS			**Basis**
Operating & Maintenance Costs			
Variable O&M Costs			
Bags and Cage Replacement Costs	$874,000		Based on 5-year bag life, a bag size of 91ft^2/bag, a baghouse with 21,860 bags, and a bag cost differential of $200/bag ($380/bag v. $180/bag).
Ash Disposal Cost	$0		The additional disposal cost will be minimal.
Auxiliary Power Cost	$0		Pressure drop will be essentially the same with either bag, however the PTFE-coated bag may require more frequent cleaning.
Total Variable O&M Cost	$874,000		
Fixed O&M Costs			
Operating Labor	$17,500		1/4 additional operator @$70,000/operator/year added for expected more frequent cleaning of PTFE-coated bags.
Supervisory Labor	$3,500	20.0%	of Operating Labor cost
Administrative Labor	$2,000	3.0%	of Operating, Supervisory and Maintenance Labor
Maintenance Materials	$67,500	1.5%	of purchased equipment cost (typical value for fabric filters)
Maintenance Labor	$40,500	60.0%	of maintenance materials cost
Total Fixed O&M Cost	$131,000		
Indirect Operating Cost			
Property Taxes	$60,300	1%	of total capital investment (EPA Guidelines)
Insurance	$60,300	1%	of total capital investment (EPA Guidelines)
Administration	$60,300	1%	of total capital investment (EPA Guidelines)
Total Indirect Operating Cost	$180,900		
Total Annual Operating Cost	**$1,185,900**		
TOTAL ANNUAL COST			
Annualized Capital Cost	**$693,600**		
Annual Operating Cost	**$1,185,900**		
Total Annual Cost	**$1,879,500**		
TOTAL PM-10 REMOVED (tons/year)	**119**		Difference between 0.012 and 0.015 lb/mmBtu @ 100% capacity factor
COST EFFECTIVENESS ($/ton removed)	**$15,805**		

IPP Unit 3—PM_{10} BACT Questions

Draft Technical Memorandum

To: Steve Sands
CH2MHill

December 18, 2003
Resubmitted 1-31-04

From: Ken Snell / Bill Rosenquist
Sargent & Lundy LLC

Subject: IPP Unit 3 – PM_{10} BACT Questions

Provided below are responses to questions 1a and 1b of the Richard Sprott letter to Reed Searle dated November 24, 2003.

Question 1a.

> The cost analysis for the PM_{10} BACT analysis provided in the NOI did not have annualized cost and cost effectiveness (dollars per ton). However, IPSC provided additional information on November 10, 2003 that we are presently reviewing. Should we need further information, we will let you know as soon as possible.

Response to Question 1a.

Appendix I-3 of IPP's May 14, 2003 NOI Addendum provided detailed performance and cost information regarding the proposed Unit 3 fabric filter, including an incremental cost effectiveness analysis to support the conclusions in IPP's original PM_{10} BACT analysis. As UDAQ states in Question 1a, IPP submitted additional analysis on November 10, 2003, including the annualized and average cost effectiveness ($/ton controlled) for each technically feasible fabric filter system.

Two fabric filter systems were evaluated in the IPP BACT analysis: (1) a fabric filter system equipped with woven fiber glass or Ryton-type bags; and (2) a fabric filter equipped with specialty-coated polytetrafluoroethylene (PTFE) bags. The PTFE-coated bags may provide some incremental additional PM10 control, but are more expensive than woven fiber glass or Ryton-type bags.

IPP's May 14, 2003 Appendix I-3 submittal included an incremental cost effectiveness analysis comparing the two fabric filter systems. The cost analysis was reviewed by DAQ, and clarifications were provided to DAQ in two technical memorandums submitted on November 10, 2003.

The revised incremental cost effectiveness of PTFE-coated specialty bags was determined to be approximately $15,805/ton of additional PM_{10} removed. IPP concluded, based on average and incremental cost effectiveness, and taking into account the quantity of PM_{10} controlled and the limited operating experience with PTFE-coated bags on large pulverized coal-fired boilers, that PTFE-coated bags should be excluded as BACT for IPP Unit 3.

As indicated in Question 1a, DAQ is in the process of reviewing the additional information provided on November 10, 2003. The project team is available to assist DAQ in a final review of this issue, and is prepared to answer questions relating to the analysis submitted. If DAQ should need any additional information for final resolution of this question, please let us know as soon as possible.

Question 1b.

> IPSC needs to provide rationale as to why the proposed limit is so much higher than historical data for the existing two units and what has been achieved elsewhere with a similar control device. For example, historically (during the period 1997-2001), IPP Units 1 & 2 have had calculated baghouse removal efficiencies of 99.9% and emission rates between 0.0033-0.0099 lb/MMBtu (coal ash content between 8.64-10.34%). In addition, the PM_{10} emission rate at the Northampton Generating Station in Pennsylvania (with baghouse) is 0.010 lb/MMBtu (filterable and condensable) and they tested at 0.0041-0.0045 lb/MMBtu. Yet, IPSC has proposed 0.015 lb/MMBtu for PM_{10} filterable emissions, at 12% ash content and 99.825% removal efficiency.
>
> This information is not intended to be the basis for a permit limit at the actual performance levels. We recognize that there must be a margin for compliance. However, we would like to understand the basis for the margin between the permitted limit and the anticipated actual performance of the unit. This newer unit should be as good or better than the existing units unless some powerful demonstration can be made to justify a higher limit.

Response to Question 1b.

The BACT analysis will result in an enforceable permit limit that must be complied with on a continuous long-term basis. As DAQ recognized in Question 1b, there must be a margin between the expected emissions, which fluctuate over time, and the permit limit.

The BACT emission limit established during the initial permitting process will be enforceable over the life of the unit. As a result, the BACT analysis must take into account the full range of possible fuels, operating conditions, operating system fluctuations, and normal wear-and-tear on the units and control systems. An emission rate based on the physical limitations of the best available control technology, plus a reasonable margin for compliance, should represent BACT assuming that the permitted emission limit does not cause or contribute to a violation of an NAAQS or PSD increment.

Based on expected fuel characteristics, a review of recently permitted/proposed pulverized coal-fired units, and expected vendor guarantees,[1] IPP proposed a PM_{10} BACT emission limit of 0.015 lb/mmBtu. Impact modeling at this anticipated permit limit demonstrates that IPP Unit 3 will not cause or contribute to a violation of any NAAQS or PSD increment.

The Intermountain Power Station has a history of compliant operation, and IPP fully expects that Unit 3 will be operated in compliance with all permit limits. Therefore, IPP expects that Unit 3 will continually operate, under all operating conditions, at a controlled PM_{10} emission rate below 0.015 lb/mmBtu. The margin between the expected actual emission rate and the permit limit is necessary to take into account fuel variability and the normal fluctuations associated with a properly operated fabric filter control system.

<u>Fuel Characteristics</u>

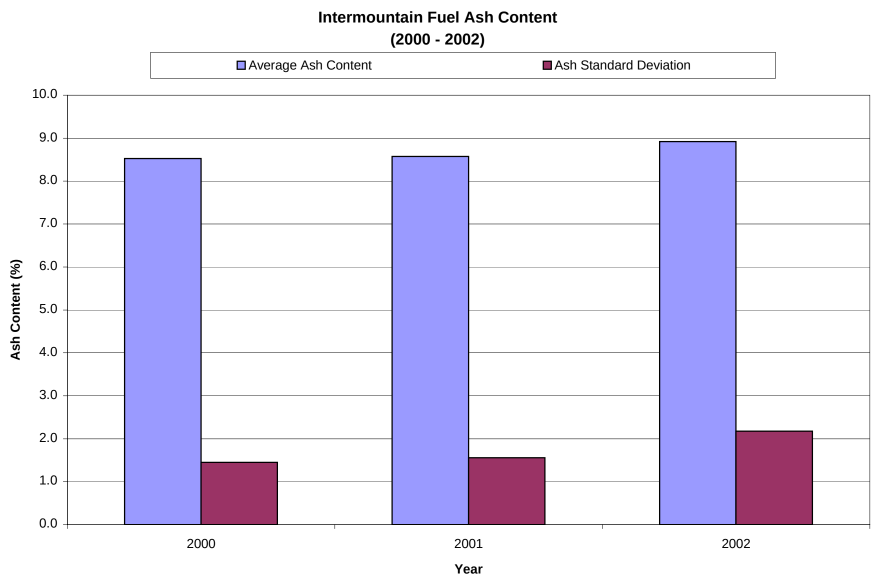
IPP conducted a detailed study of the Utah coal reserves, and anticipated coal characteristics, available over the next 25 years. Results of this study were submitted to UDAQ in the NOI supplement titled “Intermountain Power Project (IPP) Unit 3 Coal Supply.” This study concluded, based on actual Utah coal mine data, that much of the easily obtained high quality Utah coals have been mined, or are currently being mined, and Utah is just beginning to see mines with less than ideal geological conditions and coal qualities.

Figures 1 and 2 summarize data regarding the actual ash content of coal shipments to Intermountain Power Station and Hunter Power Station during the years 2000 – 2002.

[1] Information regarding vendor guarantees has been submitted to DAQ as confidential business information.

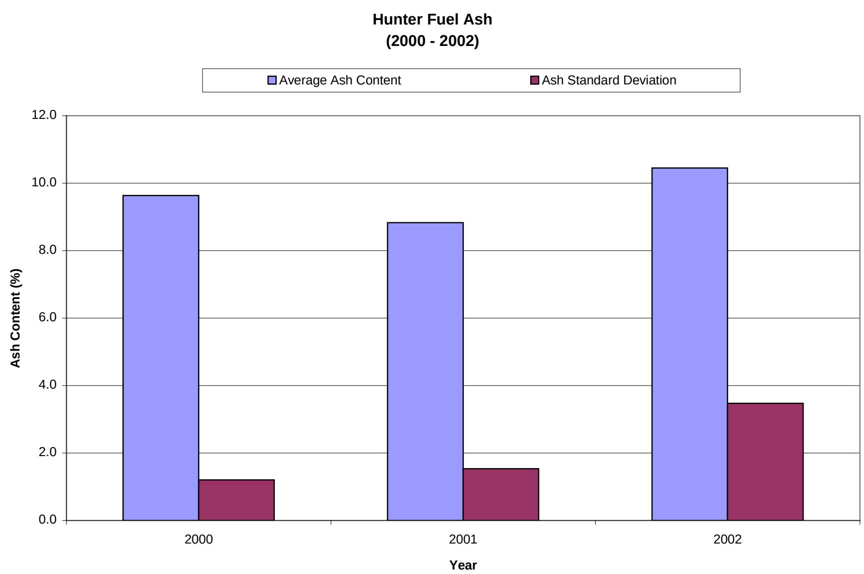
Both facilities receive coal from Utah mines. Figures 1 and 2 include the actual average ash content of coals shipped to each facility, and the standard deviation observed in the fuel ash content. Data for Figures 1 and 2 were obtained from the Federal Energy Egulatory Commission (FERC) Form 423 "Monthly Report of Cost and Quality of Fuels for Electric Plants."[2]

Figure 1
Fuel Ash Information – Intermountain Power Station



[2] The FERC Form 423 data is available at http://www.eia.doe.gov/cneaf/electricity/page/ferc423.html.

Figure 2
Fuel Ash Information – Hunter Power Station



It can be seen from Figures 1 and 2 that the average ash content of Utah coals shipped to both Intermountain and Hunter increased between the years 2000 and 2002. More importantly, the standard deviation of the ash content also increased during the same time period. An increase in the standard deviation of the fuel ash content indicates increased variability in the fuel characteristics.

Because IPP must permit Unit 3 for the life of the plant, IPP must include a reasonable estimate of the anticipated future coal characteristics. Based on a review of data from Utah mines, IPP concluded that an ash content of 12% represents a reasonably conservative description of future Utah coal reserves. Ash content will impact particulate loading to the fabric filter, and can affect the fly ash composition. An ash content of 12% at IPP Unit 2 will result in an uncontrolled PM_{10} emission rate of approximately 77,620 lb/hr.

<u>System Fluctuations</u>

IPP has proposed a very stringent PM10 emission rate for Unit 3. To ensure compliance, IPP must continually monitor the boiler and fabric filter, ensure that the fabric filter (and entire boiler system) are properly operating, and respond quickly and efficiently to any upset conditions.

A controlled PM_{10} emission rate of 135.8 lb/hr (0.015 lb/mmBtu at full load) is equivalent to a PM_{10} concentration of approximately 6.256×10^{-7} lb/acf of exhaust gas.[3] At this level, factors such as mechanical integrity of the filter housing become very important. Because of the high exhaust gas flow rate and high particulate loading, a problem with any part of the fabric filter system could result in a compliance concern. The Unit 3 fabric filter will have approximately 20,000 to 30,000 bags, each with a bag cleaning mechanism. Mechanical problems that can impact flue gas flow through the filters, and the controlled PM_{10} emission rate, include:

- bags not tightly fastened to the outlet duct nozzle,
- loose bag hangers,
- bags torn during construction or improperly manufactured, and
- failed welds or cracks that occur within the extensive ducting system.

Operating conditions that can cause an increase in the fabric's fiber spacing and potentially higher particulate emissions include:

- Bag blinding as a result of moisture in the flue gas or low flue gas temperatures. Bag blinding will block part of the filter and cause a high flue gas velocity through the remaining open bag areas. A high flue gas velocity can lead to erosion of the fabric fibers in those areas.

- High flue gas temperatures associated with unit startup, shutdown, and load changes can cause deterioration of fabric, resulting in larger openings in the fabric mesh through which more particulate matter can pass.

- Fly ash is abrasive and will over time erode the fabric material.

Because of the extreme control efficiency required of the fabric filter system, any minor operational upset can result in compliance concerns. It is appropriate that the permit limit take into account reasonably foreseeable, normally occurring, operational fluctuations, and allow IPP to respond to operational changes in a timely manner.

<u>Fabric Filter Cleaning Cycles</u>

Fabric filters are most effective when a layer of particulate matter (or cake) has formed on the fabric surface. As particulate laden gas flows through a filter the captured particulate matter forms a cake on the surface of the fabric. This deposit increases both the filtration efficiency of the fabric and its resistance to gas flow.

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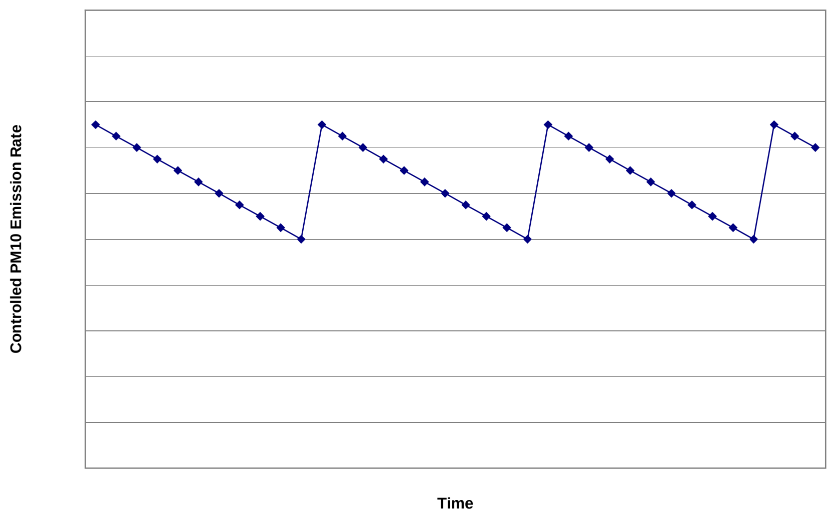
[3] This calculation is based on an flue gas flow rate to the fabric filter of 3,617,117 acfm.
(135.8 lb/hour 4 60 min/hour) = 2.263 lb/minute
2.263 lb/min 4 3,617,117 acf/min = 6.256×10^{-7} lb/acf exhaust gas.

Thus, the fabric-filter must have a mechanism for periodic cleaning of the deposited cake. The effectiveness of the filter will be at its lowest immediately after cleaning, and will increase as the filter cake re-forms (until cleaning is required because of excess pressure drop). The relative effectiveness of a fabric filter, as a function of the bag cleaning cycle, is shown schematically in Figure 3. The IPP Unit 3 permit limit must take into account emission fluctuations associated with the fabric filter cleaning mechanism.

Figure 3
Fabric Filter Effectiveness as a Function the Bag Cleaning Cycle



Particular matter composition is a complex function of the coal properties, boiler firing configuration, boiler operation, and pollution control equipment upstream of the fabric filter. Fly ash composition is a function of the fuel characteristics and boiler design, and generally consists of the inorganic residue in the coal and varying amounts of carbon or coke particles resulting from incomplete combustion. The inorganic ash particles are a function of the fuel, and consist primarily of silicates, oxides, and sulfates, together with small quantities of phosphates and other trace compounds. Fuel characteristics, boiler configuration, boiler operation, and pollution control systems will affect the fly ash composition, flue gas temperature, and exhaust gas flow rate, all parameters affecting the fabric filter control system.

With respect to UDAQ's specific question regarding the Northampton Generating Plant located in Allentown, Pennsylvania, it is IPP's understanding that the Northampton unit is a 110 MW circulating fluidized bed (CFB) boiler that fires anthracite culm. Anthracite culm is a waste product produced from the mining/sizing of anthracite coal. Characteristics of anthracite culm, including heating value, moisture content, volatile matter, ash content, and ash characteristics all differ significantly from the characteristics of Utah bituminous coal.

The Northampton CFB and IPP Unit 3 PC firing configurations are also completely different. In a CFB boiler, coal is burned in a bed of inert particulate matter (typically limestone for SO2 absorption), which is suspended or "fluidized" by the combustion air. The combustion temperature in a CFB is lower than the combustion temperature in a pulverized coal boiler. Fluidizing the combustion bed promotes carryover of solids, so high-temperature cyclones are typically used on a CFB to capture the bed material for return to the primary combustion chamber. Circulating the bed solids promotes complete combustion and increases limestone utilization.

The Northampton unit is much smaller than IPP Unit 3, fires a different fuel, uses a different boiler design, will have significantly different exhaust gas characteristics (e.g., flow rate and temperature), and employs different NOx and SO2 emission control systems. Because of these differences, this becomes an apples-to-oranges comparison, and it is inappropriate to use the Northampton unit to establish a BACT emission rate for IPP Unit 3.

Conclusions

BACT is an emission limit which UDAQ, on a case-by-case basis taking into account energy, environmental, and economic impacts and other costs, determines is achievable for IPP Unit 3. Based on expected fuel characteristics, a review of recently permitted pulverized coal-fired units, and expected vendor guarantees, IPP proposed a PM_{10} BACT emission limit of 0.015 lb/mmBtu. As discussed above, IPP expects Unit 3 to consistently achieve PM_{10} emissions below 0.015 lb/mmBtu. However, the permit limit will be enforceable over the life of the unit, and must include a margin to account for future coal characteristics and normal operating fluctuations of the fabric filter system, and must allow IPP a reasonable amount of time to respond to operational changes.

A permit limit of 0.015 lb/mmBtu is consistent with BACT determinations made by other states for large pulverized coal-fired units. For example, the Springerville Generating Station in Arizona, and the Bull Mountain and Hardin plants in Montana were all permitted at 0.015 lb/mmBtu.[4] Other recently permitted plants, including the KCPL Hawthorn Plant in Missouri, Holcomb Station in Kansas, Thoroughbred Station in Kentucky, and Plum Point Station in Arkansas, have been permitted with an emission

[4] The Bull Mountain permit includes a provision that the facility conduct emissions testing after start-up to determine the feasibility of achieving an emission rate of 0.012 lb/mmBtu.

limit of 0.018 lb/mmBtu. Only one pulverized coal-fired plant, Wygen 2, has been permitted with a PM_{10} emission limit below 0.015 lb/mmBtu. Based on economic information submitted with the Wygen 2 permit the State of Wyoming concluded that a PM_{10} emission limit of 0.012 lb/mmBtu was economically feasible for the facility. However, based on economic data submitted to DAQ on November 10, 2003, IPP has concluded that this more restrictive PM_{10} emission rate is not economically justified for IPP Unit 3. Furthermore, impact modeling at this emission limit demonstrates that IPP Unit 3 will not cause or contribute to a violation of any NAAQS or PSD increment.

PM_{10} BACT Cost Analysis

Draft Technical Memorandum

To:	Milka Radulovic UDEQ Division of Air Quality	January 12, 2004 Resubmitted 1-31-04
cc:	Steve Sands CH2MHill	
From:	Ken Snell Sargent & Lundy LLC	
Subject:	PM10 BACT Cost Analysis	

This memo addresses questions regarding IPA's PM10 BACT cost analysis. Specifically, this memo addresses apparent inconsistencies between IPA's PM10 BACT cost analysis (submitted to UDAQ in a Technical Memorandum dated November 7, 2003) and a PM10 BACT cost analysis prepared by the Federal Land Manger (FLM).

The FLM PM10 BACT cost analysis was provided to UDAQ as an excel file named "IPP#3.xls". The file included several worksheets that will be referenced in this memo, including:

Worksheet Name	Description
Assume	Assumptions used to calculate cost effectiveness at 0.015 lb/mmBtu.
Cap Cost	Total Capital Investment for the 0.015 lb/mmBtu case.
Ann Cost	Total Annual Cost for the 0.015 lb/mmBtu case.
$T	Cost effectiveness ($/ton) of the 0.015 lb/mmBtu case.
Assume(PTFE)	Assumptions used to calculate cost effectiveness at 0.012 lb/mmBtu.
Cap Cost(PTFE)	Total Capital Investment for the 0.012 lb/mmBtu case.
Ann Cost(PTFE)	Total Annual Cost for the 0.012 lb/mmBtu case.
$T(PTFE)	Cost effectiveness ($/ton) of the 0.012 lb/mmBtu case.

1. Comments Regarding FLM Assumptions FLM Worksheets: "Assume" and "Assume(PTFE)"

1.a. Multiplier to Obtain Gross Cloth Area

As discussed in previous submittals, IPA has proposed to control PM10 emissions from Unit 3 using a highly efficient reverse air fabric filter. The cleaning mechanism associated with a reverse air fabric filter consists of reversing the flow of gas through an isolated compartment of filters to collapse the filter bags and fracture the filter cake. Therefore, at any given time, a percentage of the unit's filter bags will be off-line for cleaning. The fabric filter design must account for this cleaning mechanism.

Sargent & Lundy (S&L) calculated the maximum flue gas flow rate to the fabric filter at 3,617,117 acfm. Based on engineering judgment and experience, S&L calculated the unit's gross cloth area based on an air/cloth ratio of 2.0, with a margin of 10% to account for the cleaning mechanism. Based on these assumptions, the unit's gross cloth area was calculated to be 1,989,415 ft^2. See, submittal: IPP Unit 3 – PM10 BACT Questions dated November 7, 2003. Assuming a bag size of 91 ft^2, a gross cloth area of 1,989,415 ft^2 results in a baghouse containing 21,860 bags.

In its PM10 BACT analysis, the FLM assumed a margin of 4% to account for the cleaning mechanism. This assumption was based on information in USEPA's Office of Air Quality Planning and Standards Control Cost Manual (OAQPS Control Cost Manual EPA/452/B-02-001). See, OAQPS Control Cost Manual, Section 6, Chapter 1, Table 1.2. Based on this assumption, the gross cloth area of the fabric filter was estimated to be 1,880,901 ft^2, resulting in a baghouse with approximately 20,669 bags.

It should be noted that the OAQPS Control Cost Manual does not directly address controls associated at electrical generating units. Section 1, subsection 1.1 of the Manual states: "Furthermore, this Manual does not directly address the controls needed to control air pollution at electrical generating units (EGUs) because of the differences in accounting for utility sources." The Manual should be used as a guideline, coupled with engineering judgment and recent experience.

Be that as it may, reducing the gross cloth area to 1,880,901ft^2 will not have a significant impact on the PM10 BACT cost analysis.

1.b. Calculation of the Uncontrolled PM10 Emission Rate

In its PM10 BACT analysis, IPA assumed that all particulate matter emitted as fly ash from the boiler would be emitted as PM10 (i.e., particulate matter with an aerodynamic equivalent diameter less than 10 microns). On the other hand, the FLM calculated the uncontrolled PM10 emission rate based on particulate size distribution in AP-42.

Although the fabric filter will be designed to control all particulate matter emitted from the boiler, it is likely that a certain percentage of the uncontrolled particulate matter will have an aerodynamic diameter greater than 10 microns. Therefore, to calculate the cost effectiveness of the fabric filter (with respect to PM10 only) it is appropriate to adjust the uncontrolled particulate emission rate.

AP-42 Section 1.1 includes the following emission factors for uncontrolled PM10 from coal-fired boilers:

Table 1.1-4:
Filterable PM10 = 2.3A lb/ton coal fired
Where: A = % ash content of coal
Emission Factor Rating: E

AP-42 Table 1.1-6:
Cumulative particle size distribution for dry bottom boilers burning pulverized bituminous and subbituminous coal. 23% of the uncontrolled particulate matter will have a particle size 10 microns or below.

The uncontrolled PM10 emission rate using each approach is provided below:

		PM = PM10	**AP-42 Table 1.1-4**	**AP-42 Table 1.1-6**
Maximum Coal Feed Rate	lb/hr	808,541	808,541	808,541
	ton/hr		404.27	
Ash Content of Fuel	%	12%	12%	12%
Fly Ash : Bottom Ash Ratio	%	80% fly ash		80% fly ash
AP-42 Emission Factor		na	2.3A	23% of PM_{total}
PM10 Calculation		(808,541 x 0.12) x 0.8 =	2.3 x 12 = 27.6 lb/ton	77,620 x 0.23 =
Uncontrolled PM10 Emission Rate	lb/hr	77,620	11,158	17,853
Uncontrolled PM10 Emission Rate	tpy	339,976	48,872	78,196

The baseline PM10 emission rate will affect the calculation of the fabric filter's control efficiency and average cost effectiveness. However, it will not change the controlled emission rate or incremental cost effectiveness.

In order to compare the control efficiency of the proposed Unit 3 fabric filter to other, recently permitted, coal-fired utility boilers, it is appropriate to assume that PM_{total} = PM10 (i.e., uncontrolled PM10 emission rate = 77,620 lb/hr). This approach is consistent with all other recently permitted utility coal fired boilers. However, to be consistent with the FLM BACT cost calculations, IPA will recalculate the average cost effectiveness using the Table 1.1-4 AP-42 emission factor (PM10 = 2.3A lb/ton).

1.c. Operating and Maintenance Labor Cost Assumption

In its PM10 BACT cost analysis, the FLM used an operating labor cost and maintenance labor cost of $7.99/hour. These labor costs appear to be too low. The annual cost for operating and maintenance labor (including benefits) will be approximately $70,000 per year. This is the cost for one employee working a 40 hour week (or 2,080 hours per year). Therefore, the hourly rate in the BACT cost estimate should be $70,000 4 2,080 = $33.65/hour.

1.d. Interest Rate Used to Calculate Capital Recover Cost

The interest rate used to calculate the annual capital recovery cost is a pretax marginal rate of return on private investment. Based on experience in the utility industry, and a review of recently submitted BACT cost analyses for coal-fired boilers, S&L used an interest rate of 11% in its BACT cost analysis. The FLM used an interest rate of 7% based on information in the OAQPS Cost Manual.

The interest rate will change the annual capital recovery cost, and the total annual cost associated with the control equipment. However, reducing the interest rate to 7% will not significantly change the BACT cost effectiveness analysis. Therefore, for consistency, IPA has revised its PM10 BACT cost analysis using an interest rate of 7% (see, response 7).

2. Comments Regarding the Capital Cost Estimates
FLM Worksheets: "Cap Cost" and "Cap Cost(PTFE)"

The FLM followed the guidance in the OAQPS Cost Manual to calculate total capital investment required for the proposed fabric filter. As stated in previous submittals, IPA's capital cost estimate was provided by S&L, and was based on OAQPS guidance and recent experience.

A comparison of the total capital investment calculations is provided below:

	FLM 0.015 Case	**IPA 0.015 Case**	**FLM 0.012 Case**	**IPA 0.012 Case**
Total Capital Investment $	$42,818,276	$45,507,000	$49,504,540	$51,638,000
$/kW-net	$47.6/kW-net	$50.7/kW-net	$55.0/kW-net	$57.4/kW-net

Although different approaches were used to calculate total capital investment, the final estimates varied by less than 10%. This variation is well within the level of accuracy for capital cost estimates in a BACT cost analysis, and will not significantly affect the BACT cost effectiveness analysis.

3. Comments Regarding the Calculation of Annual Operating Costs FLM Worksheets: "Ann Cost" and "Ann Cost(PTFE)"

3.a. Labor Rates

As discussed above, a labor rate of $33.65/hr should be used to calculate operating and maintenance labor costs.

It should also be noted that the FLM labor estimate was based on information in section 1.5.1.1 of the OAQPS Cost Manual, which states: "Typical operating labor requirements are 2 to 4 hours per shift for a wide range of filter sizes…. Small or well-performing units may require less time, while very large or troublesome units may require more." Although IPA expects its fabric filter to be well-performing, the IPA Unit 3 fabric filter will be very large. Thus, it is not clear why the FLM used the operating labor estimate for small units.

3.b. Maintenance Labor and Materials

Annual maintenance labor and material costs in the FLM cost estimate were based on statements in the OAQPS Cost Manual (section 1.5.1.3). The FLM assumed 1 hour/shift for maintenance labor, and an equivalent cost for maintenance materials. Based on these estimates, the maintenance labor cost and maintenance material cost were both estimated to be $8,750/year. In S&L's opinion this approach grossly underestimates the maintenance costs associated with a $50,000,000 installation containing more than 20,000 bags and the associated hangers, fans, ductwork, etc.

The default value for maintenance costs associated with a fabric filter in USEPA's Coal Utility Environmental Cost (CUECost) Worksheet is 5% of the installed equipment cost. Based on CUECost, and engineering judgment, S&L assumed a maintenance material cost of 1.5% of the purchased equipment cost, and a maintenance labor cost equal to 60% of the materials cost.

4. **Comments Regarding the Calculation of Annual Costs for the PTFE Case FLM Worksheets: "Ann Cost(PTFE)"**

It appears that calculation of the indirect annual costs in the Ann Cost(PTFE) worksheet references the wrong supporting worksheet. Administrative charges, property taxes and insurance are estimated as a percent of the total capital investment. However, the Ann Cost(PTFE) worksheet references the total capital investment of the 0.015 Case ("Cap Cost") rather than the total capital investment for the 0.012 Case ("Cap Cost(PTFE)").

5. **Recalculating the Annual Costs FLM Worksheets: "Ann Cost" and "Ann Cost(PTFE)"**

Changing the labor rate (as discussed above), and correcting the calculation of the indirect annual costs for the PTFE case, the total annual cost for each option is recalculated as follows:

0.015 Case: "Ann Cost"

	FLM Worksheet	Revised Value	Comments
Total Capital Investment	$42,818,276	no change	
Capital Recovery Cost	$3,450,571	no change	
Total Direct Annual Costs	$2,342,007	$2,495,183	labor rate change
Total Indirect Annual Costs	$5,185,877	$5,258,377	labor rate change
Total Annual Cost	$7,527,883	$7,753,560	labor rate change

0.012 Case: "Ann Cost(PTFE)"

	FLM Worksheet	Revised Value	Comments
Total Capital Investment	$49,504,540	no change	
Capital Recovery Cost	$3,450,571	$3,989,393	original worksheet referenced the total capital investment for the 0.015 Case
Total Direct Annual Costs	$3,469,862	$3,633,388	labor rate change
Total Indirect Annual Costs	$5,185,877	$6,064,650	original worksheet referenced the total capital investment for the 0.015 Case
Total Annual Cost	$8,655,739	$9,698,037	change in labor rates, indirect annual costs and capital recovery cost

6. Recalculating Average Cost Effectiveness FLM Worksheets: "$T" and "$T(PTFE)"

Based on the revised annual costs presented above, the annual and incremental cost effectiveness of each fabric filter system is recalculated as follows:

	Units	0.015 Case	0.012 Case	Incremental Cost Effectiveness
Uncontrolled Emissions	tpy	48,871	48,871	
Controlled Emissions	tpy	595	476	
Pollutants Removed	tpy	48,277	48,396	119
Annual Cost	$/year	$7,753,560	$9,694,470	$1,944,477
Cost Effectiveness	$/ton	$161	$200	$16,352

7. Recalculating the IPA Average and Incremental Cost Effectiveness

S&L recalculated the average cost effectiveness and incremental cost effectiveness of the fabric filter using an uncontrolled PM10 emission rate of 48,872 tpy, a margin of 4% to account for off-line cleaning, and a pretax marginal rate of return on private investment of 7% (rather than 11%). The revised IPA cost analysis is summarized below:

		Revised 0.015 Case	Revised 0.012 Case	Incremental Cost Effectiveness
Uncontrolled Emissions	tpy	48,871	48,871	
Controlled Emissions	tpy	595	476	
Pollutants Removed	tpy	48,277	48,396	119
Annual Cost	$/year	$9,023,500	$10,697,800	$1,674,300
Cost Effectiveness	$/ton	$187	$221	$14,070

Conclusions

The average cost effectiveness of the fabric filter system equipped with specialty bags will be approximately 20 – 25% more expensive then the same system equipped with woven fiberglass or Ryton-type bags. Because of the large quantity of PM10 removed by the fabric filter, a 20% increase in cost effectiveness is significant.

The specialty bag system may reduce annual PM10 emissions by approximately 119 tons at a cost ranging from $1.67 to $1.94 million dollars. This results in an incremental cost effectiveness of approximately $14,000 to $16,350 per ton. This incremental cost is significantly greater than the average cost effectiveness of the fabric filter system, and should eliminate the specialty bags from consideration as BACT.

APPENDIX I-4

NO_X BACT

Nitrogen Oxide Emissions and Control

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Nitrogen Oxide Emissions and Control

Background

In December 2002, Intermountain Power Authority (IPA) submitted a Notice of Intent (NOI) to permit and construct a new nominal 950-gross MW (900-net MW) pulverized coal-fired unit at the Intermountain Power Project station near Delta, Utah. In the NOI, IPA proposed low NOx burners and overfire air combustion controls with selective catalytic reduction (SCR) as the best available control technology (BACT) for the control of NOx emissions. During subsequent NOI Technical Review Meetings between IPA and the Utah Department of Environmental Quality – Division of Air Quality (UDAQ), representatives of UDAQ requested additional information regarding the lowest achievable NOx emission rate, and the maximum achievable control efficiency of an SCR control system.

In response to UDAQ's request for additional information, IPA is providing a more detailed description of the information used to form the basis of our proposed NOx BACT emission control system. The information contained herein should be considered part of IPA's BACT determination, and supplemental to Section 6.2 of the above referenced NOI.

IPA concluded in its BACT determination that the combination of LNB/OFA and SCR represents BACT for the control of NOx emissions from a pulverized coal-fired boiler. Based on site-specific technical information a controlled NOx emission rate of 0.07 lb/mmBtu (30-day rolling average) represents the most restrictive emission rate that can be achieved on a consistent basis using this combination of control systems.

Technical Discussion

I. NOx Formation

The formation of nitrogen oxides (NO_x) is determined by the interaction of chemical and physical processes occurring primarily within the flame zone of the boiler. There are two principal forms of NO_x designated as "thermal" NO_x and "fuel" NO_x. Thermal NO_x formation is the result of oxidation of atmospheric nitrogen contained in the inlet gas in the high-temperature, post-flame region of the combustion zone. The major factors influencing thermal NO_x formation are temperature, the concentration of combustion gases (primarily nitrogen and oxygen) in the inlet air, and residence time within the combustion zone. Fuel NO_x is formed by the oxidation of nitrogen in the fuel. NO_x

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formation can be controlled by adjusting the combustion process and/or installing post-combustion controls.

Control methods for NO_x can be divided into two types of control technologies: post-combustion controls and combustion controls. Combustion controls reduce the amount of NO_x that is generated in the boiler. Post-combustion controls remove NO_x from the boiler exhaust gas.

In its BACT determination, IPA considered several potential NOx emission control technologies (See, Intermountain Power Project Unit 3, Notice of Intent, December 2002, Section 6.2.4). A complete description of the control options identified as BACT in the NOI, including design limits and balance-of-plant impacts, is provided below.

II. Combustion Controls

IPA has proposed two combustion control techniques as part of its boiler NOx control system: low NOx burners (LNB) and overfire air (OFA).

Low NO_x burners limit NO_x formation by controlling both the stoichiometric and temperature profiles of the combustion flame in each burner flame envelope. This control is achieved with design features that regulate the aerodynamic distribution and mixing of the fuel and air, yielding reduced oxygen (O_2) in the primary combustion zone, reduced flame temperature and reduced residence time at peak combustion temperatures. The combination of these techniques produces lower NO_x emissions during the combustion process.

In the OFA process, the injection of air into the firing chamber is staged into two zones. The staging of the combustion air reduces NO_x formation by two mechanisms. The staged combustion results in a cooler flame, and the staged combustion results in less oxygen reacting with fuel molecules. However, the degree of staging is limited by operational problems. Excessive staging can result in incomplete combustion conditions and increased emissions of CO and VOCs.

Designing the boiler using the most advanced commercially available LNB[1] combustion system in conjunction with OFA is expected to consistently reduce potential thermal NO_x emissions by approximately 50%. The uncontrolled NOx emission rate from a pulverized coal-fired boiler is typically in the range of 400 – 500 ppmvd @ 3% O_2.

[1] As used in this report, the term "LNB" is used generically, and refers to advanced low-NOx burners available from leading boiler/burner manufacturers. This term should not be confused with vendor-specific trade names. As burner manufacturers make incremental improvements in their burner performance, new titles are used to describe their products, for example, advanced low-NOx burners, ultra-low-NOx burners, TFS-2000™, and B&W DRB-4Z™.

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LNB/OFA combustion controls should reduce the NO_x concentration to approximately 200 – 250 ppmvd @ 3% O_2. A NOx concentration of 200 – 250 ppmvd @ 3% O_2 in the boiler flue gas equates to a controlled NOx emission rate of approximately 0.275 – 0.35 lb/MMBtu.[2]

Although the combination of LNB+OFA may be able to achieve, under optimal short-term conditions, NOx emission rates slightly below 0.275 – 0.35 lb/mmBtu range, the mechanisms to reduce NO_x formation (e.g., cooler flame and reduced O_2 availability) also tend to increase the formation and emission of CO and VOCs. Furthermore, the combustion system will be subject to continuously changing variables, including load changes and fuel characteristics. Under actual long-term operating conditions, it is expected that a NO_x emission rate of 0.35 lb/MMBtu can be maintained while controlling CO and VOC formation below the proposed BACT emission rates of 0.15 and 0.005 lb/mmBtu, respectively, and without damaging the furnace by operating under a reducing atmosphere in the burner zone on a consistent basis.

III. Post-Combustion NOx Control

In addition to designing the boiler with LNB+OFA, IPA has proposed selective catalytic reduction (SCR) to reduce post-combustion NOx. SCR involves injecting ammonia into the boiler flue gas in the presence of a catalyst to reduce NO_x to N_2 and water. The overall SCR reactions are:

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

The performance of an SCR system is influenced by several factors including flue gas characteristics, flue gas temperature, inlet NO_x level, surface area, volume and age of the catalyst, and the amount of ammonia slip that is acceptable. Another factor affecting SCR performance is the condition of the catalyst material. As the catalyst degrades over time or is damaged, NO_x removal decreases.

The optimal temperature range depends on the type of catalyst used, but is typically between 560 ^oF and 800 ^oF to maximize NO_x reduction efficiency and minimize salt formation. This temperature range typically occurs between the economizer and air heater in a large utility boiler. Below this range, ammonium sulfate is formed resulting in catalyst deactivation. Above the optimum temperature, the catalyst will sinter and thus deactivate rapidly.

[2] Kokkinos, A., Wasyluk, D., Boris, M., "Retrofit Low NOx Experience for Tangentially-Fired Boilers – 2002 Update," Presented to: ICAC Forum 'O2: Cutting NOx, Houston, TX, February 12-13, 2002.

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Several balance of plant impacts and collateral environmental issues must be taken into consideration when designing an SCR control system. The extrinsic effects of SCR are principally related to ammonia (NH_3) being present in the flue gas stream, and the conversion of SO_2 to SO_3.

One of the most significant collateral consequences of SCR operation is the oxidation of SO_2 to SO_3 across the catalyst. SO_3 can react with ammonia to form ammonium bisulfate. Under certain conditions, ammonium bisulfate can cause major blockage in the air heater, as well as on the catalyst surface. Ammonium bisulfate is also classified as a condensible particulate. The formation of ammonium bisulfate is a function of SO_3 and NH_3 concentration, and the SCR operating temperature.

Excess SO_3 can also react with water in the flue gas to form micron sized sulfuric acid mist droplets. Sulfuric acid in the flue gas increases the propensity for corrosion of downstream plant equipment. To minimize the balance-of-plant impacts from an SCR system, the SCR must be designed to minimize the oxidation of SO_2 to SO_3 and NH_3 slip.

Based on an inlet NO_x concentration to the SCR of 200 – 250 ppmvd @ 3% O_2, it is expected that an SCR system can achieve a post-combustion NO_x concentration of 40 – 50 ppmvd @ 3% O_2. This represents a post-combustion NOx removal efficiency of 80%. The SCR should be capable of achieving this controlled NOx concentration while maintaining an acceptable SO_2 to SO_3 oxidation rate and acceptable NH_3 slip. A controlled NOx concentration of 40 – 50 ppmvd @ 3% O_2 is equivalent to a NOx emission rate of approximately 0.07 lb/mmBtu, and, in conjunction with LNB+OFA represents an overall NOx control efficiency of approximately 90%.

IV. NOx Control Limitations

Although it is possible that a more aggressive NOx emission limit could be achieved when the unit is new and clean, it has not been demonstrated that this level of performance can be consistently achieved during long-term operation. As discussed above, several factors influence the performance of an SCR system, including the volume, age and surface area of the catalyst, performance of inlet NO analyzers, NOx distribution across the catalyst, flue gas characteristics, and NH_3-NOx ratio. Achieving a consistent NOx removal efficiency requires maintaining these variables continuously over a long-term basis.

Another critical factor in SCR performance is catalyst degradation. Catalyst that has been in service for a period of time will have decreased performance because of normal deactivation and deterioration. There are many factors that cause the catalyst to deactivate including poisoning, blockage, and physical destruction. The main coal properties impacting SCR performance, in terms of catalyst life, are sulfur, arsenic, alkali and alkaline earth based constituents, ash burden, chlorine, fluorine and unburned carbon

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in the fly ash.[3] For example, earth metals in the coal, especially oxides of calcium and magnesium can react with SO_3 in the flue gas to form sulfates that deposit on the catalyst surface, block pores and reduce catalyst activity.

Although SCR is being used to control NOx emissions from pulverized coal-fired boilers, SCR is a relatively new control system and there is limited long-term operating experience. Furthermore, there is no actual operating experience demonstrating the affect that Utah bituminous coals may have on the SCR catalyst. Although Utah coals do not appear to exhibit qualities that will adversely impact SCR performance, without actual operating experience the possibility exists that flue gas characteristics unique to Utah coals may cause unforeseen catalyst deterioration or deactivation.

Mr. J. Edward Cichanowicz has evaluated the NOx emission trends for SCR-equipped pulverized coal-fired units.[4] Mr. Cichanowicz evaluated the actual NOx emission rates, and actual control efficiencies, from seven dry-bottom pulverized coal-fired boilers equipped with SCR. The boilers in the study all had uncontrolled NOx emission rates in the range of 0.20 to 0.44 lb/mmBtu.[5] SCRs in the study achieved NOx control efficiencies ranging from 41.5 to 84.9%, and controlled NOx emission rates of approximately 75 – 100 ppmvd @ 3% O_2. Of the seven units evaluated, only 4 were operating near or below a NOx outlet level of 0.10 lb/mmBtu, and the averaging time had to be extended to 3,600 hours for all four units to meet this level.[6] Shorter averaging periods were more restrictive, and, in fact, on a 30-day averaging period (720 hours) only two units were able to meet an emission limit of 0.10 lb/mmBtu. The data in Mr. Cichanowicz's evaluation suggest that the most aggressive NOx emission rate currently achieved at pulverized coal-fired boilers with a 30-day averaging period is in the range of 0.10 lb/mmBtu.

Even though the most aggressive NOx emission rate currently achieved with SCR on a pulverized coal-fired boiler is approximately 0.10 lb/mmBtu, based on several technical assumptions, IPA has proposed a NOx emission limit of 0.07 lb/mmBtu. First, Unit 3 will be designed with low-NOx burners and overfired air to reduce the boiler NOx concentration. As discussed above, IPA believes it can maintain a boiler NOx emission

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[3] Sanyal, A., Pircon, J.J., "What and How Should You Know About U.S. Coal to Predict and Improve SCR Performance?", Proceedings of the USEPA, DOE, EPRI Combined Power Plant Air Pollution Control "Mega" Symposium, Chicago, IL, August 20 –23, 2001.

[4] Cichanowicz, J.E., Smith, L.L, SCR Performance Analysis Hints at Difficulty in Achieving High NOx Removal Targets, Power Engineering, November 2002.

[5] See Table 2 of the Cichanowicz paper. Note that the unit with an uncontrolled NOx emission rate fired PRB coal. The dry bottom boiler units firing bituminous coals had uncontrolled NOx emission rates of 0.393 to 0.436 lb/mmBtu.

[6] Cichanowicz, Figure 3.

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rate of 0.35 lb/mmBtu, while maintaining acceptable CO and VOC emission rates. The six bituminous dry bottom boilers included in Mr. Cichanowicz's study had boiler NOx emission rates of 0.393 to 0.436 lb/mmBtu. Second, actual operating experience with SCRs on pulverized coal-fired units should lead to better SCR designs and controls. Design changes that should lead to better NOx control include increased flue gas/ammonia mixing, advancements in catalyst activity, and improved control loops.

SCR is a relatively new control system, and there is no actual operating experience with SCR and Utah bituminous coals. Nevertheless, based on the Unit 3 boiler design and information available from SCR vendors, IPA believes it can achieve a controlled NOx emission rate of 0.07 lb/mmBtu while maintaining acceptable CO and VOC emission rates, and minimizing collateral balance-of-plant impacts such as SO_3 to SO_3 oxidation and NH_3 slip.

Conclusions

In its BACT analysis (IPP Unit 3, NOI, Section 6.2.4), IPA evaluated the effectiveness of several potential NOx control technologies, and concluded that combustion controls (LNB+OFA) and post-combustion control (SCR) represent the most effective combination of commercially available NOx control technologies.

Based on a review of the actual operating history at large pulverized coal-fired boilers, and a review of the technical literature, it is expected that the combination of LNB+OFA can reduce the boiler NOx emission rate over a long-term basis to approximately 0.35 lb/mmBtu. LNB+OFA should be able to maintain this emission rate without generating unacceptable levels of CO and VOCs, and with out damaging the furnace by operating under a reducing atmosphere in the burner zone on a consistent basis.

IPA's BACT analysis also concluded that SCR represented the most effective, commercially available, post-combustion NOx control. Based on operating data from existing pulverized coal-fired boilers, and taking into account balance-of-plant impacts, SO_2 to SO_3 oxidation, NH_3 slip, and catalyst deactivation and deterioration, IPA expects that the SCR can be designed to reduce the flue gas NOx concentration to approximately 40 – 50 ppmvd @ 3% O_2. This represents an SCR control efficiency of approximately 80% (based on a boiler NOx concentration of 200 – 250 ppmvd @ 3% O_2), and a controlled emission rate of 0.07 lb/mmBtu.

IPA is proposing a controlled NOx emission limit of 0.07 lb/mmBtu even though data from existing coal-fired boilers indicate that the most aggressive NOx emission rate currently achieved at pulverized coal-fired boilers with a 30-day averaging period is in the range of 0.10 lb/mmBtu. Furthermore, SCR has not been demonstrated on a boiler firing Utah bituminous coal, and the possibility exists that properties unique to Utah coal may adversely impact SCR performance.

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IPA's proposed NOx BACT emission rate of 0.07 lb/mmBtu (30-day rolling average) represents a very stringent NOx emission limit. Based on a review of the U.S.EPA RBLC Database (see, IPP Unit 3, NOI, Appendix F), and a review of recently permitted coal-fired boilers, an emission rate of 0.07 lb/mmBtu is significantly lower than the most stringent NOx permit limit at any operating pulverized coal-fired boiler, and equivalent to the most stringent NOx permit limit proposed for any new pulverized coal boiler.

APPENDIX I-5

SO_2 BACT

Flue Gas Desulfurization – Control Efficiency

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Flue Gas Desulfurization – Control Efficiency

Background

In December 2002, Intermountain Power Authority (IPA) submitted a Notice of Intent (NOI) to permit and construct a new nominal 950-gross MW (900-net MW) pulverized coal-fired unit at the Intermountain Power Project station near Delta, Utah. In the NOI, IPA proposed wet flue gas desulfurization (FGD) as the best available control technology (BACT) for the control of sulfur dioxide (SO_2) emissions. During subsequent NOI Technical Review Meetings between IPA and the Utah Department of Environmental Quality – Division of Air Quality (UDAQ), representatives of UDAQ requested additional information regarding the lowest achievable SO_2 emission rate, and the maximum achievable control efficiency of a wet FGD system.

In response to UDAQ's request for additional information, IPA is providing a more detailed description of the information used to form the basis of our SO_2 BACT determination. The information contained in this report should be considered part of IPA's BACT determination, and supplemental to Section 6.2 of the above referenced NOI.

IPA has concluded, based site-specific technical information presented herein, that the most restrictive SO_2 emission rate that can be achieved on a long-term basis is 0.10 lb/mmBtu (30-day rolling average), which represents an SO_2 control efficiency of 92.5% based on worst-case design coal characteristics.

Technical Discussion

The generation of sulfur dioxide (SO_2) in a coal-fired utility boiler is directly related to the sulfur content and heating value of the fuel burned. The sulfur content and heating value of coal can vary dramatically depending on the source of the coal.

IPP has proposed firing the new Unit 3 primarily on Utah bituminous coal. Based on historical analyses of Utah bituminous coal, IPP has projected that the worst-case design fuel (e.g., the fuel that will result in the highest emission rates) will have a heating value of 11,193 Btu/lb, and maximum sulfur content of 0.75%.[1] Assuming 100% of the fuel sulfur converts to SO_2 in the boiler, the maximum SO_2 emission rate, without post-

[1] A detailed description of the fuels evaluated for Unit 3 and the method used to determine the worst-case design fuel characteristics is included in a separate BACT supplement write-up entitled *Intermountain Power Project Unit 3 Coal Supply*.

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combustion controls, would be 1.34 lb/mmBtu. An emission rate of 1.34 lb/mmBtu is equivalent to an SO_2 concentration in the flue gas of approximately 686 ppmvd @ 3% O_2.

Several flue gas scrubbing techniques can be used to reduce SO_2 emissions from coal combustion. In its NOI, IPP reviewed the technical feasibility of several scrubbing systems, and concluded that wet limestone scrubbing provided the most stringent SO_2 control (See, Intermountain Power Project, Notice of Intent, Section 6.3.2, December 2002, and supplements thereto).

Wet limestone scrubbing systems, especially those employing forced oxidation, have become state-of-the-art for achieving SO_2 removal from coal-fired boiler flue gas. The wet limestone scrubbing process uses an alkaline slurry made by adding limestone ($CaCO_3$) to water. The alkaline slurry is sprayed in the absorber, typically countercurrent to the flue gas flow, and reacts with SO_2 in the flue gas. Insoluble calcium sulfite ($CaSO_3$) and calcium sulfate ($CaSO_4$) solids are formed in the scrubber and are removed as a wet solid waste by-product.

IPP has proposed an SO_2 BACT emission rate of 0.10 lb/mmBtu heat input (30-day rolling average). Achieving a controlled emission rate of 0.10 lb/mmBtu will require a control efficiency of 92.5% when firing the worst-case design fuel.

The chemistry of wet scrubbing consists of a complex series of kinetic and equilibrium-controlled reactions occurring in the gas, liquid, and solid phases. In general, the amount of SO_2 absorbed from the flue gas is governed by the vapor-liquid equilibrium between SO_2 in the flue gas and the absorbent liquid. If no soluble alkaline species are present in the liquid, the liquid quickly becomes saturated with SO_2 and absorption is limited.[2] Likewise, as the flue gas SO_2 concentration goes down, absorption will be limited by the SO_2 equilibrium vapor pressure. Therefore, high control efficiencies are easier to achieve as the flue gas SO_2 concentration increases, and high control efficiencies would not be expected as the flue gas SO_2 concentration is reduced. Because control efficiency is a function of the SO_2 concentration in the flue gas, control efficiency can be a misleading indicator of the effectiveness of a FGD system.

The SO_2 concentration in the boiler flue gas is a function of the fuel's heating value and sulfur content. Depending on the fuel characteristics, uncontrolled SO_2 concentrations in utility boiler flue gas typically range from approximately 1,200 to 4,500 ppmvd. The Utah bituminous fuel proposed for Unit 3 has a relatively high heating value and

[2] Combustion Fossil Power – A Reference Book on Fuel Burning and Steam Generation, edited by Joseph P. Singer, Combustion Engineering, Inc., 4th ed., 1991 (pp. 15-41).

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relatively low sulfur content, and the maximum uncontrolled SO_2 concentration in Unit 3 is expected to be around 686 ppmvd.

Based on a review of recently submitted PSD permit applications for pulverized coal-fired boilers, the most aggressive proposed SO_2 control efficiencies are associated with boilers that will burn high sulfur coals and have a high uncontrolled SO_2 concentration in the boiler flue gas. For example, the Thoroughbred Generating Station proposed wet FGD with an SO_2 control efficiency of 97.9% (based on worst-case design fuel). Likewise, the Prairie State Generating Station proposed wet FGD with a control efficiency of 97.9%. However, both of these projects will utilize a high-sulfur midwestern bituminous coal. A comparison of the fuel characteristics, flue gas SO_2 concentration, control efficiencies, and proposed controlled SO_2 emission rates for Thoroughbred, Prairie States, and IPP Unit 3 is provided below:

	Worst-Case Design Fuel Characteristics		Maximum Uncontrolled SO2 Emission Rate	Approximate Uncontrolled SO2 Concentration in Flue Gas	Proposed Control Efficiency	Approximate Controlled SO2 Concentration
Facility	**Heating Value (Btu/lb)**	**Sulfur Content (%)**	**(lb/mmBtu)**	**(ppmvd)**	**(%)**	**(ppmvd)**
Thoroughbred	9,962	4.24	8.51	4,358	97.9	91.5
Prairie State	8,780	4.0	9.11	4,665	97.9	98.0
Intermountain	11,193	0.75	1.34	686	92.5	51.5

As discussed, control efficiency is a function of several variables, including the concentration of SO_2 in the flue gas. The fuel proposed for IPP Unit 3 will generate only approximately 15% of the flue gas SO_2 generated by firing a higher sulfur bituminous coal. Although physical/chemical constraints of the wet FGD system may limit the control efficiency at IPP, IPP's controlled SO_2 emission rate will still be significantly lower than the emission rate achieved at similar projects.

Conclusion

Wet FGD will provide the most aggressive SO_2 control, and, based on site-specific considerations, IPP has concluded that the most restrictive SO_2 emission rate that can be achieved on a long-term basis is 0.10 lb/mmBtu (30-day rolling average). To achieve a controlled SO_2 emission rate of 0.10 lb/mmBtu, the proposed wet FGD system must be able to achieve a control efficiency of 92.5% (based on worst-case design fuel).

Although, wet FGD systems with higher control efficiencies (based on worst-case design fuel) have been proposed at other pulverized coal-fired projects, those projects have also proposed burning a fuel that will generate a significantly higher uncontrolled SO_2

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emission rate. Control efficiency is a function of the uncontrolled SO_2 concentration in the flue gas. High control efficiencies can not be maintained as the uncontrolled flue gas SO_2 concentration decreases. Therefore, control efficiency can be a misleading indicator of a control system's effectiveness.

In its BACT analysis, IPP proposed an SO_2 emission rate of 0.10 lb/mmBtu (30-day rolling average). An emission rate of 0.10 lb/mmBtu represents the most stringent SO_2 emission rate permitted at any similar source, and will require a control efficiency of 92.5% base on worst-case design fuel. Although IPP can not propose a more aggressive control efficiency (based on site-specific considerations), IPP's SO_2 emission rate will still be significantly lower than the emission rate achieved at similar projects.

SO2 Control—Effect of Averaging Time on Wet FGD System Performance and Design

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Sulfur Dioxide Control
Effect of Averaging Time on Wet FGD System Performance and Design

Background

In December 2002, Intermountain Power Authority (IPA) submitted a Notice of Intent (NOI) to permit and construct a new nominal 950-gross MW (900-net MW) pulverized coal-fired unit at the Intermountain Power Project station near Delta, Utah. In the NOI, IPA proposed wet flue gas desulfurization (FGD) as the best available control technology (BACT) for the control of sulfur dioxide (SO_2) emissions, and IPA proposed a maximum SO_2 emission limit of 0.10 lb/mmBtu based on a 30-day rolling average. During subsequent NOI Technical Review Meetings between IPA and the Utah Department of Environmental Quality – Division of Air Quality (UDAQ), representatives of UDAQ requested IPA to address the potential impacts of reducing the compliance averaging time from a 30-day rolling average to a 24-hour rolling average or even a 3-hour rolling average.

In response to UDAQ's request, IPA reviewed and analyzed actual emissions data from three existing coal-fired power plants equipped with wet FGD. Based on this review, IPA has concluded that: (1) wet FGD systems do not continuously operate under ideal steady-state conditions and that the controlled SO_2 emission rate will fluctuate under normal operating conditions; (2) reducing the averaging time will significantly impact IPA's ability to comply with a stringent SO_2 BACT emission limit; (3) modifications can be made to the wet FGD system to reduce the response time to upset conditions, but these modifications will not ensure compliance with a stringent emission limit over short averaging times; (4) an SO_2 emission limit of 0.10 lb/mmBtu (30-day rolling average) represents the most restrictive emission limit of any recently permitted pulverized coal-fired unit; and (5) EPA's recent settlement of NSR/PSD enforcement cases provide for SO_2 (and NOx) BACT limits averaged over a period of 30 days (see Attachments 1 and 2). A BACT emission limit based on a 30-day rolling average is also needed to address startup, shutdown and malfunctions exceedances, averaging them over a 30-day period.

Technical Discussion

I. Analysis of Emissions Data

In order to quantify the impact that reduced averaging times may have on reported emission rates, Sargent & Lundy examined hourly emissions data from three coal-fired electric generating plants. The plants (Bonanza Unit 1, Navajo Unit 2, and Hunter Unit 3) are among the 10 coal-fired plants in the U.S. with the lowest actual sulfur dioxide

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(SO_2) emission rates.[1] The plants were selected for this evaluation because of their proximity to IPA's proposed Unit 3, and the fact that all three plants are base loaded pulverized coal-fired units and use wet FGD to control SO_2 emissions.

Actual reported hourly SO_2 emission rates were obtained for each plant from the U.S.EPA's air-markets website (see footnote 1). Emissions data were obtain for the period beginning January 1, 2001 and ending on December 31, 2001. Because each of the units are permitted with a different SO_2 emission rate, Sargent & Lundy normalized the emissions data by dividing the reported hourly SO_2 emission rate by the facility's permit limit. Therefore, SO_2 emission rates in this evaluation are shown as a percent of each unit's permitted emission rate.

In order to avoid misleading emission spikes, data from the three plants were adjusted to take into account, as much as possible, startups and shutdowns. This adjustment was made by excluding from the raw data any emissions information produced during periods when the plant's load was less than 30% of the unit's Maximum Continuous Rating (MCR). Loads less than 30% of MCR are likely to occur only during startup or shutdown of the boiler. Emission rates during startup and shutdown are generally higher than during normal operation, and including the low load data would tend to increase the average emission rates.

Based on the normalized hourly emission rates, the 3-, 24-, and 720-hour (30-day) rolling averages were calculated for each unit. A summary of the average and maximum emission rates, and standard deviation for each averaging period is provided in Table 1. Detailed charts showing the normalized 3-, 24-, and 720-hour rolling averages are included in Attachment 1.

Table 1
Normalized SO_2 Emission Rates
Adjusted for Startups, Shutdowns, and Malfunctions
(Permitted Emission Limit = 1.0 based on 30-day Rolling Average)

	Bonanza Unit 1			**Navajo Unit 2**			**Hunter Unit 3**		
Averaging Period	**3 Hour**	**24 Hour**	**720 Hour**	**3 Hour**	**24 Hour**	**720 Hour**	**3 Hour**	**24 Hour**	**720 Hour**
Average	0.378	0.380	0.379	0.342	0.339	0.339	0.792	0.773	0.776
Maximum	1.725	0.649	0.451	8.252	1.725	0.4204	13.287	3.503	1.136
Standard Deviation	0.1184	0.0943	0.0349	0.1530	0.0620	0.0409	0.7902	0.3613	0.1004

[1] This statement is based on a review of actual SO_2 emission rates reported by electricity generating units. Actual emissions information is available on the U.S.EPA air-market website (www.epa.gov/airmarkets/emissions/index.html).

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II. Discussion

Averaging time does not affect the annual emission rate of a pollutant, but can significantly affect the emissions data reported to a regulatory agency, especially with regard to the maximum emission rate. Figure 1 shows the maximum normalized SO_2 emission rate for each averaging time. As the averaging time decreases, the reported maximum emission rate increases.

From the data summarized in Figure 1, it can be seen that only one of the plants studied exceeded their permit limit based on a 30-day rolling average, however, all three plants would have reported exceedences if their averaging time was reduced to 3-hours. Table 2 provides an indication of the number of potential exceedences each plant would have experienced at each averaging time.

Figure 1
Maximum Normalized SO2 Emission Rate

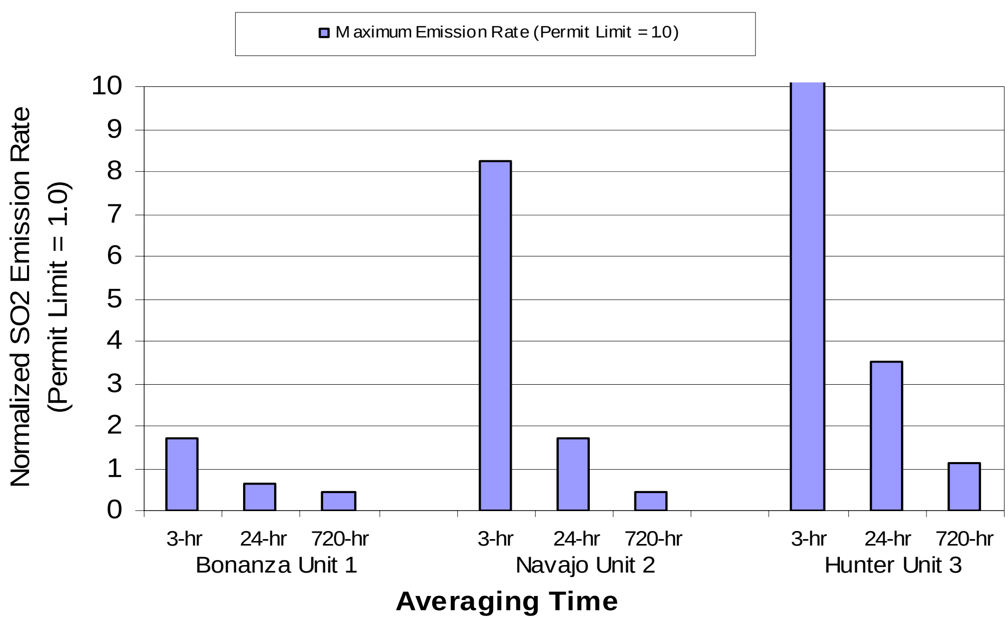

Table 2
Potential Hours of Exceedance Due to Different Averaging Times*

	3 Hour	24 Hour	720 Hour
Bonanza Unit 1	7	0	0
Navajo Unit 2	7	3	0
Hunter Unit 3	525	726	144

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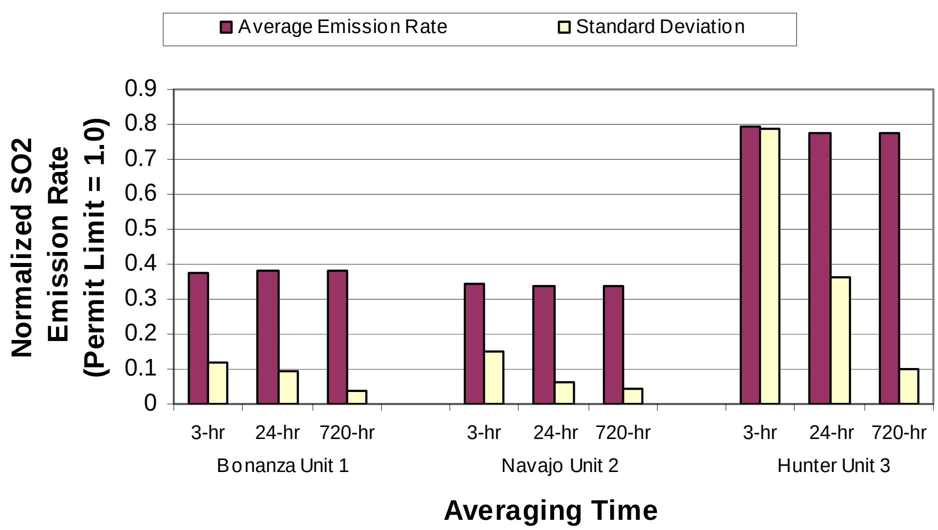
* Exceedances reported as the annual number of hours (on a rolling basis) above the normalized permit limit of 1.0.

One measure of variability of a data set is standard deviation. Figure 2 graphs the normalized average emission rate and standard deviation for each averaging period. It can be seen that standard deviation (and therefore variability) is inversely related to averaging time, that is, as the averaging time goes down the standard deviation increases. This is expected, as fluctuations in the SO_2 emission rate would be more pronounced with the shorter averaging times.

Figure 2
Normalized SO2 Emission Rates



Another important result of this data evaluation is the fact that the average emission rates for each plant do not significantly change as the averaging time decreases (see Figure 2). The fact that the average emission rates do not significantly change for each averaging time indicates that fluctuations to the controlled SO_2 emission rate were remedied in a relatively short period of time.

For the most part, SO_2 emission rates above the permitted levels at the plants examined occurred during time of sudden load changes most likely due to start-ups and shutdowns. However, even when the emissions data were adjusted to account for startups and shutdowns, each plant experienced fluctuations in their SO_2 emission rate, and the effect of these fluctuations became more pronounced as the averaging time was reduced. Whether these fluctuations were due to changes to boiler or turbine operation, problems

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with the CEM system, changes to the fuel characteristics, or changes to other subsystems at the facility cannot be determined from the available data. However, because the average emission rate is essentially the same for all averaging times, these fluctuations appear to be associated with the normal operation of an FGD system.

III. Wet Flue Gas Desulfurization

FGD performance is a function of numerous operating variables including, among other things, coal quality, load changes, equipment upsets, oxidation/slurry tank dynamics, process chemistry, and control system response time.

For example, the coal's heating value and sulfur content will directly affect the SO_2 concentration in the flue gas stream. Coal, by its very nature, does not have a uniform heating value or sulfur content. Coal characteristics will vary from mine to mine and even within different seams of the same mine.[2] Therefore, SO_2 loading to the FGD will constantly vary during the operating life of the unit, and the chemistry within the FGD absorption vessel must be continuously adjusted in response to the SO_2 loading.

Likewise, routine equipment problems can effect the chemistry/efficiency of the FGD system. Examples of typical equipment problems that may occur during the normal operating life of an FGD include slurry pump failures, spray pump failures, scaling, mist eliminator plugging, plugged spray nozzles, and plugged strainers. Equipment problems can be minimized with a comprehensive inspection and maintenance program, and are usually identified and remedied quickly. However, as with all mechanical systems, some equipment problems are unavoidable. Equipment problems can lead to short-term increases in the controlled SO_2 emission rate, and may jeopardize compliance with short averaging times.

Due to advances in equipment reliability, most new wet FGD systems are designed with one reaction vessel designed to treat 100% of the flue gas flow. 100% reaction vessels are generally sized to achieve a gas flow velocity of approximately 11- 13 feet per second (fps) to provide adequate contact between the gas and the scrubber slurry. Wet FGD systems will typically have 1 or 2 slurry spray levels located toward the top of the reaction vessel to provide slurry flow countercurrent to the gas flow. Although 100% designs have proven to be very dependable and reliable, reaction time to a system upset, such as plugged spray nozzles or pump failure, may be somewhat delayed.

[2] Information describing the expected coal characteristics for potential fuels at IPA Unit 3 are presented in a separate BACT supplement entitled *Intermountain Power Project Unit 3 Coal Supply*.

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Wet FGD systems have proven to be very reliable, however wet FGD systems, like all emission control systems, take time to respond to process changes. Factors that affect response time of a FGD system include:

- Lag between the time flue gas leaves the absorber and the SO_2 concentration is analyzed at by the unit's CEMs.
- Response time for system controls and control valves.
- Gas and liquid flow through the system.
- Variations in coal sulfur content.

Another design characteristic of a FGD system that effects the system's response time is the size of the slurry storage and reaction tanks. Wet scrubbing systems typically have reaction tanks located in the base of the absorber tower with a liquid residence time of 5-7 minutes. The residence time in the reaction and storage tanks is necessary to ensure adequate oxidation of calcium sulfite to calcium sulfate, and to minimize problems that would be encountered during a "cold" startup. These problems can include supersaturation of the scrubbing liquor and the formation of calcium sulfite and calcium sulfate scale on scrubber internals. The formation of calcium sulfite and calcium sulfate scale on scrubber internals can be a severe problem.

When a change in flue gas composition occurs due to a change in fuel characteristics, limestone quality, boiler load, or mode of operation, it will take time for the FGD system to "catch-up." To respond to a change in flue gas composition, adjustments must be made to the system's recirculation rate, liquid-to-gas ratio, and absorber stoichiometry. The response time for a FGD system to fully correct for a process change can be from 30 minutes to several hours depending upon process change and system design characteristics.

Design changes that may be considered to reduce system response time include:

- Additional slurry pumps for each spray level.
- Addition of an extra level of sprays in each absorber tower over normal design.
- Reduced solids residence time in oxidation tank.
- Reduced liquid residence time in oxidation tank.
- Increased oxidizing airflow and dispersion in the oxidation tank.

IV. Unit 3 FGD Design

The wet FGD system proposed for Unit 3 is being designed to minimize fluctuations and allow for compliance with the proposed emission limit over a reasonable averaging time.

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The Unit 3 FGD system is being designed with two absorbers (rather than one), and the size of each absorber vessel is being increased from 50% gas flow a nominal 67% gas flow under normal operating conditions. In addition, the vessels are being designed to be capable of treating 100% of the flue gas flow under extraordinary conditions.

Under normal operating conditions, each vessel will treat 50% of the flue gas. Gas flow velocity through the vessels under normal operating conditions will be approximately 8 – 9 fps. In the event that one of the reaction vessels is taken out of service, the other vessel will be capable of receiving 100% of the flue gas flow. Under these conditions, gas flow velocity through the vessel will increase to approximately 15 fps.

Maintaining the removal efficiency required to achieve a controlled SO_2 emission limit of 0.10 lb/mmBtu (30-day rolling average) with one absorber will require the installation of additional slurry pumps and spray headers. In addition, because of the potential for high velocity operation, the units will be designed with two-stage horizontal and one-stage vertical mist eliminators to capture liquid droplets. Increasing the size of the reaction vessels, and installing the additional slurry pumps and spray headers will increase the capital cost of the FGD system by approximately $25,000,000.

Even though the Unit 3 FGD is being designed to maintain a controlled SO_2 emission rate of 0.10 lb/mmBtu with only one absorber module, redirecting the gas flow to a single scrubber module will not be accomplished instantaneously, and the increased gas flow will change the scrubber's stoichiometry and operating parameters. Therefore, even under optimal conditions, it will take some time to redirect the gas flow, adjust the scrubber chemistry, and re-establish steady-state operation.

V. Regulatory Analysis of BACT Emission Limits and Averaging Times

This section of the paper analyzes the regulatory requirements for averaging times for BACT emission limits.

The Proposed SO_2 and NO_x Limits Averaged over a 30 Day Period Represent BACT

The proposed BACT limits for SO_2 of 0.10 lb/mmBtu and for NOx of 0.07 lb/mmBtu, both averaged over 30-days, are appropriate from a regulatory perspective, and as stated above, necessary from a practical perspective. An averaging period provides the permittee with a limited, but reasonable, period of time to respond to normal unavoidable fluctuations in a control systems' operation. Consent decrees resolving EPA's and DOJ's NSR litigation against both VEPCO and WEPCO, both resolved in the past weeks, each included BACT limits that contained no shorter averaging times than 30 days. Both consent decrees set 2013 BACT limits for NO_x at 0.100 lb/mmBtu averaged over 30 days, using SCR or an approved equivalent, levels *above* IPP's proposed limit. The

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WEPCO consent decree also provided a 2013 SO_2 BACT limit of 0.100 lb/mmBtu averaged over 30 days, exactly as proposed by IPP, while the VEPCO consent decree provides for even higher SO_2 limits of between 0.13 and 0.15 lb/mmBtu averaged over 30 days, depending on the unit.[3] Further, the WEPCO consent decree only requires particulate limits of 0.30 lb/mmBtu, twice the level proposed by IPP.

BACT emissions limits must be met on a continual basis at all levels of operation.[4] EPA New Source Review Workshop Manual (Draft Oct. 1990) at B.56. These limits must be met each rolling 30-day period, not only for a single year, but for each period in every year over the entire life of the project. Having said that, the Manual does expressly recognize that, if properly defined and set to ensure compliance with the NAAQS provisions, permit conditions "may include alternate conditions for startup, shutdown, and malfunctions such as maximum emission limits and operational practices and limits." See Manual at H.8. Thus, the IPA proposed BACT permit limit represents a cap of what is achievable at all ranges of operating conditions, loads, percent operating time, etc., at each and every rolling 30-day period not just for a particular year, but over the entire life of the project. If UDAQ decides that a shorter averaging period is required, then IPA requests that separate BACT limits be established for periods of startup, shutdown and malfunction. Needless to say EPA and DOJ have recently set BACT limits in proposed Federal Court Consent Decrees at or above those proposed by IPP, and averaging at no less than 30 days with an exclusion only for malfunction. It is obviously legal to do so.

VI. Modeling Uncontrolled Emission Rates is Wholly Inappropriate

It is improper to model a potential uncontrolled 24-hour emission rate as part of this analysis.

EPA guidance makes clear that there may be other emissions limits, in addition to the BACT limits, included in a PSD permit to ensure compliance with the NAAQS or other standards, if they are required. The November 24, 1986 guidance specifically states that it may be necessary to include short-term limits, if necessary, to protect the NAAQS in addition to the BACT limit. Thus, if it is necessary to protect a SO_2 NAAQS, a shorter-term limit can be established, in addition to the BACT limit, stringent enough to demonstrate compliance with the NAAQS. However, here IPA modeling indicates that the BACT emission limit will not cause or contribute to a violation of the NAAQS or other standards, so a 24-hour limit is unnecessary.

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[3] Each consent decree resolved NSR claims against the respective companies. Because EPA's policy requires the agency to seek injunctive relief to apply BACT at current levels, the respective NOx and SO_2 emission limits must represent BACT. *See* Guidance on the Appropriate Injunctive Relief for Violations of Major New Source Review Requirements (Nov. 17, 1998).

[4] Of course, Utah rules excuse from violation properly reported unavoidable breakdowns. R307-107.

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Rather than modeling uncontrolled emission rates, the appropriate way to determine compliance with the 24-hour SO_2 NAAQS is to model the representative actual emissions of nearby sources (including IPP Units 1 and 2) and a proposed BACT limit for Unit 3. If the modeling shows no NAAQS violation on the second highest day, the BACT limit is sufficient to demonstrate compliance with the NAAQS. Since IPA is able to show that maximum controlled emissions still met the NAAQS, no limit separate from the BACT limit is necessary to meet the NAAQS, because operation of the control device, which will be required in the permit, would be sufficient to comply with the NAAQS. A shorter term limit to demonstrate compliance with the NAAQS is only necessary if a level below maximum controlled PTE is required to model NAAQS compliance. If such an additional limit is necessary, that limit is additional and separate from the selected BACT limit, per the New Source Review Workshop Manual and EPA guidance. If the modeled value is above the unit's PTE, considering controls, there is no need for a separate limit. Finally, the VEPCO and WEPCO Consent Decrees further demonstrate that a 30-day rolling average is sufficient for both NSR and NAAQS purposes, given the fact that the VEPCO Decree has been agreed to by all of the northeastern states.

Conclusions

Actual emissions data from coal-fired units using wet FGD to control SO_2 emissions indicate that, even excluding periods of startup and shutdown, a FGD system that is maintained and operated so that malfunctions are infrequent, sudden, and not caused by poor maintenance or careless operation, will still experience fluctuations in the controlled SO_2 emission rate. Fluctuations to the controlled SO_2 emission rate become more pronounced as the averaging times decrease. Decreased averaging times will not reduce the annual emissions of a pollutant, but can jeopardize a unit's ability to comply with its permitted SO_2 emission limit. Furthermore, when BACT emission limits are protective of the NAAQS and other air quality standards, additional emission limits based on reduced averaging times are not appropriate.

The wet FGD system proposed for Unit 3 is being designed, to the extent possible, to reduce the response time to normal fluctuations. The design criteria for Unit 3 were selected to maintain a high degree of availability and consistent SO_2 reduction. Proposed design changes include:

- two reaction vessels rather than one;
- increasing the size of the reaction vessels to provide for 100% flue gas flow through either vessel (at an increased gas flow rate);
- additional/redundant slurry pumps for each spray level;
- addition of an extra spray level in each absorber tower over a normal design; and
- enhanced mist eliminators.

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The design changes proposed for the Unit 3 FGD should reduce the system's response time to fluctuations in process chemistry due to coal quality changes, load changes, and equipment upsets. However, actual operating data from existing systems indicate that wet FGDs are dynamic operations, and fluctuations in the controlled SO_2 emission rate are normal. Although changes can be incorporated into the system's design to minimize response time to process changes, all of the fluctuations can not be engineered out.

PSD impact modeling conducted by IPA based on the proposed BACT emission limit, and including actual emissions of other nearby sources, indicates that IPA Unit 3 will not cause or contribute to a violation of any applicable NAAQS or air quality standard. Therefore, pursuant to EPA guidelines, a reasonable averaging time is appropriate, and additional short-term emission limits are not necessary. This approach is consistent with the recent consent decrees resolving EPA's and DOJ's NSR litigation against VEPCO and WEPCO.

In order to provide some assurance that IPA Unit 3 will be capable of complying with the proposed BACT emission limit, and ensure that the facility will not emit excess emissions, the following compliance strategies are proposed for discussion:

1. The averaging time in the permit should be of sufficient duration as to allow for normal fluctuations in FGD operation, and allow the facility time to identify and remedy the cause of any excess emissions (e.g., equipment problem, CEMs malfunction, etc.). However, the averaging time must be short enough to ensure that impact modeling conducted to support the PSD permit application was representative of actual operations, and that emissions from the facility will not cause violations of applicable NAAQS standards. As proposed in the original NOI, this should be a 30-day rolling average. A 30-day rolling average is the averaging time most frequently specified in the operating permits at currently operating coal-fired utility boilers, and is consistent with averaging times included in consent decrees issued to resolve NSR litigation. In fact, all the units included in this evaluation have a 30-day rolling average permit limit.

2. Because excess emissions are often associated with load changes, the permit should include an exclusion from the maximum emission rates during periods of start-up and shutdown. Unit 3 will be a baseload unit, so the number of start-ups and shutdowns will be limited, and emissions during start-up and shutdown should not impact the facility's annual emission rate.

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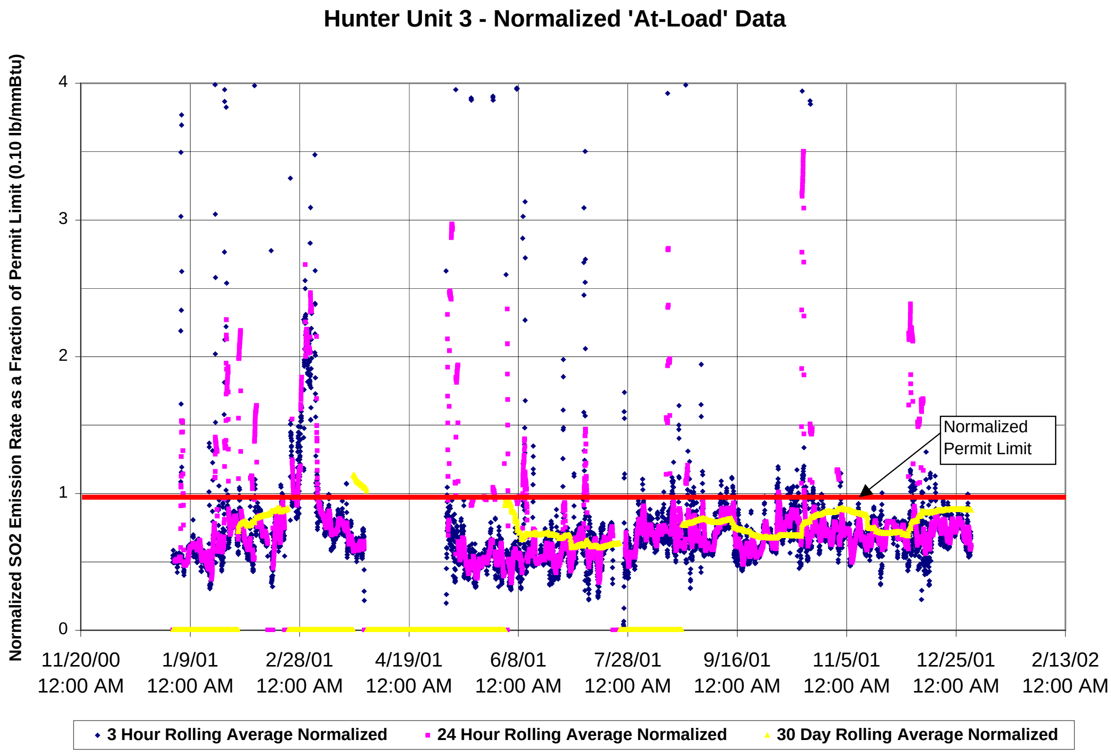
Attachment 1
SO2 Emission Data
3-hour, 24-hour, and 720-hour Rolling Averages



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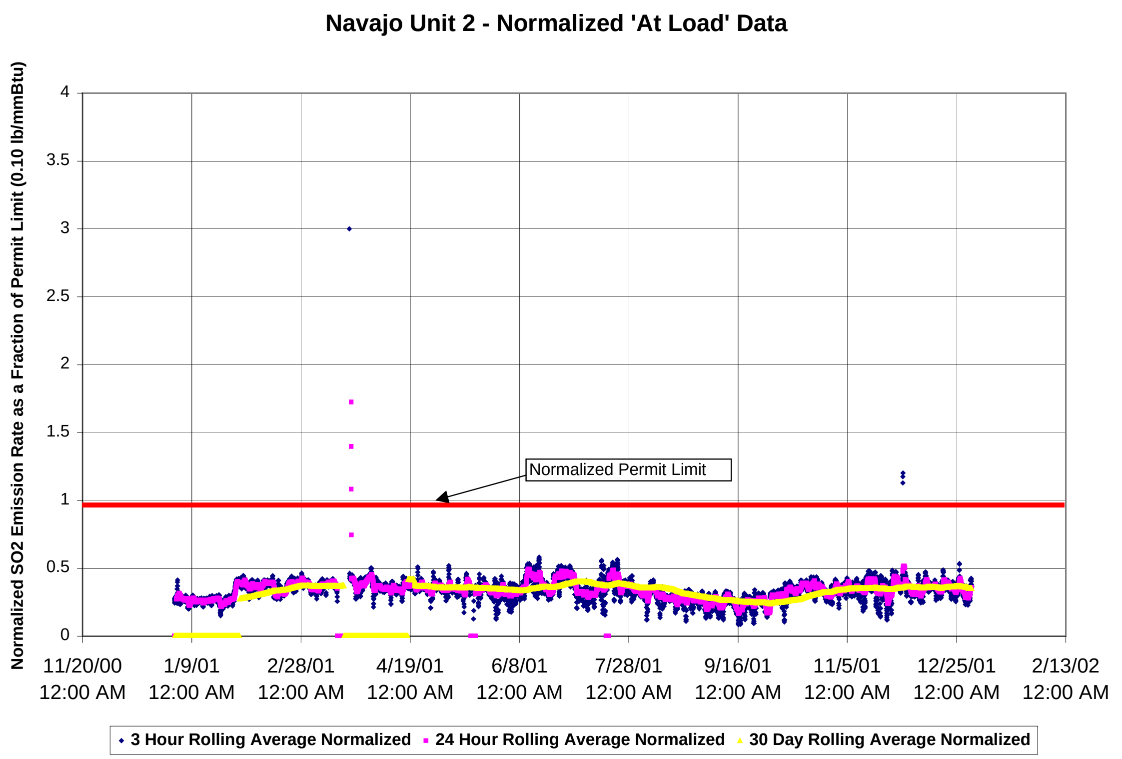

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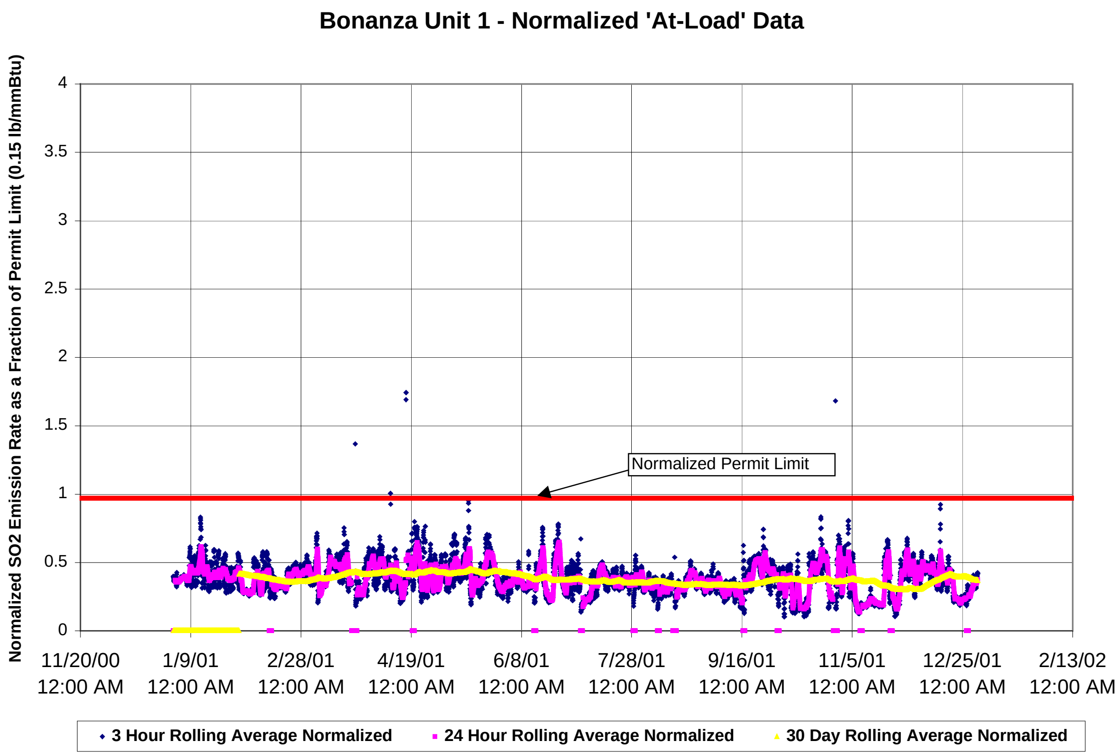

UNITED STATES DISTRICT COURT
EASTERN DISTRICT OF VIRGINIA

UNITED STATES OF AMERICA, STATE OF NEW YORK, STATE OF NEW JERSEY, STATE OF CONNECTICUT, COMMONWEALTH OF VIRGINIA STATE OF WEST VIRGINIA Plaintiffs, v. VIRGINIA ELECTRIC AND POWER COMPANY, Defendant.	)	CIVIL ACTION NO.

CONSENT DECREE

WHEREAS Plaintiff, the United States of America ("the United States"), on behalf of the United States Environmental Protection Agency ("EPA"), has filed a Complaint alleging that Defendant, Virginia Electric and Power Company ("VEPCO"), commenced construction of major modifications of major emitting facilities in violation of the Prevention of Significant Deterioration ("PSD") requirements at Part C of the Clean Air Act ("Act"), 42 U.S.C. §§ 7470-7492;

WHEREAS on April 24, 2000, EPA issued a Notice of Violation ("NOV") to VEPCO with respect to certain alleged violations of PSD;

WHEREAS Plaintiff, the State of New York, filed a complaint against VEPCO on July

20, 2000, alleging violations of the Act at VEPCO's Mount Storm Power Station located in northeastern West Virginia;

WHEREAS Plaintiff, the State of Connecticut, has issued VEPCO a notice of intent to sue, alleging violations of the Act and also has filed a complaint alleging violations of the Act at certain VEPCO electric generating units;

WHEREAS Plaintiff, the State of New Jersey, has issued to VEPCO a notice of intent to sue, alleging violations of the Act and also filed a complaint alleging violations of the Act at certain VEPCO electric generating units;

WHEREAS Plaintiff the Commonwealth of Virginia is filing a Motion for Leave to Intervene and Complaint in Intervention alleging that VEPCO may have violated Virginia's air pollution regulations found at 9 VAC 50-80-1700, *et seq.*, "Permits for Major Stationary Sources and Major Modifications Locating in Prevention of Significant Deterioration Areas," at one or more of its coal-fired generating units located in Virginia and that such violations may recur or other similar violations may occur in the future;;

WHEREAS the Parties consent to intervention by the Commonwealth of Virginia;

WHEREAS Plaintiff the Commonwealth of Virginia has a significant interest in this litigation by reason of its aforesaid Complaint as well as by reason of: (1) the fact that a significant portion of the relief provided by this Decree will involve facilities located within Virginia and regulated by the Commonwealth and no other State, and (2) the fact that such relief will directly impact the issuance to the affected facilities of permits under the Commonwealth's program approved pursuant to Title V of the Clean Air Act;

WHEREAS, Section 10.1-1186.4 of the Code of Virginia specifically authorizes the Attorney General of Virginia to seek to intervene in pending federal enforcement actions such as this one brought by the United States through the Environmental Protection Agency.

WHEREAS Plaintiff the State of West Virginia is filing a Motion for Leave to Intervene and Complaint in Intervention alleging that VEPCO may have violated West Virginia's air pollution regulations found at 45CAR14, "Permits for Construction and Major Modification of Major Stationary Sources of Air Pollution for the Prevention of Significant Deterioration," at one or more of its coal-fired generating units located in West Virginia and that such violations may recur or other similar violations may occur in the future;

WHEREAS the Parties consent to intervention by the State of West Virginia;

WHEREAS Plaintiff the State of West Virginia has a significant interest in this litigation by reason of its aforesaid Complaint as well as by reason of: (1) the fact that a significant portion of the relief provided by this Decree will involve facilities located within West Virginia and regulated by the State of West Virginia and no other State, and (2) the fact that such relief will directly impact the issuance to the affected facilities of permits under the West Virginia program approved pursuant to Title V of the Clean Air Act;

WHEREAS, Section 22-1-6 (d)(3) of the West Virginia Code specifically authorizes the Secretary of the West Virginia Department of Environmental Protection to enforce the statutes or rules which the Department is charged with enforcing.

WHEREAS VEPCO, a large electric utility, responded in a constructive way to Plaintiffs' notices of intent to sue and the NOV and expended significant time and effort to develop and agree to the terms of settlement embodied in this Decree;

WHEREAS VEPCO asserts that installation and operation of the pollution controls required by this Decree will result in emission reductions beyond current regulatory requirements;

WHEREAS the steam electric generating units at VEPCO's Mount Storm Power Station qualified for alternative emission limitations under 40 CFR Section 76.10 because VEPCO demonstrated under the applicable standard that they were not capable of meeting the emissions limitations otherwise applicable under the Clean Air Act's Acid Rain Nitrogen Oxides Emission Reduction Program;

WHEREAS Plaintiffs and VEPCO disagree fundamentally over the nature and scope of modifications that may be made to steam electric generating units without implicating the New Source Review requirements (including PSD) under the Act and its regulations;

WHEREAS nothing in this Decree resolves or is intended to resolve those disagreements;

WHEREAS VEPCO has advised the United States and the Plaintiff States that VEPCO has entered into this Consent Decree in reliance on the expectation that EPA will continue to enforce the modification provisions of the Act's New Source Review program in substantially the same manner as set forth in the complaints filed herein;

WHEREAS VEPCO has been advised that the United States retains all of its discretion concerning whether and how to enforce the Clean Air Act against any person, nothing in this Consent Decree is intended to predict or impose enforcement activities on EPA or the United States, and that the obligations of VEPCO under this Consent Decree are not conditional on subsequent enforcement activities of the Federal government;

WHEREAS the Plaintiffs allege that their Complaints state claims upon which the relief can be granted against VEPCO under Sections 113, 167, or 304 of the Act, 42 U.S.C. §§ 7413, 7477, or 7604;

WHEREAS VEPCO has not answered any of the Complaints in light of the settlement memorialized in this Decree;

WHEREAS VEPCO has denied and continues to deny the violations alleged in the NOV and the Complaints; maintains that it has been and remains in compliance with the Act and is not liable for civil penalties or injunctive relief; and states that it is agreeing to the obligations imposed by this Decree solely to avoid the costs and uncertainties of litigation and to improve the environment;

WHEREAS VEPCO intends to comply with any applicable Federal or State Implementation Plans that result from the NO_x SIP Call (63 Fed. Reg. 57356 (1998)) separate and apart from the obligations imposed by this Decree, and such Federal or State Implementation Plans that may ultimately result from the NO_x SIP Call are not intended to be enforceable under this Decree, and instead are enforceable in accordance with their own terms and the laws pertaining to them;

WHEREAS the Plaintiffs and VEPCO agree that settlement of these actions is fair, reasonable, and in the best interest of the Parties and the public, and that entry of this Consent Decree without further litigation is the most appropriate means of resolving this matter;

WHEREAS the Plaintiffs and VEPCO have consented to entry of this Decree without the trial or other litigation of any allegation in the complaints;

NOW THEREFORE, without any admission of fact or law, and without any admission of the violations alleged in the Complaints or NOV, it is hereby ORDERED, ADJUDGED, AND DECREED as follows:

I. JURISDICTION AND VENUE

1. Solely for purposes of entry and enforcement of this Decree, the parties agree that this Court has jurisdiction over the subject matter herein and over the Parties consenting hereto pursuant to 28 U.S.C. §§ 1331, 1345, 1355, and 1367 and pursuant to Sections 113 and 167 of the Act, 42 U.S.C. §§ 7413 and 7477, and also pursuant to 42 U.S.C. §7604(a). Venue is proper under Section 113(b) of the Act, 42 U.S.C. § 7413(b), and under 28 U.S.C. § 1391(b) and (c). VEPCO consents to and shall not challenge entry of this Consent Decree or this Court's jurisdiction to enter and enforce this Consent Decree. Except as expressly provided for herein, this Consent Decree shall not create any rights in any party other than the Plaintiffs and VEPCO. VEPCO consents to entry of this Decree without further notice.

II. APPLICABILITY

2. Scope. The provisions of this Consent Decree shall apply to and be binding upon – consistent with Section XXVIII ("Sale or Transfers of Ownership Interests") – the Plaintiffs and VEPCO, including VEPCO's officers, employees, and agents solely in their capacities as such. Unless otherwise specified, each requirement on VEPCO under this Consent Decree shall become effective thirty days after entry of this Decree.

3. Notice to those Performing Decree-Mandated Work. VEPCO shall provide a copy of this

Decree to all vendors, suppliers, consultants, or contractors performing any of the work described in Sections IV through IX. Notwithstanding any retention of contractors, subcontractors or agents to perform any work required under this Consent Decree, VEPCO shall be responsible for ensuring that all work is performed in accordance with the requirements of this Consent Decree. In any action to enforce this Consent Decree, VEPCO shall not assert as a defense the failure of its employees, servants, agents, or contractors to take actions necessary to comply with this Decree, unless VEPCO establishes that such failure is delayed or excused under Section XXVI ("Force Majeure").

III. DEFINITIONS

4. Every term expressly defined by this Section shall have the meaning given that term herein. Every other term used in this Decree that is also a term used under the Act or the regulations implementing the Act shall mean in this Decree what such terms mean under the Act or those regulations.

5. "30-Day Rolling Average Emission Rate" for a Unit means and is calculated by (A) summing the total pounds of the pollutant in question emitted from the Unit during an Operating Day and the previous twenty-nine (29) Operating Days; (B) summing the total heat input to the Unit in mmBTU during the Operating Day and during the previous twenty-nine (29) Operating Days; and (C) dividing the total number of pounds of pollutants emitted during the thirty (30) Operating Days by the total heat input during the thirty (30) Operating Days, and converting the resulting value to lbs/mmBTU. A new 30-Day Rolling Average Emission Rate shall be calculated for each new Operating Day. In calculating all 30-Day Rolling Average Emission

Rates VEPCO :

A. shall include all emissions and BTUs commencing from the time the Unit is synchronized with a utility electric distribution system through the time that the Unit ceases to combust fossil fuel and the fire is out in the boiler, except as provided by Subparagraph B, C, or D**;**

B. shall use the methodologies and procedures set forth in 40 C.F.R. Part 75;

C. may exclude emissions of NOx and BTUs occurring during the fifth and subsequent Cold Start Up Period(s) that occur in any 30-Day period if inclusion of such emissions would result in a violation of any applicable 30-Day Rolling Average Emissions Rate, and if VEPCO has installed, operated and maintained the SCR in question in accordance with manufacturers' specifications and good engineering practices. A "Cold Start Up Period" occurs whenever there has been no fire in the boiler of a Unit (no combustion of any fossil fuel) for a period of six hours or more. The emissions to be excluded during the fifth and subsequent Cold Start Up Period(s) shall be the less of (1) those NOx emissions emitted during the eight hour period commencing when the Unit is synchronized with a utility electric distribution system and concluding eight hours later or (2) those emitted prior to the time that the flue gas has achieved the SCR operational temperature as specified by the catalyst manufacturer; and

D. may exclude NOx emissions and BTUs occurring during any period of malfunction (as defined at 40 C.F.R. 60.2) of the SCR.

6. "30-Day Rolling Average Removal Efficiency" means the percent reduction in the SO_2 Emissions Rate achieved by a Unit's FGD over a 30 Operating Day period, as further described by the terms of this Decree.

7. "Air Quality Control Region" means a geographic area designated under Section 107(c)

of the Act, 42 U.S.C. § 7407(c).

8. "Boiler Island" means a Unit's (A) fuel combustion system (including bunker, coal pulverizers, crusher, stoker, and fuel burners); (B) combustion air system; (C) steam generating system (firebox, boiler tubes, and walls); and (D) draft system (excluding the stack), all as further described in "Interpretation of Reconstruction," by John B. Rasnic U.S. EPA (November 25, 1986) and attachments thereto.

9. "Capital Expenditures" means all capital expenditures, as defined by Generally Accepted Accounting Principles (GAAP), as VEPCO applied GAAP to its Boiler Island expenditures for the calendar years 1995-2000. Excluded from "Capital Expenditure" is the cost of installing or upgrading pollution control devices and the cost of altering or replacing any portion of the Boiler Island if such alteration or replacement is required in accordance with good engineering practices to accomplish the installation or upgrading of a pollution control device to meet the requirements of this Decree.

10. "CEMS" or "Continuous Emission Monitoring System," for obligations involving NO_x and SO_2 under this Decree, shall mean "CEMS" as defined in 40 C.F.R. Section 72.2 and installed and maintained as required by 40 C.F.R. Part 75.

11. "Clean Air Act" or "Act" means the Clean Air Act, 42 U.S.C. §§7401-7671q, and its implementing regulations.

12. "Completed," when used in connection with Sections XI through XVII (Resolution of Certain Civil Claims) and with respect to a change or modification, means the time when the Unit subject to the change or modification has been returned to service and is capable of generating electricity.

13. “Connecticut” means the State of Connecticut.

14. “Consent Decree” or “Decree” means this Consent Decree and its Appendices A through C, which are incorporated by reference (Appendix A -- “Coal-Fired Steam-Electric Generating Units Constituting the VEPCO System”; Appendix B -- “Consent Decree Reporting Form”; and Appendix C -- “Mitigation Projects that Shall be Completed Under this VEPCO Consent Decree”).

15. “Defendant” means Virginia Electric and Power Company or VEPCO.

16. “Emission Rate” means the number of pounds of pollutant emitted per million BTU of heat input (“lb/mmBTU”), measured as required by this Consent Decree.

17. “EPA” means the United States Environmental Protection Agency.

18. “ESP” means electrostatic precipitator, a pollution control device for the reduction of PM.

19. “FGD” means a pollution control device that employs flue gas desulfurization technology to remove SO_2 from flue gas.

20. “Improved Unit” means, in the case of NOx, a VEPCO System Unit scheduled under this Decree to be equipped with SCR and, in the case of SO2, means a VEPCO System Unit scheduled under this Decree to be equipped with an FGD, or Possum Point Units 3 and 4 because of their conversion to natural gas, as listed in Appendix A of this Decree and any amendment thereto. A Unit may be an Improved Unit for one pollutant without being an Improved Unit for the other.

21. “KW” means a kilowatt, which is one thousand Watts or one thousandth of a megawatt (MW).

22. “lb/mmBTU” means the number of pounds of pollutant emitted per million British Thermal Units of heat input.

23. “MW” means megawatt or one million Watts.

24. “National Ambient Air Quality Standards” means national air quality standards promulgated pursuant to Section 109 of the Act, 42 U.S.C. § 7409.

25. “New York” means the State of New York.

26. “New Jersey” means the State of New Jersey.

27. “NOV” means the Notice of Violation issued by EPA to VEPCO, dated April 24, 2000.

28. “NO_x” means oxides of nitrogen, as further described by the terms of this Decree.

29. “NSR” means New Source Review and refers generally to the Prevention of Significant Deterioration and Non-Attainment provisions of Parts C and D of Subchapter I of the Act.

30. “Operating Day” for a coal-fired Unit means any calendar day on which such a Unit burns fossil fuel.

31. “Other Unit” means any Unit of the VEPCO System that is not an Improved Unit for the pollutant in question. A Unit may be an Improved Unit for NOx and an Other Unit for SO2 and vice versa.

32. “Ozone Season” means the five-month period from May 1 through September 30 of any year after 2004. For the year 2004, “Ozone Season” means the period from May 31, 2004, through September 30, 2004.

33. “Paragraph” means a provision of this Decree preceded by an Arabic number.

34. “Parties” means VEPCO, the United States, Virginia, West Virginia, New York, New Jersey, and Connecticut.

35. "Plaintiffs" means the United States, New York, New Jersey, Connecticut, Virginia, and West Virginia.

36. "PM" means total particulate matter as further described by the terms of this Decree.

37. "PM CEM" or "PM Continuous Emission Monitor" means equipment that samples, analyses, measures, and provides PM emissions data -- by readings taken at frequent intervals -- and makes an electronic or paper record of the PM emissions measured.

38. "Pollution Control Upgrade Analysis" means the technical study, analysis, review, and selection of control technology recommendations (including an emission rate or removal efficiency) performed in connection with an application for a federal PSD permit, taking into account the characteristics of the existing facility. Except as otherwise provided in this Consent Decree, such study, analysis, review, and selection of recommendations shall be carried out in accordance with applicable federal and state regulations and guidance describing the process and analysis for determining Best Available Control Technology (BACT), as that term is defined in 40 C.F.R. §52.21(b)(12), including, without limitation, the December 1, 1987 EPA Memorandum from J. Craig Potter, Assistant Administrator for Air and Radiation, regarding Improving New Source Review (NSR) Implementation. Nothing in this Decree shall be construed either to: (A) alter the force and effect of statements known as or characterized as "guidance" or (B) permit the process or result of a "Pollution Control Upgrade Analysis" to be considered BACT for any purpose under the Act.

39. "ppm" means parts per million by dry volume, corrected to 15 percent O_2.

40. "Project Dollars" means VEPCO's properly documented internal and external costs incurred in carrying out the dollar-limited projects identified in Section XXI ("Mitigation

Projects") and Appendix C, as determined in accordance with Generally Accepted Accounting Principles (GAAP) (subject to review by the Plaintiffs), and provided that such costs comply with the Project Dollars and other requirements for such expenditures and payments set forth in Section XXI ("Mitigation Projects") and Appendix C.

41. "PSD" means Prevention of Significant Deterioration, as that term is understood under Part C of Subchapter I of the Clean Air Act, 42 U.S.C. §§ 7470 - 7492 and 40 C.F.R. Part 52.

42. "PSD Increment" means the maximum allowable increase in a pollutant's concentration over the baseline concentration within the meaning of Section 163 of the Act, 42 U.S.C. § 7473 and 40 C.F.R. § 51.166(c).

43. "SCR" means a pollution control device that employs selective catalytic reduction to remove NO_x from flue gas.

44. "Seasonal System-Wide Emission Rate" for a pollutant means the total pounds of the pollutant emitted by the VEPCO System during the period from May 1 through September 30 of each calendar year, divided by the total heat input (in mmBTU) to the VEPCO System during the period from May 1 through September 30 of the same calendar year. VEPCO shall calculate the Seasonal System-Wide Emission Rates from hourly CEMS data collected and analyzed in compliance with the 40 C.F.R. Part 75.

45. "Section" means paragraphs of this Decree collected under a capitalized heading that is preceded by a Roman Numeral.

46. "SO_2" means sulfur dioxide, as described further by the terms of this Decree.

47. "SO_2 Allowance" means the same as the definition of "allowance" found at 42 U.S.C. Section 7651a(3): "an authorization, allocated to an affected unit, by the Administrator [of EPA]

under [Subchapter IV of the Act] to emit, during or after a specified calendar year, one ton of sulfur dioxide."

48. "Subparagraph" means any subdivision of a Paragraph identified by any number or letter.

49. "System-Wide Annual Emission Rate" for a pollutant shall mean the total pounds of the pollutant emitted by the VEPCO System during a calendar year, divided by the total heat input (in mmBTU) to the VEPCO System during the same calendar year. VEPCO shall calculate and analyze the System-Wide Annual Emission Rates from hourly CEM data collected in compliance with 40 C.F.R. Part 75.

50. "Title V Permit" means each permit required under Subchapter V of the Clean Air Act, 42 U.S.C. § 7661, et seq., for each electric generating plant that includes one or more Units that are part of the VEPCO System.

51. "VEPCO System" means all the Units listed here and described further in Appendix A: Bremo Power Station Units 3 and 4 (in Fluvanna County, Virginia); Chesapeake Energy Center Units 1, 2, 3, and 4 (near Chesapeake, Virginia); Chesterfield Power Station Units 3, 4, 5, and 6 (in Chesterfield County, Virginia); Clover Power Station Units 1 and 2 (in Halifax County, Virginia); Mount Storm Power Station Units 1, 2, and 3 (in northeastern West Virginia); North Branch Power Station Units 1A and 1B (in northeastern West Virginia); Possum Point Power Station Units 3 and 4 (in Northern Virginia, about twenty-five miles south of Washington, D.C.); and Yorktown Power Station Units 1 and 2 (in Yorktown, Virginia).

52. "Virginia" means the Commonwealth of Virginia.

53. "Watt" means a unit of power equal to one joule per second.

54. "West Virginia" means the State of West Virginia.

55. "Unit" means a generator, the steam turbine that drives the generator, the boiler that produces the steam for the steam turbine, the equipment necessary to operate the generator, turbine and boiler, and all ancillary equipment, including pollution control equipment or systems necessary for the production of electricity.

IV. NO_x EMISSION REDUCTIONS AND CONTROLS

56. Unit-Specific SCR Installations and Performance Requirements. VEPCO shall install an SCR on each Unit listed below, no later than the date specified below and, commencing on that date and continuing thereafter, operate each SCR to meet a 30-Day Rolling Average Emission Rate for NO_x of 0.100 lb/mmBTU for each listed Unit, except that VEPCO shall meet a 30-Day Rolling Average Emissions Rate of 0.110 lb/mmBTU for Mount Storm Units 1, 2 and 3:

Units on Which VEPCO Shall Install an SCR	Latest Date by which VEPCO Must: (A) Complete Installation of Fully Operational SCR, and (B) Start Operation that Meets 30-Day Rolling Average NO_x Emission Rate
Mount Storm Unit 1	January 1, 2008
Mount Storm Unit 2	January 1, 2008
Mount Storm Unit 3	January 1, 2008
Chesterfield Unit 4	January 1, 2013
Chesterfield Unit 5	January 1, 2012
Chesterfield Unit 6	January 1, 2011
Chesapeake Energy Center Unit 3	January 1, 2013
Chesapeake Energy Center Unit 4	January 1, 2013

57. VEPCO also shall use best efforts to operate each SCR required under this Decree whenever VEPCO operates the Unit served by the SCR, in accordance with manufacturers' specifications, good engineering practices, and VEPCO's operational and maintenance needs.

58. Year-Round Operation of SCRs. Beginning on January 1, 2008, and continuing thereafter, in accordance with the SCR installation schedule provided for in Paragraph 56 (Unit specific SCR Installation and Performance Requirements), every VEPCO System Unit served by an SCR required pursuant to Paragraph 56 shall operate year-round and achieve and maintain a NO_x 30-Day Rolling Average Emission Rate of no more than 0.100 lb/mmBTU, except that

Mount Storm Units 1, 2 and 3 shall achieve a NOx 30-Day Rolling Average Emission Rate of no more than 0.110 lb/mmBTU.

59. <u>VEPCO System: Interim Control of NO_x Emissions: 2004 through 2007</u>. Commencing in 2004 and ending on December 31, 2007, VEPCO shall control NO_x emissions under the provisions of either Subparagraph (A) or (B) of this Paragraph. VEPCO may elect to comply with either Subparagraph in any calendar year and may change its election from year to year. VEPCO shall notify the Parties in writing on or before January 1 of each calendar year of whether it elects to comply with Subparagraph (A) or Subparagraph (B) for that year. If VEPCO fails to provide such notice by January 1 of any year, the last elected option for the prior calendar year shall be deemed to apply, and, if none, Subparagraph (B) shall be deemed to apply for such year. The requirements of this Paragraph shall terminate on December 31, 2007:

(A) During the following three time periods, VEPCO shall control emissions of NO_x by operating SCRs on VEPCO System Units of at least the mega-wattage capacities specified and shall achieve a 30-Day Rolling Average Emission Rate for NOx of no greater than 0.100 lb/mmBTU at each such Unit, except that Mount Storm Units 1, 2 and 3 shall achieve a NOx 30-Day Rolling Average Emission Rate of no more than 0.110 lb/mmBTU, as follows:

(i) May 31, 2004, through April 30, 2005: Operate SCR on combined capacity of at least 375 MW on any combination of VEPCO System Units, but at least one Unit so controlled shall be at the Chesterfield Station.

(ii) May 1, 2005, through April 30, 2006: Operate SCR on combined capacity of at least 875 MW on any combination of VEPCO System Units, but at least one-half of the 875 MW so controlled shall be from a Unit or Units at the Chesterfield and/or Mt. Storm Stations.

(iii) May 1, 2006, through December 31, 2007: Operate SCR on combined capacity of at least 1,450 MW on any combination of VEPCO System Units, but at least one-half of the 1,450 MW so controlled shall be from a Unit or Units at the Chesterfield and/or Mt. Storm Stations; or

(B) During the Ozone Seasons of the years 2004 through 2007, actual NO_x emissions from the VEPCO System shall not exceed a Seasonal System Wide Emission Rate greater than 0.150 lb/mmBTU. VEPCO's compliance with this limit shall be achieved, in part, by operating an SCR at the Mt. Storm and Chesterfield Stations.

60. VEPCO System NO_x Limits 2003 and thereafter: Declining, System-Wide Tonnage Caps. Actual, total emissions of NO_x from the VEPCO System in each calendar year, beginning in 2003 and continuing thereafter, shall not exceed the number of tons specified below:

Calendar Year	Total Permissible NO_x Emissions (in Tons) from VEPCO System
2003	104,000
2004	95,000
2005	90,000
2006	83,000
2007	81,000
2008	63,000
2009	63,000
2010	63,000
2011	54,000
2012	50,000
2013 and each year thereafter	30,250

61. VEPCO System-Wide, Annual Average NO_x Emission Rate. Commencing January 1, 2013, and continuing thereafter, actual NO_x emissions from the VEPCO System shall not exceed a System-Wide Annual Average Emission Rate of 0.150 lb/mmBTU.

62. NOx Measurement and Calculation Procedures and Methods. In determining emission rates for NO_x, VEPCO shall use those applicable monitoring or reference methods specified in 40 C.F.R. Part 75.

63. Evaluation of NOx Emission Limitations Based Upon Performance Testing. At any time after September 30, 2004, VEPCO may submit to the Plaintiffs a proposed revision to the applicable 30-Day Rolling Average Emissions Rate for NOx on any VEPCO System Unit

equipped with SCR and subject to a 30-Day Rolling Average Emission Rate. To make a successful petition, VEPCO must demonstrate that it cannot consistently achieve the Decree-mandated NOx emissions rate for the Unit in question, considering all relevant information, including but not limited to the past performance of the SCR, reasonable measures to achieve the designed level of performance of the SCR in question, the performance of other NOx controls installed at the unit, and the operational history of the Unit. VEPCO shall include in such proposal an alternative 30-Day Rolling Average Emissions Rate. VEPCO also shall retain a qualified contractor to assist in the performance and completion of the petition for an alternate 30-Day Rolling Average Emissions Rate for NOx. VEPCO shall deliver with each submission all pertinent documents and data that support or were considered in preparing such submission. If the Plaintiffs disapprove the revised emission rate, such disagreement is subject to Section XXVII ("Dispute Resolution"). VEPCO shall make any submission for any Unit under this Paragraph no later than fifteen months after the compliance date specified for that unit in Paragraph 56 ("Unit-Specific SCR Installations and Performance Requirements").

V. SO_2 EMISSION REDUCTIONS AND CONTROLS

64. Installation and Construction of, and Improvements to, plus Removal Efficiencies Required on, FGDs Serving: Clover Units 1 and 2, Mount Storm Units 1, 2, and 3, and Chesterfield Units 5 and 6. VEPCO shall construct or improve -- as applicable -- FGDs for each Unit listed below, to meet or exceed the Removal Efficiencies for SO_2 specified below, in accordance with the schedules set out below. VEPCO shall operate each FGD so that each Unit shall continuously meet or exceed the SO_2 removal efficiency specified for it, as a 30-Day

Rolling Average Removal Efficiency, during the time periods described (Phases I and II):

Plant Name and Unit Number	**Duration of Phase I Removal Efficiency Requirement**	**Phase I Minimum 30-Day Rolling Average Removal Efficiency (%)**	**Duration of Phase II Removal Efficiency Requirement**	**Phase II Minimum 30-Day Rolling Average Removal Efficiency (%)**
Clover Unit 1	Meet 30-Day Rolling Average by 09/01/ 2003 and thereafter	95.0	Same as Phase I	Same as Phase I
Clover Unit 2	Meet 30-Day Rolling Average by 09/01/ 2003 and thereafter	95.0	Same as Phase I	Same as Phase I
Mt. Storm Unit 1	Meet 30-Day Rolling Average by 09/01/ 2003 and through 12/31/04	93.0	Jan. 1, 2005, and thereafter	95.0
Mt. Storm Unit 2	Meet 30-Day Rolling Average by 09/01/ 2003 and through 12/31/04	93.0	Jan. 1, 2005, and thereafter	95.0
Mt. Storm Unit 3	Meet 30-Day Rolling Average by 09/01/ 2003 and through 12/31/04	93.0	Jan. 1, 2005, and thereafter	95.0

Chesterfield Unit 5	Oct. 12, 2012, and thereafter	95.0	Same as Phase I	Same a Phase I
Chesterfield Unit 6	Jan. 1, 2010, and thereafter	95.0	Same as Phase I	Same as Phase I

65. <u>Chesterfield FGD Construction</u>. This Decree does not require VEPCO to begin: (A) physical construction on or begin significant equipment procurement for the FGD for Chesterfield Unit 6 prior to July 1, 2008, or (B) physical construction on or significant equipment procurement for the FGD for Chesterfield Unit 5 before January 1, 2010.

66. <u>Option of Compliance with an Emission Rate after an FGD Demonstrates SO_2 30-Day Rolling Average Removal Efficiency of at least 95.0%</u>. Once a Unit (and its FGD) listed in Paragraph 64 demonstrates at least 95 percent removal efficiency for SO_2 for at least 180 consecutive days of operation without FGD bypass as specified in Paragraph 67 (omitting days on which the Unit did not combust fossil fuel) on a 30-Day Rolling Average basis, then VEPCO -- at its option and with written, prior notice to the Plaintiffs -- shall meet the following emission rate for SO_2 rather than the 30-Day Rolling Average Removal Efficiency specified in Paragraph 64:

Plant and Unit Eligible to Make 180-Day Demonstration	**Maximum SO_2 30-Day Rolling Average Emission Rate VEPCO shall meet in Lieu of 95.0%, 30-Day Rolling Average Removal Efficiency**
Clover Unit 1	**0.130**
Clover Unit 2	**0.130**
Chesterfield Unit 5	**0.130**
Chesterfield Unit 6	**0.130**

Mount Storm Unit 1	**0.150**
Mount Storm Unit 2	**0.150**
Mount Storm Unit 3	**0.150**

67. Interim Mitigation of Mount Storm SO_2 Emissions While FGDs are Improved. Notwithstanding the requirement to meet a specific percent removal or emission rate at Mount Storm Units 1, 2, or 3, in limited circumstances, VEPCO may operate such Units without meeting required Removal Efficiencies or Emission Rates in the case of FGD scrubber outages or downtime of the FGD scrubber serving each such Unit, if such operation complies with the following requirements. For this Paragraph, FGD outage or downtime "day" shall consist of a 24-hour block period commencing in the hour the FGD ceases to operate, and continuing in successive 24-hour periods until the hour the FGD is placed back into operation. Any period of less than 24 hours of FGD downtime shall count as a full "day". For the FGD serving Unit 3, because it has two separately operating absorber vessels, outage or downtime may be measured in "1/2 day" (12-hour) increments – one for each absorber – but otherwise on the same basis as a "day" is counted for outage or downtime on the FGDs serving Units 1 and 2.

(A) In any calendar year from 2003 through 2004 for Mount Storm Unit 3, and in any calendar year from 2003 through 2004 for Mount Storm Units 1 and 2, VEPCO may operate Mount Storm Units 1, 2, or 3 in the case of outage or downtime of the FGD serving such Unit, if all of the following conditions are satisfied:

(i) VEPCO does not operate Mount Storm Units 1, 2, or 3 during FGD outages or downtime on more than thirty (30) "days", or any part thereof, in any calendar year; in the case of Mount Storm Unit 3, operation during an outage or downtime in either of the two FGD absorber vessels serving the Unit shall count as operation during a "1/2" day of FGD outage or downtime;

(ii) All other available VEPCO System Units on-line at the Mount Storm Station and Clover Power Station are dispatched ahead of the Mount Storm Unit experiencing the FGD outage or downtime;

(iii) For each of the first twenty (20) "days" in a calendar year, or part thereof, that a Unit operates under this Paragraph VEPCO surrenders to EPA (using the procedure Section VI, Paragraph 72) one SO_2 Allowance, in addition to any surrender or possession of allowances required under Title IV or under any other provision of this Consent Decree, for each ton of SO_2 actually emitted in excess of the SO_2 emissions that would have occurred if coal containing 1.90 lb/mmBTU sulfur had been burned; and

(iv) For each "day", or part thereof, that a Unit operates under this Paragraph beyond twenty (20) "days" in a calendar year, VEPCO shall surrender to EPA (using the procedure in Section VI, Paragraph 72) one SO_2 Allowance, in addition to any surrender or possession of allowances required under Title IV or under any other provision of this Consent Decree, for each ton of SO_2 actually emitted in excess of SO_2 emissions that would have occurred if coal containing 1.70 lb/mmBTU sulfur had been burned.

(B) In any calendar year from 2005 through 2007, VEPCO may operate Mount Storm Units 1, 2, or 3 in the case of FGD outage or downtime, if all of the following conditions are satisfied:

(i) VEPCO does not operate Mount Storm Units 1 or 2 during FGD outages or downtime on more than thirty (30) "days", or any part thereof, in any calendar year; and in the case of Mount Storm Unit 3, operation during an outage or downtime in either one of the two FGD absorber vessels serving the Unit shall count as operation during "1/2" day of FGD outage or downtime;

(ii) All other available VEPCO System Units on-line at the Mount Storm Station and Clover Power Station are dispatched ahead of the Mount Storm Unit experiencing the FGD outage or downtime;

(iii) For each of the first ten (10) "days", or part thereof, in a calendar year that a Unit operates under this Paragraph VEPCO surrenders to EPA (using the procedure in Section VI, Paragraph 72) one SO_2 Allowance, in addition to any surrender or possession of allowances required under Title IV or under any other provision of this Consent Decree, for each ton of SO_2 actually emitted in excess of the SO_2 emissions that would have occurred if coal containing 1.90 lb/mmBTU sulfur had been burned;

(iv) For each day that a Unit operates under this Paragraph from the eleventh through the twentieth "days", or part thereof, in a calendar year, VEPCO shall surrender to EPA (using the procedure in Section VI, Paragraph 72) one SO_2 Allowance, in addition to any surrender or possession of allowances required under Title IV or under any other provision of this Consent Decree, for each of the tons of SO_2 actually emitted that equal the mass emissions difference between actual emissions and those that would have occurred if coal containing 1.70

lb/mmBTU sulfur had been used.; and

(v) For each day that a Unit operates under this Paragraph beyond twenty (20) “days”, or part thereof, in a calendar year, VEPCO shall surrender to EPA (using the procedure Section VI, Paragraph 72) one SO_2 Allowance, in addition to any surrender or possession of allowances required under Title IV or under any other provision of this Consent Decree, for each ton of SO_2 actually emitted in excess of SO_2 emissions that would have occurred if coal containing 1.50 lb/mmBTU sulfur had been burned;

(C) In any calendar year from 2008 through 2012, VEPCO may operate Mount Storm Units 1, 2, or 3 in the case of FGD outages or downtime, if all of the following conditions are satisfied:

(i) VEPCO does not operate Mount Storm Units 1, 2, or 3 during FGD outages or downtime on more than ten (10) “days”, or part thereof, in any calendar year; in the case of Mount Storm Unit 3, operation during an outage or downtime in either of the two FGD absorber vessels serving the Unit shall count as “1/2” day of operation during an FGD outage or downtime;

(ii) All other available VEPCO System Units on-line at the Mount Storm Station and Clover Station are dispatched ahead of the Mount Storm Unit experiencing the FGD outage or downtime; and

(iii) VEPCO surrenders to EPA (using the procedure of Section VI, Paragraph 72) one SO_2 Allowance, in addition to any surrender or possession of allowances required under Title IV or under any other provision of this Consent Decree, for each ton of SO_2 actually emitted in excess of SO_2 emissions that would have occurred if coal with 1.50 lb/mmBTU sulfur had been burned.

68. Calculating 30-Day Rolling Average Removal Efficiency of a VEPCO System FGD. The SO_2 30-Day Rolling Average Removal Efficiency for a VEPCO System FGD shall be obtained and calculated using SO_2 CEMS data in compliance with 40 CFR Part 75 (from both the inlet and outlet of the control device) by subtracting the outlet 30-Day Rolling Average Emission Rate from the inlet 30-Day Rolling Average Emission Rate on each day the boiler operates, dividing that difference by the inlet 30-Day Rolling Average Emission Rate, and then multiplying by 100. A new 30-Day Rolling Average Removal Efficiency shall be calculated for each new Operating Day. In the case of FGDs serving Chesterfield Units 5 and 6 or Mount Storm Units 1, 2, or 3, if any flue gas emissions containing SO_2 did not pass through the inlet of the Unit's scrubber on a day when the Unit operated, VEPCO must account for, report on, and include any such emissions in calculating the FGD Removal Efficiency for that day and for every 30-Day Rolling Average of which that day is a part.

69. Commencing within 30 days after lodging of this Decree, VEPCO shall use best efforts to operate each such FGD at all times the Unit the FGD serves is in operation, provided that such FGD system can be operated consistent with manufacturers' specifications, good engineering practices and VEPCO's operational and maintenance needs. In calculating a 30-Day Rolling Average Removal Efficiency or a 30-Day Rolling Average Emission Rate for a Mount Storm Unit, VEPCO need not include SO_2 emitted by Unit while its FGD is shut down in compliance with Paragraph 67 ("Interim Mitigation of Mount Storm SO_2 Emissions While FGDs are Improved").

70. SO$_2$ Measurement Methods. VEPCO shall conduct all emissions monitoring for SO_2 in compliance with 40 C.F.R. Part 75.

VI. ANNUAL SURRENDER OF SO_2 ALLOWANCES

71. Annual Surrender. On or before March 31 of every year beginning in 2013 and continuing thereafter, VEPCO shall surrender 45,000 SO_2 Allowances. In each year, this surrender of SO_2 Allowances may be made either directly to EPA or by first transferring the SO_2 Allowances to another person in the manner provided for by this Decree.

72. Surrender Directly to EPA. If VEPCO elects to make an annual surrender directly to EPA, VEPCO shall, on or before March 31, 2013, and on or before March 31 of each year thereafter, submit SO_2 Allowance transfer request forms to EPA's Office of Air and Radiation's Clean Air Markets Division directing the transfer of 45,000 SO_2 Allowances held or controlled by VEPCO to the EPA Enforcement Surrender Account or to any other EPA Account to which the EPA may direct. As part of submitting these transfer requests, VEPCO shall irrevocably authorize the transfer of these Allowances and VEPCO shall also identify – by name of account and any applicable serial or other identification numbers or plant names – the source and location of the Allowances being surrendered, as well as any information required by the transfer request form.

73. Alternate Method of Surrender. If VEPCO elects to make an annual surrender of SO_2 Allowances to a person other than EPA, VEPCO shall include a description of such transfer in the next report submitted to Plaintiffs pursuant to Section XIX ("Periodic Reporting") of this Consent Decree. Such report shall: (A) provide the identity of the third-party recipient(s) of the

SO_2 Allowances and a listing of the serial numbers of the transferred allowances; (B) include a certificate in compliance with Section XIX from the third-party recipient(s) stating that it (they) will not sell, trade, or otherwise exchange any of the allowances and will not use any of the allowances to meet any obligation imposed by any environmental law. No later than the next periodic report due 12 months after the first report of the transfer, VEPCO shall include in the Section XIX reports to Plaintiffs a statement that the third-party recipient(s) permanently surrendered the allowances to EPA within one year after VEPCO transferred the allowances to the third-party recipient(s). VEPCO shall not have finally complied with the allowance surrender requirements of this Paragraph until all third-party recipient(s) shall have actually surrendered the transferred allowances to EPA.

74. Changes to Decree-Mandated SO_2 Allowance Surrenders Beginning in 2013, and every year thereafter:

(A) If changes in Title IV of the Act or it implementing regulations decrease the number of SO_2 Allowances that are allocated to the VEPCO System Units for the year 2013 or any year thereafter, or if other applicable law either: (A) awards fewer than 127,363 SO_2 Allowances to the VEPCO System or (B) directs non-reusable surrender of SO_2 Allowances by VEPCO, then the number of SO_2 Allowances that VEPCO must surrender in such a year under this Section shall decrease by the same amount;

(B) If changes to Title IV of the Act or its implementing regulations result in (i) a reduction of SO_2 Allowances to the VEPCO System and (ii) any amount of SO_2 Allowances being auctioned-off, and the national SO_2 Allowance pool reflects a nationwide reduction in SO_2 Allowances of less than 35.6% from the 2010 national pool, then the number of SO_2 Allowances that VEPCO must surrender in such year under this Section of this Decree shall decrease as follows:

45,000 – (127,363 x the percent reduction of the National pool)

Thus, if the national pool of SO_2 Allowances is reduced by greater than 35.6% from the 2010 national pool of SO_2 allowances, then VEPCO is not required to surrender any SO_2 Allowances under this Decree. But in no event shall VEPCO keep in excess of 82,363 SO_2 Allowances allocated in any year after 2012 to the VEPCO System.

(C) If changes to Title IV of the Act or its implementing regulations result in an increase of SO_2 Allowances to VEPCO, then VEPCO's annual obligation to surrender such Allowances under this Decree shall increase by the amount of such increase.

75. Use of SO_2 Allowances Related to VEPCO System Units Scheduled for FGDs under the Decree. For all SO_2 Allowances allocated to Mount Storm Unit 1 on or after January 1, 2003, Mount Storm Unit 2 on or after January 1, 2003, Chesterfield Unit 5 on or after October 1, 2012, and Chesterfield Unit 6 on or after January 1, 2010, VEPCO may use such SO_2 Allowances only to (A) meet the SO_2 Allowance surrender requirements established for the VEPCO System under this Decree; (B) meet the limits imposed on VEPCO under Title IV of the Act; or (C) meet any federal or state future emission reduction programs that use or rely on Title IV SO_2 Allowances for compliance, in whole or in part. However, if VEPCO operates a FGD serving Mount Storm Unit 1, Mount Storm Unit 2, Chesterfield Unit 5, or Chesterfield Unit 6 either: (A) earlier than required by a provision of this Decree or (B) at a 30-Day Rolling Average Removal Efficiency greater than, or a 30-Day Rolling Average Emissions Rate less than that required by this Decree, then VEPCO may use for any lawful purpose SO_2 Allowances equal to the number of tons of

SO_2 that VEPCO removed from the emission of those Units in excess of the SO_2 tonnage reductions required by this Decree, so long as VEPCO timely reports such use under Section XIX.

76. Other Limits on Use of SO_2 Allowances. VEPCO may not use the same SO_2 Allowance more than once. VEPCO may not use the SO_2 Allowances surrendered under this Section for any other purpose, including, but not limited to, any sale or trade of such Allowances for use by any person other than VEPCO or by any Unit not part of the VEPCO System, except as provided by Paragraph 73 ("Alternate Method of Surrender"). Other than the limits stated in this Decree on use of SO_2 Allowances or limits imposed by law, this Decree imposes no other limits on how VEPCO may use SO_2 Allowances.

77. No Entitlement Created. This Consent Decree does not entitle VEPCO to any allocation of SO_2 Allowances under the Act.

VII. PM EMISSION REDUCTIONS AND CONTROLS

78. Use of Existing PM Pollution Control Equipment. Commencing within 30 days after lodging of this Decree, VEPCO shall operate each ESP and baghouse within the VEPCO System to maximize PM emission reductions through the procedures established in this Paragraph. VEPCO shall (A) commence operation no later than two hours after commencement of combustion of any amount of coal in the controlled System Unit, except that this requirement shall apply to Bremo Power Station Units 3 and 4 commencing two hours after cessation of oil injection to the boiler, and provided that, for all ESP-equipped Units, "combustion of any amount of coal" shall not include combustion of coal that is the result of clearing out a Unit's coal mills as the Unit is returned to service; (B) fully energize each available portion of each

ESP, except those ESP fields that have been out of service since at least January 1, 2000, consistent with manufacturers' specifications, the operational design of the Unit, and good engineering practices, and repair such fields that go out of service consistent with the requirements of this Paragraph; (C) maintain power levels delivered to the ESPs, consistent with manufacturers' specifications, the operational design of the Unit, and good engineering practices; and (D) continuously operate each ESP and baghouse in compliance with manufacturers' specifications, the operational design of the Unit, and good engineering practices. Whenever any element of any ESP that has been in service at any time since January 1, 2000 fails, does not perform in accordance with manufacturers' specifications and good engineering practices, or does not operate in accordance with the standards set forth in this Paragraph, VEPCO shall use best efforts to repair the element no later than the next available Unit outage appropriate to the repair task. The requirements of this Paragraph do not apply to Possum Point Units 3 and 4 until January 1, 2004, and do not apply at all when those Units burn natural gas.

79. ESP and Baghouse Optimization Studies and Recommendations. VEPCO shall complete an optimization study, in accordance with the schedule below, for each VEPCO System Unit served by an ESP or baghouse (except Possum Point Units 3 and 4, in light of their conversion to natural gas), which shall recommend: the best available maintenance, repair, and operating practices that will optimize ESP or baghouse availability and performance in accordance with manufacturers' specifications, the operational design of the Unit, and good engineering practices. These studies shall consider any ESP elements not in service prior to January 1, 2000, to the extent changes to such elements may be required to meet a PM Emission Rate of 0.030 lb/mmBTU. Any operating practices or procedures developed and approved under this

Paragraph shall become a part of the standard specified in (D) of Paragraph 78 ("Use of Existing PM Pollution Control Equipment"), above, and shall be implemented in compliance with that Paragraph. VEPCO shall retain a qualified contractor to assist in the performance and completion of each study. VEPCO shall submit each completed study to the United States for review and approval. (The United States will consult with the other Plaintiffs before completing such review). VEPCO shall implement the study's recommendations within 90 days (or any longer time period approved by the United States) after receipt of approval by the United States. If VEPCO seeks more than 90 days to implement the recommendations contained in the study, then VEPCO shall include, as part of the study, the reasons why more than 90 days are necessary to implement the recommendations, e.g., the need to order or install parts or equipment, retain specialized expertise, or carry out training exercises. VEPCO shall maintain each ESP and baghouse as required by the study's recommendations and shall supplement the ESP operational standard in (D) of Paragraph 78 to include any operational elements of the study and its recommendations. The schedule for completion and submission to the United States of the optimization studies shall be as follows:

Number and Choice of VEPCO System Units on Which VEPCO Shall Complete and Submit Optimization Studies	**Number of Months After Lodging of the Decree that VEPCO Shall Submit Optimizations Studies to the U.S.**
Four Units (including at least one Unit at Mount Storm or Chesterfield)	12 Months
Three More Units (including at least two at any one or more of the following VEPCO stations – Mount Storm, Chesterfield, and Bremo, if not already done)	24 Months

Two More Units (including at least two located at any one or more of the following VEPCO stations – Mount Storm, Chesterfield, and Bremo, if not already done)	36 Months
Two More Units	48 Months
Two More Units	60 Months
All Other Units	72 Months

80. Alternative to Pollution Control Upgrade Analysis. Within 270 days after VEPCO receives the United States' approval of the ESP optimization study for a VEPCO System Unit, VEPCO may elect to achieve for any Unit the objectives of, and thereby avoid, the Pollution Control Upgrade Analysis otherwise required by this Section by certifying to the United States, in writing, that: (A) the ESP shall continue to be operated and maintained in compliance with the approved optimization plan, pursuant to Paragraphs 78 and 79 of this Section, respectively, and (B) that the enforceable PM emission limit for this Unit shall be 0.030 lb/mmBTU, either commencing immediately or on and after the date required by this Decree for completion of FGD installations or improvements at that Unit (or after installation of any other FGD system VEPCO chooses to install at a Unit prior to 2013). Otherwise, VEPCO shall comply with Paragraph 82 (Pollution Control Upgrade Analysis, Construction of PM Controls, Compliance with New Emission Rate"), below.

81. PM Emission Rate Determination. The methods specified in this Paragraph shall be the reference methods for determining PM Emission Rates along with any other method approved by EPA under its authority to establish or approve such methods. The PM Emission Rates established under Paragraph 80 of this Section shall not apply during periods of "startup" and "shutdown" or during periods of control equipment or Unit malfunction, if the malfunction meets

the requirements of the Force Majeure Section of this Consent Decree. Periods of "startup" shall not exceed two hours after any amount of coal is combusted (except that for Bremo Power Station Units 3 and 4, this two-hour period begins upon cessation of injection of oil into the boiler). Periods of "shutdown" shall only commence when the Unit ceases burning any amount of coal (or in the case of Bremo Power Station Units 3 and 4, when any oil is introduced into the boiler). Coal shall not be deemed to be combusted if it is burned as a result of clearing out a Unit's coal mills as the Unit is returned to service. The reference methods for determining PM Emission Rates shall be those specified in 40 C.F.R. Part 60, Appendix A, Method 5 or Method 17, using annual stack tests. VEPCO shall calculate PM Emission rates from the annual stack tests in accordance with 40 C.F.R. 60.8(f) and 40 C.F.R. 60.48a(b). The annual stack-testing requirement of this Paragraph shall be conducted as described in Paragraph 95 and may be satisfied by: (A) any annual stack tests VEPCO may conduct pursuant to its permits or applicable regulations from the States of Virginia and West Virginia if such tests employ reference test methods allowed under this Decree, or (B) installation and operation of PM CEMs required under this Decree.

82. Pollution Control Upgrade Analysis of PM, Construction of PM Controls, Compliance with New Emission Rate. For each VEPCO System Unit served by an ESP -- other than Possum Point Units 3 and 4 and those Units that meet the requirements of Paragraph 80 ("Alternative to Pollution Control Upgrade Analysis") -- VEPCO shall complete a Pollution Control Upgrade Analysis and shall deliver the Analysis and supporting documentation to the United States for review and approval (after consultation with the other Plaintiffs). Notwithstanding the definition of Pollution Control Upgrade Analysis (Paragraph 38), VEPCO shall not be required to consider

in this Analysis: (A) the replacement of any existing ESP with a new ESP, scrubber, or baghouse, or (B) the installation of any supplemental pollution control device similar in cost to a replacement ESP, scrubber, or baghouse (on a total dollar-per-ton-of-pollution-removed basis).

83. VEPCO shall retain a qualified contractor to assist in the performance and completion of each Pollution Control Upgrade Analysis. Within one year of the United States' approval of the work and recommendation(s) made in the Analysis (or within a longer period of time properly sought by VEPCO and approved by the United States), VEPCO shall complete all recommendation(s). If VEPCO seeks more than one year from the date of the United States' approval of the Analysis to complete the work and recommendations called for by the Analysis, VEPCO must state the amount of additional time required and the reasons why additional time is necessary. Thereafter, VEPCO shall operate each ESP in compliance with the work and recommendation(s), including compliance with the specified Emission Rate. The schedule for completion and submission to the United States of the Pollution Control Upgrade Analyses for each Unit subject to this Paragraph shall be 12 months after the United States approves the ESP optimization study for each Unit pursuant to Paragraph 79 (unless VEPCO has elected to use the alternative to the Pollution Control Upgrade Analysis under Paragraph 80 for the Unit).

84. Performance Testing of Equipment Required by Pollution Control Upgrade Analysis. Between 6 and 12 months after VEPCO completes installation of the equipment called for by each approved Pollution Control Upgrade Analysis, VEPCO shall conduct a performance test demonstration to ensure that the approved PM emission limitation set forth in the Analysis can be consistently achieved in practice, including all requirements pertaining to proper operation and maintenance of control equipment. If the performance demonstration shows that the

approved control equipment cannot consistently meet the required PM emission limitation, VEPCO shall revise the Pollution Control Upgrade Analysis and resubmit it to the United States for review and approval of an alternative emissions limitation.

85. Installation and Operation of PM CEMs. VEPCO shall install, calibrate, operate, and maintain PM CEMs, as specified below. Each PM CEM shall be comprised of a continuous particle mass monitor measuring particulate matter concentration, directly or indirectly, on an hourly average basis and a diluent monitor used to convert results to units of lb/mmBTU. VEPCO may select any type of PM CEMS that meets the requirements of this Consent Decree. VEPCO shall maintain, in an electronic database, the hourly average emission values of all PM CEMS in lb/mmBTU. During Unit startups, VEPCO shall begin operating the PM CEMs in accordance with the standards set out in Paragraph 78(A) ("Use of Existing PM Pollution Control Equipment"), and VEPCO shall thereafter use reasonable efforts to keep each PM CEM running and producing data whenever any Unit served by the PM CEM is operating. VEPCO shall submit to EPA for review and approval a plan to install, calibrate and operate each PM CEM. VEPCO shall thereafter operate each PM CEM in accordance with the approved plan.

86. Installation of PM CEMs – First Round (Three Units). On or before December 1, 2003, VEPCO shall designate which three VEPCO System Units will have PM CEMs installed, in accordance with this Paragraph. No later than 12 months after entry of this Decree (or a longer time period approved by the United States, not to exceed 18 months after entry of this Decree) VEPCO shall install, calibrate, and commence operation of the following:

(A) PM CEMs in the stacks that service at least two of the following VEPCO System Units: Mount Storm Units 1, 2, and 3, and Clover Units 1 and 2; and

(B) at least one additional PM CEM at any other ESP-equipped Unit in the VEPCO System, as selected by VEPCO.

If VEPCO seeks more than 12 months after entry of the Decree to complete installation and calibration of the PM CEMs, then VEPCO shall include a full explanation of the reasons why it requires more than 12 months after entry of the Decree to complete installation and calibration.

87. Consultation Before the First Round of PM CEMs. Prior to installing any PM CEMs, VEPCO and the United States shall meet, consult, and agree to adequate mechanisms for treating potential emission limitation exceedances that may occur during installation and calibration periods of the PM CEMs that may exceed applicable PM emission limitations. VEPCO and the United States shall invite the States of Virginia and West Virginia to participate in these discussions.

88. Option for Consultation Both Before and After Installation of the First or Second Round of PM CEMs. Either before the first or second round of PM CEMs installations, or after such PM CEMs are installed and producing data, or both, the United States and VEPCO shall meet, upon the request of either, to examine further the data that may or may not be generated by the PM CEMs. This issue should be addressed in light of the regulatory or permit-based mass emission limit set for the Unit before it was equipped with a PM CEM or any PM emission limitation established or to be established under this Section of the Decree, and the parties should take appropriate and acceptable actions to address any issues concerning periodic short term Unit process and control device upsets and/or averaging periods. In the event VEPCO or the United States call for such a meeting, the United States and VEPCO shall invite the States of Virginia and West Virginia to participate.

89. Demonstration that PM CEMs Are Infeasible. No earlier than 2 years after VEPCO has installed the first round of PM CEMs, VEPCO may attempt to demonstrate that it is infeasible to continue operating PM CEMs. As part of such demonstration, VEPCO shall submit an alternative PM monitoring plan for review and approval by the United States. The plan shall explain the basis for stopping operation of the PM CEMs and propose an alternative-monitoring plan. If the United States disapproves the alternative PM monitoring plan, or if the United States rejects VEPCO's claim that it is infeasible to continue operating PM CEMs, such disagreement is subject to Section XXVII ("Dispute Resolution").

90. "Infeasible to Continue Operating PM CEMs" – Standard. Operation of a PM CEM shall be considered "infeasible" if, by way of example, the PM CEMS: (A) cannot be kept in proper condition for sufficient periods of time to produce reliable, adequate, or useful data; or (B) VEPCO demonstrates that recurring, chronic, or unusual equipment adjustment or servicing needs in relation to other types of continuous emission monitors cannot be resolved through reasonable expenditures of resources; or (C) chronic and difficult Unit operation issues cannot be resolved through reasonable expenditure of resources; or (D) the data produced by the CEM cannot be used to assess PM emissions from the Unit or performance of the Unit's control devices. If the United States determines that VEPCO has demonstrated infeasibility pursuant to this Paragraph, VEPCO shall be entitled to discontinue operation of and remove the PM CEMs.

91. PM CEM Operations Will Continue During Dispute Resolution or Proposals for Alternative Monitoring. Until the United States approves an alternative monitoring plan or until the conclusion of any proceeding under Section XXVII ("Dispute Resolution"), VEPCO shall continue operating the PM CEMs. If EPA has not issued a decision regarding an alternative

monitoring plan within 90 days VEPCO may initiate action under the Dispute Resolution provisions (Section XXVII) under this Consent Decree.

92. Installation and Operation of PM CEMs – Second Round (6 Units). Unless VEPCO has been allowed to cease operation of the PM CEMs under Paragraph 89 ("Demonstration that PM CEMs Are Infeasible"), then VEPCO shall install, calibrate, and commence operation of PM CEMs that serve at least 6 more Units. In selecting the VEPCO System Units to receive PM CEMs under this second round, VEPCO must assure that Mount Storm Units 1, 2, and 3 and Clover Units 1 and 2 all receive PM CEMs if they have not already received PM CEMs under the first round. VEPCO may select the other VEPCO System Units to receive the required PM CEMs. The options for consultation regarding first round PM CEMs under Paragraphs 87 and 88 shall also be available for second round PM CEMs. VEPCO shall install PM CEMs that serve two VEPCO System Units in each of the years 2007, 2008, and 2009 under this second round of PM CEMs.

93. Common Stacks. Installation of a PM CEM on Mount Storm Units 1 and 2 or on Yorktown Units 1 and 2 shall count as installation of PM CEMs on 2 units in recognition of the common stack that serves these Units. VEPCO and the United States shall agree in writing on the method for apportioning emissions to the Units served by common stacks.

94. Data Use. Data from PM CEMs shall be used by VEPCO, at minimum, to monitor progress in reducing PM emissions. Nothing in this Consent Decree is intended to or shall alter or waive any applicable law (including, but not limited to, any defense, entitlements, challenges, or clarifications related to the Credible Evidence Rule (62 Fed. Reg. 8314 (Feb. 27, 1997))) concerning the use of data for any purpose under the Act, generated either by the reference

methods specified herein or otherwise.

95. Other Testing and Reporting Requirements. Commencing in 2004, VEPCO shall conduct a stack test for PM on each stack servicing each Unit in the VEPCO System (excluding Possum Point Units 3 and 4 in 2004, and in any subsequent year in which such Units have not burned coal). Such PM stack testing shall be conducted at least once per every four successive "QA Operating Quarters" (as defined in 40 C.F.R. § 72.2) and the results of such testing shall be submitted to the Plaintiffs as part of the periodic reporting under Section XIX ("Periodic Reporting") and Appendix B. Following installation of each PM CEM, VEPCO shall include all data recorded by PM CEMs, including submission in electronic format, if available, in the reports required by Section XIX.

VIII. POSSUM POINT UNITS 3 & 4: FUEL CONVERSION, INSTALLATION OF CONTROLS

96. Fuel Conversion. VEPCO shall cease all combustion of coal at Possum Point Units 3 and 4 prior to May 1, 2003, in preparation for the conversion of Possum Point Units 3 and 4 to operate on natural gas, and shall not operate these Units again until that fuel conversion is complete and the Units are firing natural gas. VEPCO shall continuously operate such equipment to control NOx emissions in compliance with State permitting requirements. VEPCO also shall limit the combined emissions from Possum Point Units 3 and 4 to 219 tons of NOx in any 365 days, rolled daily, and determined as follows: Add the total NOX emissions from Possum Point Units 3 and 4 on any given day, occurring after entry of this Decree, to the total NOX emissions from those two Units for the preceding 364 consecutive days occurring after

entry of the Decree; the sum of those emissions may never exceed 219 tons. If VEPCO exceeds this 219-ton limit, VEPCO shall install and operate SCR at BACT levels within 3 years of the exceedance at either Yorktown Unit 1 (173 MW), or Yorktown Unit 2 (183 MW), or Bremo Unit 4 (170 MW). VEPCO may select which of these Units receives the SCR so long as the following are true for the Unit:

(A) An SCR is not required under regulatory requirements for the Unit;

(B) VEPCO had not planned to install an SCR on such Unit to help comply with any requirement as of the day of exceedance at Possum Point; and

(C) The Unit is not required to meet an emission rate that would call for installation of SCR.

If these conditions are not met for any of the three listed Units, then VEPCO shall install the required SCR at the next largest Unit (in MW) within the VEPCO System that meets the conditions of subparagraphs (A) through (C).

97. <u>Return to Combustion of Coal After Gas Conversion</u>. If VEPCO uses coal rather than natural gas to operate Possum Point Units 3 or 4 on or after May 1, 2003, VEPCO shall install controls on such Unit(s) and meet the following requirements for NO_x, SO_2, and PM emissions, on or after May 1, 2003:

(A) For NO_x, the more stringent of: (i) a 30-Day Rolling Average Emission Rate of 0.100 lb/mmBTU or (ii) the NO_x emission rate that would be LAER at the time that VEPCO returns to firing Possum Point Units 3 or 4 with coal;

(B) For SO_2, a 30-Day Rolling Average Removal Efficiency of at least 95.0%; and

(C) For PM, an Emission Rate of no more than 0.030 lb/mmBTU.

98. Measurements At Possum Point. The applicable methods and rules specified in other portions of this Decree for measuring emission rates and removal efficiencies for NO_x, SO_2, and PM also apply to the emission standards, as applicable, established under Paragraph 96 and 97 ("Fuel Conversion" and "Return to Combustion of Coal After Gas Conversion") for Possum Point Units 3 and 4.

IX. INSTALLING ADDITIONAL CONTROLS ON VEPCO SYSTEM UNITS

99. If, prior to November 1, 2004, this Consent Decree is modified to require that VEPCO:

(A) Install additional NO_x or SO_2 pollution control devices on a VEPCO System Unit not scheduled for installation of such control device as part the original Decree;

(B) Commence full-time (year-round) operation of such control device no later than January 1, 2008; and

(C) Operate the control device and the Unit it serves in compliance with a performance standard of 0.100 lb/mmBTU 30-Day Rolling Average Emission Rate for NO_x or a 95.0% 30-Day Rolling Average Removal Efficiency for SO_2;

then the modification of the Consent Decree shall also provide that such Unit be treated as an Improved Unit as to the pollutant that has been controlled in compliance with this Section.

100. Reference Methods. The reference and monitoring methods specified in other portions of this Decree for measuring all emission rates and removal efficiencies for NO_x, SO_2, and PM also apply to the emission standards established under this Section.

X. PERMITS

101. Timely Application for Permits. Unless expressly stated otherwise in this Consent Decree, in any instance where otherwise applicable law or this Consent Decree require VEPCO to secure a permit to authorize constructing or operating any device under this Consent Decree, VEPCO shall make such application in a timely manner. Such applications shall be completed and submitted to the appropriate authorities to allow sufficient time for all legally required processing and review of the permit request. Failure to comply with this provision shall allow Plaintiffs to bar any use by VEPCO of Section XXVI ("Force Majeure") where a Force Majeure claim is based upon permitting delays.

102. New Source Review Permits. This Consent Decree shall not be construed to require VEPCO to apply for or obtain a permit pursuant to the New Source Review requirements of Parts C and D of Title I of the Act for any work performed by VEPCO within the scope of the resolution of claims provisions of Sections XI through XVII (Resolution of Certain Civil Claims).103. Title V Permits . Whenever VEPCO applies for a Title V permit or a revision to such a permit, VEPCO shall send, at the same time, a copy of such application to each Plaintiff. Also, upon receiving a copy of any permit proposed for public comment as a result of such application, VEPCO shall promptly send a copy of such proposal to each Plaintiff, thereby allowing for timely participation in any public comment opportunity.

104. Title V Permits Enforceable on Their Own Terms. Notwithstanding the reference to Title V permits in this Decree, the enforcement of such permits shall be in accordance with their own terms and the Act. The Title V permits shall not be directly enforceable under this Decree, though any term or limit established by or under this Decree shall be enforceable under this

Decree regardless of whether such term has or will become part of a Title V Permit, subject to the limits of Section XXX ("Conditional Termination of Enforcement, Continuation of Terms, and First Resort to Title V Permit").

105. Consent Decree Requirements To Be Proposed for Inclusion in Title V Permits. Whenever VEPCO applies for Title V Permit(s), or for amendment(s) to existing Title V Permit(s), for the purpose of including the requirements of this Decree in such permits, VEPCO shall include in such application all performance, operational, maintenance, and control technology requirements specified by or created under this Consent Decree, not only for particular Units in the VEPCO System but also for the VEPCO System itself – including, but not limited to, emission rates, removal efficiencies, allowance surrenders, limits on use of emission credits, and operation, maintenance and optimization requirements, unless otherwise limited by Sections XI through XVII. VEPCO shall notify all Plaintiffs of any applicable requirement within its Title V permit application that may be more stringent than the requirements of this Consent Decree.

106. Methods to be Used in Applying for Title V Permit Provisions Applicable to the VEPCO System. VEPCO shall include provisions in any Title V permit application(s) submitted in accordance with Paragraph 105 ("Consent Decree Requirements To Be Proposed for Inclusion in Title V Permits") that comply with this Consent Decree's NO_x VEPCO System Declining Tonnage Cap (Section IV, Paragraph 60), the VEPCO System-Wide Annual Average Emission Rate for NO_x (Section IV, Paragraph 61), and the Annual Surrender of SO_2 Allowances from the

VEPCO System (Section VI, Paragraphs 71). In making such application, VEPCO shall use either the provisions listed below or any other method agreed to in advance by written stipulation of all the Parties and filed with this Court:

(A) For the VEPCO System declining NO_x cap in Section IV, Paragraph 61 ("VEPCO System NO_x Limits 2002 and thereafter: Declining, System-Wide Tonnage Caps"), each Unit in the VEPCO System shall be limited in perpetuity to a specified portion of the NO_x annual emissions cap that ultimately descends to 30,250 tons, provided the total of the VEPCO System declining tonnage caps for NO_x submitted for inclusion in the Title V permits shall be no greater for any year than the tonnage specified for each calendar year for the VEPCO System). The NO_x emission tons shall be allocated to each Unit within the VEPCO System. No Unit shall exceed its allocation except that VEPCO can trade NOx emissions tons between Units within the VEPCO System in order to comply with any given Unit-specific allocation. Compliance with the NO_x Annual System-Wide Annual Average Emissions cap shall be determined each year by whether each Unit holds a sufficient number of NO_x emission tons allocated to it in the Title V permit, or acquired by it through trades with other Units in the VEPCO System, to cover the Unit's actual, annual NO_x emissions; and

(B) For the System-Wide, Annual Average NO_x Emissions Rate specified in Section IV, Paragraph 61, ("VEPCO System-Wide, Annual Average NO_x Emission Rate") VEPCO shall prepare a VEPCO System-Wide NO_x emissions BTU-weighted averaging plan for all the Units in the VEPCO System, and in doing so, shall use all the appropriate methods and procedures specified at 40 C.F.R. § 76.11 in preparing such a plan. As part of that plan, VEPCO shall prepare an "alternative contemporaneous allowable annual emissions limitation" (in lb/mmBTU) for each Unit in the VEPCO System, as described by 40 C.F.R. § 76.11. After this allocation and establishment of an "alternative contemporaneous allowable annual emissions limitation," VEPCO's compliance with Paragraph 61 ("VEPCO System-Wide, Annual Average NO_x Emission Rate") shall be determined in the manner described by 40 C.F.R. § 76.11, as applicable, and shall be based on whether each Unit meets the applicable "alternative contemporaneous allowable annual emissions limitation" for the NO_x emissions BTU weighted averaging plan; provided, however, that if any Unit(s) does not meet such emissions limitation, such Unit(s) shall still be in compliance if VEPCO shows that all the Units in the emissions averaging plan, in aggregate, do not exceed the BTU-weighted NO_x System-Wide Emissions Rate; and

(C) For the Annual Surrender of SO_2 Allowances required by Section VI, the annual SO_2 Allowance surrender requirement of 45,000 SO_2 Allowances shall either be divided up and allocated to specific Units of the VEPCO System or assigned to a single VEPCO System Unit – as VEPCO elects.

XI. RESOLUTION OF CERTAIN CIVIL CLAIMS OF THE UNITED STATES.

107. Claims Based on Modifications Occurring Before the Lodging of Decree. Entry of this Decree shall resolve all civil claims of the United States under either: (i) Parts C or D of Subchapter I of the Clean Air Act or (ii) 40 C.F.R. Section 60.14, that arose from any

modification commenced at any VEPCO System Unit prior to the date of lodging of this Decree, including but not limited to, those modifications alleged in the U.S. Complaint in this civil action or in the EPA NOV issued to VEPCO on April 24, 2000.

108. Claims Based on Modifications after the Lodging of Decree. Entry of this Decree also shall resolve all civil claims of the United States for pollutants regulated under Parts C or D of Subchapter I of the Clean Air Act and regulations promulgated as of the date of the lodging of this Decree, where such claims are based on a modification completed before December 31, 2015 and:

A) commenced at any VEPCO System Unit after lodging of this Decree or

B) that this Consent Decree expressly directs VEPCO to undertake.

The term "modification" as used in this Paragraph shall have the meaning that term is given under the Clean Air Act statute as it existed on the date of lodging of this Decree.

109. Reopener. The resolution of the civil claims of the United States provided by this Section is subject to the provisions of Section XII.

XII. REOPENING OF U.S. CIVIL CLAIMS RESOLVED BY SECTION XI

110. Bases for Pursuing Resolved Claims Across VEPCO System. If VEPCO:

(A) Violates Paragraph 59(A) or (B) (VEPCO System-Wide, Interim Control of NOX Emissions, 2004 through 2007); or

(B) Violates Paragraph 60 (VEPCO System-Wide NOX Tonnage Limits 2003 and thereafter: Declining, System-Wide Tonnage Caps); or

(C) Violates Paragraph 61 (VEPCO System-Wide Average NOX Emission Rate) in any calendar year (or ozone season, as applicable); or

(D) Fails by more than ninety days to complete installation of and commence timely year-round operation of any SCR or FGD required by Paragraphs 56 or 64 or Sections VIII or IX; or

(E) Fails to limit VEPCO System SO2 emissions to 203,693 tons or less in each calendar year starting with 2005 and thereafter;

then the United States may pursue any claims at any VEPCO System Unit otherwise resolved under Section XI, where the modification(s) on which such claim is based was commenced, under way, or completed within five years preceding the violation or failure specified in items (A) through (E) above, unless such modification was undertaken at an Improved Unit and commenced prior to the date of lodging of this Consent Decree.

111. Other Units. The resolution of claims of United States in Section XI shall not apply to claims arising from modifications at Other Units commenced less than five years prior to the occurrence of one or more of the following:

(A) a modification or (collection of modifications) commenced after lodging of this Decree at such Other Unit, individually (or collectively) increase the maximum hourly emission rate for such Unit for the relevant pollutant (NOx or SO2) as measured by 40 C.F.R. § 60.14(b) and (h); or

(B) the aggregate of all Capital Expenditures made at such Other Unit exceed $125/KW on the Unit's Boiler Island (based on the Maximum Dependable Capacity numbers in the North American Electric Reliability Council's Generating Availability

Database for the year 2002) during any of the following five-year periods: January 1, 2001, through December 31, 2005; January 1, 2006, through December 31, 2010; January 1, 2011, through December 31, 2015. (Capital Expenditures shall be measured in calendar year 2000 constant dollars, as adjusted by the McGraw-Hill Engineering News-Record Construction Cost Index); or

(C) modification(s) commenced after lodging of this Decree resulting in emissions increase(s) of the relevant pollutant that actually occurred from any such Other Unit, where such increase(s):

(1) present by themselves or in combination with other emissions or sources "an imminent and substantial endangerment" within the meaning of Section 303 of the Act, 42 U.S.C. § 7603; or

(2) cause or contribute to violation of a National Ambient Air Quality Standard in any Air Quality Control Area that is in attainment with that NAAQS; or

(3) cause or contribute to violation of a PSD increment; or

(4) cause or contribute to any adverse impact on any formally recognized air quality and related values in any Class I area.

112. Solely for purposes of Subparagraph 111(C), above: (i) the determination of whether emissions increase(s) of the relevant pollutant actually occurred at the Unit must take into account any emissions changes relevant to the modeling domain that have occurred or will occur under this Decree at other VEPCO System Units; and (ii) an emissions increase shall not be deemed to have actually occurred unless annual emissions of the relevant pollutant from all

VEPCO System Units at the plant at which such Unit is located (and treating Mount Storm and North Branch as a single plant for this purpose) have exceeded such plant's emissions of that pollutant after the lodging of this Consent Decree, as specified below:

Plant	SO2 Annual Emissions (tons)	NOX Annual Emissions (tons)
Bremo	13,463	4,755
Chesapeake	35,923	10,657
Chesterfield	75,330	15,858
Clover	Improved	10,076
Mt. Storm / North Branch	19,992	40,188
Yorktown	26,755	5,066

113. Introduction of any new or changed National Ambient Air Quality Standard shall not, standing alone, provide the showing needed under Subparagraph 111(C) (1)-(4) to pursue any claim resolved under Section XI.

114. Fuel Limit. The resolution of claims provided by Section XI shall not apply to any modification commenced on a Unit within five years prior to the date on which VEPCO:

(A) fires such Unit with any fuel or fuel mix that is either prohibited by applicable state law or that is not otherwise authorized by the relevant state; or

(B) increases the current (as of February 1, 2003) coal contracting bid specification or contract specifications that limit fuel sulfur content in securing coal for a Unit, as summarized in Appendix A. This Paragraph does not apply to VEPCO's use of: (i) a fuel or fuel mix specifically called for by this Decree, if any, or (ii) any coal in any coal-fired Unit regardless of the fuel's sulfur content, so long as such use occurs after the Unit is being served by an FGD or other control equipment that can maintain 95.0% Removal Efficiency for SO2, on a 30-day, rolling average basis.

115. Improved Units. The resolution of claims provided by Section XI shall not apply to a modification (or collection of modifications), if commenced after the lodging of this Decree at an Improved Unit, that individually (or collectively) increase the maximum hourly emission rate of that Unit for NO_x or SO_2 (as measured by 40 C.F.R. § 60.14 (b) and (h)) by more than ten percent (10%) of the maximum hourly emission rate for that Unit.

XIII. RESOLUTION OF PAST CLAIMS OF NEW YORK, NEW JERSEY, AND CONNECTICUT

116. The States of New York, New Jersey, and Connecticut agree that this Decree resolves all of the following civil claims that have been or could have been brought against VEPCO for violations at Units at Mount Storm, Chesterfield or Possum Point prior to the lodging of this Decree:

(A) The Prevention of Significant Deterioration or Non- Attainment provisions of Parts C and D of the Clean Air Act, 42 U.S.C. § 7401 *et seq.* and related state provisions; and(B) 40 C.F.R. § 60.1.

XIV. RESOLUTION OF CIVIL CLAIMS OF THE COMMONWEALTH OF VIRGINIA.

117. Claims Based on Modifications Occurring Before the Lodging of Decree. Subject to the specific limitations in this Section, entry of this Decree shall resolve all civil and administrative claims of the Commonwealth of Virginia that arose from any modification (physical change or change in the method of operation, including construction of any air pollution control project at any VEPCO System Unit) under applicable federal statutes (Section 7410 (a)(2)(C), Part C or D of Subchapter I of the Clean Air Act or 40 CFR Section 60.14) or applicable state regulations (Article 6 (9 VAC 5-80-1100 et seq.), Article 8 (9 VAC 5-80-1700 et seq.) or Article 9 (9 VAC 5-80-2000 et seq.) of Part II of 9 VAC 5 Chapter 80, and provisions of 9 VAC 5, Chapter 50, that are equivalent to 40 C.F.R. § 60.14(a)), and, as to the state regulations, all applicable predecessor regulations. This Paragraph shall apply to any modification commenced at any VEPCO System Unit located in the Commonwealth prior to the date of lodging of this Decree.

118. Claims Based on Modifications after the Lodging of Decree. Subject to the specific limitations in this Section, entry of this Decree shall also resolve all civil and administrative claims of the Commonwealth of Virginia arising from any modification (physical change or change in the method of operation, including construction of any air pollution control project at any VEPCO system Unit) under applicable federal statutes (Section 7410 (a)(2)(C), Part C or D of Subchapter I of the Clean Air Act) or applicable state regulations (Article 6 (9 VAC 5-80-

1100 et seq.), Article 8 (9 VAC 5-80-1700 et seq.) or Article 9 (9 VAC 5-80-2000 et seq.) of Part II of 9 VAC 5 Chapter 80 and any successor regulations). This Paragraph shall apply to any modification at any VEPCO System Unit located in the Commonwealth commenced on or after lodging of this Decree that is completed before December 31, 2015, or are those that this Consent Decree expressly directs VEPCO to undertake.

119. Reopener. The resolution of the civil claims of the Commonwealth of Virginia provided by this Section is subject to the provisions of Section XV.

120. General. Each term used in Paragraph 118 that is also a term used under the Clean Air Act shall mean what such term means under the Act as it existed on the date of lodging of this Decree.

121. Commonwealth's Authority Regarding NAAQS Exceedances. Nothing in this Section shall be construed to affect the Commonwealth's authority under applicable federal statutes and applicable state regulations to impose appropriate requirements or sanctions on any VEPCO System Unit when emissions from the plant at which such unit is located result in violation of, or interfere with the attainment and maintenance of, any ambient air quality standard, or the plant fails to operate in conformance with any applicable control strategy, including any emissions standards or emissions limitations.

122. Nothing in this Section shall prevent the Commonwealth from issuing to any VEPCO System Unit a permit under either Article 5 (9 VAC 5-80-800 et seq.) or Article 6 (9 VAC 5-80-1100 et seq.) for the purpose of preserving the terms and conditions of this Decree as applicable federal requirements upon the expiration of the Decree.

XV. REOPENING OF VIRGINIAS' CLAIMS RESOLVED BY SECTION XIV

123. Bases for Pursuing Resolved Claims Across VEPCO System. If VEPCO:

(A) Violates Paragraph 59(A) or (B) (VEPCO System-Wide, Interim Control of NOx Emissions, 2004 through 2007); or

(B) Violates Paragraph 60 (VEPCO System-Wide NOx Tonnage Limits 2003 and thereafter: Declining, System-Wide Tonnage Caps); or

(C) Violates Paragraph 61 (VEPCO System-Wide Average NOx Emission Rate) in any calendar year (or ozone season, as applicable); or

(D) Fails by more than ninety days to complete installation of and commence timely year-round operation of any SCR or FGD required by Paragraphs 56 or 64 or Sections VIII or IX; or

(E) Fails to limit VEPCO System SO2 emissions to 203,693 tons or less in each calendar year starting with 2005 and thereafter;

then the Commonwealth of Virginia may pursue any claims at any VEPCO System Unit located in the Commonwealth otherwise resolved under Section XIV, where the modification(s) on which such claim is based was commenced, under way, or completed within five years preceding the violation or failure specified above, unless such modification was undertaken at an Improved Unit and commenced prior to the date of lodging of this Consent Decree.

124. Other Units. The resolution of claims of the Commonwealth of Virginia in Section XIV shall not apply to claims arising from modifications at Other Units located in the Commonwealth commenced less than five years prior to the occurrence of one or more of the following:

(A) One or more modifications at such Other Unit commenced after lodging of this Decree, individually or collectively, increase the maximum hourly emission rate for such Unit for the relevant pollutant (NOx or SO2) as measured by 40 C.F.R. § 60.14(b) and (h); or

(B) The aggregate of all Capital Expenditures made at such Other Unit is in excess of $125/KW on the Unit's Boiler Island (based on the Maximum Dependable Capacity numbers in the North American Electric Reliability Council's Generating Availability Database for the year 2002) during any of the following five-year periods: January 1, 2001, through December 31, 2005; January 1, 2006, through December 31, 2010; January 1, 2011, through December 31, 2015. (Capital Expenditures shall be measured in calendar year 2000 constant dollars, as adjusted by the McGraw-Hill Engineering News-Record Construction Cost Index); or

(C) Modification(s) commenced after lodging of this Decree resulting in emissions increase(s) of the relevant pollutant that actually occurred from any such Other Unit, where such increase(s):

(1) present by themselves or in combination with other sources "an imminent and substantial endangerment" within the meaning of Section 303 of the Act, 42 U.S.C. § 7603; or

(2) cause or contribute to violation of a National Ambient Air Quality Standard in any Air Quality Control Area that is in attainment with that NAAQS; or

(3) cause or contribute to violation of a PSD increment; or

(4) cause or contribute to any adverse impact on any formally recognized air quality and related values in any Class I area.

Solely for purposes of this Subparagraph (C), (1) determination of whether there is an emissions increase that actually occurred resulting from modification(s) at the Unit must take into account any emissions changes relevant to the modeling domain that have occurred or will occur under this Decree at other VEPCO System Units; and (2) no such increase from a Unit will be deemed to have occurred if annual emissions of the relevant pollutant from all VEPCO System Units at the plant at which such Unit is located (and treating Mount Storm and North Branch as a single plant for this purpose) do not exceed such plant's emissions of that pollutant after lodging of this Consent Decree, as specified in Paragraph 112. Also, introduction of any new or changed National Ambient Air Quality Standard shall not, standing alone, provide the showing needed under this Subparagraph (C) (1)-(4) to pursue any claim resolved under Section XIV.

125. <u>Improved Units</u>. The resolution of claims provided by Section XIV shall not apply to a modification (or collection of modifications), if commenced after lodging of this Decree, at an Improved Unit located in the Commonwealth that individually (or collectively) increase the maximum hourly emission rate of that Unit for NO_x or SO_2 (as measured by 40 C.F.R. § 60.14 (b) and (h)) by more than ten percent (10%) of the maximum hourly emission rate for that Unit.

XVI. RESOLUTION OF CIVIL CLAIMS OF THE STATE OF WEST VIRGINIA

126. Claims Based on Modifications Occurring Before the Lodging of Decree. Subject to the specific limitations in this Section, entry of this Decree shall resolve all civil claims of the State of West Virginia that arose under applicable federal statutes and regulations (Section 7410 (a)(2)(C), Parts C or D of Subchapter I of the Clean Air Act or 40 CFR Section 60.14) or applicable state regulations (45CSR13, 45CSR14 and 45CSR19, as well as the provisions of 45CSR16 that are equivalent to 40 CFR Section 60.14(a)) and, as to the state regulations, all applicable predecessor regulations, from any modification (physical change or change in the method of operation, including but not limited to construction of any air pollution control project at any VEPCO System Unit). This Paragraph shall apply to any modification at any VEPCO System Unit located in West Virginia commenced prior to the date of lodging of this Decree.

127. Claims Based on Modifications after the Lodging of Decree. Subject to the specific limitations in this Section, entry of this Decree shall also resolve all civil claims of the State of West Virginia arising under applicable federal statutes (Section 7410 (a)(2)(C) and Parts C or D of Subchapter I of the Clean Air Act) or applicable state regulations (45CSR13, 45CSR14 and 45CSR19 and any successor regulations from any modification (physical change or change in the method of operation, including but not limited to construction of any air pollution control project at any VEPCO system Unit. This Paragraph shall apply to any modification at any VEPCO System Unit located in West Virginia commenced on or after the date of lodging of this Decree that is completed before December 31, 2015, or is among those that this Consent Decree expressly directs VEPCO to undertake.

128. Reopener. The resolution of the civil claims of the State of West Virginia provided by this Section is subject to the provisions of Section XVII.

129. General. Each term used in Paragraph 127 that is also a term used under the Clean Air Act shall mean what such term means under the Act as it existed on the date of lodging of this Decree.

130. West Virginia's Authority Regarding NAAQS Exceedances. Nothing in this Decree shall be construed to affect West Virginia's authority under applicable federal statutes and applicable state statutes or regulations to impose appropriate requirements or sanctions on any VEPCO System Unit when emissions from the plant at which such unit is located result in violation of, or interfere with the attainment and maintenance of, any ambient air quality standard, or the plant fails to operate in conformance with any applicable control strategy, including any emissions standards or emissions limitations.

131. Nothing in this Section shall prevent West Virginia from issuing to any VEPCO System Unit a permit under either 45CSR13 or 45CSR14) for the purpose of preserving the terms and conditions of this Decree as applicable federal requirements upon the expiration of the Decree.

XVII. REOPENING OF WEST VIRGINIA'S CLAIMS RESOLVED BY SECTION XVI.

132. Bases for Pursuing Resolved Claims Across VEPCO System. If VEPCO:

(A) Violates Paragraph 59(A) or (B) (VEPCO System-Wide, Interim Control of NOx Emissions, 2004 through 2007); or

(B) Violates Paragraph 60 (VEPCO System-Wide NOx Tonnage Limits 2003 and thereafter: Declining, System-Wide Tonnage Caps); or

(C) Violates Paragraph 61 (VEPCO System-Wide Average NOx Emission Rate) in any calendar year (or ozone season, as applicable); or

(D) Fails by more than ninety days to complete installation of and commence timely year-round operation of any SCR or FGD required by Paragraphs 56 or 64 or Sections VIII or IX; or

(E) Fails to limit VEPCO System SO2 emissions to 203,693 tons or less in each calendar year starting with 2005 and thereafter;

then the State of West Virginia may pursue any claims at any VEPCO System Unit located in the state otherwise resolved under Section AA, where the modification(s) on which such claim is based was commenced, under way, or completed within five years preceding the violation or failure specified above, unless such modification was undertaken at an Improved Unit and completed prior to the date of lodging of this Consent Decree.

133. Other Units. The resolution of claims of the State of West Virginia in Section AA shall not apply to claims arising from modifications at Other Units located in West Virginia commenced less than five years prior to the occurrence of one or more of the following:

(A) One or more modifications at such Other Unit, individually or collectively, increase the maximum hourly emission rate for such Unit for the relevant pollutant (NOx or SO2) as measured by 40 C.F.R. § 60.14(b) and (h); or

(B) The aggregate of all Capital Expenditures made at such Other Unit is in excess of $125/KW on the Unit's Boiler Island (based on the Maximum Dependable Capacity numbers in the North American Electric Reliability Council's Generating Availability Database for the year 2002) during any of the following five-year periods: January 1, 2001, through December 31, 2005; January 1, 2006, through December 31, 2010; January 1, 2011, through December 31, 2015. (Capital Expenditures shall be measured in calendar year 2000 constant dollars, as adjusted by the McGraw-Hill Engineering News-Record Construction Cost Index); or

(C) Modification(s) resulting in emissions increase(s) of the relevant pollutant that actually occurred from any such Other Unit, where such increase(s):

(1) present by themselves or in combination with other sources "an imminent and substantial endangerment" within the meaning of Section 303 of the Act, 42 U.S.C. § 7603; or

(2) cause or contribute to violation of a National Ambient Air Quality Standard in any Air Quality Control Area that is in attainment with that NAAQS; or

(3) cause or contribute to violation of a PSD increment; or

(4) cause or contribute to any adverse impact on any formally recognized air quality and related values in any Class I area.

Solely for purposes of this Subparagraph (C), (i) determination of whether there is an emissions increase that actually occurred resulting from modification(s) at the Unit must take into account any emissions changes relevant to the modeling domain that have occurred or will occur under this Decree at other VEPCO System Units; and (ii) no such increase from a Unit will be deemed to have occurred if annual emissions of the relevant pollutant from all VEPCO System Units at the plant at which such Unit is located (and treating Mount Storm and North Branch as a single plant for this purpose) do not exceed such plant's emissions of that pollutant, as specified in Paragraph 112. Also, introduction of any new or changed National Ambient Air Quality Standard shall not, standing alone, provide the showing needed under this Subparagraph (C) (1)-(4) to pursue any claim resolved under Section XVI.

134. Improved Units. The resolution of claims provided by Section XVI shall not apply to a modification (or collection of modifications), if commenced after lodging of this Decree, at an Improved Unit located in West Virginia that individually (or collectively) increase the maximum hourly emission rate of that Unit for NO_x or SO_2 (as measured by 40 C.F.R. § 60.14 (b) and (h)) by more than ten percent (10%) of the maximum hourly emission rate for that Unit.

XVIII. OTHER PROVISIONS ON ALLOWANCES AND CREDITS

135. NO_x Credits. For any and all actions taken by VEPCO to conform to the requirements of this Decree, VEPCO shall not use or sell any resulting NO_x emission allowances or credits in any emission trading or marketing program of any kind; provided, however that:

(A) NO_x emission allowances or credits allocated to the VEPCO System by the Administrator of EPA under the Act, or by any State under its SIP in response to the EPA NO_x SIP Call, or the EPA Section 126 Rulemaking, or any other similar emissions trading or marketing program of any kind, may be used by VEPCO and its parent company (Dominion Resources) or its subsidiaries or affiliates to meet their own federal and/or state Clean Air Act regulatory requirements for any air emissions source owned or operated, in whole or in part, by VEPCO or Dominion Resources, Inc. or its subsidiaries or affiliates and;

(B) VEPCO may trade in any federal or state program any NO_x emissions allowances which are generated from VEPCO's operating its SCRs, or equivalent control technology, at Chesterfield Units 4, 5, and 6; or Chesapeake Units 3 and 4; or any VEPCO System Unit on which SCR is installed under Section IX (Installing Additional Units on VEPCO System Units), either:

(1) Earlier than required by this Decree or other applicable law; or

(2) At time periods of the year not required by this Consent Decree or by applicable law; or

(3)At a 30-Day Rolling Average Emission Rate that is more stringent than required by this Decree.

(C) VEPCO may trade in any federal or state program NO_x emissions allowances which are generated from VEPCO's operating its SCRs, or equivalent control technology, at Mt. Storm Units 1, 2, and 3 as follows:

(1) 100% of NOx allowances generated earlier than required by this Decree or other applicable law; or

(2) 100% of NOx allowances generated at time periods of the year not required by this Consent Decree or by applicable law; or (3) 50% of NOx allowances generated by achieving a 30-Day Rolling Average Emission Rate more stringent than required by this Consent Decree. The remaining 50% of the NOx allowances generated may be used in accordance with Subparagraph A or be retired.

136. Netting Limits. Nothing in this Decree shall prevent VEPCO from claiming creditable contemporaneous emissions decreases from emission reductions effected by VEPCO prior to the June 30, 2001. For emission control actions taken by VEPCO to conform with the terms of this Consent Decree, including, but not limited to, improvements to ESPs and FGDs, installation of FGDs, installation of SCRs, and the fuel conversion of Possum Point Units 3 and 4, any emission reductions generated up to the level necessary to comply with the provisions of this Decree (and excluding simple control equipment operating requirements) shall not be considered as a creditable contemporaneous emission decrease for the purpose of obtaining a netting credit under the Act's New Source Review program; provided, however, that nothing in this Decree shall be construed to prohibit VEPCO's seeking such treatment for decreases in emissions resulting from VEPCO's ceasing combustion of coal at Possum Point Unit 3 or Possum Point Unit 4, if:

(A) Such decreases are used in VEPCO's demonstrating whether the conversion of Possum Point Units 3 and 4 (plus the installation of up to two new units 540 MW (nominal) each, combined cycle electric generating units at Possum Point) would result in a net significant emissions increase; and

(B) VEPCO either (i) installs and continuously operates LAER on Possum Point Units 3 or 4 or (ii) demonstrates that the use of natural gas will result in a net emissions decrease; and

(C) VEPCO also complies with the NOx emissions cap and other requirements in Paragraph 96 for Possum Point Units 3 and 4 under this Decree and also installs SCR controls for NO_x on the new combined cycle unit(s).

XIX. PERIODIC REPORTING

137. Compliance Report. After entry of this Decree, VEPCO shall submit to Plaintiffs a periodic report, in compliance with Appendix B, within sixty (60) days after the end of each half of the calendar year (January through June and July through December).

138. Deviations Report. In addition to the reports required by the previous paragraph, if VEPCO violates or deviates from any provision of this Consent Decree, VEPCO shall submit to Plaintiffs a report on the violation or deviation within ten (10) business days after VEPCO knew or should have known of the event. In the report, VEPCO shall explain the cause or causes of the violation or deviation and any measures taken or to be taken by VEPCO to cure the reported violation or deviation or to prevent such violation or deviations in the future. If at any time, the provisions of the Decree are included in Title V Permits, consistent with the requirements for such inclusion in the Decree, then the deviation reports required under applicable Title V regulations shall be deemed to satisfy all the requirements of this Paragraph.

139. VEPCO's reports (Periodic and Deviations) shall be signed by VEPCO's Vice President of Fossil and Hydro, or, in his or her absence, VEPCO's Vice President of Technical Services, or higher ranking official, and shall contain the following certification:

> I certify under penalty of law that this information was prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my directions and my inquiry of the person(s) who manage the system, or the person(s) directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I understand that there are significant penalties for making misrepresentations to or misleading the United States.

140. If any allowances are surrendered to any third party pursuant to Section VI the third

party's certification shall be signed by a managing officer of the third party's and shall contain the following language:

> I certify under penalty of law that _____________ [name of third party] will not sell, trade, or otherwise exchange any of the allowances and will not use any of the allowances to meet any obligation imposed by any environmental law. I understand that there are significant penalties for making misrepresentations to or misleading the United States.

XX. CIVIL PENALTY

141. Within thirty (30) calendar days of entry of this Consent Decree, VEPCO shall pay to the United States a civil penalty of $5.3 million. The civil penalty shall be paid by Electronic Funds Transfer ("EFT") to the United States Department of Justice, in accordance with current EFT procedures, referencing the USAO File Number ____________ and DOJ Case Number 90-5-2-1-07122 and the civil action case name and case number of this action. The costs of EFT shall be VEPCO's responsibility. Payment shall be made in accordance with instructions provided by the Financial Litigation Unit of the U.S. Attorney's Office for the Eastern District of Virginia. Any funds received after 11:00 a.m. (EST) shall be credited on the next business day. VEPCO shall provide notice of payment, referencing the USAO File Number, DOJ Case Number 90-5-2-1-07122, and the civil action case name and case number, to the Department of Justice and to EPA, as provided in Section XXIX, Paragraph 187 ("Notice"). Failure to timely pay the civil penalty shall subject VEPCO to interest accruing from the date payment is due until the date payment is made at the rate prescribed by 28 U.S.C. § 1961, and shall render VEPCO liable for all charges, costs, fees, and penalties established by law for the benefit of a creditor or of the United States in securing payment.

XXI. MITIGATION PROJECTS

142. General. VEPCO shall submit for review and approval plans for the completion of the Mitigation Projects described in this Section, complying with the schedules and other terms of this Consent Decree and plans for such Projects approved under this Decree. In performing these Projects, VEPCO shall spend no less than $13.9 million Project Dollars. VEPCO shall make available the full amount of the Project Dollars required by this Paragraph within one year of entry of this Decree. VEPCO shall maintain for review by the Plaintiffs, upon request, all documents identifying Project Dollars spent by VEPCO. All plans and reports prepared by VEPCO or by other persons pursuant to the requirements of this Section of the Consent Decree shall be publicly available from VEPCO, without charge. No Project Dollars may be made available or expended to undertake an obligation already required by law.

143. Good Faith. VEPCO shall use good faith efforts to secure as much benefit as possible for the Project Dollars expended, consistent with the applicable requirements and limits of this Decree.

144. Other Project Requirements. In addition to the requirements imposed for each Project specified in this Decree, including Appendix C and the approved plans, the following requirements shall apply. If VEPCO elects (where such election is allowed) to undertake a Project by contributing funds to another person or instrumentality to carry out the Project, that person or instrumentality must, in writing: (A) identify its legal authority for accepting such funding, and (B) identify its legal authority to conduct the Project for which VEPCO contributes the funds. Regardless of whether VEPCO elects (where such election is allowed) to undertake

the Project itself or to do so by contributing funds to another person or instrumentality that will carry out the Project, VEPCO acknowledges that it shall receive credit for expenditure of such funds as Project Dollars only in accordance with the approved plans. Provided however, that when VEPCO elects to undertake a Project by providing funds to a State or any instrumentality thereof, VEPCO shall receive credit for any timely expenditure of funds upon transfer of such funds to such State or instrumentality thereof, as long as the VEPCO provides payment in accordance with Appendix C and the approved plan. VEPCO shall certify, as part of the proposed plan submitted to the Plaintiffs for any contemplated Project, that no person is required by any law, other than this Consent Decree, to perform the Project described in the proposed plan. Within sixty (60) days following the completion of each approved Project, VEPCO shall submit to the Plaintiffs a report that documents the date that all aspects of the project were implemented, VEPCO's results in completing the project, including the emission reductions or other environmental or health benefits achieved, and the Project Dollars expended by VEPCO in implementing the Project. Based on consideration of these reports and the approved plans, and any other available, relevant information, the United States (after consultation with the other Plaintiffs) will advise VEPCO whether the Project has met the requirements of the Decree. VEPCO shall submit the required plans for, and complete, each Project, as approved by the United States, and by any other Plaintiff within whose territory a Project would be implemented, all as specified further in Appendix C to this Decree.

XXII. STIPULATED PENALTIES & ALLOWANCE OR CREDIT SURRENDERS

145. Within thirty (30) days after written demand from the United States, and subject to the provisions of Sections XXVI ("Force Majeure") and XXVII ("Dispute Resolution"), VEPCO shall pay the following stipulated penalties to the United States (and surrender the specified number of emission allowances or credits) for each failure by VEPCO to comply with the terms of this Consent Decree, as follows.

146. For each violation of each limit, rate or removal efficiency that is measured on a 30-day Rolling Average or shorter averaging period imposed on NO_x , SO_2, and PM under Sections IV, V, VII, VIII ("Possum Point"), and IX ("Installing Additional Controls on VEPCO System Units"):

(A) less than 5% in excess of the limit: $2,500 per day per violation;

(B) equal to or greater than 5% in excess of the limit: $5,000 per day per violation;

(C) equal to or greater than 10% in excess of the limit: $10,000 per day per violation.

(D) For failure to meet any VEPCO System-Wide emissions requirement (Paragraph 59(A) and (B) "VEPCO System: Interim Control of NOX Emissions: 2004 through 2007; Paragraph 60"VEPCO System NOX Limits 2003 and thereafter: Declining , System-Wide Tonnage Caps; and Paragraph 61 VEPCO System –Wide, Annual Average NOX Emission Rate): $5,000 per ton for the first 100 tons resulting from the violation, and $10,000 per ton for each additional ton resulting from the violation.

147. Other Specific Failures. For failure to:

(A) install timely and commence operation timely of SCR on each Unit (each SCR installation) specified in Section IV, Paragraph 56 ("Unit-Specific SCR Installations and Annual Performance Requirements"): (i) $10,000 per day, per violation, for the first 30 days; and (ii) $27,500 per day, per violation, thereafter.

(B) complete any FGD improvements or installation needed to meet emission limits imposed under Section V, Paragraph 64 ("Construction, Upgrading, and Removal Efficiencies Required or on FGDs Serving Clover Units 1 and 2, Mount Storm Unites 1, 2, and 3, and Chesterfield Units 5 and 6"): (i) $ 10,000 per day, per violation, for the first 30 days; and (ii) $20,000 per day, per violation, thereafter.

(C) surrender timely the annually-required 45,000 SO_2 Allowances surrender under Section VI: $27,500 per day, per violation plus the surrender 100 additional SO_2 Allowances per day per violation.

(D) timely transfer the annually-required surrender of 45,000 SO_2 Allowances by VEPCO to any third party under Section VI: $27,500 per day, per violation plus the surrender 100 additional SO_2 Allowances per day per violation.

(E) comply with any requirement in this Consent Decree regarding the use of any SO_2 or NO_x allowances or credits: surrender three times the allowances or credits handled in violation of the requirement.

(F) complete timely the proper installation of all equipment called for under Section VII (PM Emission Reductions and Controls) or under any plan or submission approved by EPA under Section VII: (i) $ 10,000 per day, per violation, for the first 30 days; and (ii) $20,000 per day, per violation, thereafter.

(G) conduct a required stack test of PM emissions on each VEPCO System Unit where such test is required under Section VII: $1,000 per day, per violation.

(H) Submit timely and complete reports called for under Section XIX ("Periodic Reporting"): $1,000 per day, per violation.

(I) Complete any funding for any of the Projects described in Section XXI (Mitigation Projects): $1,000 per day, per violation for the first 30 days; and $5,000 per day, per violation thereafter.

148. Violations of any limit based on a 30-Day Rolling Average constitutes thirty (30) days of violation but where such a violation (for the same pollutant and from the same Unit or source) recurs within periods less than thirty (30) days, VEPCO shall not be obligated to pay a daily stipulated penalty, for any day of the recurrence for which a stipulated penalty has already been paid.

XXIV. ACCESS, AND INFORMATION COLLECTION AND RETENTION

149. Access, Inspection, Investigation. Any authorized representative of EPA, including independent contractors, upon presentation of credentials, shall have a right of entry upon the premises of any facility in the VEPCO System at any reasonable time and for any reasonable purpose regarding monitoring compliance with the provisions of this Consent Decree, including inspecting plant equipment and inspecting and copying all records maintained by VEPCO required by this Consent Decree. VEPCO shall retain such records for a period of fifteen (15)

years from the date of entry of this Consent Decree. Nothing in this Consent Decree shall limit any information-gathering or inspection authority of EPA under the Act, including but not limited to Section 114 of the Act, 42 U.S.C. Section 7414.

XXV. COORDINATION OF ENFORCEMENT & DISPUTE RESOLUTION

150. United States - Enforcement and Dispute Resolution. The United States may enforce any and all requirements of this Decree and may invoke dispute resolution provisions of this Decree as to any requirement of this Decree to which dispute resolution applies and also may participate in adjudication of any claim of Force Majeure made by VEPCO or any other Party.

151. VEPCO - Dispute Resolution. VEPCO may invoke the dispute resolution provisions of this Decree over any requirement of this Decree to which dispute resolution applies.

152. States - Enforcement. Consistent with Section XXV, The State of New York, New Jersey, or Connecticut, or any combination of them, may enforce only the following requirements of this Decree:

(A) those requirements imposed directly on a Unit at Mount Storm, Chesterfield, and Possum Point;

(B) any or all of the following VEPCO System-Wide requirements: Section IV Paragraph 59 ("Interim NO_x Emissions for VEPCO System"), Paragraph 60 ("VEPCO System NO_x Declining Tonnage Caps") and Paragraph 61 ("NO_x System-Wide Average Emission Rate"] and Section VI, Paragraph 71 (Annual Surrender of SO_2 Allowances); and

(C) those requirements involving timely and proper performance of Decree-mandated mitigation projects (Section XXI and Appendix C).

153. The Commonwealth of Virginia and the State of West Virginia may enforce all of the requirements of this Decree applicable to VEPCO units within their respective jurisdictions, including the system-wide cap.

154. States - Dispute Resolution. The States of New York, New Jersey, Connecticut, Virginia, or West Virginia, or any combination of them, may invoke dispute resolution only over those Decree requirements that such State could enforce under this Decree and may participate as a plaintiff in any matter in which VEPCO asserts Force Majeure under this Decree only if the matter concerns a requirement which such State could have enforced under the terms of this Decree. Notwithstanding the preceding sentence, the States of New York, New Jersey, Connecticut, Virginia, or West Virginia, or any combination of them, may participate as a plaintiff in any matter in which VEPCO asserts force majeure under this Decree, to the extent that resolution of the legal issue(s) at stake in that matter would affect the ability of New York, New Jersey, Connecticut, Virginia, or West Virginia to enforce any of the requirements specified in Paragraphs 152 and 153_of this Section.

155. Consultation Among Plaintiffs. Absent exigent circumstances, the United States, New York, New Jersey, Connecticut shall consult prior to enforcing a requirement under this Decree or prior to invoking Dispute Resolution (Section) for any issue, which the given State could enforce under this Decree. Absent exigent circumstances, the United States, Virginia, and West Virginia shall consult prior to enforcing a requirement under this Decree or prior to invoking Dispute Resolution (Section XXVII) for any issue which the given State could enforce under this Decree. If such consultation reveals that, for any reason, the United States does not intend to

participate, in the first instance, in either the Decree enforcement or invocation of Dispute Resolution contemplated by New York, New Jersey, or Connecticut, Virginia, or West Virginia then the consultation required by this Section is not satisfied until after "Senior Management Level Officials" of United States consult with the "Senior Management Level Officials" of each Plaintiff intending to enforce a requirement under the Decree or to invoke dispute resolution under it. The United States shall undertake such consultation and shall complete it within twenty-eight (28) days after the consultation with the States and the United States demonstrates that the United States does not intend to participate in the activity contemplated by one or more of the States. Only for purposes of the consultation requirement of this Section, "Senior Management Level Official" means:

(A) For the United States: Director of the Office of Regulatory Enforcement, U.S. EPA Office of Enforcement and Compliance Assurance, and Chief of the Environmental Enforcement Section, U.S. DOJ Environment & Natural Resources Division;

(B) For New York: Chief of the Environmental Protection Bureau, Office of the Attorney General of the State of New York;

(C) For New Jersey: Assistant Attorney General in Charge of Environmental Protection, Office of the Attorney General of the State of New Jersey;

(D) For Connecticut: Director of the Environmental Department, Office of the Attorney General for the State of Connecticut;

(E) For Virginia: Director of the Environmental Unit, Special Prosecutions Section, Public Safety and Law Enforcement Division, Office of the Attorney General of the Commonwealth of Virginia; and

(F) For West Virginia: Director of the Division of Air Quality, West Virginia Department of Environmental Protection

156. Confirmation of Consultation. Contemporaneous with any filing to enforce the Decree or to invoke Dispute Resolution (Section XXVII), the moving Plaintiff shall serve on VEPCO a written statement noting that the consultation required by this Section has been completed, unless Plaintiff is relying on the "exigent circumstances" exception of this Section. If a Plaintiff invokes the "exigent circumstances" exception in lieu of completing this consultation process, that Plaintiff must then serve on VEPCO an explanation of the need for acting in advance of completing such consultation. "Exigent" is intended to have its normal meaning when used in this Section of the Decree, and reliance by a Plaintiff on this exception is subject to review by the Court.

XXVI. FORCE MAJEURE

157. General. If any event occurs which causes or may cause a delay in complying with any provision of this Consent Decree or causes VEPCO to be in violation of any provision of this Decree, VEPCO shall notify the Plaintiffs in writing as soon as practicable, but in no event later than ten (10) business days following the date VEPCO first knew, or within ten (10) business days following the date VEPCO should have known by the exercise of due diligence, that the event caused or may cause such delay or violation, whichever is earlier. In this notice, VEPCO shall reference this Paragraph of this Consent Decree and describe the anticipated length of time the delay or violation may persist, the cause or causes of the delay or violation, the measures taken or to be taken by VEPCO to prevent or minimize the delay or violation, and the schedule by which those measures will be implemented. VEPCO shall

adopt all reasonable measures to avoid or minimize such delays and prevent such violations.

158. Failure of Notice. Failure by VEPCO to comply with the notice requirements of this Section shall render this Section voidable by the Plaintiffs authorized under Sections XXV (Coordination of Enforcement and Dispute Resolution) to enforce a Consent Decree requirement against which VEPCO could interpose the force majeure assertion in question. If voided, the provisions of this Section shall have no effect as to the particular event involved.

159. Plaintiffs' Response. The Plaintiffs authorized under Sections XXV (Coordination of Enforcement and Dispute Resolution) to enforce a Consent Decree requirement against which VEPCO could interpose the force majeure assertion in question shall notify VEPCO, in writing, regarding VEPCO's claim of a delay in performance or violation within fifteen (15) business days after completion of procedures specified in Section XXV ("Enforcement Coordination"). If the Plaintiffs agree that the delay in performance or the violation has been or will be caused by circumstances beyond the control of VEPCO, including any entity controlled by VEPCO, and that VEPCO could not have prevented the delay through the exercise of due diligence, the parties shall stipulate to such relief as appropriate, which shall usually be an extension of the required deadline(s) for every requirement affected by the delay for a period equivalent to the delay actually caused by such circumstances. Such stipulation shall be filed as a modification to this Consent Decree in order to be effective. VEPCO shall not be liable for stipulated penalties for the period of any such delay.

160. Disagreement. If the Plaintiffs authorized under Sections XXV (Coordination of Enforcement and Dispute Resolution) to enforce a Consent Decree requirement against which VEPCO could interpose the force majeure assertion in question, do not accept VEPCO's claim

that a delay or violation has been or will be caused by a Force Majeure event, or do not accept VEPCO’s proposed remedy, to avoid the imposition of stipulated penalties VEPCO must submit the matter to this Court for resolution by filing a petition for determination. Once VEPCO has submitted the matter, the United States, and other Plaintiffs as provided in Paragraph 159, shall have fifteen (15) business days to file a response(s). If VEPCO submits the matter to this Court for resolution, and the Court determines that the delay in performance or violation has been or will be caused by circumstances beyond the control of VEPCO, including any entity controlled by VEPCO, and that VEPCO could not have prevented the delay or violation by the exercise of due diligence, VEPCO shall be excused as to that event(s) and delay (including stipulated penalties otherwise applicable), but only for the period of time equivalent to the delay caused by such circumstances.

161. Burden of Proof. VEPCO shall bear the burden of proving that any delay in performance or violation of any requirement of this Consent Decree was caused by or will be caused by circumstances beyond its control, including any entity controlled by it, and that VEPCO could not have prevented the delay by the exercise of due diligence. VEPCO shall also bear the burden of proving the duration and extent of any delay(s) or violation(s) attributable to such circumstances. An extension of one compliance date based on a particular event may, but will not necessarily, result in an extension of a subsequent compliance date.

162. Events Excluded. Unanticipated or increased costs or expenses associated with the performance of VEPCO's obligations under this Consent Decree shall not constitute circumstances beyond the control of VEPCO or serve as a basis for an extension of time under this Section. However, failure of a permitting authority to issue a necessary permit in a timely

fashion may constitute a Force Majeure event where the failure of the permitting authority to act is beyond the control of VEPCO, and VEPCO has taken all steps available to it to obtain the necessary permit, including, but not limited to, submitting a complete permit application, responding to requests for additional information by the permitting authority in a timely fashion, accepting lawful permit terms and conditions, and prosecuting appeals of any allegedly unlawful terms and conditions imposed by the permitting authority in an expeditious fashion.

163. Potential Force Majeure Events. The parties agree that, depending upon the circumstances related to an event and VEPCO's response to such circumstances, the kinds of events listed below could qualify as Force Majeure events: construction, labor, or equipment delays; acts of God; Malfunction for PM as malfunction is defined in 40 C.F.R. 60.2; and orders by governmental officials, acting under and authorized by applicable law, that direct VEPCO to supply electricity in response to a legally declared, system-wide (or state-wide) emergency.

164. Prohibited Inferences. Notwithstanding any other provision of this Consent Decree, this Court shall not draw any inferences nor establish any presumptions adverse to any party as a result of VEPCO delivering a notice pursuant to this Section or the parties' inability to reach agreement on a dispute under this Part.

165. Extended Schedule. As part of the resolution of any matter submitted to this Court under this Section, the Parties by agreement with approval from this Court, or this Court by order, may, as allowed by law, extend the schedule for completion of work under this Consent Decree to account for the delay in the work that occurred as a result of any delay or violation. VEPCO shall be liable for stipulated penalties for its failure thereafter to complete the work in accordance with the extended schedule.

XXVII. DISPUTE RESOLUTION

167. Scope of Disputes Covered and Eligibility of Parties to Participate. The dispute resolution procedure provided by this Section shall be available to resolve all disputes arising under this Consent Decree, except as provided in Section XXVI ("Force Majeure") or in this Section, provided that the Party making such application has made a good faith attempt to resolve the matter with the other Parties. Invocation and participation of this Section also shall be done in compliance with Section XXV ("Coordination of Enforcement and Dispute Resolution").

168. Invocation of Procedure. The dispute resolution procedure required herein shall be invoked by one Party to this Consent Decree giving written notice to another advising of a dispute pursuant to this Section. The notice shall describe the nature of the dispute and shall state the noticing party's position with regard to such dispute. The Party receiving such a notice shall acknowledge receipt of the notice, and the parties shall expeditiously schedule a meeting to discuss the dispute informally not later than fourteen (14) days following receipt of such notice.

169. Informal Phase. Disputes submitted to dispute resolution under this Section shall, in the first instance, be the subject of informal negotiations among the parties. Such period of informal negotiations shall not extend beyond thirty (30) calendar days from the date of the first meeting among the Parties' representatives unless they agree to shorten or extend this period.

170. Formal Phase. If the Parties are unable to reach agreement during the informal negotiation period, the Plaintiffs, shall provide VEPCO with a written summary of their position regarding the dispute. The written position provided by the Plaintiffs shall be considered binding unless, within thirty (30) calendar days thereafter, VEPCO files with this Court a petition that

describes the nature of the dispute and seeks resolution. The Plaintiffs may respond to the petition within forty-five (45) calendar days of filing. Where the nature of the dispute is such that a more timely resolution of the issue is required, the time periods set out in this Section may be shortened upon successful motion of one of the parties to the dispute.

171. Prohibited Inference. This Court shall not draw any inferences nor establish any presumptions adverse to either party as a result of invocation of this Section or the parties' inability to reach agreement.

172. Alteration of Schedule. As part of the resolution of any dispute under this Section, in appropriate circumstances the parties may agree, or this Court may order if warranted by law, an extension or modification of the schedule for completion of work under this Consent Decree to account for the delay that occurred as a result of dispute resolution. VEPCO shall be liable for stipulated penalties for its failure thereafter to complete the work in accordance with the extended or modified schedule.

173. Applicable Standard of Law. The Court shall decide all disputes pursuant to applicable principles of law for resolving such disputes; provided, however, that the parties reserve their rights to argue for what the applicable standard of law should be for resolving any particular dispute. Notwithstanding the preceding sentence of this Paragraph, as to disputes involving the submittal for review and approval under Section VII, the Court shall sustain the position of the United States as to disputes involving PM CEMs, any Pollution Control Upgrade Analysis, and optimization measures for PM that should be undertaken – unless VEPCO demonstrates that the position of the United States is arbitrary or capricious.

XXVIII. SALES OR TRANSFERS OF OWNERSHIP INTERESTS

174. Joint and Several Liability By Transfer of Certain VEPCO Property. If VEPCO proposes to sell or transfer any of its real property or operations subject to this Consent Decree, VEPCO shall advise the purchaser or transferee in writing of the existence of this Consent Decree prior to such sale or transfer, and shall send a copy of such written notification to the Plaintiffs pursuant to Section XXIX, Paragraph 187 ("Notices") at least sixty (60) days before such proposed sale or transfer. Before closing such purchase or transfer, a modification of this Consent Decree shall make the purchaser or transferee a party defendant to this Decree and jointly and severally liable with VEPCO for all the requirements of this Decree that may be applicable to the transferred or purchased property or operations, including joint and several liability with VEPCO for all Unit-specific requirements and all VEPCO System-Wide requirements, namely: VEPCO System-Wide Annual Average Emission Rate for NO_x (Section IV), SO_2 Allowance surrenders (Section VI), and VEPCO System NO_x annual tonnage caps (Section IV) .

175. Option for Alternative Request on System-Wide obligations. VEPCO may propose and the United States may agree to restrict the scope of joint and several liability of any purchaser or transferee for any VEPCO System-Wide obligations to the extent such obligations may be adequately separated in an enforceable manner using the methods provided by or approved under Section X ("Permits").

176. Option for Alternative Request on Particular VEPCO System Units. VEPCO also may propose, and the United States may agree to execute, a modification that transfers responsibility for completing Decree-required capital improvements from VEPCO to the

purchaser of property at which the capital improvement is required.

177. Standard for Reviewing a VEPCO Request. Liability transfers sought by VEPCO under this Section of the Decree shall be granted by the United States (or by all the Plaintiffs, as applicable) if the relevant Plaintiffs agree that:

(A) The purchaser or transferee has appropriately contracted with VEPCO to assume the obligations and liabilities applicable to the Unit; and

(B) VEPCO and the purchaser or transferee have properly allocated any emission allowance, credit requirement, or other Decree-imposed obligation on the VEPCO System, which also implicates the Unit to be transferred.

In the case of transfers of VEPCO System Units at Chesterfield and/or Mount Storm, VEPCO's scope of liability for either VEPCO System-Wide requirements or for Decree-required capital improvement on Units at those plants shall not be transferred unless the States of New York, New Jersey, and Connecticut concur with the United States' determination to accept liability of only the purchaser or transferee, as opposed to joint and several liability between VEPCO and the purchaser.

178. No limit on contractual allocation of responsibility that does not affect rights of the Plaintiffs. This Section of the Decree shall not be construed to impede VEPCO and any purchaser or transferee of real property or operations subject to this Decree from contractually allocating as between themselves the burdens of compliance with this Decree, provided that both VEPCO and such purchaser or transferee shall remain jointly and severally liable to the Plaintiffs for those obligations of the Decree specified above, absent approval under this Section of a VEPCO request to allocate liability.

XXIX. GENERAL PROVISIONS

179. Effect of Settlement. This Consent Decree is not a permit; compliance with its terms does not guarantee compliance with all applicable Federal, State, or Local laws or regulations.

180. Criminal Liability. This Consent Decree does not apply to any claim(s) of alleged criminal liability, which are reserved, nor to any claims resolved and then reopened under the terms of this Decree.

181. Limitation on Procedural Bars to Other Claims. In any subsequent administrative or judicial action initiated by Plaintiffs for injunctive relief or civil penalties relating to the facilities covered by this Consent Decree, VEPCO shall not assert any defense or claim based upon principles of waiver, res judicata, collateral estoppel, issue preclusion, claim splitting, or other defense based upon any contention that the claims raised by the Plaintiffs in the subsequent proceeding were brought, or should have been brought, in the instant case; provided, however, that nothing in this Paragraph is intended to affect the validity of Sections XI through XVII (Resolution of Certain Civil Claims).

182. Other Laws. Except as specifically provided by this Consent Decree, nothing in this Consent Decree shall relieve VEPCO of its obligation to comply with all applicable Federal, State, and Local laws and regulations. Subject to Sections XI through XVII, nothing contained in this Consent Decree shall be construed to prevent or limit the Plaintiffs' rights to obtain penalties or injunctive relief under the Clean Air Act or other federal, state, or local statutes or

regulations.

183. Third Parties. This Consent Decree does not limit, enlarge, or affect the rights of any party to this Consent Decree as against any third parties.

184. Costs. Each party to this action shall bear its own costs and attorneys' fees.

185. Public Documents. All information and documents submitted by VEPCO to the United States or the other Plaintiffs under this Consent Decree shall be subject to public inspection, unless subject to legal privileges or protection or identified and supported as business confidential, under applicable law. VEPCO may not seek such protection concerning submittals required by the Decree that concern mitigation projects (Section XXI).

186. Public Comment. The parties agree and acknowledge that final approval by the United States and entry of this Consent Decree is subject to the policy statement reproduced at Title 28 C.F.R. § 50.7, which provides for notice of the lodging of this Consent Decree in the Federal Register, an opportunity for public comment, and the right of the United States to withdraw or withhold consent if the comments disclose facts or considerations which indicate that the Consent Decree is inappropriate, improper, or inadequate.

187. Notice. Unless otherwise provided herein, notifications to or communications with the Plaintiffs or VEPCO shall be deemed submitted on the date they are postmarked and sent either by overnight mail, return receipt requested, or by certified or registered mail, return receipt requested. Except as otherwise provided herein, when written notification to or communication with the Plaintiffs or VEPCO is required by the terms of this Consent Decree, it shall be addressed as follows:

For the United States of America:

Chief
Environmental Enforcement Section
U.S. Department of Justice
P.O. Box 7611, Ben Franklin Station
Washington, D.C. 20044-7611
DJ# 90-5-2-1-07122

– and –

Director, Air Enforcement Division
Office of Enforcement and Compliance Assurance
U.S. Environmental Protection Agency
Ariel Rios Building [2242A]
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

– and –

Regional Administrator
U.S. EPA Region III
1650 Arch Street
Philadelphia, PA 19106

For Commonwealth of Virginia:
Director
Virginia Department of Environmental Quality
629 East Main Street
P.O. Box 10009
Richmond, VA 23240-0009

For State of West Virginia:
Director, Division of Air Quality
Department of Environmental Protection
7012 MacCorkle Avenue SE
Charleston, WV 25304

For State of New York:
Bureau Chief
Environmental Protection Bureau
New York Attorney General's Office

120 Broadway
New York, New York 10271

For State of New Jersey:
Administrator
Air and Environmental Quality Compliance and Enforcement
P.O. Box 422
401 East State Street, Floor 4
Trenton, NJ 08625

– and –

Section Chief
Environmental Enforcement
Division of Law
P.O. Box 093
25 Market Street, 7th Floor
Trenton, NJ 08625

For State of Connecticut:
Department Head
Environmental Protection Department
Connecticut Attoreny General's Office
55 Elm Street
Hartford, CT 06106

For VEPCO:
Senior Vice President – Fossil and Hydro
Dominion Energy – Dominion Generation
5000 Dominion Boulevard
Glenn Allen, VA 23060

Any Party may change either the notice recipient or the address for providing notices to it by serving all other parties with a notice setting forth such new notice recipient or address.

188. Procedure for Modification. There shall be no modification of this Decree unless such modification is in writing , is filed with the Court, and either:

(a) bears the written approval of all of the Parties and is approved by the Court, or

(b) is otherwise allowed by applicable law.

189. Continuing Jurisdiction. The Court shall retain jurisdiction of this case after entry of this Consent Decree to enforce compliance with the terms and conditions of this Consent Decree and to take any action necessary or appropriate for its interpretation, construction, execution, or modification. During the term of this Consent Decree, any party may apply to the Court for any relief necessary to construe or effectuate this Consent Decree.

190. Complete Agreement. This Consent Decree constitutes the final, complete, and exclusive agreement and understanding among the parties with respect to the settlement embodied in this Consent Decree. The parties acknowledge that there are no representations, agreements, or understandings relating to the settlement other than those expressly contained in this Consent Decree, including Appendices A ("Coal-Fired Steam-Electric Generating Units Constituting the VEPCO System"), B ("Consent Decree Reporting Form"), and C ("Mitigation Projects that Shall be Completed Under this VEPCO Consent Decree"). Appendices A through C are incorporated into and part of this Consent Decree

191. Non-Severability Absent Re-Adoption by the Parties. If this Consent Decree, in whole or in part, is held invalid by a court vested with jurisdiction to make such a ruling, and if such ruling becomes a final judgment, then after entry of such final judgment, no Party shall be bound to any undertaking that would come due or have continued under this Decree after the date of that final judgment, and the Decree shall be void from the entry of such final judgment. At any time, upon consent of all the Parties, the Parties may preserve that portion of this Decree not held invalid by agreeing, in a writing submitted to this Court, to keep in force that portion of this Decree not held invalid.

192. Citations to Law. Except as expressly provided otherwise by this Decree,

provisions of law expressly cited by this Decree shall be construed to mean the provision cited as it is defined under law.

193. Meaning of Terms. Every term expressly defined by this Decree shall have the meaning given to that term by this Decree, and every other term used in this Decree that is a term used under the Act or the regulations implementing the Act shall mean in this Decree what such term means under the Act or those regulations.

194. Calculating and Measuring Performance. Performance standards, emissions limits, and other quantitative standards set by or under this Decree must be met to the number of significant digits in which the standard or limit is expressed. Thus, for example, an Emissions Rate of 0.090 is not met if the actual Emissions Rate is 0.091. VEPCO shall round the fourth significant digit to the nearest third significant digit, or the third significant digit to the second significant digit, depending upon whether the limit is expressed to two or three significant digits. Thus, for example, if an actual Emissions Rate is 0.0904, that shall be reported as 0.090, and shall be in compliance with an Emissions Rate of 0.090, and if an actual Emissions Rate is 0.0905, that shall be reported as 0.091, and shall not be in compliance with an Emissions Rate of 0.090. VEPCO shall collect and report data to the number of significant digits in which the standard or limit is expressed. As otherwise applicable and unless this Decree expressly directs otherwise, the calculation and measurement procedures established under 40 C.F.R. Parts 75 and 76 apply to the measurement and calculation of NO_x and SO_2 under this Decree.

195. Independent Requirements. Each limit and / or other requirement established by or under this Decree is a separate, independent requirement.

196. Written Statements to be Sent to all Plaintiffs. Notwithstanding any other

provision of this Decree, VEPCO shall supply to all Parties to this Decree all notices, reports, applications, elections, and any other written statement that the Decree requires VEPCO to supply to any Party to the Decree.

197. Applicable Law on Data Use Still Applies. Nothing in this Consent Decree alters or waives any applicable law (including, but not limited to, any defenses, entitlements, or clarifications related to the Credible Evidence Rule (62 Fed. Reg. 8314, Feb. 27, 1997)) concerning use of data for any purpose under the Act, generated by the reference methods specified herein or otherwise.

XXX. CONDITIONAL TERMINATION OF ENFORCEMENT, CONTINUATION OF TERMS, AND FIRST RESORT TO TITLE V PERMIT

198. Termination as to Completed Tasks. As soon as VEPCO completes any element of construction required by this Decree or completes any requirement that will not recur, VEPCO may seek termination of that portion of the Decree that dictated such requirement.

199. Conditional Termination of Enforcement through Consent Decree. Once VEPCO:

(A) believes it has successfully completed and commenced successful operation of all pollution controls (new and upgrades) required by Decree;

(B) holds final, Title V Permits -- covering all Units in the VEPCO System -- that include as enforceable permit terms all of the performance and other requirements for the VEPCO System as required by Section X ("Permits"), and

(C) certifies that the date is later than December 31, 2015;

then VEPCO may file a notice with the Court of these facts. Unless within forty-five

(45) days after VEPCO files such a notice, any Plaintiff objects to the accuracy of that notice, enforcement based on Decree violations that occurred after the filing of the notice shall be through the applicable Title V Permit and not through this Decree.

200. Resort to Enforcement under this Consent Decree. Notwithstanding paragraph 199, if enforcement of a provision of this Decree cannot be pursued by a party under the applicable Title V permit, or if a Decree requirement was intended to be part of the Title V Permit and did not become or remain part of such permit, then such requirement may be enforced under the terms of this Decree at any time.

SO ORDERED, THIS _________ DAY OF _______________, 2003.

____
UNITED STATES DISTRICT COURT JUDGE

FOR THE UNITED STATES OF AMERICA:

____
THOMAS L. SANSONETTI
Assistant Attorney General
Environmental and Natural Resources Division
United States Department of Justice

____
THOMAS A. MARIANI
Assistant Chief
Environmental Enforcement Section
Environmental and Natural Resources Division
United States Department of Justice

JOHN PETER SUAREZ
Assistant Administrator
Office of Enforcement and Compliance Assurance
United States Environmental Protection Agency

BRUCE C. BUCKHEIT
Director, Air Enforcement Division
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RICHARD ALONSO
Attorney Advisor
Air Enforcement Division
Office of Enforcement and Compliance Assurance
United States Environmental Protection Agency

DONALD S. WELSH
Regional Administrator
Region 3
United States Environmental Protection Agency

FOR THE STATE OF NEW YORK:

____

ELLIOT SPITZER
Attorney General
State of New York

FOR THE STATE OF NEW JERSEY:

____
PETER C. HARVEY
Acting Attorney General of New Jersey

FOR THE STATE OF CONNECTICUT:

____

RICHARD BLUMENTHAL
Attorney General
State of Connecticut

____

CARMEL A. MOTHERWAY
Assistant Attorney General
State of Connecticut

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KIMBERLY P. MASSICOTTE
Assistant Attorney General
State of Connecticut

FOR THE COMMONWEALTH OF VIRGINIA:

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ROGER L. CHAFFE
Senior Assistant Attorney General
Commonwealth of Virginia

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ROBERT G. BURNLEY
Director
Department of Environmental Quality
Commonwealth of Virginia

FOR THE STATE OF WEST VIRGINIA:

____

JOHN BENEDICT
Director
Division of Air Quality
West Virginia Department of Environmental Protection

____

ROLAND T. HUSON, III
Senior Counsel
Office of Legal Services
West Virginia Department of Environmental Protection

FOR VIRGINIA ELECTRIC AND POWER COMPANY:

____

EDWARD RIVAS
Sr. Vice President
Fossil and Hydro
Virginia Electric and Power Company

APPENDIX A TO "VEPCO" CONSENT DECREE
THE UNITS COMPRISING THE "VEPCO SYSTEM" IN
UNITED STATES, ET AL. V. VIRGINIA ELECTRIC AND POWER CO.

Steam Electric Generating Unit: Plant Name, Unit Number, Unit Abbreviation, & Nominal Nameplate ("MW")	Improved Unit for SO_2 Under Decree Paragraph 64	Improved Unit for NO_x Under Decree Paragraph 56	Optimization for PM Required under Decree Section VII
Bremo Unit 3 ("BR 3") 69 MW	NO	NO	YES
Bremo Unit 4 ("BR 4") 185 MW	NO	NO	YES
Chesapeake Unit 1 ("CEC 1") 112 MW	NO	NO	YES
Chesapeake Unit 2 ("CEC 2") 112 MW	NO	NO	YES
Chesapeake Unit 3 ("CEC 3") 185 MW	NO	YES	YES
Chesapeake Unit 4 ("CEC 4") 239 MW	NO	YES	YES
Clover Unit 1 ("CL 1") 393 MW	YES	NO	YES
Clover Unit 2 ("CL 2") 393 MW	YES	NO	YES
Chesterfield Unit 3 ("CH 3") 112 MW	NO	NO	YES
Chesterfield Unit 4 ("CH 4") 187 MW	NO	YES	YES
Chesterfield Unit 5 ("CH 5") 359 MW	YES	YES	YES
Chesterfield Unit 6 ("CH 6") 694 MW	YES	YES	YES

APPENDIX A (continued)			
Steam Electric Generating Unit: Plant Name, Unit Number, Unit Abbreviation, & Nominal Nameplate ("MW")	Improved Unit for SO_2 Under Decree Paragraph 64	Improved Unit for NO_x Under Decree Paragraph 56	Optimization for PM Required under Decree Section VII
Mt. Storm Unit 1 ("MS 1") 551 MW	YES	YES	YES
Mt. Storm Unit 2 ("MS 2") 551 MW	YES	YES	YES
Mt. Storm Unit 3 ("MS 3") 552 MW	YES	YES	YES
North Branch ("NB") 92 MW	NO	NO	YES
Possum Point Unit 3 ("PP 3") 114 MW	YES	YES	NO
Possum Point Unit 4 ("PP 4") 239 MW	YES	YES	NO
Yorktown Unit 1 ("YT 1") 187 MW	NO	NO	YES
Yorktown Unit 2 ("YT 2") 187 MW	NO	NO	YES

Appendix A: Coal Specifications for Sulfur

Unit	Fuel SO2 Specification (lbs SO2/mmBtu)	Fuel Sulfur Specification (lbs S/mmBtu)	Fuel Sulfur Specification (% by weight)
Bremo Unit 3	2.64		
Bremo Unit 4	2.64		
Chesapeake Unit	2.64		
Chesapeake Unit	2.64		
Chesapeake Unit	2.64		
Chesapeake Unit	2.64		
Chesterfield Unit	2.64		
Chesterfield Unit	2.64		
Chesterfield Unit	2.64		
Chesterfield Unit	2.64		
Clover Unit 1	N/A		
Clover Unit 2	N/A		
Mt. Storm Unit 1		1.9	
Mt. Storm Unit 2		1.9	
Mt. Storm Unit 3		1.9	
North Branch			4
Possum Point	N/A		
Possum Point	N/A		
Yorktown Unit 1	2.64		
Yorktown Unit 2	2.64		

APPENDIX B - REPORTING REQUIREMENTS

VEPCO shall submit its semi-annual report as required by Paragraph 137 electronically and in hard copy form. Each semi-annual report shall be certified as required by Paragraph 139 of this Consent Decree. The semi-annual report is in addition to all other notices and reporting obligations under the Consent Decree. VEPCO shall provide the following information in each of the required semi-annual reports:

I. NO_x Reporting Requirements

A. Installation and Seasonal/Annual Operation of SCRs

1. The progress of construction (such as, if construction is not underway, the construction schedule, dates of contract execution, major component delivery, and, if construction is underway, the estimated percent of installation and estimated construction completion date) and, once construction is complete, the date of final installation and of acceptance testing under the SCR contract, of SCR controls required under Paragraph 56 of the Consent Decree.

2. Commencing when 30-Day Rolling Average Emission Rates become applicable, the 30-Day Rolling Average Emission Rate (lbs/mmBTU) as defined in Paragraph 5, for each operating day for each Unit utilizing SCRs required under Paragraph 56 of the Consent Decree.

3. Within the first report that identifies a 30-Day Rolling Average Emission Rate (lbs/mmBTU) for each SCR, at least five (5) example calculations (including raw CEM data in electronic format for the calculation) used to determine the 30-Day Rolling Average Emission Rate. If at any time VEPCO changes any aspect within the methodology used in determining the 30-Day Rolling Average Emission Rate, VEPCO shall explain the change and the reason for using the new methodology.

4. All instances, and explain events, that cause deviations from any 30-Day Rolling Average Emission Rate in lbs/mmBTU required in Paragraph 56. VEPCO shall identify any corrective actions taken in response to such deviation.

5. A description of the how VEPCO met the SCR performance efforts required in Paragraph 57 (Best Efforts).

B. Interim Control of NO_x Emissions

1. In addition to the notice required under paragraph 59, within each semi-annual report covering activities in 2004 through 2007, identify the compliance option selected as between Paragraph 59(A) and 59(B) for that given year and

the date that the notification required in Paragraph 59 was submitted to the Plaintiffs, if any such notification is required under Paragraph 59.

2. If VEPCO implements option (A) under Paragraph 59, report which Unit or Units will utilize year-round SCR control(s) and the amount of MW represented by the identified Units and report for each Unit controlled with year-round SCR the 30-Day Rolling Average Emission Rate (lbs/mmBTU) as defined in Paragraph 5 for each operating day.

3. If VEPCO implements option (B) under Paragraph 59, the Seasonal System-Wide Emission Rate (lbs/mmBTU) as defined in Paragraph 44, within the first report that identifies a Seasonal System Wide Emission Rate, provide at least five (5) example calculations (including raw CEM data in electronic format for the calculations) used to determine the Seasonal System Wide Emission Rate. If at any time VEPCO changes any aspect within the methodology used in determining the Seasonal System-Wide Emission Rate, VEPCO shall explain the change and the reason for using the new methodology.

C. Annual NO_x System-Wide Requirements

1. Within the last report for any given year for which a report is due, report the total NO_x emissions from the VEPCO System, and for each VEPCO System Unit, for the calendar year covered by the report as tons per year.

2. Within the last report for any given year for which a report is due, commencing in 2013, report the System Wide Annual Emission Rate and the underlying calculation for the VEPCO System for the previous calendar year (starting with the year 2013) as lbs/mmBTU.

D. Miscellaneous NO_x Provisions

1. For each Unit in the "VEPCO System" that utilizes SCR control pursuant to a requirement of the Consent Decree, all NO_x emissions (in tons) excluded from any NO_x emission calculation, as permitted in Paragraph 5 and an explanation for excluding such emission, as specified in subparagraph 2, below. The requirement to report tons of emissions excluded, but no other provisions, shall expire on December 31, 2015.

2. Commencing when any VEPCO System Unit becomes subject to a 30-Day Rolling Average Emissions Rate for NO_x and utilizes an SCR pursuant to a requirement of the Consent Decree, VEPCO shall report:

    a. The date and time that the fire is extinguished;

b. The date and time that the Unit is restarted and the date and time that the Unit is synchronized with an utility electric distribution system after the restart;

c. The NO_x emissions emitted by the Unit prior to the time that the Unit was synchronized with an utility electric distribution system;

d. On the fifth and subsequent Cold Start Up Periods that occur within any 30-Day period, the earlier of the date and time that (1) is eight hours after the Unit is synchronized with a utility electric distribution system, or (2) the flue gas has reached the SCR operational temperature as specified by the catalyst manufacturer;

e. The NO_x emissions emitted during the fifth and subsequent Cold Start Up Periods;

f. Identification of the date, time and duration of any period when emissions are excluded due to a malfunction of the SCR, as provided by Paragraph 5, and supporting information regarding the malfunction, the cause, and corrective actions taken, and the amount of NO_x emissions during the malfunction.

E. Possum Point

The tons of NO_x from Possum Point Units 3 and 4 rolled daily as determined by Paragraph 96.

II. SO_2 Reporting Requirements

A. SO_2 Removal Efficiency Requirements

1. The progress of construction and improvement (such as, if construction is not underway, the dates of contract execution, the estimated percent of installation, and major component delivery) and, once construction and improvement is complete, the date of final installation, improvement, and operation of FGDs required under Paragraph 64 of the Consent Decree, and of initial performance testing, if any.

2. Commencing when any 30-Day Rolling Average Removal Efficiency for SO_2 becomes applicable for each FGD as defined in Paragraph 64, the 30-Day Rolling Average Removal Efficiency for SO_2 for each operating day.

3. Within the first report that identifies a 30-Day Rolling Average Removal Efficiency for each FGD, at least five (5) example calculations (including raw CEM data in electronic format for the calculations) used to determine the 30-Day Rolling Average Removal Efficiency for SO_2. If at any time VEPCO

changes any aspect within the methodology used in determining the 30-Day Rolling Average Removal Efficiency for SO_2, VEPCO shall explain the change and the reason for using the new methodology.

B. SO_2 Emission Rate

1. For Clover Units 1 & 2, Mt. Storm Units 1, 2, & 3 and Chesterfield Units 5 & 6 upon qualifying for a 30-Day Rolling Average Emission Rate as provided in Paragraph 66 of the Consent Decree, the 30-Day Rolling Average Emission Rate (lbs/mmBTU), as defined in Paragraph 5, for each operating day for each Unit qualifying for the SO_2 emission rate.

2. Within the first report that identifies a 30-Day Rolling Average Emission Rate for each FGD, at least five (5) example calculations (including raw CEM data in electronic format for the calculations) used to determine the 30-Day Rolling Average Emission Rate. If at any time VEPCO changes any aspect within the methodology used in determining the 30-Day Rolling Average Emission Rate, VEPCO shall explain the change and the reason for using the new methodology.

3. A description of the how VEPCO met the FGD performance efforts required in Paragraph 69 (Best Efforts).

C. FGD Bypass Days at Mt. Storm (Consent Decree Paragraph 67)

1. For each FGD outage or FGD downtime at Mt. Storm Units 1, 2 or 3, as allowed under Paragraph 67, the following information:

   a. The date and time the outage/downtime began;
   b. The date and time that the FGD that was offline was returned to operation and the duration of the FGD outage/downtime;
   c. A narrative explanation of corrective or maintenance actions taken by VEPCO;
   d. The total SO_2 emitted from the Unit during the FGD outage/downtime;
   e. The total amount of SO2 emission, in tons, that would have been emitted at the Unit during the FGD outage/downtime had VEPCO burned coal with the sulfur content required by the Consent Decree, during the FGD outage/downtime;
   f. The amount of allowances to be surrendered and provide evidence that VEPCO surrendered to EPA the amount of SO_2 Allowances required to be surrendered under Paragraph 67;
   g. Report that the Unit with the FGD outage/downtime was not dispatched ahead of the other Mount Storm Units or the Clover Power Station Units during the FGD outage/downtime and the dispatch order

for each Unit of the VEPCO System during the FGD outage/downtime; and

h. By Unit, a year-to-date tabulation of the number and duration of FGD outages/downtime at Mt. Storm Units 1, 2, & 3, and the total amount of FGD outage/downtime permitted by the Consent Decree for that year.

D. Miscellaneous SO_2 Provisions

1. Commencing when any VEPCO System Unit becomes subject to a 30-Day Rolling Average Removal Efficiency or Emission Rate requirement for SO_2, for each Unit in the "VEPCO System" that utilizes FGD control pursuant to a requirement of the Consent Decree, when a Unit is taken out of service and the fire in the boiler is extinguished during the reporting period:

   a. The date and time that the fire is extinguished;
   b. The date and time the Unit is restarted;
   c. The date and time that the Unit is synchronized with an utility electric distribution system after the restart; and
   d. SO_2 emissions emitted by the Unit prior to the time that the Unit was synchronized with a utility electric distribution system, ending on December 31, 2015.

2. Within the last report for any given year, report the total SO_2 emissions from the VEPCO System for the calendar year covered by the report as tons per year, and for each Unit in the VEPCO System, report the annual SO_2 emissions in tons per year for the calendar year covered by the report.

E. Annual Surrender of SO_2 Allowances

1. Beginning in 2013, whether it made the annual SO_2 allowance surrender required by the Consent Decree to the U.S. EPA and shall provide documentation verifying this surrender.

2. If VEPCO surrenders the SO_2 allowances to a third party, the following information:

   a. The identity of the third-party recipients(s) of the SO_2 allowances and a listing of the serial numbers of the transferred allowances;
   b. A certification from the third-party recipient(s) that it (they) will not sell, trade or otherwise exchange any of the allowances and will not use any of the allowances to meet any obligation imposed by any law.
   c. Within 12 months after the first report of the transfer, VEPCO shall provide documentation that the third-party recipients(s) of the SO_2 allowances permanently surrendered the allowances to U.S. EPA

within one year after VEPCO transferred the allowances the third-party recipient(s).

F. Super-compliance Trading of Allowances

1. The amount of SO_2 Allowances and NO_x emission allowances or credits used or traded pursuant to Paragraph 75 and Section XVIII and the calculations or data justifying the generation of the used or traded allowances or credits.

III. PM Requirements

A. Use of PM Controls Existing at the Time the Decree was Entered and PM Emissions Rate

1. Until a Unit is subject to a PM emissions rate pursuant to this Consent Decree, the following information for each Unit:

a. The calendar days on which the ESP was not operating at any time that the Unit was in operation;
b. If, in accordance with Paragraphs 78 and 79, an ESP or portion thereof fails, does not perform in accordance with the equipment manufacturer's specifications or is shutdown by VEPCO, the calendar date of each such instance, the time that the failure or inadequate performance of the ESP began, all corrective actions undertaken by VEPCO and the calendar date and time that the ESP was restored to the mode of operation required by Paragraphs 78 and 79. VEPCO shall also report any additional corrective actions undertaken in response to the event.

2. For each Unit in the VEPCO System at which a PM emission rate applies pursuant to this Consent Decree, the following information:

a. The PM Emission Rate (lbs/mmBTU) for the Unit, determined under the Consent Decree;
b. If, in accordance with Paragraphs 78 and 79, an ESP or portion thereof fails, or does not perform in accordance with the equipment manufacturer's specifications, the calendar date of each such instance, the time that the failure or sub-par performance of the ESP began, all corrective actions undertaken by VEPCO and the calendar date and time that the ESP was restored to the mode of operation required by Paragraphs 78 and 79. VEPCO shall also report any additional corrective actions undertaken in response to the event.

3. Information required to be reported within the approved PM optimization plans.

4. A description of the how VEPCO met the PM control device performance efforts required in Paragraph 78 (Best Efforts).

B. PM CEMs

1. For each PM CEM installed on a Unit in the VEPCO System:

a. If the PM CEM was installed during the reporting period, the date of installation of the PM CEM;
b. The dates that the PM CEM operated;
c. If the PM CEM did not operate continuously throughout the quarter without interruption whenever the Unit it serves was operating, the date and time that the PM CEM was not operating, a description of the cause of the PM CEM's outage, the steps taken by VEPCO to fix the PM CEM, any additional corrective actions undertaken by VEPCO in response to the event and the time and date that the PM CEM was returned to service.

C. Performance Testing/Monitoring of PM Emission

1. For each Unit in the VEPCO System:

a. If the Unit was required to perform a stack test pursuant to the Consent Decree, the executive summary and results of the stack test;
b. If the Unit has a PM CEM, the three-hour average emission rate for PM emissions (or such longer period as is specified in any applicable PM emissions limitation requirement), in lb/mmBtu.

IV. Deviation Reporting

A. In addition to reporting under Paragraph 137, a summary of all deviations that occurred during the reporting period and the date that the deviation was initially reported under Paragraph 138.

B. Within each deviation report submitted under Paragraph 138, the following information:

1. The Consent Decree requirement under which the deviation occurred, with a reference to the Consent Decree paragraph containing the requirement;

2. The date and time that the deviation occurred;

3. The date and time that the deviation was corrected;

4. The data, calculations or other information indicating that a deviation occurred; and

5. A narrative description of the cause or suspected cause of the deviation, the steps taken by VEPCO to correct the deviation and any additional corrective actions taken by VEPCO in response to the deviation.

V. Mitigation Project Reporting

A. The progress such as the schedule for completion of the project dates of contract execution, and estimated percent of completion of the Mitigation Projects required in Section XXI of the Consent Decree.

B. The amount of Project Dollars expended on Mitigation Projects.

VI. VEPCO Submissions

A list all plans or submissions and the date submitted to the Plaintiffs for the reporting period, and identify if any are pending the review and approval of the Plaintiff.

VII. VEPCO Capital Projects

A list of all Capital Expenditures performed throughout the VEPCO System on the Boiler Islands in order to determine meeting the threshold established in Paragraphs 111, 124, and 133.

VIII. Additional Information

Provide a response to any reasonable request by the Plaintiffs for any additional information regarding these reporting requirements or the obligations and requirements of this Consent Decree.

APPENDIX C – MITIGATION PROJECTS REQUIREMENTS

In compliance with and in addition to the requirements in Section XXI of the Consent Decree, VEPCO shall comply with the requirements of this Appendix to ensure that the benefits of the environmental mitigation protects are achieved. No Party may submit a proposed plan for a mitigation project until after entry of the Consent Decree.

I. Clean Diesel, Idle Reduction and School Bus Retrofit Project - To Be Conducted within the District of Columbia, Delaware, Maryland, Pennsylvania, Virginia and West Virginia and Resource Lands Project

A. Within 90 days after entry of the Consent Decree, VEPCO shall submit a plan to EPA for review and approval for the completion of the Clean Diesel, Idle Reduction and School Bus Retrofit Project in which VEPCO shall spend no less than $2,500,000 Project Dollars to retrofit diesel engines with emission control equipment, replace diesel engines with cleaner engines, subsidize the use of clean diesel fuels or install equipment or implement strategies that will reduce engine idling in the above listed jurisdictions.

B. The plan shall satisfy the following criteria:

1. Involve fleets located in geographically diverse areas and/or fleets operated in nonattainment areas or areas at significant risk of nonattainment status within the listed states, taking into account other clean diesel projects called for under this Decree.
2. Provide for the retrofit of high emitting, in service heavy-duty diesel engines with verified emissions control equipment. Retrofit technology may include but not be limited to oxidation catalysts and particulate matter filters that will reduce particulate matter and hydrocarbon emissions.
3. Provide for the replacement of engines with those that meet the 2007 engine standards and/or are equipped with verified emission control technology.
4. Involve vehicles that are located in areas in which ultra low sulfur diesel fuel (ULSD) is already available or is scheduled to become available and where such fuel is required for retrofit technology. For affected municipalities, school districts or similar local government entities whose fleet will be retrofitted, the plan may provide for (a) the procurement of tanks or other infrastructure required enabling that fleet to obtain and use ULSD and (b) offsetting higher fuel costs from the requirement to use ULSD.
5. Provide for the use of alternative diesel fuels that reduce emissions of particulate matter, nitrogen oxides and/or hydrocarbons including but not

limited to emulsions and biodiesel fuels.

6. Provide for the installation of verified idle reduction technology and/or idle reduction strategies that effectively reduce emissions from idling engines through equipment such as electrification stations and/or implementation of outreach and education programs to implement policies that reduce idling time.
7. Account for hardware and installation costs, and may provide also for incremental maintenance costs and/or costs of repairs on such hardware for a period of up to four years after installation.
8. Limit recipients of retrofits to fleets that legally bind themselves to maintain any equipment installed in connection with the project during and after completion of the project.
9. Establish minimum standards for any third-party with whom VEPCO might contact to carry out this program that include prior experience in arranging vehicle retrofits, ULSD purchases, anti-idling campaigns, etc. and a record of prior ability to interest and organize fleets, school districts, community groups, etc. to join a clean diesel program.
10. A schedule for completing each portion of the project.

C. Within 180 days after entry of the Consent Plans, VEPCO shall submit a plan to EPA for review and approval for the identification, acquisition, restoration, management and/or preservation of resource lands to mitigate or compensate for lost service uses possibly resulting from past power plant emissions in which VEPCO shall spend no less than $500,000. The proposed plan shall satisfy the following criteria:

1. Provide a means for the identification of available resource lands which may be used to mitigate any past impacts of acid rain deposition or other possible effects of power plant emissions and assess the value of such lands in providing such benefits as contributing to carbon sequestration, restoring forest productivity and other relevant factors.

2. Establish a process for carrying out the plan, including the identification of resources, staff and/or other entities charged with project execution, management and oversight during the terms of the Decree, and develop a related schedule for completing each portion of the project.

3. Within 180 days after approval of the proposed selection process identify particular plots of land that are consistent with the specifications outlined.

4. Submit the identified plots of land with recommended selection criteria

within a reasonable period of time. Develop legal options for acquiring, restoring and assuring the continued preservation of identified lands.

D. Performance - Upon approval of plan by the United States, VEPCO shall complete the mitigation project according to the approved plan and schedule.

II. **Solar Photovoltaic (PV) Project – To Be Conducted in New York State**

A. New York shall propose to VEPCO and the U.S. a plan using $2.1 million to accomplish the installation of solar photovoltaics ("PVs") on municipal buildings in New York. These building would then use the PV-generated energy, in part to help remove some demand for energy from the electrical grid during peak demand periods. The project will be administered through the New York State Energy Research and Development Authority's (NYSERDA) Solar Photovoltaics program.

B. New York's proposed plan must:

1. Describe how the work or project to be performed is consistent with requirements of Section II.A, above;

a) Include a general schedule and budget (for $2.1 million) for completion of the work; including payment instructions for VEPCO's submission of funds to the State, along with a requirement of periodic reports to all Parties on the progress of the work called for in the proposed plan through completion of the project;
b) Describe generally the expected environmental benefit for project or work called for under the proposed plan; and
c) Describe briefly how work or project described in the proposed plan meets the requirements of Section XXI of the Decree.

C. VEPCO's obligation for this project shall terminate once a plan exists for this project or work and VEPCO has transferred at least $2.1 million to New York to complete the project or work described in the plan. VEPCO shall transfer this sum as soon as possible after the proposed plan is developed but no later than December 31, 2003, unless untimely submission of the proposed plan or material deficiency in such plan requires payment after that date.

D. If New York (or NSYERDA) is later unwilling or unable to perform the project specified here, then New York, in consultation with VEPCO, shall select an alternative project or projects designed to accomplish the same kinds of goals as intended for this project. After proceeding through this proposed plan process for the alternative project, VEPCO shall fund such project or projects in the amount of $2.1 million.

III. Mitigating Harm to Health Related to Air Pollution in New Jersey and New York: Public Transit -- Diesel Bus Catalyzed Particulate Filters

A. New Jersey shall supply to VEPCO and the U.S. a plan to use $2.7 million to accomplish the installation of catalyzed particulate filters (CPFs) on late-model conventional diesel buses used to transport commuters from various locations in the State of New Jersey into New York City. Operating exclusively on ultra-low sulfur diesel fuel, these CPF-equipped buses will further significantly reduce harmful emissions of carbon monoxide, hydrocarbons, and particulate matter in both New Jersey and New York. The project will be administered by the New Jersey Transit Corporation.

B. New Jersey's proposed plan must:

1. Describe how the work or project to be performed is consistent with requirements of Section III.A, above;
2. Include a general schedule and budget (for $2.7 million) for completion of the work, including payment instructions for VEPCO's submission of funds to the State, along with a requirement of periodic reports to all Parties on the progress of the work called for in the proposed plan through completion of the project;
3. Describe generally the expected environmental benefit for project or work called for under the proposed plan; and
4. Describe briefly how the work or project described in the proposed plan meets the requirements of Section XXI of the Decree.

C. VEPCO's obligation for this project shall terminate once a plan exists for this project or work and VEPCO has transferred at least $2.7 million to New Jersey to complete the project or work described in the plan. VEPCO shall transfer this sum as soon as possible after the proposed plan is developed but no later than December 31, 2003, unless untimely submission of the proposed plan or material deficiency in such plan requires payment after that date.

IV. School Bus Retrofit Project – To be Conducted in the State of Connecticut

A. The State of Connecticut will supply VEPCO and the U.S. a plan to use $1.1 million to purchase and install particulate filters for diesel school buses that operate in selected urban communities in that State. The proposed plan may include any combination of the following: (i) conversion of conventional diesel-powered, school buses to buses with particulate traps, (ii) procuring of ultra-low sulfur diesel fuel (and necessary infrastructure) to power for up to three years buses converted in the manner described in (i), and/or (iii) install additional air pollution controls on such buses. The proposed plan will be limited to pollution control devices, fuels, and other measures needed to convert diesel buses to include CRT or other particulate traps and other controls (including support infrastructure).

B. Connecticut's proposed plan must:

1. Describe how the work or project to be performed is consistent with requirements of Section IV.A, above;
2. Include a general schedule and budget (for $1.1 million) for completion of the work, including payment instructions for VEPCO's submission of funds to the State, along with a requirement of periodic reports to all Parties on the progress of the work called for in the proposed plan through completion of the project;
3. Describe generally the expected environmental benefit for project or work called for under the proposed plan; and
4. Describe briefly how the work or project described in the proposed plan meets the requirements of Section XXI of the Decree.

C. VEPCO's obligation for this project shall terminate once a plan exists for this project or work and VEPCO has transferred at least $1.1 million to Connecticut to complete the project or work described in the plan. VEPCO shall transfer this sum as soon as possible after the proposed plan is developed but no later than December 31, 2003, unless untimely submission of the proposed plan or material deficiency in such plan requires payment after that date.

V. School Bus Retrofit Program to be Carried Out in Commonwealth of Virginia

A. Commonwealth of Virginia shall supply to VEPCO and the U.S. a plan to use $2.0 million to accomplish any combination of the following concerning in-service diesel-powered school buses in the Commonwealth: retrofitting buses with pollution control devices and techniques and infrastructure needed to support such retrofits, engine replacements that will reduce emissions of particulates or ozone precursors, and changeover to CNG fuel or low diesel fuel. These projects are to be carried out in areas either non in attainment with ambient air quality standards in the Commonwealth or at risk of being reclassified as nonattainment, such as Fairfax, Hampton Roads, and Virginia Beach

B. Commonwealth's proposed plan must:

1. Describe how the work or project to be performed is consistent with requirements of Section V.A, above;
2. Include a general schedule and budget (for $2.0 million) for completion of

the work, including payment instructions for VEPCO's submission of funds to the Commonwealth, along with a requirement of periodic reports to all Parties on the progress of the work called for in the proposed plan through completion of the project;

3. Describe generally the expected environmental benefit for project or work called for under the proposed plan; and
4. Describe briefly how the work or project described in the proposed plan meets the requirements of Section XXI of the Decree.

C. VEPCO's obligation for this project shall terminate once a plan exists for this project or work and VEPCO has transferred at least $2.0 million to the Commonwealth to complete the project or work described in the plan. VEPCO shall transfer this sum as soon as possible after the proposed plan is developed but no later than December 31, 2003, unless untimely submission of the proposed plan or material deficiency in such plan requires payment after that date

VI. Protecting Forests and other Natural Resources in West Virginia's Cheat Gorge / Big Sandy Area.

A. The State of West Virginia will supply VEPCO and the U.S. a $2.0 million proposed plan for the purchase and maintenance of property and/or conservation easements that would preserve forests and other environmentally sensitive areas in and around the Cheat Gorge / Big Sandy area of the West Virginia, for the purposes of making or expanding a public wildlife management area in the State and thus preserving an important sources of carbon sequestration. The proposed plan also will include needed steps for securing and maintaining valid conservation easements under applicable law and for securing clear title, as applicable.

B. West Virginia's proposed plan must:

1. Describe how the work or project to be performed is consistent with requirements of Section VI.A, above;
2. Include a general schedule and budget (for $2.0 million) for completion of the work; including payment instructions for VEPCO's submission of funds to the State or its designee, along with a requirement of periodic reports to all Parties on the Progress of the work called for in the proposed plan through completion of the project;
3. Describe generally the expected environmental benefit for project or work called for under the proposed plan; and
4. Describe briefly how work or project described in the proposed plan meets the requirements of Section XXI of the Decree.

C. VEPCO's obligation for this project shall terminate once a plan exists for this project or work and VEPCO has transferred at least $2.0 million to West Virginia or its designee. VEPCO shall transfer this sum as soon as possible after the proposed plan is developed but no later than December 31, 2003, unless untimely submission of the proposed plan or material deficiency in such plan requires payment after that date.

D. If West Virginia is unwilling or unable to perform the project specified here, West Virginia, in consultation with VEPCO, shall select an alternative project or projects designed to accomplish the same kinds of goals as intended for this project. After proceeding through this proposed plan process for this alternative project(s), VEPCO shall fund such project or projects in the amount of $2.0 million.

VII. National Park Service Alternative-Fueled and Hybrid Vehicles Project.

A. The National Park Service will supply VEPCO a plan for using $1.0 million in accordance with the Park System Resource Protection Act, 16 U.S.C Section 19jj, to improve air quality in and about the Shenandoah National Park, either by securing alternative-fueled vehicles for trial use in and around the Park (including necessary ancillary equipment such as a fueling station) or for implementing another project also intended to reduce damage to those resources caused by air pollution suffered by the Park.

B. NPS's proposed plan must:

1. Describe how the work or project to be performed is consistent with requirements of Section VII.A, above;
2. Include a general schedule and budget (for $1.0 million) for completion of the work; including payment instructions for VEPCO's submission of funds to the Natural Resource Damage and Assessment Fund, along with a requirement of periodic reports to all Parties on the Progress of the work called for in the proposed plan through completion of the work.
3. Describe generally the expected environmental benefit for project or work called for under the proposed plan; and
4. Describe briefly how work or project described in the proposed plan meets the requirements of Section XXI of the Decree.

C. VEPCO's obligation for this project shall terminate once an approved plan exists for this project or work and VEPCO has transferred at least $1.0 million to the Natural Resource Damage and Assessment Fund. VEPCO shall transfer this sum as soon as possible after the proposed plan is approved but no later than December 31, 2003, unless untimely submission of the proposed plan or material deficiency in such plan requires payment after that date.

IN THE UNITED STATES DISTRICT COURT
FOR THE EASTERN DISTRICT OF WISCONSIN

UNITED STATES OF AMERICA	)	
	)	
Plaintiff,	)	
	)	
v.	)	Civil Action No. __________
	)	
WISCONSIN ELECTRIC POWER COMPANY,	)	
	)	
Defendant.	)	
	)	
____	)	

CONSENT DECREE

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WHEREAS, the United States of America ("the United States"), on behalf of the United States Environmental Protection Agency ("EPA") has filed a Complaint with this Consent Decree, against Wisconsin Electric pursuant to Sections 113(b) and 167 of the Clean Air Act (the "Act"), 42 U.S.C. §§ 7413(b) and 7477, for injunctive relief and the assessment of civil penalties for alleged violations of:

(a) the Prevention of Significant Deterioration provisions in Part C of Subchapter I of the Act, 42 U.S.C. §§ 7470-92;

(b) the nonattainment New Source Review provisions in Part D of Subchapter I of the Act, 42 U.S.C. §§ 7501-7515;

(c) the federally-enforceable State Implementation Plan developed by the State of Michigan (the "Michigan SIP");

(d) the federally-enforceable State Implementation Plan developed by the State of Wisconsin (the "Wisconsin SIP"); and

WHEREAS, in its Complaint, Plaintiff alleges, *inter alia,* that Wisconsin Electric failed to obtain the necessary permits and install the controls necessary under the Act to reduce its sulfur dioxide, nitrogen oxides, and/or particulate matter emissions, and that such emissions can damage human health and the environment;

WHEREAS, the Plaintiff alleges that its Complaint states claims upon which relief can be granted against Wisconsin Electric under Sections 113 and 167 of the Act, 42 U.S.C. §§ 7413 and 7477, and 28 U.S.C. § 1355;

WHEREAS, Wisconsin Electric has not answered or otherwise responded to the Complaint filed by the United States in light of the settlement memorialized in this Consent Decree;

WHEREAS, Wisconsin Electric has denied and continues to deny the violations alleged in the Complaint, maintains that it has been and remains in compliance with the Act and is not liable for civil penalties or injunctive relief, and states that it is agreeing to the obligations imposed by this Consent Decree solely to avoid the costs and uncertainties of litigation, and to reduce its emissions;

WHEREAS, EPA provided Wisconsin Electric and the States of Michigan and Wisconsin with actual notice of violations pertaining to Wisconsin Electric's alleged violations, in accordance with Section 113(a)(1)of the Act, 42 U.S.C. § 7413(a)(1);

WHEREAS, the Parties anticipate that the States of Michigan and Wisconsin may seek to intervene in this case, and the Parties anticipate that they will consent to such intervention;

WHEREAS, Wisconsin Electric, consistent with its environmental, health and safety policy, met with the United States in February 2003, to resolve the Parties' respective goals for achieving emission reductions of certain emissions at the electric generating stations covered under this Consent Decree;

WHEREAS, the Parties anticipate that the installation and operation of pollution control equipment pursuant to this Consent Decree will achieve significant reductions in SO_2, NO_x and PM emissions and thereby improve air quality and that certain actions that Wisconsin Electric has agreed to undertake are expected to advance technologies and methodologies for reducing certain air emissions, including mercury;

WHEREAS, nothing in this Consent Decree is intended to prohibit the use of emission reductions under this Consent Decree to demonstrate attainment with §110 of the Act (42 U.S.C. § 7410);

WHEREAS, Wisconsin Electric has begun the process of retiring the coal-fired units at the Port Washington Generating Station and has applied for and received permits to construct two new combined cycle natural gas units at that facility;

WHEREAS, Wisconsin Electric is seeking approval, including air emissions permits, to construct three new coal-fired units in Wisconsin at a site adjacent to the South Oak Creek Generating Station, designated as the Elm Road Generating Station;

WHEREAS, EPA supports the construction of cleaner power plants to meet growing energy demands;

WHEREAS, the United States and Wisconsin Electric have agreed, and the Court by entering this Consent Decree finds: that this Consent Decree has been negotiated in good faith and at arms length; that this settlement is fair, reasonable, in the best interest of the Parties and in the public interest; consistent with the goals of the Act; and that entry of this Consent Decree without further litigation is the most appropriate means of resolving this matter;

and

WHEREAS, the United States and Wisconsin Electric have consented to entry of this Consent Decree without trial of any issue;

NOW, THEREFORE, without any admission of fact or law, and without any admission of the violations alleged in the Complaint it is hereby ORDERED, ADJUDGED, AND DECREED as follows:

I. JURISDICTION AND VENUE

1. This Court has jurisdiction over this action, the subject matter herein, and the Parties consenting hereto, pursuant to 28 U.S.C. §§ 1331, 1345, 1355, and 1367, Sections 113(b) and 167 of the Act, 42 U.S.C. §§ 7413(b) and 7477, the Michigan SIP, 40 C.F.R. § 52.1180(b); 45 Fed. Reg. 8348 (February 7, 1980), and the Wisconsin SIP, 40 C.F.R. § 52.2570; Wis. Admin. Code, NR § 405. Venue is proper under Section 113(b) of the Act, 42 U.S.C. § 7413(b), and under 28 U.S.C. § 1391(b) and (c). Solely for the purposes of this Consent Decree and the Plaintiff's underlying Complaint, Wisconsin Electric waives all objections and defenses that it may have to the claims set forth in the underlying Complaints, and to the jurisdiction of the Court over Wisconsin Electric and this action, and to venue in this District. Wisconsin Electric shall not challenge the terms of this Consent Decree or this Court's jurisdiction to enter and enforce this Consent Decree. For purposes of the Complaint filed by the United States in this matter and resolved by the Consent Decree, and for purposes of entry and enforcement of this Decree, Wisconsin Electric waives any defense or objection based on standing. Except as expressly provided for herein, this Consent Decree shall not create any rights in any party other than the United States and Wisconsin Electric. Except as provided by Section XXVII (Public Comment), the Parties consent to entry of this Consent Decree without further notice.

II. APPLICABILITY

2. Upon entry, the provisions of this Consent Decree shall apply to and be binding upon the United States and Wisconsin Electric, its successors and assigns, and Wisconsin Electric's officers, employees, and agents solely in their capacities as such.

3. Wisconsin Electric shall provide a copy of this Consent Decree to all vendors, suppliers, consultants, contractors, agents, and any other company or organization retained to perform any of the work required by this Consent Decree. Notwithstanding any retention of contractors, subcontractors, or agents to perform any work required under this Consent Decree, Wisconsin Electric shall be responsible for ensuring that all work is performed in accordance with the requirements of this Consent Decree. In any action to enforce this Consent Decree, Wisconsin Electric shall not assert as a defense the failure of its officers, directors, employees, servants, agents, or contractors to take actions necessary to comply with this Consent Decree, unless Wisconsin Electric establishes that such failure resulted from a Force Majeure Event, as defined in Paragraph 143 of this Consent Decree.

III. DEFINITIONS

4. A "30-day Rolling Average Emission Rate" shall be determined by calculating an arithmetic average of all hourly emission rates in lb/mmBTU for the current day and the previous 29 Operating Days. A new 30-day Rolling Average Emission Rate shall be calculated for each new Operating Day. Each 30-Day Rolling Average Emission Rate shall include all start-up, shut down and Malfunction periods within each Operating Day. A Malfunction shall be excluded from this Emission Rate, however, if it is determined to be a Force Majeure Event and satisfies the Force Majeure provisions of this Consent Decree.

5. "30-Day Rolling Average Removal Efficiency" means the percent reduction in the mass of a pollutant achieved by a Unit's pollution control device over a 30-day period. This percentage shall be calculated by subtracting the Unit's outlet 30-Day Rolling Average Emission Rate from the Unit's inlet 30-Day Rolling Average Emission Rate, dividing that difference by

the Unit's inlet 30-Day Rolling Average Emission Rate, and then multiplying by 100. A new 30-Day Rolling Average Removal Efficiency shall be calculated for each new Operating Day, and shall include all periods of startup, shutdown and Malfunction within an Operating Day. A Malfunction shall be excluded from this removal efficiency, however, if it is determined to be a Force Majeure Event and satisfies the Force Majeure provisions of this Consent Decree.

6. "Air Quality Control Region" means a geographic area designated under Section 107(c) of the Act, 42 U.S.C. § 7407(c).

7. "Baseline" means the annual average emissions of SO_2 and NO_x of the Plants in the Wisconsin Electric System for calendar years 2000 and 2001, as measured under 40 C.F.R. Part 75.

8. "Boiler Island" means a Unit's (A) fuel combustion system (including bunker, coal pulverizers, crusher, stoker, and fuel burners); (B) combustion air system; (C) steam generating system (i.e., firebox, boiler tubes and walls); and (D) draft system (excluding the stack), as further described in "Interpretation of Reconstruction," by John B. Rasnick, U.S. EPA (November 25, 1986) and the attachments thereto.

9. "BH" means baghouse, a pollution control device for the reduction of particulate matter ("PM").

10. "Capital Expenditure" means all capital expenditures, as defined by Generally Accepted Accounting Principles ("GAAP"), excluding the cost of installing or upgrading pollution control devices.

11. "CEMS" or "Continuous Emission Monitoring System" means, for obligations involving NO_x and SO_2 under this Decree, the devices defined in 40 C.F.R. § 72.2 and installed and maintained as required by 40 C.F.R. Part 75.

12. "Clean Air Act" or "Act" means the federal Clean Air Act, 42 U.S.C. §§7401-7671q, and its implementing regulations.

13. "Consent Decree" or "Decree" means this Consent Decree.

14. "Elm Road Generating Station" means the proposed coal-fired electric generating units, for which Wisconsin Electric is seeking regulatory approval to construct at a site adjacent to the South Oak Creek Generating Station.

15. "Emission Rate" means the number of pounds of pollutant emitted per million BTU of heat input ("lb/mmBTU"), measured in accordance with this Consent Decree.

16. "EPA" means the United States Environmental Protection Agency.

17. "ESP" means electrostatic precipitator, a pollution control device for the reduction of particulate matter ("PM").

18. "Existing Units" means those Units included in the Wisconsin Electric System.

19. "Flue gas desulfurization system," or "FGD," means a pollution control device that employs flue gas desulfurization technology for the reduction of sulfur dioxide.

20. "Fossil fuel" means any hydrocarbon fuel, including coal, petroleum oil, or natural gas.

21. "Improved Unit" means, in the case of NO_x, a Wisconsin Electric System Unit scheduled under this Decree to be equipped with SCR (or equivalent NOx control technology approved pursuant to Paragraph 56) or to be retired, and, in the case of SO_2, a Wisconsin Electric

System Unit scheduled under this Decree to be equipped with an FGD (or equivalent SO_2 control technology approved pursuant to Paragraph 71) or to be retired. A Unit may be an Improved Unit for one pollutant without being an Improved Unit for the other.

22. "lb/mmBTU" mean one pound of a pollutant per million British Thermal Units of heat input.

23. "Malfunction" means malfunction as that term is defined under 40 C.F.R.§ 60.2.

24. "MW" means a megawatt, or one million Watts.

25. "National Ambient Air Quality Standards" means national air quality standards promulgated pursuant to Section 109 of the Act, 42 U.S.C. § 7409.

26. "New Units" means any coal-fired or natural gas fired units that commence operation after entry of this Consent Decree, including but not limited to the re-powered natural gas units at the Port Washington Generating Station.

27. "NO_x" means oxides of nitrogen, as measured in accordance with the provisions of this Consent Decree.

28. "Nonattainment NSR" means the nonattainment area New Source Review program within the meaning of Part D of Subchapter I of the Act, 42 U.S.C. §§ 7510-7515, 40 C.F.R. Part 51.

29. "NSPS" means New Source Performance Standards within the meaning of Part A of Subchapter I, of the Clean Air Act, 42 U.S.C. § 7411, 40 C.F.R. Part 60.

30. "Operating Day" means any calendar day on which a Unit fires fossil fuel.

31. “Other Unit” means any Unit of the Wisconsin Electric System that is not an Improved Unit for the pollutant in question. A Unit may be an Improved Unit for NOx and an Other Unit for SO_2 and vice versa.

32. “PM Control Device” means an electrostatic precipitator (“ESP”) or a baghouse (“BH”), devices which reduce emissions of particulate matter (PM).

33. “Parties” means Wisconsin Electric and the United States.

34. “Permitting State” means the state in which a particular Unit is located from which Wisconsin Electric is required to obtain permits, licenses, or approvals in order to install or operate a source of air pollution.

35. “Plaintiff” means the United States.

36. “PM” means particulate matter, as measured in accordance with the provisions of this Consent Decree.

37. “PM CEMS” or “PM continuous emission monitoring system” means equipment that samples, analyzes, measures, and provides PM emissions data -- by readings taken at frequent intervals – and makes an electronic or paper record of the PM emissions measured.

38. “PM Emission Rate” shall mean the average number of pounds of PM emitted per million BTU of heat input (“lb/mmBTU”), as measured in annual stack tests, in accordance with the reference methods set forth in 40 C.F.R. Part 60, Appendix A, Method 5 or Method 17.

39. “Project Dollars” means Wisconsin Electric’s expenditures and payments incurred or made in carrying out the projects identified in Section IX of this Consent Decree (Environmental Projects) to the extent that such expenditures or payments both: (a) comply with the Project Dollar and other requirements set by this Consent Decree in Section IX of this

Consent Decree (Environmental Projects); and (b) constitute Wisconsin Electric's external costs for contractors, vendors, and equipment, and its internal costs consisting of employee time, travel, and other out-of-pocket expenses specifically attributable to these particular projects and documented in accordance with "GAAP".

40. "PSD" means Prevention of Significant Deterioration within the meaning of Part C of Subchapter I of the Clean Air Act, 42 U.S.C. §§ 7470 - 7492 and 40 C.F.R. Part 52.

41. "SCR" means a device that employs selective catalytic reduction technology for the reduction of nitrogen oxides.

42. "SO_2" means sulfur dioxide, as measured in accordance with this Consent Decree.

43. "SO_2 Allowance" means an "allowance," as defined at 42 U.S.C. § 7651a(3): an authorization, allocated to an affected unit, by the Administrator of EPA under Subchapter IV of the Act, to emit, during or after a specified calendar year, one ton of sulfur dioxide.

44. [RESERVED.]

45. "System-wide 12-Month Rolling Average Emission Rate" means (a) summing the pounds of pollutant in question emitted from the Wisconsin Electric System during the most recent complete month and the previous eleven (11) months, (b) summing the heat input to the Wisconsin Electric System in mmBTU during the most recent complete month and the previous eleven (11) months, and (c) dividing the total number of pounds of pollutants emitted during the twelve (12) months by the total heat input during the twelve (12) months, and expressing the resulting figure in lbs/mmBTU. A new System-wide 12-Month Rolling Average Emission Rate shall be calculated for each new complete month. Each "System-wide 12-Month Rolling

Average Emission Rate" shall include all start-up, shut down and Malfunction periods within each complete month.

46. "System-wide 12-Month Rolling Tonnage" means the sum of the tons of pollutant in question emitted from the Wisconsin Electric System in the most recent month and the previous eleven (11) months. A new System-wide 12-Month Rolling Tonnage will be calculated for each new complete month.

47. "Title V Permit" means the permit required of Wisconsin Electric's major sources under Subchapter V of the Clean Air Act, 42 U.S.C. §§ 7661-7661e.

48. "Unit" means, for the purpose of this Consent Decree, collectively, the coal pulverizer, the stationary equipment that feeds coal to the boiler, the boiler that produces steam for the steam turbine, the steam turbine, the generator, the equipment necessary to operate the generator, steam turbine and boiler, and all ancillary equipment, including pollution control equipment, or systems necessary for the production of electricity. An electric utility steam generating station may be comprised of one or more Units.

49. "Unit-Specific 12-Month Rolling Tonnage" means the sum of the tons of pollutant in question emitted from the applicable Unit in the most recent month and the previous eleven (11) months. A new Unit-Specific 12-Month Rolling Tonnage will be calculated for each new complete month.

50. "WEC" means Wisconsin Energy Corporation, the parent company of Wisconsin Electric and W.E. Power.

51. "W.E. Power" means W.E. Power LLC, a subsidiary of WEC and an affiliate of Wisconsin Electric.

52. “Wisconsin Electric” means the Wisconsin Electric Power Company.

53. “Wisconsin Electric System” means, solely for purposes of this Consent Decree, the following twenty-three (23) coal-fired, electric utility steam generating Units (with the rated $MW_{(net)}$ capacity of each Unit noted in parentheses):

- Presque Isle Generating Station in Marquette, Michigan - Unit 1 (25 MW), 2 (37.5 MW), 3 (54.4 MW), 4 (57.8 MW), 5 (90 MW), 6 (90 MW), 7 (90 MW), 8 (90 MW), and 9 (90 MW);
- Pleasant Prairie Generating Station in Kenosha, Wisconsin - Units 1 (616.6 MW) and 2 (616.6 MW);
- South Oak Creek Generating Station in Oak Creek, Wisconsin - Units 5 (275 MW), 6 (275 MW), 7 (317.6 MW), and 8 (324 MW);
- Port Washington Generating Station in Port Washington, Wisconsin - Units 1 (80 MW), 2 (80 MW), 3 (80 MW), and 4 (80 MW);
- Valley Generating Station in Milwaukee, Wisconsin - Units 1 (80 MW), 2 (80 MW), 3 (80 MW), and 4 (80 MW).

IV. UNITS TO BE CONTROLLED OR RETIRED

54. Wisconsin Electric shall either satisfy the emission control requirements of Paragraphs 55 and 70 with regard to the following Units or retire and permanently cease to operate the following Units within the Wisconsin Electric System by the following dates:

Unit	**Date by which Wisconsin Electric Must Control or Cease to Operate Unit**
Port Washington Unit 4	Upon Entry of this Consent Decree
Port Washington Unit 1	December 31, 2004
Port Washington Unit 2	December 31, 2004
Port Washington Unit 3	December 31, 2004
Oak Creek Unit 5	December 31, 2012
Oak Creek Unit 6	December 31, 2012
Presque Isle Unit 1	December 31, 2012
Presque Isle Unit 2	December 31, 2012
Presque Isle Unit 3	December 31, 2012
Presque Isle Unit 4	December 31, 2012

V. NO_x EMISSION REDUCTIONS AND CONTROLS

A. NO_x Emission Controls

55. Wisconsin Electric shall install and commence continuous operation of Selective Catalytic Reduction technology ("SCR") (or equivalent NO_x control technology approved pursuant to Paragraph 56) so as to achieve a 30-Day Rolling Average Emission Rate not greater than 0.100 lb/mmBTU NO_x on the following Units within the Wisconsin Electric System by the following dates:

Unit	Date by Which Wisconsin Electric Must Complete Installation and Continuously Operate SCR
Pleasant Prairie Unit 2	December 31, 2003
Pleasant Prairie Unit 1	December 31, 2006
Oak Creek Unit 7	December 31, 2012
Oak Creek Unit 8	December 31, 2012

56. With prior written notice to and approval from EPA, Wisconsin Electric may, in lieu of installing and operating any such SCR, install and operate equivalent NO_x control technology so long as such equivalent NO_x control technology achieves a 30-Day Rolling Average Emission Rate not greater than 0.100 lb/mmBTU NO_x.

57. Wisconsin Electric shall continuously operate SCR (or equivalent NOx control technology approved pursuant to Paragraph 56) at all times that the Unit it serves is in operation consistent with the technological limitations, manufacturers' specifications, and good operating practices, for the SCR or equivalent technology.

58. Wisconsin Electric shall also operate either low NO_x burners ("LNB") or combustion control technology on the following Units within the Wisconsin Electric System. Such low-NO_x burner or combustion control technology shall be operational in accordance with the following schedule:

Units to be Controlled	NO_x Control	Deadline for Commencement of Operation
Valley Boiler 1	LNB and Combustion Optimization Software (Existing LNB and Combustion Optimization Software)	30 days after the date of lodging of this Consent Decree
Valley Boiler 2	LNB and Combustion Optimization Software (Existing LNB and Combustion Optimization Software)	30 days after the date of lodging of this Consent Decree
Valley Boiler 3	LNB and Combustion Optimization Software (Existing LNB and Combustion Optimization Software)	30 days after the date of lodging of this Consent Decree
Valley Boiler 4	LNB and Combustion Optimization Software (Existing LNB and Combustion Optimization Software)	30 days after the date of lodging of this Consent Decree
Presque Isle Unit 5	LNB and Combustion Optimization Software	December 31, 2003
Presque Isle Unit 6	LNB and Combustion Optimization Software	December 31, 2003
Presque Isle Unit 7	LNB and Combustion Optimization Software (Existing LNB)	December 31, 2005
Presque Isle Unit 8	LNB and Combustion Optimization Software (Existing LNB)	December 31, 2005
Presque Isle Unit 9	LNB and Combustion Optimization Software (Existing LNB)	December 31, 2006

B. System-Wide NO_x Emission Limits

59. Wisconsin Electric shall not exceed the Wisconsin Electric System-wide 12-Month Rolling Average Emission Rates for NO_x as specified below:

Beginning on	**System-wide 12-Month Rolling Average Emission Rate for NO_x**
January 1, 2005	0.270 lbs/mmBTU
January 1, 2007	0.190 lbs/mmBTU
January 1, 2013	0.170 lbs/mmBTU

60. In addition to meeting the system-wide emission limit set forth in the preceding Paragraph, Wisconsin Electric shall not emit NO_x on a System-wide 12-Month Rolling Tonnage basis from the Wisconsin Electric System in an amount greater than the following number of tons:

Beginning on	**System-wide 12-Month Rolling Tonnage Limitation for NO_x**
January 1, 2005	31,500 tons
January 1, 2007	23,400 tons
January 1, 2013	17,400 tons

Wisconsin Electric shall meet the above NO_x tonnage limitations exclusively through the operation of all control equipment required to be installed and operated by this Decree, Unit retirements, and any additional control equipment that Wisconsin Electric installs and operates. Wisconsin Electric shall not use NO_x allowances or credits to comply with these limitations.

C. NOx Emission Limitations at Presque Isle Units 1 and 2

61. In addition to meeting the System-wide 12-Month Rolling Tonnage limitations for NO_x set forth in Paragraph 60, after December 31, 2003, Wisconsin Electric shall not emit NO_x from the Units 1 and 2 at the Presque Isle Generating Plant in an amount greater than 130 and 194 tons per year, respectively, based upon a Unit-Specific 12-Month Rolling Tonnage. If a Unit exceeds the applicable Unit-Specific 12-Month Rolling Tonnage limitation specified in this Paragraph, Wisconsin Electric shall install and operate LNB technologies on that Unit no later than December 31 of the calendar year following such exceedance.

62. So long as Units 1 through 4 at the Presque Isle Generating Station discharge through a common stack, are of the same design and combust the same fuel, Wisconsin Electric shall determine monthly mass emissions of NO_x by apportioning NO_x emissions from the common stack to Units 1 and 2. To apportion emissions, Wisconsin Electric shall utilize the load based apportionment protocol used in the Acid Rain Program to apportion heat rates to units that share a common stack. Each month, Wisconsin Electric shall calculate the Unit-Specific 12-month Rolling Tonnage of NO_x mass (tons/year) attributed to Units 1 and 2.

D. Use of NO_x Emission Allowances

63. For any and all actions taken by Wisconsin Electric to conform to the requirements of this Consent Decree, Wisconsin Electric shall not use, sell, or trade any resulting NO_x emission allowances or credits in any emission trading or marketing program of any kind, except as provided in this Consent Decree.

64. NO_x emission allowances or credits allocated to the Wisconsin Electric System by the Administrator of EPA under the Act, or by any State under its State Implementation Plan,

may be used by Wisconsin Electric to meet its own federal and/or state Clean Air Act regulatory requirements for any Existing Unit or New Unit owned or operated, in whole or in part, by Wisconsin Electric.

65. Nothing in this Consent Decree shall preclude Wisconsin Electric from using, selling, or transferring NO_x emission reductions below the emission requirements of Wi. Admin. Code NR 428 among the units in the Wisconsin Electric System in order to demonstrate compliance with either Wi. Admin. Code NR 428 or Mich. Admin. Code Rule 801. Use of emission reductions generated from the Wisconsin Electric System to comply with the requirements of Mich. Admin. Code Rule 801 will conform to the Memorandum of Understanding ("MOU") among the State of Wisconsin, the State of Michigan and Wisconsin Electric, dated November 8, 2002, as that MOU may be amended from time to time.

66. Nothing in this Consent Decree shall preclude Wisconsin Electric from using, selling or transferring excess NO_x emission allowances or credits that may arise as a result of:

a. activities which occur prior to the date of entry of this Consent Decree;

b. achieving NO_x emission reductions at an Improved Unit that are below both the 30-Day Rolling Average Emission Rate of 0.100 lb/mmBTU NO_x and the System-wide 12-Month Rolling Tonnage limitations set forth in this Consent Decree; or

c. the NO_x emission reductions achieved by virtue of Wisconsin Electric's installation and operation any NO_x pollution controls prior to the dates required under Section V (NO_x Emission Reductions and Controls) of this Consent Decree, so long as Wisconsin Electric timely reports the creation of such allowances or credits in accordance with Section XII of this Consent Decree. For purposes of this Paragraph, excess NO_x emission allowances or credits equal the number of tons of NO_x that Wisconsin Electric removed from its emissions that are in excess of the NO_x reductions required by this Decree.

67. Wisconsin Electric may not purchase or otherwise obtain NO_x allowances or credits from another source for purposes of complying with the requirements of this Consent Decree. However, nothing in this Consent Decree shall prevent Wisconsin Electric from purchasing or otherwise obtaining NO_x allowances or credits from another source for purposes of complying with state or federal Clean Air Act requirements to the extent otherwise allowed by law.

E. General NO_x Provisions

68. In determining Emission Rates for $NO_{x,}$ Wisconsin Electric shall use CEMs in accordance with those reference methods specified in 40 C.F.R. Part 75.

69. In calculating the 30-day Rolling Average Emission Rate or System-wide 12-Month Rolling Average Emission Rate for NO_x for a given Unit or group of Units, Wisconsin Electric shall not exclude any period of time that the Unit(s) is/are in operation, including periods in which any NO_x emission control technology for the Unit(s) is not in operation.

VI. SO_2 EMISSION REDUCTIONS AND CONTROLS

A. SO_2 Emission Controls

1. New FGD Installations

70. Wisconsin Electric shall install and commence continuous operation of Flue Gas Desulfurization technology ("FGD") (or equivalent SO_2 control technology approved pursuant to Paragraph 71) so as to achieve either a 30-Day Rolling Average Emission Rate of not greater than 0.100 lb/mmBTU SO_2 or a 30-day Rolling Average SO_2 Removal Efficiency of at least 95 percent on the following Units within the Wisconsin Electric System by the dates specified below:

Unit	Date by which Wisconsin Electric Must Complete Installation and Continuously Operate FGD
Pleasant Prairie Unit 1	December 31, 2006
Pleasant Prairie Unit 2	December 31, 2007
Oak Creek Unit 7	December 31, 2012
Oak Creek Unit 8	December 31, 2012

71. In lieu of installing and operating such FGDs, Wisconsin Electric may, with prior written notice to and approval from EPA, install and operate equivalent SO_2 control technology, so long as such equivalent SO_2 control technology achieves a 30-Day Rolling Average Emission Rate of not greater than 0.100 lb/mmBTU SO_2 or a 30-day Rolling Average Removal Efficiency of at least 95 percent.

72. Wisconsin Electric shall continuously operate each FGD (or equivalent SO_2 control technology approved pursuant to Paragraph 71) in the Wisconsin Electric System at all

times that the Unit it serves is in operation, except that, following startup of the Unit, Wisconsin Electric need not operate such control technology until the Unit is fired with any coal. Wisconsin Electric shall use good operating practices at all times that the Unit is in operation.

B. System-Wide SO_2 Emission Limits

73. Wisconsin Electric shall not exceed the Wisconsin Electric System-Wide 12-Month Rolling Average Emission Rates for SO_2 as specified below:

Beginning on	**System-wide 12-Month Rolling Average Emission Rate for SO_2**
January 1, 2005	0.76 lbs/mmBTU
January 1, 2007	0.61 lbs/mmBTU
January 1, 2008	0.45 lbs/mmBTU
January 1, 2013	0.32 lbs/mmBTU

74. In addition to installing the controls, retiring Units, achieving the SO_2 Emission Rates or Removal Efficiencies described in Paragraph 70, and surrendering the SO_2 Allowances required in this Consent Decree, Wisconsin Electric shall not emit SO_2 on a System-wide 12-Month Rolling Tonnage basis from the Wisconsin Electric System in an amount greater than the following number of tons:

Beginning on	**System-wide 12-Month Rolling Tonnage Limit for SO_2**
January 1, 2005	86,900 tons
January 1, 2007	74,400 tons
January 1, 2008	55,400 tons
January 1, 2013	33,300 tons

Wisconsin Electric shall meet the above SO_2 tonnage limitations exclusively through the operation of all control equipment required to be installed and operated by this Decree, Unit retirements, and any additional control equipment that Wisconsin Electric installs and operates. Wisconsin Electric shall not use SO_2 allowances or credits to comply with these limitations.

C. Surrender of SO_2 Allowances

75. For purposes of this Subsection, the "surrender of allowances" means permanently surrendering allowances from the accounts administered by EPA for all units in the Wisconsin Electric System, so that such allowances can never be used to meet any compliance requirement under the Clean Air Act, the Michigan or Wisconsin State Implementation Plans, or this Consent Decree.

76. Beginning on January 1, 2004, Wisconsin Electric may use any SO_2 Allowances allocated by EPA to the Wisconsin Electric System only to satisfy the operational needs of Existing Units or New Units. Wisconsin Electric shall not sell or transfer any allocated SO_2 Allowances to a third party, except as provided in Paragraphs 77, 78 and 81 below. However, for the calendar years 2004 through 2007, Wisconsin Electric may bank SO_2 allowances allocated by EPA to the Units in the Wisconsin Electric System for use at the Existing Units or New Units during the years 2004 through 2007.

77. For each calendar year, beginning with calendar year 2007, Wisconsin Electric shall surrender to EPA, or transfer to a non-profit third party selected by Wisconsin Electric for surrender, any SO_2 Allowances that exceed the operational needs of the Existing Units and New Units for SO_2 Allowances, collectively. Surrender shall occur annually thereafter and within 45 days of Wisconsin Electric's receipt from EPA of the Annual Deduction Reports for SO_2. In

addition, in calendar year 2008, Wisconsin Electric shall surrender any allowances allocated by EPA to the Units in the Wisconsin Electric System that were banked and not used during the years 2004 through 2007. Wisconsin Electric shall surrender SO_2 Allowances by the use of applicable United States Environmental Protection Agency Acid Rain Program Allowance Transfer Form.

78. If any allowances are transferred directly to a third party, Wisconsin Electric shall include a description of such transfer in the next report submitted to the Plaintiffs pursuant to Section XII (Periodic Reporting) of this Consent Decree. Such report shall: (i) provide the identity of the non-profit third-party recipient(s) of the SO_2 Allowances and a listing of the serial numbers of the transferred SO_2 Allowances; and (ii) include a certification by the third-party recipient(s) stating that the recipient will not sell, trade, or otherwise exchange any of the allowances and will not use any of the SO_2 Allowances to meet any obligation imposed by any environmental law. No later than the next Section XII periodic report due 12 months after the first report due after the transfer, Wisconsin Electric shall include in a statement that the third-party recipient(s) surrendered the SO_2 Allowances for permanent surrender to EPA within one year after Wisconsin Electric transferred the SO_2 Allowances to them. Wisconsin Electric shall not have complied with the SO_2 Allowance surrender requirements of this Paragraph until all third-party recipient(s) shall have actually surrendered the transferred SO_2 Allowances to EPA.

79. For all SO_2 Allowances surrendered to EPA, Wisconsin Electric shall first submit an SO_2 Allowance transfer request form to EPA's Office of Air and Radiation's Clean Air Markets Division directing the transfer of the SO_2 Allowances held or controlled by Wisconsin Electric to the EPA Enforcement Surrender Account or to any other EPA account that EPA may

direct. As part of submitting these transfer requests, Wisconsin Electric shall irrevocably authorize the transfer of these SO_2 Allowances and identify -- by name of account and any applicable serial or other identification numbers or station names -- the source and location of the SO_2 Allowances being surrendered.

80. The requirements in Paragraphs 76 and 77 of this Decree pertaining to Wisconsin Electric's use and retirement of SO_2 Allowances are permanent injunctions not subject to any termination provision of this Decree. These provisions shall survive any termination of this Decree in whole or in part.

81. Notwithstanding the provisions in Paragraph 76 and 77, nothing in this Consent Decree shall preclude Wisconsin Electric from using, banking, selling or transferring excess emission SO_2 allowances that may arise as a result of:

a. activities which occur prior to the date of entry of this Consent Decree;

b. achieving SO_2 emissions at an Improved Unit that are below both the 30-Day Rolling Average Emission Rate of 0.100 lb/mmBTU SO_2 and the System-wide 12-Month Rolling Tonnage limitations set forth in this Consent Decree;

c. achieving a 30-Day Rolling Average Removal Efficiency at an Improved Unit greater than 95 percent and achieving emissions below the System-wide 12-Month Rolling Tonnage limitations set forth in this Consent Decree; or

d. the installation and operation of any SO_2 pollution controls prior to the dates required under Section VI (SO_2 Emission Reductions and Controls) of this Consent Decree so long as Wisconsin Electric timely reports such use under Section XII. For purposes of this paragraph, excess SO_2 emission allowances equal the number of tons of SO_2 that Wisconsin Electric removed from its emissions that are in excess of the SO_2 reductions required by this Decree.

D. Fuel Limitations

82. Wisconsin Electric shall not burn coal having a sulfur content greater than any amount authorized by regulation or state permit at any Wisconsin Electric System Unit. Upon entry of the Consent Decree, Wisconsin Electric shall not receive petroleum coke at any Unit that is not controlled by an FGD (or equivalent SO_2 control technology approved pursuant to Paragraph 71), except that Wisconsin Electric may continue to receive petroleum coke at Presque Isle Units 1 through 6 until June 30, 2006.

E. General SO_2 Provisions

83. In determining Emission Rates for SO_2, Wisconsin Electric shall use CEMs in accordance with those reference methods specified in 40 C.F.R. Part 75 and 40 C.F.R. Part 60.

84. For Units that are required to be equipped with SO_2 control equipment and that are subject to the 95% removal provisions, the outlet SO_2 Emission Rate and the inlet SO_2 Emission Rate shall be determined in accordance with 40 C.F.R. § 75.15 (using SO_2 CEMS data from both the inlet and outlet of the control device). For Units that are required to meet a 0.100 lb/mmBTU limitation, the SO_2 Emission Rate shall be determined only at the outlet of the control equipment in accordance with 40 C.F.R. § 75.15 (using SO_2 CEMS data from only the outlet of the control device).

VII. PM EMISSION REDUCTIONS AND CONTROLS

A. Optimization of PM Controls

85. Within 45 days of lodging of this Consent Decree and continuing thereafter, Wisconsin Electric shall continuously operate each Particulate Matter Control Device on its Existing Units to maximize PM emission reductions, consistent with the operational and maintenance limitations of the Units. Specifically, Wisconsin Electric shall, at a minimum: (a) energize each section of the ESP for each Unit, regardless of whether that action is needed to comply with opacity limits; (b) maintain the energy or power levels delivered to the ESPs for each Unit to achieve the greatest possible removal of PM; (c) make best efforts to expeditiously repair and return to service transformer-rectifier sets when they fail; and (d) maintain an ongoing bag leak detection and replacement program to assure optimal operation of each BH.

B. Upgrade of PM Controls

86. Within 365 days of lodging of this Consent Decree, Wisconsin Electric shall operate each of the ESPs and BHs within the Wisconsin Electric System, except Units 5 and 6 at the Presque Isle Generating Station, to achieve and maintain a PM Emission Rate of 0.030 lb/mmBTU. Presque Isle Unit 5 shall achieve and maintain a PM Emission Rate of 0.030 lb/mmBTU by June 30, 2005 and Presque Isle Unit 6 shall achieve and maintain a PM Emission Rate of 0.030 lb/mmBTU by June 30, 2006.

87. Wisconsin Electric shall continuously operate each ESP and BH in the Wisconsin Electric System at all times that the Unit it serves is combusting coal. Wisconsin Electric shall use good operating practices at all times that the Unit is combusting coal.

C. PM Monitoring

1. PM Stack Tests

88. Beginning in calendar year 2004, and continuing annually thereafter, Wisconsin Electric shall conduct a performance test on each Wisconsin Electric System Unit. The annual stack test requirement imposed on each Wisconsin Electric System Unit by this Paragraph may be satisfied by Wisconsin Electric's stack tests conducted as required by its permits from the States of Michigan and Wisconsin for any year that such stack tests are required under the permits. Wisconsin Electric may perform biannual rather than annual testing provided that (a) two of the most recently completed test results from tests conducted in accordance with Method 5 or Method 17 demonstrate that the particulate matter emissions are equal to or less than a 0.015 lb/mmBTU emission limitation, or (b) the Unit is equipped with a PM CEMS in accordance with Paragraph 93. Wisconsin Electric shall perform annual rather that biannual testing the year immediately following any test result demonstrating that the particulate matter emissions are greater than a 0.015 lb/mmBTU emission limitation.

89. The reference and monitoring methods and procedures for determining compliance with Emission Rates for PM shall be those specified in 40 C.F.R. Part 60, Appendix A, Method 5 or Method 17. Use of any particular method shall conform to the EPA requirements specified in 40 C.F.R. Part 60, Appendix A and 40 C.F.R. § 60.48a (b) and (e), or any federally approved SIP method. Wisconsin Electric shall calculate the PM Emission Rates from the stack test results in accordance with 40 C.F.R. § 60.8(f), and 40 C.F.R. § 60.46a(c). The results of each PM stack test shall be submitted to EPA within 45 days of completion of each test.

90. The PM Emission Rates established under Paragraph 86 of this Section shall not apply during periods of startup and shutdown or during periods of control equipment or Unit Malfunction, if the Malfunction meets the requirements of the Force Majeure section of this Consent Decree. Periods of startup shall not exceed two hours after any amount of coal is combusted. Periods of shutdown shall only commence when the Unit ceases burning any amount of coal.

2. PM CEMS

91. Wisconsin Electric shall undertake a program to install and operate Continuous Emission Monitoring System for Particulate Matter ("PM CEMS"). Each PM CEMS shall be comprised of a continuous particle mass monitor measuring particulate matter concentration, directly or indirectly, on an hourly average basis and a diluent monitor used to convert results to units of lb/mmBTU. Wisconsin Electric shall maintain, in an electronic database, the hourly average emission values of all PM CEMS in lb/mmBTU. Wisconsin Electric shall use reasonable efforts to keep each PM CEMS running and producing data whenever any Unit served by the PM CEMS is operating.

92. No later than one year prior to the deadline to commence operation as set forth in Paragraph 93, Wisconsin Electric shall submit to EPA for review and approval a plan for the installation and certification of each PM CEMS.

93. Wisconsin Electric shall install, certify, and operate PM CEMS on 10 Units, stacks or common stacks in accordance with the following schedule:

Unit	Deadline to Commence Operation	Location
Presque Isle Units 1-4	April 1, 2006	Common Outlet Flue at Stack
Presque Isle Unit 5	April 1, 2006	Stack
Presque Isle Unit 6	April 1, 2006	Stack
Presque Isle Units 7-9	April 1, 2006	Common Outlet Duct of TOXECON
Oak Creek Units 5&6	April 1, 2005	Common Stack
Oak Creek Unit 7	April 1, 2005	Precipitator Outlet Duct
Oak Creek Unit 8	April 1, 2005	Precipitator Outlet Duct
Pleasant Prairie Units 1&2	April 1, 2005	Common Stack
Valley Unit 1	April 1, 2006	Common Stack
Valley Unit 2	April 1, 2006	Common Stack

94. Notwithstanding the requirements of Paragraph 93, by April 1, 2005, Wisconsin Electric may install two mercury CEMS, one of which will be installed at Pleasant Prairie Unit 1 or Unit 2, and one of which will be installed at Oak Creek Unit 7 or Unit 8, in lieu of a PM CEMS on Presque Isle Units 1 through 4 and one of the units at Valley.

95. No later than 120 days prior to the deadline to commence operation of each PM CEMS, Wisconsin Electric shall submit to EPA for approval pursuant to Section XIII (Review and Approval of Submittals) a proposed Quality Assurance/Quality Control ("QA/QC") protocol that shall be followed in calibrating such PM CEMS. Following EPA's approval of the protocol, Wisconsin Electric shall thereafter operate each PM CEMS in accordance with the approved protocol.

96. In developing both the plan for installation and certification of the PM CEMS and the QA/QC protocol, Wisconsin Electric may use the criteria set forth in EPA's proposed revisions to Performance Specification 11: Specification and Test Procedures for PM CEMS and Procedure 2: PM CEMS at Stationary Sources (PS 11), as published at 66 Fed. Reg 64176 (December 12, 2001) or other available PM CEMS guidance.

97. No later than 90 days after Wisconsin Electric begins operation of the PM CEMS, Wisconsin Electric shall conduct tests of each PM CEMS to demonstrate compliance with the PM CEMS plan submitted to and approved by EPA in accordance with Paragraph 92.

98. If after Wisconsin Electric operates the PM CEMS for at least two years, and if the Parties then agree that it is infeasible to continue operating PM CEMS, Wisconsin Electric shall submit an alternative PM monitoring plan for review and approval by EPA. The plan shall include an explanation of the basis for stopping operation of the PM CEMS and a proposal for an alternative monitoring protocol. Until EPA approves such plan, Wisconsin Electric shall continue to operate the PM CEMS.

99. Operation of a PM CEMS shall be considered "infeasible" if (a) the PM CEMS cannot be kept in proper condition for sufficient periods of time to produce reliable, adequate, or useful data consistent with the QA/QC protocol; or (b) Wisconsin Electric demonstrates that recurring, chronic, or unusual equipment adjustment or servicing needs in relation to other types of continuous emission monitors cannot be resolved through reasonable expenditures of resources. If the United States determines that Wisconsin Electric has demonstrated infeasibility pursuant to this Paragraph, Wisconsin Electric shall be entitled to discontinue operation of and remove the PM CEMS.

3. PM Reporting

100. Following the installation of each PM CEMS, Wisconsin Electric shall begin and continue to report to EPA, pursuant to Section XII, the data recorded by the PM CEMS, expressed in lb/mmBTU on a 3-hour, 24-hour, 30-day, and 365-day rolling average basis in electronic format, as required in Paragraph 91.

D. General PM Provisions

101. In determining the PM Emission Rate, Wisconsin Electric shall use the reference methods specified in 40 C.F.R. Part 60, Appendix A, Method 5 or Method 17, using stack tests, or alternative methods that are either promulgated by EPA or requested by Wisconsin Electric and approved by EPA. Wisconsin Electric shall also calculate the PM Emission Rates from annual (or biannual) stack tests in accordance with 40 C.F.R. § 60.8(f). Wisconsin Electric shall also determine PM Emission Rates using PM CEMS consistent with the approved QA/QC protocol.

102. Data from the PM CEMS shall be used by Wisconsin Electric, at a minimum, to monitor progress in reducing PM emissions. Nothing in this Consent Decree is intended to, or shall, alter or waive any applicable law (including any defenses, entitlements, challenges, or clarifications related to the Credible Evidence Rule, 62 Fed. Reg. 8315 (Feb. 27, 1997)) concerning the use of data for any purpose under the Act, generated either by the reference methods specified herein or otherwise.

VIII. PROHIBITION ON NETTING CREDITS OR OFFSETS FROM REQUIRED CONTROLS

103. For any and all actions taken by Wisconsin Electric to comply with the requirements of this Consent Decree, including but not limited to the upgrade of ESPs and BHs, the installation of FGDs, SCRs, or equivalent control devices approved under this Consent Decree, the re-powering of certain units, the retirement of certain units, and the reduction of emissions to satisfy annual emission tonnage limitations, any emission reductions generated shall not be considered as a creditable contemporaneous emission decrease for the purpose of obtaining a netting credit under the Clean Air Act's Nonattainment NSR and PSD programs. Notwithstanding the preceding sentence, Wisconsin Electric may use any creditable contemporaneous emission decreases of Volatile Organic Compounds ("VOCs") generated under this Consent Decree for the purpose of obtaining a netting credit for VOCs under the Clean Air Act's Nonattainment NSR and PSD programs.

104. Nothing in this Consent Decree is intended to preclude the emission reductions generated under this Decree from being considered as creditable contemporaneous emission decreases for the purpose of attainment demonstrations submitted pursuant to § 110 of the Act, 42 U.S.C. § 7410, or in determining impacts on NAAQS and PSD increment consumption.

IX. ENVIRONMENTAL PROJECTS

105. Wisconsin Electric, in cooperation with the United States Department of Energy ("DOE") and potentially other parties, shall design, construct, operate and analyze the first full scale TOXECON with activated carbon injection with the goal of achieving a 90% removal of all species of mercury ("the TOXECON Project"). The TOXECON Project will be implemented at Units 7, 8, and 9 of Wisconsin Electric's Presque Isle Generating Station.

106. At least six months before it plans to commence implementation of the TOXECON Project, Wisconsin Electric shall submit to the Plaintiff for review and approval pursuant to Section XIII of this Consent Decree a plan for the implementation of the TOXECON Project, including the date by which Wisconsin Electric will commence design and construction of the Project, and the date by which Wisconsin Electric will complete the Project. To the extent that any change to the TOXECON Project may be required, Wisconsin Electric shall notify the Plaintiff of such change within 60 days of becoming aware a change is necessary. Wisconsin Electric shall implement the TOXECON Project in compliance with the schedules and terms of this Consent Decree and the plans for such Project approved under this Decree.

107. For purposes of this Consent Decree, in performing the TOXECON Project, Wisconsin Electric shall, prior to December 31, 2006, spend no less than $20 million, and shall not be required to spend more than $25 million, in Project Dollars (measured in calendar year 2003 constant dollars). Wisconsin Electric shall maintain all documents required by Generally Accepted Accounting Principles to substantiate the Project Dollars spent by Wisconsin Electric, and shall provide copies of these documents to the Plaintiff within 30 days of a request by the Plaintiff for these documents.

108. All plans and reports prepared by Wisconsin Electric pursuant to the requirements of this Section in this Consent Decree shall be publicly available without charge, subject to the limitations contained in Paragraph 172.

109. Wisconsin Electric shall certify, as part of each plan submitted to the United States for any Project, that it is unaware of any person required by law, other than this Consent Decree, to perform the Project described in the plan.

110. Wisconsin Electric shall use good faith efforts to secure as much benefit as possible for the Project Dollars expended, consistent with the applicable requirements and limits of this Consent Decree.

111. Within 60 days following the completion of the TOXECON Project, Wisconsin Electric shall submit to the EPA a report that documents the date that the Project was completed, Wisconsin Electric's results of implementing the Project, including the emission reductions or other environmental benefits achieved, and the Project Dollars expended by Wisconsin Electric in implementing the Project.

112. Following completion of the TOXECON Project, Wisconsin Electric shall maintain the baghouse component of the TOXECON in the flue gas stream regardless of the results of the demonstration project. If Wisconsin Electric determines that the demonstration project has removed reasonable levels of mercury and is operationally viable, Wisconsin Electric shall also continue sorbent injection for mercury control.

113. Wisconsin Electric shall not financially benefit from the sale or transfer of the TOXECON technology or the collection or distribution of information collected during this demonstration project.

114. Wisconsin Electric shall provide the United States with semi-annual updates concerning the progress of the TOXECON Project. Wisconsin Electric also shall make information concerning the performance of the TOXECON Project available to the public in an expeditious matter, consistent with DOE's requirements concerning the disclosure of project information and subject to the limitations contained in Paragraph 172. Such information disclosure shall include, but not be limited to, release of periodic progress reports, clearly

identifying demonstrated removal efficiencies of mercury and other pollutants, sorbent injection rates and cost effectiveness. In addition, periodic technology transfer open houses and plant tours shall be scheduled, consistent with DOE's requirements for disclosure of project information and subject to the limitations contained in Paragraph 172.

X. CIVIL PENALTY

115. Within thirty (30) calendar days of entry of this Consent Decree, Wisconsin Electric shall pay to the United States a civil penalty in the amount of $ 3.2 million. The civil penalty shall be paid by Electronic Funds Transfer ("EFT") to the United States Department of Justice, in accordance with current EFT procedures, referencing USAO File Number 2003V00451 and DOJ Case Number 90-5-2-1-07493 and the civil action case name and case number of this action, with notice given to the Plaintiff, in accordance with Section XX (Notices) of this Consent Decree. The costs of such EFT shall be Wisconsin Electric's responsibility. Payment shall be made in accordance with instructions provided to Wisconsin Electric by the Financial Litigation Unit of the U.S. Attorney's Office for the Eastern District of Wisconsin. Any funds received after 2:00 p.m. EDT shall be credited on the next business day. At the time of payment, Wisconsin Electric shall provide notice of payment, referencing the USAO File Number, DOJ Case Number 90-5-2-1-07493, and the civil action case name and case number, to the Department of Justice and to EPA, as provided in Paragraph 174 (Notice) of this Consent Decree.

116. Failure to timely pay the civil penalty shall subject Wisconsin Electric to interest accruing from the date payment is due until the date payment is made at the rate prescribed by 28 U.S.C. § 1961, and shall render Wisconsin Electric liable for all charges, costs, fees, and

penalties established by law for the benefit of a creditor or of the United States in securing payment.

117. Payments made pursuant to this Section are penalties within the meaning of Section 162(f) of the Internal Revenue Code, 26 U.S.C. § 162(f), and are not tax-deductible expenditures for purposes of federal law.

XI. RESOLUTION OF CLAIMS

A. RESOLUTION OF U.S. CIVIL CLAIMS

118. Claims Based on Modifications Occurring Before the Lodging of Decree. Entry of this Decree shall resolve all civil claims of the United States under either: (i) Parts C or D of Subchapter I of the Clean Air Act or (ii) 40 C.F.R. Section 60.14, that arose from any modifications that commenced at any Wisconsin Electric System Unit prior to the date of lodging of this Decree, including but not limited to those modifications alleged in the Complaint in this civil action.

119. Claims Based on Modifications After the Lodging of Decree. Entry of this Decree also shall resolve all civil claims of the United States for pollutants regulated under Parts C or D of Subchapter I of the Clean Air Act, and under regulations promulgated as of the date of lodging of this Decree, where such claims are based on a modification completed before December 31, 2015 and:

(a) commenced at any Wisconsin Electric System Unit after lodging of this Decree; or

(b) that this Consent Decree expressly directs Wisconsin Electric to undertake.

The term "modification" as used in this Paragraph shall have the meaning that term is given under the Clean Air Act statute as it existed on the date of lodging of this Decree.

120. Reopener. The resolution of the civil claims of the United States provided by this Subsection is subject to the provisions of Section B of this Section.

B. PURSUIT OF U.S. CIVIL CLAIMS OTHERWISE RESOLVED

121. Bases for Pursuing Resolved Claims Across Wisconsin Electric System. If Wisconsin Electric violates Paragraph 60 (System-wide NO_x Rolling Tonnage Limits), Paragraph 59 (System-wide NO_x Rolling Average Emission Rate), Paragraph 74 (System-wide Rolling SO_2 Tonnage Limits), Paragraph 73 (System-wide SO_2 Emission Rates), or Paragraph 82 (Fuel Limitation), or fails by more than ninety days to complete installation and commence operation of any emission control device required pursuant to Paragraphs 55 or 70; or fails by more than ninety days to control or retire and permanently cease to operate Wisconsin Electric System Units pursuant to Paragraph 54, then the United States may pursue any claim at any Wisconsin Electric System Unit that has otherwise been resolved under Subsection A of this Section, subject to (A) and (B) below.

(A) For any claims based on modifications undertaken at an Other Unit, claims may be pursued only where the modification(s) on which such claim is based was commenced within the five years preceding the violation or failure specified in this Paragraph.

(B) For any claims based on modifications undertaken at an Improved Unit, claims may be pursued only where the modification(s) on which such claim is based was commenced (i) after lodging of the Consent Decree and (ii) within the five years preceding the violation or failure specified in this Paragraph.

122. Additional Bases for Pursuing Resolved Claims for Modifications at an Improved Unit. Solely with respect to Improved Units, the United States may also pursue claims arising

from a modification (or collection of modifications) at an Improved Unit that has otherwise been resolved under Section A if the modification (or collection of modifications) at the Improved Unit on which such claim is based (i) was commenced after lodging of this Consent Decree, and (ii) individually (or collectively) increased the maximum hourly emission rate of that Unit for NO_x or SO_2 (as measured by 40 C.F.R. § 60.14 (b) and (h)) by more than ten percent (10%).

123. Additional Bases for Pursuing Resolved Claims for Modifications at an Other Unit. Solely with respect to Other Units, the United States may also pursue claims arising from a modification (or collection of modifications) at an Other Unit that has otherwise been resolved under Section XI. A if the modification (or collection of modifications) on which the claim is based was commenced within the five years preceding any of the following events:

(A) a modification (or collection of modifications) at such Other Unit commenced after lodging of this Consent Decree increases the maximum hourly emission rate for such Other Unit for the relevant pollutant (NO_x or SO_2) as measured by 40 C.F.R. § 60.14(b) and (h);

(B) the aggregate of all Capital Expenditures made at such Other Unit exceed $125/KW on the Unit's Boiler Island (based on the capacity numbers included in Paragraph 53) during any of the following five year periods: January 1, 2006 through December 31, 2010; January 1, 2011 through December 31, 2015. For the period from the date of lodging of this Decree through December 31, 2005, the $125/KW limit shall be pro-rated to include only that portion of the five-year period (January 1, 2000 through December 31, 2005) following the date of lodging of this Decree. (Capital Expenditures shall be measured in calendar year 2002 constant dollars, as adjusted by the McGraw-Hill Engineering News-Record Construction Cost Index); or

(C) a modification (or collection of modifications) at such Other Unit commenced after lodging of this Consent Decree results in an emissions increase of NO_x and/or SO_2 at such Other Unit, and such increase:

(1) presents, by itself, or in combination with other emissions or sources, "an imminent and substantial endangerment" within the meaning of Section 303 of the Act, 42 U.S.C. §7603;

(2) causes or contributes to violation of a National Ambient Air Quality Standard ("NAAQS") in any Air Quality Control Area that is in attainment with that NAAQS;

(3) causes or contributes to violation of a PSD increment; or

(4) causes or contributes to any adverse impact on any formally-recognized air quality and related values in any Class I area.

(D) Solely for purposes of Paragraph 123, Subparagraph (C), the determination of whether there was an emissions increase must take into account any emissions changes relevant to the modeling domain that have occurred or will occur under this Decree at other Wisconsin Electric System Units. In addition, an emissions increase shall be deemed to have occurred at an Other Unit if the annual emissions of the relevant pollutant (NO_x or SO_2) from the plant at which such modification(s) occurred exceed the Baseline for that plant.

(E) The introduction of any new or changed National Ambient Air Quality Standard shall not, standing alone, provide the showing needed under Paragraph 123, Subparagraphs

(C)(2) or (C)(3), to pursue any claim for a modification at an Other Unit resolved under Subsection A of this Section.

124. [RESERVED.]

XII. PERIODIC REPORTING

125. Within 180 days after each date established by this Consent Decree for Wisconsin Electric to achieve and maintain a certain Emission Rate or Removal Efficiency at any Wisconsin Electric System Unit, Wisconsin Electric shall conduct performance tests that demonstrate compliance with the Emission Rate or Removal Efficiency required by this Consent Decree. Within 45 days of each such performance test, Wisconsin Electric shall submit the results of the performance test to EPA at the addresses specified in Section XX (Notices) of this Consent Decree.

126. Beginning thirty days after the end of the first full calendar quarter following the entry of this Consent Decree or December 31, 2003, whichever is later, continuing on a semi-annual basis until December 31, 2015, and in addition to any other express reporting requirement in this Consent Decree, Wisconsin Electric shall submit to EPA a progress report.

127. The progress report shall contain the following information:

a. all information necessary to determine compliance with this Consent Decree;

b. all information relating to emission allowances and credits that Wisconsin Electric claims to have generated in accordance with Paragraphs 66 and 81 by compliance beyond the requirements of this Consent Decree; and

c. all information indicating that the installation and commencement of operation for a pollution control device may be delayed, including the nature and cause of the delay, and any steps taken by Wisconsin Electric to mitigate such delay.

128. In any periodic progress report submitted pursuant to this Section, Wisconsin Electric may incorporate by reference information previously submitted under its Title V permitting requirements, provided that Wisconsin Electric attaches the Title V permit report and provides a specific reference to the provisions of the Title V permit report that are responsive to the information sought in the periodic progress report.

129. In addition to the progress reports required pursuant to this Section, Wisconsin Electric shall provide a written report to EPA of any violation of the requirements of this Consent Decree, including exceedances of required Emission Rates, removal efficiencies, and Unit-Specific and System-wide Rolling Average Emission Rate and Rolling Tonnage limits, within 10 business days of when Wisconsin Electric knew or should have known of any such violation. In this report, Wisconsin Electric shall explain the cause or causes of the violation and all measures taken or to be taken by Wisconsin Electric to prevent such violations in the future.

130. Each Wisconsin Electric report shall be signed by Wisconsin Electric's Vice President Environmental, or, in his or her absence, General Counsel, or higher ranking official, and shall contain the following certification:

> This information was prepared either by me or under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my evaluation, or the directions and my inquiry of the person(s) who manage the system, or the person(s) directly responsible for gathering the information, I hereby certify under penalty of law that, to the best of my knowledge and belief, this information is

> true, accurate, and complete. I understand that there are significant penalties for submitting false, inaccurate, or incomplete information to the United States.

131. If any allowances are surrendered to any third party pursuant to Section VI.C of this Consent Decree, the third party's certification shall be signed by a managing officer of the third party and shall contain the following language:

> I certify under penalty of law that,_____________ [name of third party] will not sell, trade, or otherwise exchange any of the allowances and will not use any of the allowances to meet any obligation imposed by any environmental law. I understand that there are significant penalties for making false, inaccurate, or incomplete information to the United States.

XIII. REVIEW AND APPROVAL OF SUBMITTALS

132. Wisconsin Electric shall submit and complete each plan, report, or other item to the Plaintiff whenever such a document is required to be submitted for review or approval pursuant to this Consent Decree. EPA may approve the submittal or decline to approve it and provide written comments. Within 60 days of receiving written comments from EPA, Wisconsin Electric shall either: (i) alter the submittal consistent with the written comments and provide the revised submittal for final approval to EPA if called for in this Consent Decree; or (ii) submit the matter for dispute resolution, including the period of informal negotiations, under Section XVI (Dispute Resolution) of this Consent Decree.

133. Upon receipt of EPA's final approval of the submittal, or upon completion of the submittal pursuant to dispute resolution, Wisconsin Electric shall implement the submittal in accordance with the approved submittal.

XIV. STIPULATED PENALTIES

134. For any failure by Wisconsin Electric to comply with the terms of this Consent Decree, and subject to the provisions of Sections XV (Force Majeure) and XVI (Dispute

Resolution), Wisconsin Electric shall pay, within 30 days after written demand to Wisconsin Electric by the United States the following stipulated penalties to EPA:

Consent Decree Violation	**Stipulated Penalty (Per day per violation, unless otherwise specified)**
a. Failure to pay the civil penalty as specified in Section X (Civil Penalty) of this Consent Decree	$10,000
b. Failure to meet any 30-Day Rolling Average Emission Rate, any 30-Day Rolling Average Removal Efficiency, or any other Emission Rate or emission limitation (other than the System-wide 12-month Rolling Average Emission Rates, System-wide 12-month Rolling Tonnage limitations or any other 12-month rolling limitation), where the violation is less than 5% in excess of the limits set forth in this Consent Decree	$2,500
c. Failure to meet any 30-Day Rolling Average Emission Rate, any 30-Day Rolling Average Removal Efficiency, or any other Emission Rate or emission limitation (other than the System-wide 12-month Rolling Average Emission Rates, System-wide 12-month Rolling Tonnage limitations or any other 12-month rolling limitation), where the violation is equal to or greater than 5% but less than 10% in excess of the limits set forth in this Consent Decree	$5,000
d. Failure to meet any 30-Day Rolling Average Emission Rate, any 30-Day Rolling Average Removal Efficiency, or any other Emission Rate or emission limitation (other than the System-wide 12-month Rolling Average Emission Rates, System-wide 12-month Rolling Tonnage limitations or any other 12-month rolling limitation), where the violation is equal to or greater than 10% in excess of the limits set forth in this Consent Decree	$10,000
e. Failure to meet any System-wide 12-month Rolling Average Emission Rate, where the violation is less than 5% in excess of the limits set forth in this Consent Decree	$2,500 per month

f. Failure to meet any System-wide 12-month Rolling Average Emission Rate, where the violation is equal to or greater than 5% but less than 10% in excess of the limits set forth in this Consent Decree	$5,000 per month
g. Failure to meet any System-wide 12-month Rolling Average Emission Rate, where the violation is equal to or greater than 10% in excess of the limits set forth in this Consent Decree	$10,000 per month
h. Failure to meet the System-wide 12-month Rolling SO_2 and NO_x Tonnage Limits as set out in Paragraphs 60 and 74 or any other the 12-month rolling tonnage limitation	$5,000 per ton per month for the first 100 tons over the limit, and $10,000 per ton per month for each additional ton over the limit
i. Failure to install, commence operation, or continue operation of the NO_x, SO_2, and PM pollution control devices on any Unit, or failure to retire a Unit	$10,000 during the first 30 days, $27,500 thereafter
j. Failure to meet the fuel use limitations at a Unit, as required by Paragraph 82	$10,000
k. Failure to install or operate CEMS as required in Paragraph 93, subject to Paragraph 99	$1,000
l. Failure to conduct annual or biannual performance tests of PM emissions, as required in Paragraph 88	$1,000
m. Failure to apply for the permits required by Paragraphs 165-167	$1,000
n. Failure to timely submit, modify, or implement, as approved, the reports, plans, studies, analyses, protocols, or other submittals required by this Consent Decree	$750 for the first ten days, $1,000 thereafter.

o. Using, selling, or transferring SO_2 Allowances, except as permitted by Paragraphs 76, 77 and 81	(a) three times the market value of the improperly used allowance, as measured at the time of the improper use, plus (b) the surrender, pursuant to the procedures set forth in Paragraphs 77 through 79 of this Decree, of SO_2 Allowances in an amount equal to the SO_2 Allowances used, sold, or transferred in violation of the Decree
p. Using, selling or transferring NOx allowances or credits except as permitted under Paragraph 64-66	(a) three times the market value of the improperly used allowance, as measured at the time of the improper use, plus (b) the surrender, pursuant to the procedures set forth in Section XII (Periodic Reporting) of this Decree, of NO_x allowances or credits in an amount equal to the NO_x allowances or credits used, sold, or transferred in violation of the Decree
q. Failure to surrender an SO_2 Allowance in accordance with Paragraph 77	(a) $27,500 plus (b) $1,000 per SO_2 Allowance
r. Failure to demonstrate the third-party surrender of an SO_2 Allowance in accordance with Paragraph 78	$2,500
s. Failure to undertake and complete any of the Environmental Projects in compliance with Section IX (Environmental Projects)	$1,000 for the first 30 days, $5,000 thereafter
t. Any other violation of this Consent Decree	$1,000

135. Violation of an Emission Rate or Removal Efficiency that is based on a 30-Day Rolling Average is a violation on every day on which the average is based. Violation of System-wide 12-Month Rolling Average Emission Rates, System-wide 12-Month Rolling Tonnage

Limitations or any other 12-month rolling limitation is a violation each month on which the average is based.

136. Where a violation of a 30-Day Rolling Average Emission Rate or Removal Efficiency (for the same pollutant and from the same source) recurs within periods less than 30 days, Wisconsin Electric shall not pay a daily stipulated penalty for any day of the recurrence for which a stipulated penalty has already been paid.

137. All stipulated penalties shall begin to accrue on the day after the performance is due or on the day a violation occurs, whichever is applicable, and shall continue to accrue until performance is satisfactorily completed or until the violation ceases. Nothing herein shall prevent the simultaneous accrual of separate penalties for separate violations of this Consent Decree.

138. Wisconsin Electric shall pay all stipulated penalties to the United States, in the manner set forth below in Paragraph 140, within 30 days of any violation of this Consent Decree, and shall continue to make such payments every 30 days thereafter until the violation(s) no longer continues, unless Wisconsin Electric elects within 20 days of the violation to dispute the accrual of stipulated penalties in accordance with the provisions in Section XVI (Dispute Resolution) of this Consent Decree.

139. Penalties shall continue to accrue as provided in accordance with Paragraph 137 during any dispute, with interest on accrued penalties payable and calculated at the rate established by the Secretary of the Treasury, pursuant to 28 U.S.C. § 1961, but need not be paid until the following:

a. If the dispute is resolved by agreement or by a decision of the Plaintiff that is not appealed to the Court, accrued penalties determined to be owing, together with accrued interest, shall be paid to the United States within thirty (30) days of the effective date of the agreement or the receipt of EPA's decision or order;

b. If the dispute is appealed to the Court and the Plaintiff prevails in whole or in part, Wisconsin Electric shall, within sixty (60) days of receipt of the Court's decision or order, pay all accrued penalties determined by the Court to be owing, together with accrued interest, except as provided in Subparagraph c, below;

c. If the District Court's decision is appealed by any Party, Wisconsin Electric shall, within fifteen (15) days of receipt of the final appellate court decision, pay all accrued penalties determined to be owing to the United States, together with accrued interest.

140. All stipulated penalties must be paid within thirty (30) days of the date payable, and payment shall be made in the manner set forth in Section X of this Consent Decree (Civil Penalty).

141. Should Wisconsin Electric fail to pay stipulated penalties in compliance with the terms of this Consent Decree, the United States shall be entitled to collect interest on such penalties, as provided for in 28 U.S.C. § 1961.

142. The stipulated penalties provided for in this Consent Decree shall be in addition to any other rights, remedies, or sanctions available to the United States by reason of Wisconsin Electric's failure to comply with any requirement of this Consent Decree or applicable law, except that for any violation of the Act for which this Consent Decree also provides for payment

of a stipulated penalty, Wisconsin Electric shall be allowed a credit for stipulated penalties paid against any statutory penalties imposed for such violation.

XV. FORCE MAJEURE

143. For purposes of this Consent Decree, a "Force Majeure Event" shall mean an event that has been or will be caused by circumstances beyond the control of Wisconsin Electric, its contractors, or any entity controlled by Wisconsin Electric that delays compliance with any provision of this Consent Decree or otherwise causes a violation of any provision of this Consent Decree despite Wisconsin Electric's best efforts to fulfill the obligation. "Best efforts to fulfill the obligation" include using best efforts to anticipate any potential Force Majeure Event and to address the effects of any such event (a) as it is occurring and (b) after it has occurred, such that the delay or violation is minimized to the greatest extent possible.

144. Notice. If any event occurs or has occurred that may delay compliance with or otherwise cause a violation of any obligation under this Consent Decree, as to which Wisconsin Electric intends to assert a claim of Force Majeure, Wisconsin Electric shall notify the Plaintiffs in writing as soon as practicable, but in no event later than fourteen (14) business days following the date Wisconsin Electric first knew, or by the exercise of due diligence should have known, that the Force Majeure Event caused or may cause such delay or violation. In this notice, Wisconsin Electric shall reference this Paragraph of this Consent Decree and describe the anticipated length of time that the delay or violation may persist, the cause or causes of the delay or violation, all measures taken or to be taken by Wisconsin Electric to prevent or minimize the delay or violation, the schedule by which Wisconsin Electric proposes to implement those measures, and Wisconsin Electric's rationale for attributing a delay or violation to a Force

Majeure Event. Wisconsin Electric shall adopt all reasonable measures to avoid or minimize such delays or violations. Wisconsin Electric shall be deemed to know of any circumstance of which Wisconsin Electric, its contractors, or any entity controlled by Wisconsin Electric knew or should have known.

145. Failure to Give Notice. If Wisconsin Electric fails to comply with the notice requirements of this Section, the EPA may void Wisconsin Electric's claim for Force Majeure as to the specific event for which Wisconsin Electric has failed to comply with such notice requirement.

146. Plaintiff's Response. The EPA shall notify Wisconsin Electric in writing regarding Wisconsin Electric's claim of Force Majeure within (20) twenty business days of receipt of the notice provided under Paragraph 144. If EPA agrees that a delay in performance has been or will be caused by a Force Majeure Event, the Parties shall stipulate to an extension of deadline(s) for performance of the affected compliance requirement by a period not to exceed the delay actually caused by the event. In such circumstances, an appropriate modification shall be made pursuant to Section XXIV of this Consent Decree (Modification).

147. Disagreement. If EPA does not accept Wisconsin Electric's claim of Force Majeure, the matter shall be resolved in accordance with Section XVI of this Consent Decree (Dispute Resolution).

148. Burden of Proof. In any dispute regarding Force Majeure, Wisconsin Electric shall bear the burden of proving that any delay in performance or any other violation of any requirement of this Consent Decree was caused by or will be caused by a Force Majeure Event. Wisconsin Electric shall also bear the burden of proving that Wisconsin Electric gave the notice

required by this Section and the anticipated duration and extent of any delay(s) attributable to a Force Majeure Event. An extension of one compliance date based on a particular event may, but will not necessarily, result in an extension of a subsequent compliance date.

149. Events Excluded. Unanticipated or increased costs or expenses associated with the performance of Wisconsin Electric's obligations under this Consent Decree shall not constitute a Force Majeure Event.

150. Potential Force Majeure Events. The Parties agree that, depending upon the circumstances related to an event and Wisconsin Electric's response to such circumstances, the kinds of events listed below are among those that could qualify as Force Majeure Events within the meaning of this Section: construction, labor, or equipment delays; Malfunction of a Unit or emission control device; natural gas and gas transportation availability delay; acts of God; acts of war or terrorism; and orders by a government official, government agency, or other regulatory body acting under and authorized by applicable law that directs Wisconsin Electric to supply electricity in response to a system-wide (state-wide or regional) emergency. Depending upon the circumstances and Wisconsin Electric's response to such circumstances, failure of a permitting authority to issue a necessary permit in a timely fashion may constitute a Force Majeure Event where the failure of the permitting authority to act is beyond the control of Wisconsin Electric and Wisconsin Electric has taken all steps available to it to obtain the necessary permit, including, but not limited to, submitting a complete permit application, responding to requests for additional information by the permitting authority in a timely fashion, accepting lawful permit terms and conditions, and prosecuting in an expeditious fashion appeals of any allegedly unlawful terms and conditions imposed by the permitting authority.

151. As part of the resolution of any matter submitted to this Court under this Section, the Parties by agreement, or this Court by order, may in appropriate circumstances extend or modify the schedule for completion of work under this Consent Decree to account for the delay in the work that occurred as a result of any delay agreed to by EPA or approved by this Court. Wisconsin Electric shall be liable for stipulated penalties for its failure thereafter to complete the work in accordance with the extended or modified schedule.

XVI. DISPUTE RESOLUTION

152. The dispute resolution procedure provided by this Section shall be available to resolve all disputes arising under this Consent Decree, except as provided in either this Section (Dispute Resolution) or Section XV (Force Majeure) of this Consent Decree, provided that the Party making such application has first made a good faith attempt to resolve the matter with the other Party.

153. The dispute resolution procedure required herein shall be invoked by one Party to this Consent Decree giving written notice to the other party to this Consent Decree advising of a dispute pursuant to this Section. The notice shall describe the nature of the dispute and shall state the noticing Party's position with regard to such dispute. The Party receiving such a notice shall acknowledge receipt of the notice, and the Parties in dispute shall expeditiously schedule a meeting to discuss the dispute informally not later than fourteen (14) days following receipt of such notice.

154. Disputes submitted to dispute resolution under this Section shall, in the first instance, be the subject of informal negotiations between the disputing Parties. Such period of informal negotiations shall not extend beyond thirty (30) calendar days from the date of the first

meeting among the disputing Parties' representatives unless they agree to shorten or extend this period. During the informal negotiations period, the disputing Parties may also submit their dispute to a mutually-agreed-upon alternative dispute resolution (ADR) forum if the Parties agree that the ADR activities can be completed within the 30-day informal negotiations period.

155. If the disputing Parties are unable to reach agreement during the informal negotiation period, the EPA shall provide Wisconsin Electric with a written summary of their position regarding the dispute. The written position provided by EPA shall be considered binding unless, within forty-five (45) calendar days thereafter, Wisconsin Electric seeks judicial resolution of the dispute by filing with this Court a petition. The EPA may respond to the petition within forty-five (45) calendar days of filing.

156. Where the nature of the dispute is such that a more timely resolution of the issue is required, the time periods set out in this Section may be shortened upon motion of one of the Parties to the dispute.

157. This Court shall not draw any inferences nor establish any presumptions adverse to any disputing Party as a result of invocation of this Section or the disputing Parties' inability to reach agreement.

158. As part of the resolution of any dispute under this Section, in appropriate circumstances the disputing Parties may agree, or this Court may order, an extension or modification of the schedule for the completion of the activities required under this Consent Decree to account for the delay that occurred as a result of dispute resolution. Wisconsin Electric shall be liable for stipulated penalties for its failure thereafter to complete the work in accordance with the extended or modified schedule.

159. As to disputes arising under Section VII of this Consent Decree (PM Emission Reductions and Controls), the Court shall sustain the position of the EPA as to the feasibility of obtaining accurate and reliable data from the PM CEMS that Wisconsin Electric is to install pursuant to Paragraph 93, unless Wisconsin Electric demonstrates that the position of the EPA is arbitrary or capricious. The Court shall decide all other disputes pursuant to applicable principles of law for resolving such disputes. In their initial filings with the Court under Paragraph 155, the disputing Parties shall state their respective positions as to the applicable standard of law for resolving the particular dispute.

XVII. EMISSIONS LIMITATIONS ON THE SOUTH OAK CREEK AND ELM ROAD GENERATING STATIONS

160. Wisconsin Electric has submitted an application for a PSD Permit for the construction of proposed new coal-fired generating Units, which if approved will be known as the Elm Road Generating Station. If, at any time after the date of lodging of this Consent Decree, one or more of the new units at the proposed Elm Road Generating Station is approved and constructed, Wisconsin Electric shall limit the combined emissions of SO_2, NO_x, PM, mercury, VOCs, hydrochloric acid, hydrofluoric acid, and sulfuric acid from both its South Oak Creek Generating Station and its Elm Road Generating Station to 38,400 tons per year, collectively. This emission limitation is based on actual or calculated emissions of SO_2, $NO_{x,}$ PM, mercury, VOCs, hydrochloric acid, hydrofluoric acid, and sulfuric acid from the existing units at South Oak Creek Generating Station in calendar year 2000. Compliance with this emission limitation shall be demonstrated on a 12-month rolling average. The emission limitation shall be included in the Title V operating permit issued to the South Oak Creek Generating Station and the Elm Road Generating Station, if approved and constructed.

XVIII. PERMITS

161. Unless expressly stated otherwise in this Consent Decree, in any instance where otherwise applicable law or this Consent Decree requires Wisconsin Electric to secure a permit to authorize construction or operation of any device, including all preconstruction, construction, and operating permits required under state law, Wisconsin Electric shall make such application in a timely manner. EPA will use its best efforts to expeditiously review all permit applications submitted pursuant to this Consent Decree.

162. Notwithstanding the previous paragraph, nothing in this Consent Decree shall be construed to require Wisconsin Electric to apply for or obtain a PSD or Nonattainment NSR permit for physical changes or changes in the method of operation that would give rise to claims resolved by Section XI (Resolution of Claims) of this Consent Decree.

163. When permits are required by the Paragraph 161, Wisconsin Electric shall complete and submit applications for such permits to the appropriate authorities to allow sufficient time for all legally required processing and review of the permit request. Any failure by Wisconsin Electric to submit a timely permit application for any Unit in the Wisconsin Electric System shall bar any use by Wisconsin Electric of Section XV (Force Majeure), where a Force Majeure claim is based on permitting delays.

164. Notwithstanding the reference to Title V permits in this Consent Decree, the enforcement of such permits shall be in accordance with their own terms and the Act. The Title V permits shall not be directly enforceable under this Decree, although any term or limit established by or under this Decree shall be enforceable under this Decree regardless of whether

such term has or will become part of a Title V permit, subject to the terms of Section XXVIII (Conditional Termination of Enforcement Under Decree).

165. Within ninety (90) days of entry of this Consent Decree, Wisconsin Electric shall amend any applicable Title V permit application, or apply for amendments of its Title V permits, to include a schedule for all performance, operational, maintenance, and control technology requirements established by this Consent Decree, including, but not limited to, Emission Rates, removal efficiencies, limits on fuel use, and the requirement in Paragraph 77 pertaining to surrender of SO_2 allowances.

166. Within one year from the commencement of operation of each pollution control device to be installed or upgraded on an Improved Unit under this Consent Decree, Wisconsin Electric shall apply to modify its Title V permit for the generating plant where such device is installed to reflect all new requirements applicable to that plant, including, but not limited to any applicable 30-Day Rolling Average Emission Rate or Removal Efficiency.

167. Prior to January 1, 2015, Wisconsin Electric shall apply to amend the Title V permit for each plant in the Wisconsin Electric System to include specific Emission Rates or tonnage limitations as described below. Wisconsin Electric shall be in compliance with this requirement if, by January 1, 2015, it has applied to amend each such Title V permit to include Emissions Rate limitations applicable to Improved Units and tonnage limitations applicable to plants with Other Units. Improved Units shall not exceed a 12-Month Rolling Average Emission Rate for NOx of 0.080 lb/mmBTU and a 12-Month Rolling Average Emission Rate for SO_2 of 0.080 lb/mmBTU or a Removal Efficiency of 96% for SO_2. The plants with Other Units shall meet the following Unit-specific 12-Month Rolling Tonnage:

Plant	**NO_x**	**SO_2**
Valley	3, 989	9,973
Presque Isle	7,376	17, 257

168. Wisconsin Electric shall provide the EPA with a copy of each application to amend its Title V permit, as well as a copy of any permit proposed as a result of such application, to allow for timely participation in any public comment opportunity.

169. If Wisconsin Electric sells or transfers to a Third Party Purchaser part or all of its ownership interest in a Unit in the Wisconsin Electric System, Wisconsin Electric shall comply with the requirements of Paragraph 167 with regard to that Unit, prior to any such sale or transfer unless, following any such sale or transfer, Wisconsin Electric remains the holder of the Title V permit for such facility. For purposes of this Paragraph and Section XXI, "Third Party Purchaser" refers to an entity unrelated to Wisconsin Electric, WEC or W.E. Power that may acquire an ownership interest in one or more of the Units in the Wisconsin Electric System.

XIX. INFORMATION COLLECTION AND RETENTION

170. Any authorized representative of the United States or Permitting State Agency, including their attorneys, contractors, and consultants, upon presentation of credentials, shall have a right of entry upon the premises of any facility in the Wisconsin Electric System at any reasonable time for the purpose of:

a. monitoring the progress of activities required under this Consent Decree;

b. verifying any data or information submitted to the United States in accordance with the terms of this Consent Decree;

c. obtaining samples and, upon request, splits of any samples taken by Wisconsin Electric or its representatives, contractors, or consultants; and

d. assessing Wisconsin Electric's compliance with this Consent Decree.

171. Wisconsin Electric shall retain, and instruct its contractors and agents to preserve, all non-identical copies of all records and documents (including records and documents in electronic form) now in its or its contractors' or agents' possession or control, and that directly relate to Wisconsin Electric's performance of its obligations under this Consent Decree for the following periods: (a) until December 31, 2020 for records concerning physical or operational changes undertaken in accordance with Paragraph 119 (Resolution of U.S. Claims Based On Modifications after Lodging of the Decree) of this Consent Decree; and (b) until December 31, 2017 for all other records. This record retention requirement shall apply regardless of any corporate document retention policy to the contrary.

172. All information and documents submitted by Wisconsin Electric pursuant to this Consent Decree shall be subject to any requests under applicable law providing public disclosure of documents unless (a) the information and documents are subject to legal privileges or protection or (b) Wisconsin Electric claims and substantiates that the information and documents contain confidential business information in accordance with 40 C.F.R. Part 2.

173. Nothing in this Consent Decree shall limit the authority of the EPA to conduct tests and inspections at Wisconsin Electric's facilities under Section 114 of the Act, 42 U.S.C. § 7414, or any other applicable federal or state laws, regulations or permits.

XX. NOTICES

174. Unless otherwise provided herein, whenever notifications, submissions, or communications are required by this Consent Decree, they shall be made in writing and addressed as follows:

As to the United States of America:

Chief, Environmental Enforcement Section
Environment and Natural Resources Division
U.S. Department of Justice
P.O. Box 7611, Ben Franklin Station
Washington, D.C. 20044-7611
DJ# 90-5-2-1-06965

and

Director, Air Enforcement Division
Office of Enforcement and Compliance Assurance
U.S. Environmental Protection Agency
Ariel Rios Building [2242A]
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

and

Regional Administrator
U.S. EPA Region V
77 West Jackson Blvd.
Chicago, Illinois 60604-3590

As to Wisconsin Electric:

Vice President Environmental
Wisconsin Electric Power Company
231 W. Michigan Street
Milwaukee, Wisconsin 53203

and

General Counsel
Wisconsin Electric Power Company
231 W. Michigan Street
Milwaukee, Wisconsin 53203

175. All notifications, communications or submissions made pursuant to this Section shall be sent either by: (a) overnight mail or by certified or registered mail, return receipt requested; (b) electronic transmission, unless the recipient is not able to review the transmission in electronic form. All notifications, communications and transmissions sent by overnight, certified or registered mail shall be deemed submitted on the date they are postmarked. All notifications, communications, and submissions made by electronic means shall be electronically signed and certified, and shall be deemed submitted on the date that Wisconsin Electric receives written acknowledgment of receipt of such transmission.

176. Any Party may change either the notice recipient or the address for providing notices to it by serving the other Party with a notice setting forth such new notice recipient or address.

177. [RESERVED.]

XXI. SALES OR TRANSFERS OF OWNERSHIP INTERESTS

178. If Wisconsin Electric proposes to sell or transfer part or all of its ownership interest in any Existing Unit ("Ownership Interest") to an entity unrelated to Wisconsin Electric, WEC or W.E. Power (Third Party Purchaser), it shall advise the Third Party Purchaser in writing of the existence of this Consent Decree prior to such sale or transfer, and shall send a copy of such written notification to EPA pursuant to Section XX (Notices) at least sixty (60) days before such proposed sale or transfer.

179. No sale or transfer of an Ownership Interest shall take place before the Third Party Purchaser and EPA have executed, and the Court has approved, a modification pursuant to Section XXIV (Modification) of this Consent Decree making the Third Party Purchaser a party defendant to this Consent Decree and jointly and severally liable with Wisconsin Electric for all the requirements of this Decree that may be applicable to the transferred or purchased Ownership Interests, including joint and several liability with Wisconsin Electric for all requirements specific to the Existing Unit, as well as all requirements in this Consent Decree that are not specific to these Existing Units, except as provided in Paragraph 181.

180. This Consent Decree shall not be construed to impede the transfer of any Ownership Interests between Wisconsin Electric and any Third Party Purchaser as long the requirements of this Consent Decree are met. This Consent Decree shall not be construed to prohibit a contractual allocation – as between Wisconsin Electric and any Third Party Purchaser of Ownership Interests – of the burdens of compliance with this Decree, provided that both Wisconsin Electric and such Third Party Purchaser shall remain jointly and severally liable to EPA for the obligations of the Decree applicable to the transferred or purchased Ownership Interests, except as provided in Paragraph 181.

181. If EPA agrees, EPA, Wisconsin Electric, and the Third Party Purchaser that has become a party defendant to this Consent Decree pursuant to Paragraph 179, may execute a modification that relieves Wisconsin Electric of its liability under this Consent Decree for, and makes the Third Party Purchaser liable for, all obligations and liabilities applicable to the purchased or transferred Ownership Interests. Notwithstanding the foregoing, however, Wisconsin Electric may not assign, and may not be released from, any obligation under this

Consent Decree that is not specific to the purchased or transferred Ownership Interests, including the obligations set forth in Sections IX (Environmental Projects) and X (Civil Penalty). Wisconsin Electric may propose and the EPA may agree to restrict the scope of joint and several liability of any purchaser or transferee for any obligations of this Consent Decree that are not specific to the Unit, to the extent such obligations may be adequately separated in an enforceable manner.

XXII. EFFECTIVE DATE

182. The effective date of this Consent Decree shall be the date upon which this Consent Decree is entered by the Court.

XXIII. RETENTION OF JURISDICTION

183. Continuing Jurisdiction. The Court shall retain jurisdiction of this case after entry of this Consent Decree to enforce compliance with the terms and conditions of this Consent Decree and to take any action necessary or appropriate for its interpretation, construction, execution, modification, or adjudication of disputes. During the term of this Consent Decree, either Party to this Consent Decree may apply to the Court for any relief necessary to construe or effectuate this Consent Decree.

XXIV. MODIFICATION

184. The terms of this Consent Decree may be modified only by a subsequent written agreement signed by both Parties. Where the modification constitutes a material change to any term of this Decree, it shall be effective only upon approval by the Court.

XXV. GENERAL PROVISIONS

185. This Consent Decree is not a permit. Compliance with the terms of this Consent Decree does not guarantee compliance with all applicable federal, state, or local laws or regulations.

186. This Consent Decree does not apply to any claim(s) of alleged criminal liability.

187. In any subsequent administrative or judicial action initiated by the United States for injunctive relief or civil penalties relating to the facilities covered by this Consent Decree, Wisconsin Electric shall not assert any defense or claim based upon principles of waiver, res judicata, collateral estoppel, issue preclusion, claim preclusion, or claim splitting, or any other defense based upon the contention that the claims raised by the United States in the subsequent proceeding were brought, or should have been brought, in the instant case; provided, however, that nothing in this Paragraph is intended to affect the validity of Section XI (Resolution of Claims).

188. Except as specifically provided by this Consent Decree, nothing in this Consent Decree shall relieve Wisconsin Electric of its obligation to comply with all applicable federal, state, and local laws and regulations. Subject to the provisions in Section XI (Resolution of Claims) of this Consent Decree, nothing contained in this Consent Decree shall be construed to prevent or limit the rights of the United States to obtain penalties or injunctive relief under the Act or other federal, state, or local statutes, regulations, or permits.

189. Every term expressly defined by this Consent Decree shall have the meaning given to that term by this Consent Decree, and, except as otherwise provided in this Decree,

every other term used in this Decree that is also a term under the Act or the regulations implementing the Act shall mean in this Decree what such term means under the Act or those implementing regulations.

190. Nothing in this Consent Decree alters or waives any applicable law (including but not limited to, any defenses, entitlements, or clarifications related to the Credible Evidence Rule (62 Fed. Reg. 8314 (Feb. 27, 1997))), concerning the use of data for any purpose under the Act, generated by the reference methods specified herein or otherwise.

191. Each limit and/or other requirement established by or under this Decree is a separate, independent requirement.

192. Performance standards, emissions limits, and other quantitative standards set by or under this Decree must be met to the number of significant digits in which the standard or limit is expressed. Thus, for example, an Emission Rate of 0.100 is not met if the actual Emission Rate is 0.101. Wisconsin Electric shall round the fourth significant digit to the nearest third significant digit, or the third significant digit to the second significant digit, depending upon whether the limit is expressed to two or three significant digits. Thus, for example, if an actual Emission Rate is 0.1004, that shall be reported as 0.100, and shall be in compliance with an Emission Rate of 0.100, and if an actual Emission Rate is 0.1005, that shall be reported as 0.101, and shall not be in compliance with an Emission Rate of 0.100. Wisconsin Electric shall collect and report data to the number of significant digits in which the standard or limit is expressed. As otherwise applicable and unless this Decree expressly directs otherwise, the calculation and measurement procedures established under 40 C.F.R. Parts 75 and 76 apply to the measurement and calculation of NO_x and SO_2 under this Decree.

193. This Consent Decree does not limit, enlarge or affect the rights of any Party to this Consent Decree as against any third parties.

194. This Consent Decree constitutes the final, complete and exclusive agreement and understanding between the Parties with respect to the settlement embodied in this Consent Decree, and supercedes all prior agreements and understandings between the Parties related to the subject matter herein. No document, representation, inducement, agreement, or understanding, or promise constitutes any part of this Decree or the settlement it represents, nor shall they be used in construing the terms of this Consent Decree.

195. Each Party to this action shall bear its own costs and attorneys' fees.

XXVI. SIGNATORIES AND SERVICE

196. Each undersigned representative of the Parties certifies that he or she is fully authorized to enter into the terms and conditions of this Consent Decree and to execute and legally bind the Party he or she represents to this document.

197. This Consent Decree may be signed in counterparts, and such counterpart signature pages shall be given full force and effect.

198. Each Party hereby agrees to accept service of process by mail with respect to all matters arising under or relating to this Consent Decree and to waive the formal service requirements set forth in Rule 4 of the Federal Rules of Civil Procedure and any applicable Local Rules of this Court including, but not limited to, service of a summons.

XXVII. PUBLIC COMMENT

199. The Parties agree and acknowledge that final approval by the United States and entry of this Consent Decree is subject to the procedures of 28 C.F.R. § 50.7, which provides for

notice of the lodging of this Consent Decree in the Federal Register, an opportunity for public comment, and the right of the United States to withdraw or withhold consent if the comments disclose facts or considerations which indicate that the Consent Decree is inappropriate, improper or inadequate. Wisconsin Electric shall not oppose entry of this Consent Decree by this Court or challenge any provision of this Consent Decree unless the United States has notified Wisconsin Electric, in writing, that the United States no longer supports entry of the Consent Decree.

XXVIII. CONDITIONAL TERMINATION OF ENFORCEMENT UNDER DECREE

200. Termination as to Completed Tasks. As soon as Wisconsin Electric completes a construction project or any other requirement of this Consent Decree that is not ongoing or recurring, Wisconsin Electric may seek termination of the provision or provisions of this Consent Decree that imposed the requirement.

201. Conditional Termination of Enforcement Through the Consent Decree. Once Wisconsin Electric:

(A) believes that it has successfully completed and commences successful operation of all pollution controls required by this Decree;

(B) has obtained final Title V permits (a) as required by the terms of this Consent Decree; (b) that cover all Units in this Consent Decree; and (c) that include as enforceable permit terms all of the Unit performance and other requirements required by Section XVIII (Permits); and

(C) certifies that the date is later than December 31, 2015;

then Wisconsin Electric may so certify these facts to the EPA and this Court. If EPA does not object in writing with specific reasons within forty-five (45) days of receipt of Wisconsin Electric's certification, then, for any violations that occur after the filing of notice, the United States shall pursue enforcement of the requirements contained in the Title V permit through the applicable Title V permit and not through this Consent Decree.

202. Resort to Enforcement under this Consent Decree. Notwithstanding Paragraph 201, if enforcement of a provision in this Decree cannot be pursued by a party under the applicable Title V permit, or if a Decree requirement was intended to be part of a Title V Permit and did not become or remain part of such permit, then such requirement may be enforced under the terms of this Decree at any time.

XXIX. FINAL JUDGMENT

203. Upon approval and entry of this Consent Decree by the Court, this Consent Decree shall constitute a final judgment between the United States and Wisconsin Electric.

SO ORDERED, THIS _____ DAY OF ________________, 2003.

____

UNITED STATES DISTRICT COURT JUDGE

FOR THE UNITED STATES OF AMERICA:

THOMAS L. SANSONETTI
Assistant Attorney General
Environmental and Natural Resources Division
United States Department of Justice

NICOLE VEILLEUX
ARNOLD ROSENTHAL
Trial Attorneys
Environmental Enforcement Section
Environmental and Natural Resources Division
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____

STEVEN M. BISKUPIC
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JOHN PETER SUAREZ
Assistant Administrator
Office of Enforcement and Compliance Assurance
United States Environmental Protection Agency

BRUCE C. BUCKHEIT
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United States Environmental Protection Agency

EDWARD MESSINA
Attorney Advisor
Air Enforcement Division
Office of Enforcement and Compliance Assurance
United States Environmental Protection Agency

THOMAS SKINNER
Regional Administrator
Region 5
United States Environmental Protection Agency

FOR WISCONSIN ELECTRIC:

____

RICHARD R. GRIGG
President and Chief Operating Officer
Wisconsin Electric Power Company

Wet Flue Gas Desulfurization Control Efficiency

Technical Memorandum

To: Milka Radulovic
UDEQ Division of Air Quality

Date: November 18, 2003

cc: Steve Sands
CH2MHill

From: Ken Snell / Bill Rosenquist
Sargent & Lundy LLC

Subject: Wet Flue Gas Desulfurization Control Efficiency

This technical memorandum provides a response to questions raised by UDAQ regarding the control efficiency of the wet flue gas desulfurization (WFGD) control system proposed for IPP Unit 3.

UDAQ Question: Provide reasons why the control efficiency of the proposed new WFGD system cannot be the same or better than observed efficiencies at some currently operating power plants.

Response: The control efficiency of the WFGD system proposed for IPP Unit 3 represents BACT and will result in an actual SO_2 emission rate equivalent to, or lower than, the actual SO_2 emission rate achieved in practice at any existing pulverized coal-fired boiler. Furthermore, the SO_2 emission rate proposed by IPP as an enforceable permit limit is as stringent as the enforceable SO_2 permit limit imposed on any recently permitted pulverized coal-fired boiler.

IPP's Proposed SO_2 BACT Emission Limit

IPP prepared and submitted a comprehensive top-down BACT analysis of SO_2 control technologies for the proposed unit. Information to support the SO_2 BACT analysis was included in IPP's original permit application (December 2002) and supplemented with additional information submitted in the NOI Addendum on May 14, 2003. IPP has provided detailed information regarding the proposed boiler design, fuel characteristics, WFGD chemistry, control efficiency, and the effect of averaging time on WFGD design and performance.

Based on a review of the information submitted, following the EPA's "top-down" BACT approach, IPP proposed a controlled SO_2 emission limit of 0.10 lb/mmBtu (30-day rolling average). The proposed SO_2 emission limit for IPP Unit 3 is as stringent as any recently permitted pulverized coal-fired unit, and more stringent than the permit limit included in any currently operating pulverized coal-fired unit.

WFGD Chemistry and Control Efficiency

As discussed in IPP's BACT supplement titled "Flue Gas Desulfurization – Control Efficiency" submitted to UDAQ on May 14, 2003, the chemistry of a wet scrubbing system consists of a complex series of kinetic and equilibrium-controlled reactions occurring in the gas, liquid, and solid phases. In general, the amount of SO_2 absorbed from the flue gas is governed by the vapor-liquid equilibrium between SO_2 in the flue gas and the absorbent liquid. If no soluble alkaline species are present in the liquid, the liquid quickly becomes saturated with SO_2 and absorption is limited. As the flue gas SO_2 concentration goes down, absorption will be limited by the SO_2 equilibrium vapor pressure. Therefore, SO_2 removal is easier with high SO_2 concentrations in the flue gas. High control efficiencies are easier to achieve as the flue gas SO_2 concentration increases, and high control efficiencies would not be expected as the flue gas SO_2 concentration is reduced.

Because control efficiency is a function of the SO_2 concentration in the flue gas, control efficiency can be a misleading indicator of the effectiveness of a WFGD control system. An example of how control efficiency can be misleading as a measure of effectiveness is provided below:

Facility	**Worst-Case Design Fuel Characteristics**		**Maximum Uncontrolled SO_2 Emission Rate (lb/mmBtu)**	**Approximate Uncontrolled SO_2 Concentration in Flue Gas (ppmvd)**	**Proposed Control Efficiency (%)**	**Approximate Controlled SO_2 Concentration (ppmvd)**
	Heating Value (Btu/lb)	**Sulfur Content (%)**				
Thoroughbred	9,962	4.24	8.51	4,358	97.9	91.5
Prairie State	8,780	4.0	9.11	4,665	97.9	98.0
Intermountain	11,193	0.75	1.34	686	92.5	51.5

*Information included in this table was obtained from information submitted in each facility's PSD permit application.

Even though the Thoroughbred and Prairie State facilities have proposed higher control efficiencies, IPP Unit 3 will have a significantly lower controlled SO_2 emission rate. As described above, SO_2 removal becomes more difficult as the SO_2 concentration in the flue gas decreases.

Proposed Permit Limit v. Emission Limit Achieved in Practice

UDAQ specifically asked IPP to explain why the Unit 3 WFGD control efficiency does not equal or exceed the control efficiency achieved in practice at certain existing pulverized coal-fired boilers firing a low sulfur coal. As examples, UDAQ provided the following data:

Bonanza	93% control	0.75% sulfur coal
Hunter Unit 3	93% control	0.45% sulfur
Intermountain Unit 1	94.2% control	0.48% sulfur
Intermountain Unit 2	93.2% control	0.48% sulfur

In its Notice of Intent for Unit 3, IPP proposed a controlled SO_2 emission limit of 0.10 lb/mmBtu (30-day rolling average). Based on worst case design fuel characteristics of 11,193 Btu/lb and 0.75% sulfur, the IPP Unit 3 WFGD will have to achieve a control efficiency of at least 92.5% to ensure compliance.

In order to compare IPP's proposed emission limit to control efficiencies achieved in practice, it is necessary to compare the basis for each calculation. The control efficiency and fuel sulfur numbers provided by UDAQ (summarized above) were based on information available from USEPA's Acid Rain Program, and presumably represent annual average numbers. The BACT emission limit proposed by IPP represents the maximum SO_2 emission rate Unit 3 can exhibit (on a 30-day rolling average) without incurring a compliance problem.

Unless a facility has a compliance problem, it is reasonable to assume that its annual average emission rate will be below its permitted emission limit. Likewise, it is reasonable to assume that the Unit 3 actual SO_2 emission rate will be less than 0.10 lb/mmBtu, and therefore, the actual control efficiency at IPP Unit 3 will be something greater than 92.5%.

The relationship between permitted emission limit and emission limit achieved in practice is depicted graphically in the following two charts.

Chart 1
WFGD Control Efficiency as a Function of Uncontrolled SO_2 Emission Rate

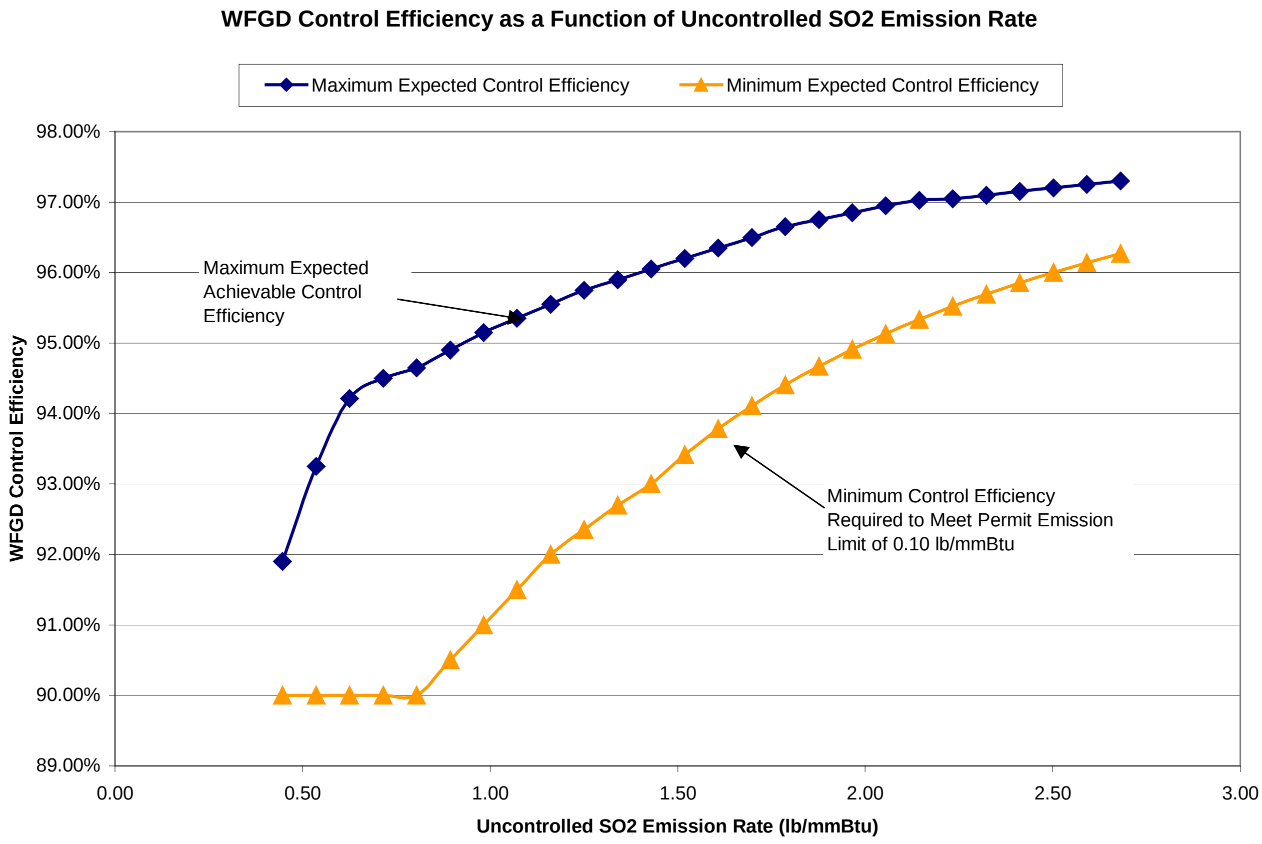


Chart 2
Comparison of Maximum/Minimum/Average Expected SO_2 Emission Rate

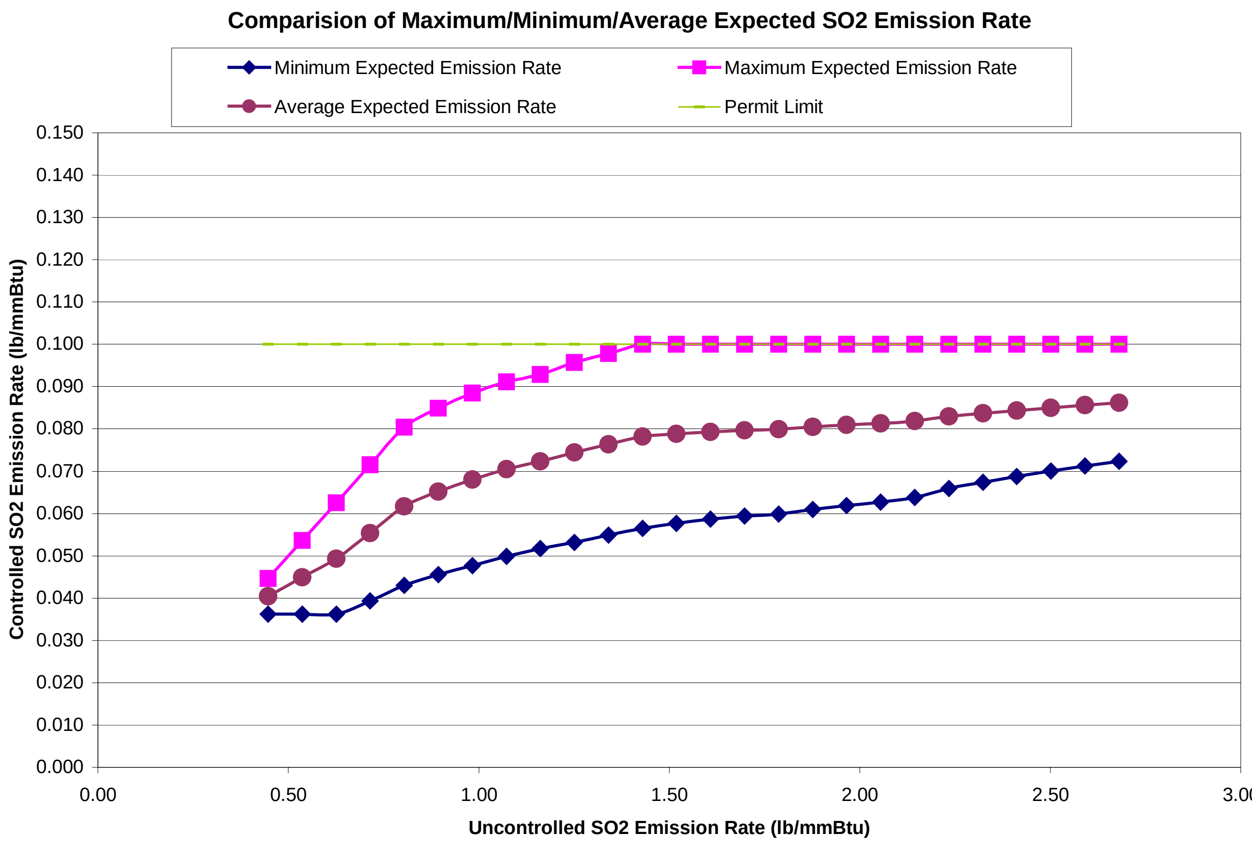


Chart 1 compares the maximum achievable control efficiency of the WFGD control system to the minimum control efficiency necessary to ensure compliance with a controlled emission limit of 0.10 lb/mmBtu. The maximum achievable control efficiency ranges from approximately 92% with very low sulfur fuel (e.g., 0.45 lb/mmBtu uncontrolled SO_2) to approximately 97.3% at an uncontrolled SO_2 emission rate of 2.68 lb/mmBtu.

At an uncontrolled SO_2 emission rate of 1.34 lb/mmBtu (based on a fuel sulfur content of 0.75%) the control efficiency needed to ensure compliance with the permit limit is approximately 92.5%. The maximum achievable control efficiency at the same fuel sulfur content is approximately

96%. The control efficiency achieved in practice would be expected to be somewhere between 92.5% and 96%, which is consistent with the best control efficiencies currently achieved in practice at facilities firing low-sulfur coals.

Chart 2 shows the maximum expected emission rate, minimum achievable emission rate and expected average emission rate as a function of the uncontrolled SO_2 emission rate. From Chart 2 it can be seen that IPP Unit 3 will achieve an SO_2 emission rate equivalent to or lower than the lowest SO_2 emission rates currently achieved in practice.

Margin Between Expected Actual Emission Rate and Permitted Emission Rate

BACT is an emission limitation which UDAQ, on a case-by-case basis taking into account energy, environmental, and economic impacts and other costs, determines is achievable for a specific installation. BACT is not the lowest emission rate achieved in practice at a similar source. IPP will be required to comply with the BACT emission limit (permit limit) on an on-going long-term basis. Therefore, in order to ensure compliance with the permit limit, it is practical to include a reasonable margin between the expected actual emission rate and the permit emission limit.

The USEPA Environmental Appeals Board has recognized that "permitting agencies have the discretion to set BACT limits at levels that do not necessarily reflect the highest possible control efficiencies but, rather will allow permittees to achieve compliance on a consistent basis." See, Three Mountain Power, PSD Appeal No. 01-05 at 21 (May 30, 2001), citing: In re Masonite Corp., 5 E.A.D. 560-61 (EAB 1994) ("There is nothing inherently wrong with setting an emission limitation that takes into account a reasonable safety factor."); and In re Knauf Fiber Glass, GmbH, PSD Appeal Nos. 99-8 to –72, slip op. at 21 (EAB, Mar. 14, 2000) ("The inclusion of a reasonable safety factor in the emission limitation is a legitimate method of deriving a specific emission limitation that may not be exceeded.").

As discussed in detail in IPP's BACT supplement titled "Sulfur Dioxide Control – Effect of Averaging Time on Wet FGD System Performance and Design" all WFGD systems will experience some short-term fluctuations in controlled SO_2 emissions. FGD performance is a function of numerous operating variables including, among other things, coal quality, load changes, equipment upsets, oxidation/slurry tank dynamics, process chemistry, and control system response time. SO_2 loading to the FGD will constantly vary during the operating life of the plant, and the chemistry within the FGD absorption vessel must be continuously adjusted in response to the SO_2 loading. Wet FGD systems have proven to be very reliable, however wet FGD systems, like all emission control systems, take time to respond to process changes.

An SO_2 emission limit of 0.10 lb/mmBtu (30-day rolling average) will ensure that the IPP Unit 3 WFGD will be operated in such a way as to continuously achieve a high control efficiency, while providing a reasonable margin to allow the system to respond to process changes. The emission limit is as stringent as any SO_2 permit limit imposed on recently permitted pulverized coal-fired boilers, and more stringent than the SO_2 permit limit at any existing pulverized coal fired unit. Finally, in order to ensure compliance with an SO_2 emission limit of 0.10 lb/mmBtu (30-day rolling average) IPP Unit 3 will have to achieve actual SO_2 emissions equivalent to, or lower than, the SO_2 emission rate achieved in practice at any existing pulverized coal-fired boiler.

IPP Unit 3 – SO_2 BACT Questions

Technical Memorandum

To: Steve Sands
CH2MHill

Date: December 18, 2003
Resubmitted 1-31-04

From: Ken Snell / Bill Rosenquist
Sargent & Lundy LLC

Subject: IPP Unit 3 – SO2 BACT Questions

Provided below are responses to questions 2a and 2b of the Richard Sprott letter to Reed Searle dated November 24, 2003.

Question 2a.

> IPSC needs to provide the rationale as to why the proposed new Wet Flue Gas Desulphurization (WFGD) efficiency cannot be the same or better than currently observed efficiencies at other operating power plants which use coal with lower sulfur content by weight than the proposed Unit #3 efficiency of 92.1%. For example, Bonanza is achieving 93% efficiency with a Sulfur content of 0.75% by weight (at 99% of maximum operation), Hunter Unit #3 is achieving 93% efficiency with a Sulfur content of 0.45% wt (at 99% of maximum operation), and IPP Units #1 and #2 are achieving 94.2% to 93.2% efficiency with a sulfur content of 0.48% (at 99% of maximum operation). (This information on the WFGD efficiencies for currently operating plants was taken from the acid rain program database).
>
> This information is not intended to be the basis for a permit limit at the actual performance levels. We recognize that there must be a margin for compliance. However, we would like to understand the basis for the margin between the permitted limit and the anticipated actual performance of the unit. This newer unit should be as good or better than the existing units unless some powerful demonstration can be made to justify a higher limit.

Response to Question 2a.

As UDAQ states in Question 2a, there must be a margin between the permit limit and the actual performance level to allow for some reasonable assurance that the facility will be able to comply with the permit limit. The PSD permitting process will result in an enforceable permit limit that the facility must comply with on a continuous long-term basis, over the life of the unit. Therefore, during the initial permitting process IPP must identify and account for all reasonably foreseeable changes that may affect operation of the boiler and emission control systems.

Several variables affect efficiency of the WFGD control system, and ultimately the controlled SO2 emission rate. Identifying which variables will affect the WFGD system, and accounting for potential changes to these variables, forms the basis for the margin between the anticipated actual performance level and the permit limit. For this evaluation, IPP will focus on two variables that can significantly affect the controlled SO2 emission limit: (1) Fuel sulfur content (or uncontrolled SO2 emission rate); and (2) WFGD system dynamics.

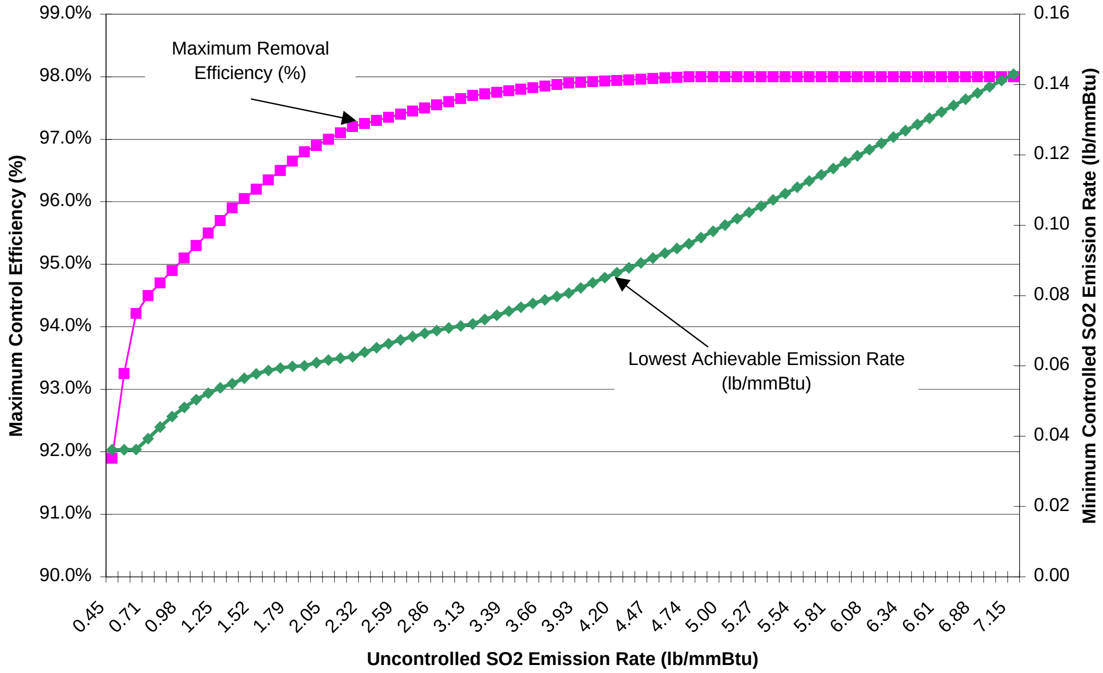
<u>Fuel Sulfur Content</u>

As described in IPP's NOI Supplement titled "Flue Gas Desulfurization – Control Efficiency" the chemistry of wet scrubbing consists of a complex series of kinetic and equilibrium-controlled reactions occurring in the gas, liquid, and solid phases. If no soluble alkaline species are present in the scrubbing liquid, the liquid quickly becomes saturated with SO2 and absorption is limited. Likewise, as the SO2 concentration in the flue gas goes down, absorption by the scrubbing liquid will be limited by the SO2 equilibrium vapor pressure. Therefore, assuming soluble alkaline species are present in the scrubbing liquid, higher control efficiencies will be achieved as the flue gas SO2 concentration increases.

Figure 1 shows the maximum control efficiency of a WFGD system (based on engineering judgment and information from existing WFGD systems) as a function of the uncontrolled SO2 emission rate. Figure 1 also plots of the minimum expected controlled SO2 emission rate as a function of the uncontrolled SO2 emission rate.

It can be seen from Figure 1 that control efficiency will increase as the uncontrolled SO2 emission rate increases. Facilities burning a high sulfur coal may be able to achieve SO2 removal efficiencies of up to 98%, while facilities burning a low sulfur coal (e.g., Utah bituminous coal) may only be able to achieve a control efficiency of 94 – 95%. However, it is important to note that even though the facilities utilizing a lower sulfur coal cannot attain removal efficiencies above approximately 95%, these facilities will still achieve a lower controlled SO2 emission rate than their counterparts burning a high sulfur coal.

Figure 1
WFGD Control Efficiency as a Function of the Uncontrolled SO2 Emission Rate



Therefore, when proposing an SO2 permit limit, IPP must take into account the anticipated sulfur content of potential fuels over the life of the unit. IPP conducted a detailed study of Utah coal reserves, and anticipated coal characteristics, available over the next 25 years. Results of this study were submitted to UDAQ in the NOI supplement titled "Intermountain Power Project (IPP) Unit 3 Coal Supply." The study concluded, based on actual Utah coal mine data, that much of the easily obtained high quality Utah coals have been mined, or are currently being mined, and Utah is just beginning to see mines with less than ideal geological conditions and coal qualities. Although Utah has approximately 800 million tons of reserves remaining (excluding the Kaiparowits Plateau coal fields), Utah's future coal outlook continues the tread of higher quality coal mines depleting their reserves and being replaced with coal mines of lesser coal quality and/or more difficult geological conditions.

Figures 2 and 3 summarize data regarding the actual fuel sulfur content of coal shipments to Intermountain Power Station and Hunter Power Station during the years 2000 – 2002.[1] Both facilities receive coal from Utah mines. Figures 2 and 3 include the actual average sulfur content

[1] Intermountain and Hunter were used because both of these stations receive coal from Utah mines. Bonanza was not included in this part of the report because according to FERC records, the Bonanza station primarily receives coal from a Colorado mine.

of coals shipped to each facility, and the standard deviation observed in the fuel sulfur content. Data for Figures 2 and 3 were obtained for the Federal Energy Regulatory Commission (FERC) Form 423 "Monthly Report of Cost and Quality of Fuels for Electric Plants."[2]

Figure 2
Fuel Sulfur Information – Intermountain Power Station

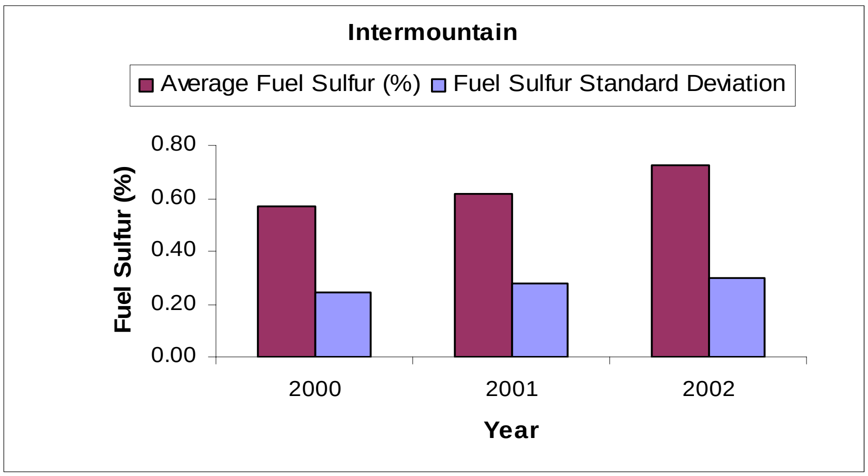
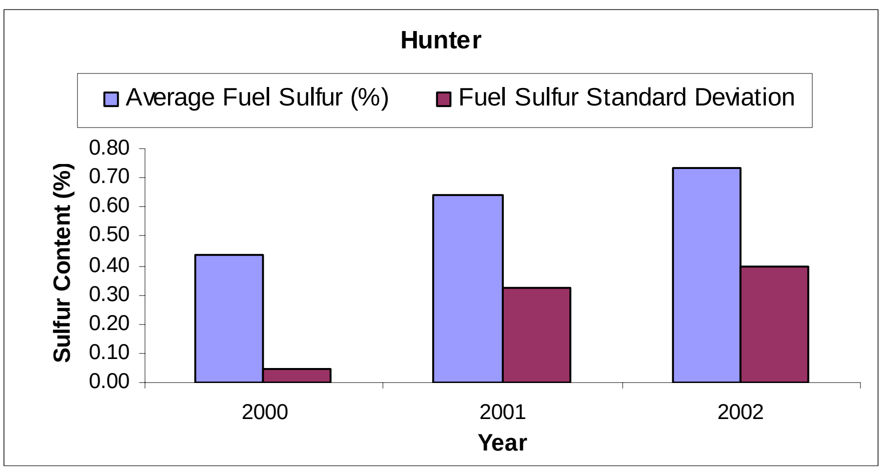


Figure 3
Fuel Sulfur Information – Hunter Power Station



[2] The FERC Form 423 data is available at http://www.eia.doe.gov/cneaf/electricity/page/ferc423.html.

It can be seen from Figures 2 and 3 that the average sulfur content of Utah coals shipped to both Intermountain and Hunter increased between the years 2000 and 2002. It can also be seen that the standard deviation of the sulfur content of fuel shipments has increased during the same time period. An increase in the standard deviation of the fuel sulfur content points toward increased variability in fuel sulfur content. As discussed in IPP's coal study (referenced above) this trend is expected to continue as higher quality coal mine reserves are depleted.

Between the years 2000 and 2002 the annual average controlled SO2 emission rates at both Intermountain Unit 2 and Hunter Unit 2 increased slightly (from 0.046 lb/mmBtu to 0.050 lb/mmBtu at Intermountain Unit 2, and from 0.063 lb/mmBtu to 0.080 lb/mmBtu at Hunter Unit 3).[3] This increase in the annual average emission rates was probably due, at least in part, to the increased fuel sulfur content. Although both plants are currently operating well below their respective SO2 permit limits, if the uncontrolled SO2 emission rate continues to increase, the margin between the permit limit and the emission limit achieved in practice will continue to decrease.

Because IPP must permit Unit 3 for the life of the unit, the permit application must include a reasonable estimate of the anticipated future coal characteristics. Based on a review of data from Utah mines, IPP concluded that a sulfur content of 0.75% represents a reasonably conservative estimate of future Utah coal reserves. Therefore, IPP proposed a permit limit based on controlling SO2 emissions from a coal containing 0.75% sulfur.

Requesting a permit limit based on burning fuel with a sulfur content of 0.75% introduces margin between the permit limit and the expected actual emission rate. However, this margin will decrease as the sulfur content of Utah coals continues to increase.

Wet FGD System Dynamics

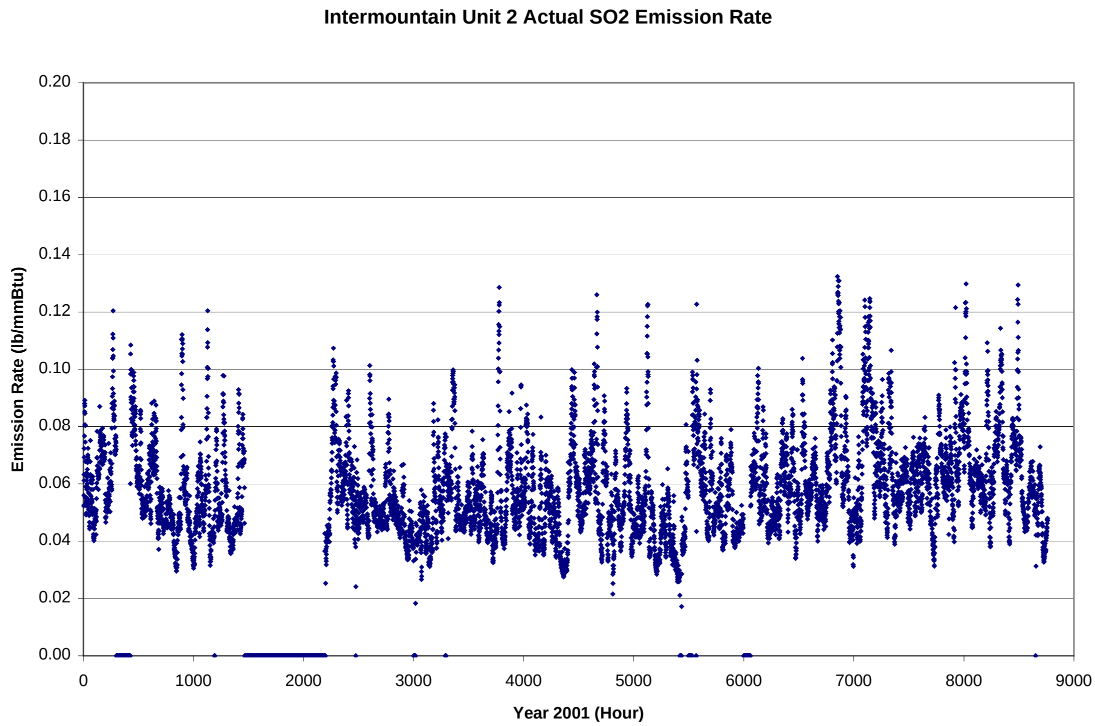
As described in IPA's NOI Supplement titled "Sulfur Dioxide Control – Effect of Averaging Time on Wet FGD System Performance and Design" WFGD control systems, like all emission control systems, are dynamic and subject to fluctuations under normal operating conditions. WFGD performance is a function of numerous operating variables including, among other things, SO2 loading, boiler load changes, equipment upsets, oxidation/slurry tank dynamics, process chemistry, and control system response time. Routine equipment upsets may also affect the chemistry of the FGD system, requiring time to re-establish system equilibrium. Examples of typical equipment problems include slurry pump failures, spray pump failures, scaling, mist eliminator plugging, plugged spray nozzles, and plugged strainers. Equipment problems are usually identified and remedied quickly, however, as with all mechanical systems, some equipment problems are unavoidable, and may result in short-term increases in the controlled SO2 emission rate.

[3] Annual average controlled SO2 emission rates were obtained from emissions data available from the U.S.EPA Acid Rain Program at http://www.epa.gov/airmarketes/emissions/index.html#reports.

IPA must propose a permit limit that includes a reasonable margin to account for fluctuations in the controlled SO2 emission rate associated with normal WFGD operation.

In order to establish a reasonable margin to account for normal fluctuations in the operation of a WFGD control system, IPP reviewed actual emissions data from three pulverized coal-fired units located in Utah and equipped with WFGD: Intermountain Unit 2, Hunter Unit 3, and Bonanza.[4] Figures 4, 5 and 6 show the actual hourly SO2 emission rate reported by each facility during 2001.[5]

Figure 4[6]



[4] These three units were chosen for review because they are located in Utah, use WFGD for SO2 control, and were identified in Mr. Sprott's November 24, 2003 letter.

[5] Actual hourly SO2 emission rate data were obtained from U.S.EPA Acid Rain Program website: www.epa.gov/airmarkets/emissions/index.html#reports.

[6] The controlled SO2 emission rate scale in each figure ranges from 0.0 to 0.2 lb/mmBtu. Emission rates greater than 0.2 lb/mmBtu were not included in the figures, however, they were included in the calculation of the annual average SO2 emission rate.

Figure 5[6]

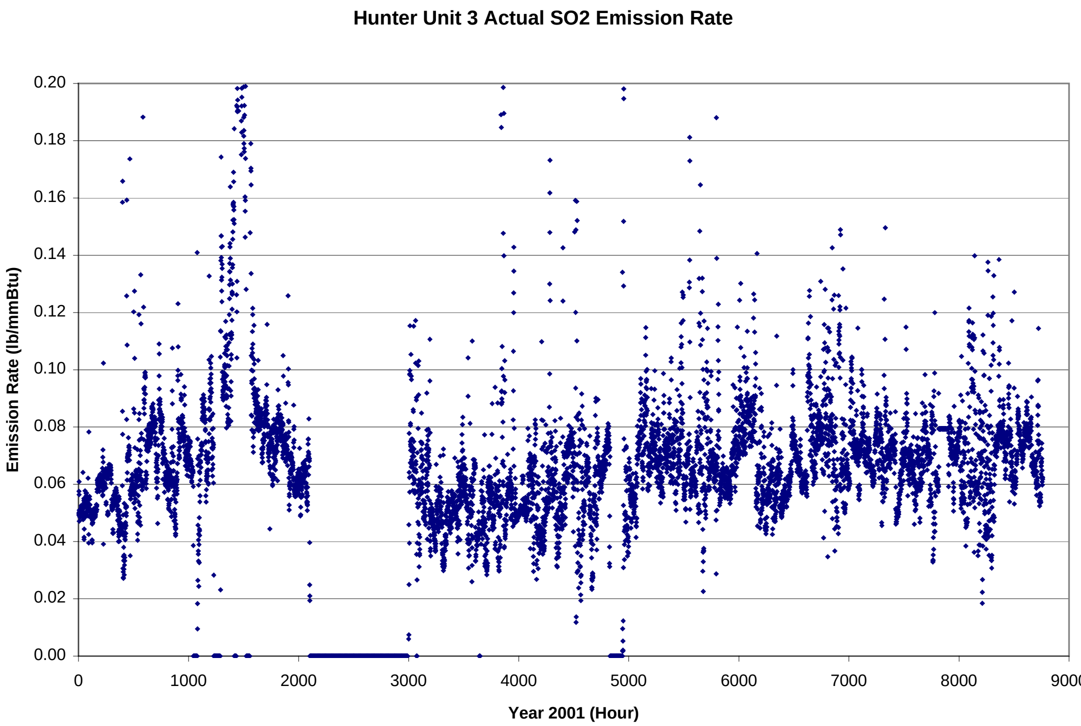
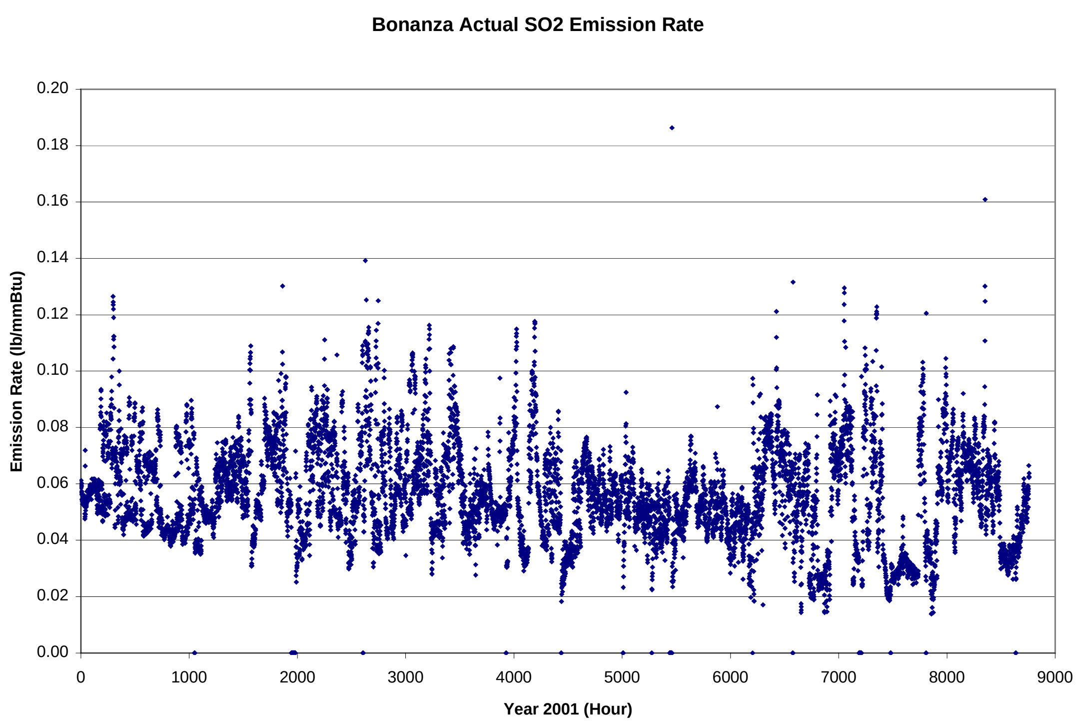


Figure 6[6]



It can be seen that all three units experienced fluctuations in the controlled SO2 emission rate. The standard deviation in the controlled SO2 emission rate provides one measure of the variability observed in the controlled SO2 emission rate. Table 1 summarizes the annual average SO2 emission rate and standard deviation observed at each unit based on 2001 Acid Rain Program data.

Table 1
2001 At Load SO2 Emissions Data*

	Intermountain Unit 2	**Hunter Unit 3**	**Bonanza**
Annual Average at Load SO2 Emission Rate	0.058 lb/mmBtu	0.080 lb/mmBtu	0.057 lb/mmBtu
Standard Deviation	0.017 lb/mmBtu	0.103 lb/mmBtu	0.021 lb/mmBtu
Standard Deviation as Percentage of Annual Average	29.3%	128.7%	36.8%

*Data for Table 1 was obtained by evaluating the actual hourly SO2 emission rate and heat input reported by each unit to the U.S.EPA Acid Rain Program.

Intermountain Unit 2 exhibited the least variability in controlled SO2 emission, based on standard deviation. Furthermore, it is known that Intermountain Unit 2 did not exhibit any major equipment failures or upsets during 2001. Therefore, the variability shown in Figure 4 should represent the normal fluctuation in controlled SO2 emissions associated with a properly operated, well maintained WFGD. The standard deviation in the SO2 emissions rate from Intermountain Unit 2 is approximately 29% of the average emission rate (i.e., 0.017 compared to 0.058 lb/mmBtu). Therefore, based on actual emissions data from a well operated, well maintained, WFGD system firing Utah bituminous coal, a standard deviation value equivalent to approximately 29% of the expected average emission rate represents a reasonably conservative margin to account for normal system fluctuations.

Conclusions

IPP must have margin between the permit limit and the anticipated actual emission rate. To establish a reasonable margin IPP must anticipate changes to the coal characteristics, and take into account normal operating fluctuations associated with the emissions control system.

IPP conducted a detailed evaluation of the Utah coal and concluded that it is very likely that the sulfur content of available coal will continue to increase over the next 25 years. Based on available coal quality data, IPP concluded and that a fuel sulfur content of 0.75% represents a reasonably conservative estimate of the sulfur content of fuels likely to be utilized by IPP Unit 3, and the appropriate value upon which to establish the Unit 3 SO2 permit limit.

IPP also evaluated the normal fluctuation in controlled SO2 emissions from Intermountain Unit 2, Bonanza, and Hunter Unit 3. Based on a review of actual SO2 emissions data, IPP concluded that a controlled SO2 emissions rate exhibiting a standard deviation equal to 629% of the average emissions rate represents a reasonable measure of normal fluctuations associated with a well maintained well operated WFGD control system.

Based on a fuel heating value of 11,193 Btu/lb and a sulfur content of 0.75% the uncontrolled SO2 emission rate is calculated to be 1.34 lb/mmBtu. The average expected control efficiency with a WFGD system at this uncontrolled emission rate is projected to be approximately 94.2%, resulting in an average actual emission rate of 0.0775 lb/mmBtu.[7] The standard deviation associated with normal WFGD operation would be approximately 0.0225 lb/mmBtu (or 29% of the expected average).

IPP would like to establish a permit limit equal to the average expected emission rate plus three standard deviations. However, this would result in a permit limit of 0.145 lb/mmBtu, and based on a review of recently permitted pulverized coal-fired units, probably exceeds the BACT emissions limit. Furthermore, this emission rate already includes margin because it was calculated based on the higher fuel sulfur content and does not take into account averaging time.

Based on expected WFGD performance, and taking into account anticipated fuel characteristics and normal system fluctuations, IPP has proposed an SO2 permit limit of 0.10 lb/mmBtu (30-day rolling average) and 0.12 lb/mmBtu (24-hour daily average - midnight-to-midnight). The 30-day rolling average emission limit is based on the expected average emission rate plus one standard deviation. The 24-hour daily average is based on the expected average emission rate plus approximately two standard deviations.

A permit limit of 0.10 lb/mmBtu (30-day rolling average) and 0.12 lb/mmBtu (24-hour daily average-midnight-to-midnight) provides reasonable margin to account for future fuel characteristics and normal fluctuations of the control system. This permit limit is more stringent than the permit limit of any operating pulverized coal-fired unit, and as stringent as the BACT emission limit established in recently issued PSD pre-construction permits. The proposed margin between the permit limit and the expected emission rate at IPP Unit 3 is less than the margin allowed at currently permitted units, and will ensure that the Unit 3 WFGD will be operated in such a manner as to minimize upsets and respond to SO2 excursions quickly and effectively.

[7] The average expected control efficiency and average actual emission rate were calculated based on the actual control efficiencies achieved in practice by the best performing units firing a western bituminous coal and using WFGD for SO2 control (e.g., Intermountain Unit 2 and Bonanza). The calculated average actual emission rate is approximately one standard deviation above the minimum achievable emission rate (e.g., 0.0775 – 0.0217 lb/mmBtu; see, Figure 1), and is consistent with the control efficiencies and emission rates achieved in practice by the best performing WFGD systems.

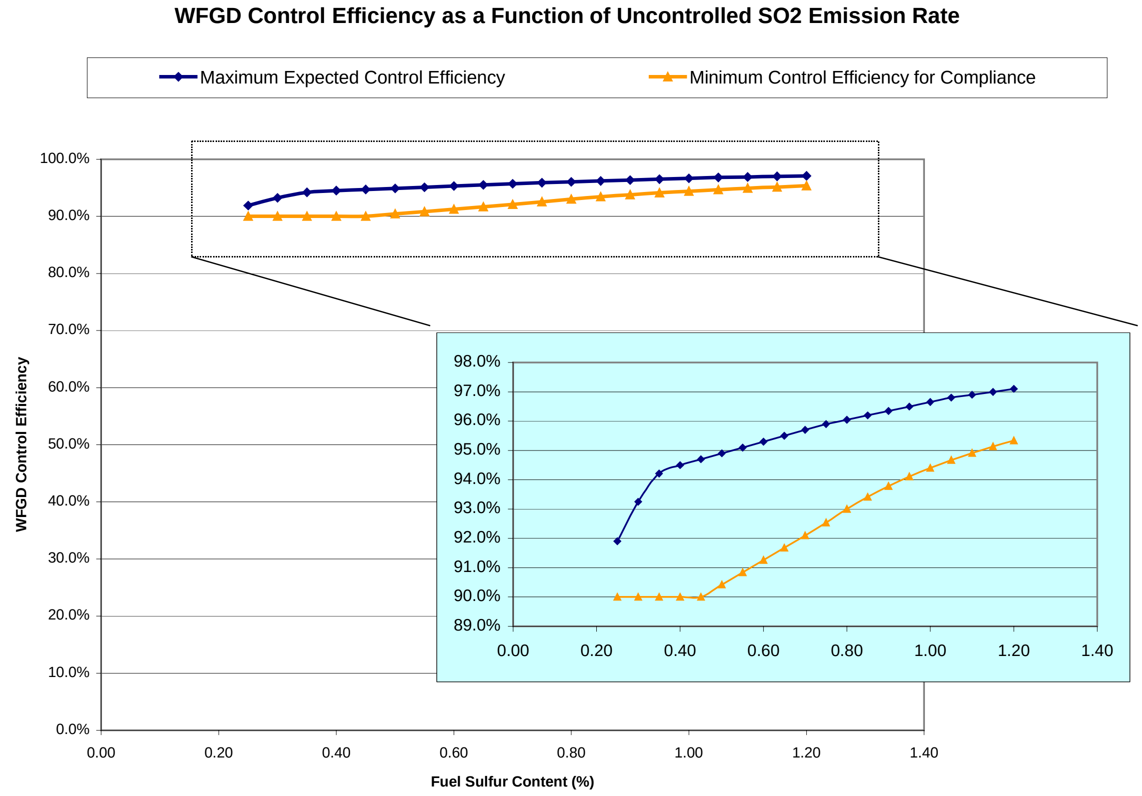
Question 2b.

> In addition to the above, IPSC needs to provide a range of efficiencies for the new Unit #3 WFGD unit for the different scenarios at the plant. IPSC has provided a WFGD efficiency of the maximum sulfur content, but not for the minimum and average sulfur contents.

Response to Question 2b.

Based on engineering judgment, reduction efficiencies achieved in practice at existing facilities, and information available from equipment vendors, a comparison of the maximum expected WFGD control efficiency and the minimum WFGD control efficiency required to ensure compliance with the proposed permit limit is presented in Figure 7 - as a function of the fuel sulfur content. As discussed in the response to Question 2a, IPP proposed a worst-case design fuel sulfur value of 0.75%. The average fuel sulfur content is expected to be in the range of 0.60 – 0.70%, and the fuel sulfur content is not expected to be below approximately 0.5%.

Figure 7



APPENDIX I-6

Sulfur Acid Mist

Evaluation of Wet Electrostatic Precipitation to Control Sulfuric Acid Mist Emissions

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EVALUATION OF WET ELECTROSTATIC PRECIPITATION TO CONTROL SULFURIC ACID MIST EMISSIONS

Background

In December 2002, Intermountain Power Agency (IPA) submitted a Notice of Intent (NOI) to permit and construct a new nominal 950-gross MW (900-net MW) pulverized coal-fired unit at the Intermountain Power Project station near Delta, Utah. In the NOI, IPA proposed wet flue gas desulfurization (FGD) as the best available control technology (BACT) for the control of sulfur dioxide and sulfur related compounds, including sulfuric acid mist. During subsequent NOI Technical Review Meetings between IPA and the Utah Department of Environmental Quality – Division of Air Quality (UDAQ), representatives of UDAQ asked whether consideration had been given to the technical and economic feasibility of a wet electrostatic precipitator (WESP) for sulfuric acid mist control.

In response to UDAQ's request for additional information, IPA is providing more detailed information regarding the technical and economic feasibility of controlling potential sulfuric acid mist emissions with a WESP system. The information contained herein should be considered part of IPA's BACT determination, and supplemental to Section 6.2 of the above referenced NOI.

IPA has concluded that WESP is neither technically or economically feasible, and does not represent BACT as defined in UAC R307-101-2, for the control of sulfuric acid mist from a large pulverized coal-fired boiler firing low sulfur bituminous coal. The basis for IPA's conclusion is provided below.

Technical Discussion

Sulfuric acid mist (H_2SO_4) is generated in a coal-fired boiler when sulfur trioxide (SO_3) in the flue gas reacts with water to form sulfuric acid. A small portion of the sulfur dioxide (SO_2) generated in the boiler will oxidize to SO_3 during the combustion process, and some additional SO_2 to SO_3 oxidation will occur across the SCR. Based on operating information from existing coal-fired boilers, and information available from equipment vendors, it is estimated that approximately 1.0% of the flue gas SO_2 will oxidize to SO_3 in the boiler, and that an additional 1.2% of the flue gas SO_2 will convert to SO_3 across the SCR. SO_3 is hygroscopic and will absorb moisture to form H_2SO_4 at gas temperatures below the sulfuric acid dewpoint.

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A portion of the SO_3 generated in the boiler and SCR will be captured in the unit's flue gas desulfurization system. IPA proposed wet FGD as BACT for SO_2 because it will provide the most stringent SO_2 control. SO_3, which is very reactive, will react with alkaline components of the desulfurization scrubber slurry. However, in the case of wet FGD, SO_3 entering the wet scrubbers may also react with water and create micron sized sulfuric acid droplets. Some of the micron-sized droplets may pass through the FGD spray levels and the mist eliminator, and be emitted as sulfuric acid mist.

SO_3 generated in the boiler and SCR may also be captured in the unit's fabric filter (BACT for PM-10 control). Fly ash cake that accumulates on the filter bags acts as an alkaline filter through which the flue gas must pass. SO_3 will readily react with alkaline components of the fly ash at temperatures below the H_2SO_4 dewpoint to form sulfate salts. The SO_3 removal efficiency of a fabric filter is dependent upon the alkalinity of the fly ash cake. Fabric filters associated with highly alkaline fly ash may significantly reduce the SO_3 concentration in the flue gas.[1]

In the BACT determination included in IPA's NOI, IPA concluded, based on the design coal information, and information available in the technical literature, that the wet FGD system would reduce potential H_2SO_4 emissions by approximately 40% (Intermountain Power Project, Notice of Intent, December 2002, page 6-1). No additional credit was taken for H_2SO_4 removal in the unit's fabric filters. To more accurately characterize the site-specific SO_3 generation rates and removal efficiencies in a boiler similar in design to the proposed Unit 3, IPA conducted stack testing at the existing IPP Unit 1.[2]

Based on the results of the stack tests, and information available in the technical literature, the following SO_3/H_2SO_4 generation rates and control efficiencies will be used in this evaluation:

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[1] In its BACT determination for PM-10, IPA considered the technical and economic feasibility of PTFE coated speciality bags for the removal of PM-10 (See section 6.2.7 of the NOI, and the paper entitled "PM10 Emissions and Fabric Filter Control Efficiency" in Appendix I of the NOI supplement). However, the type of fabric filter is not a consideration in the H_2SO_4 BACT analysis. In a fabric filter SO_3 is removed as the flue gas passes through the alkaline filter cake that accumulates on the filter bag. The filter cake will have the same properties regardless of the type of fabric used. Furthermore, bag cleaning (e.g., removing the accumulated cake) is based on pressure drop across the filter. The thickness of the filter cake will be the same regardless of the bag material.

[2] Stack testing was conducted on April 24, 2003. Results of the stack tests will be submitted to UDAQ under separate cover. IPP Unit 1 is a 950MW nominal boiler fired on Utah bituminous coal. Unit 1 is equipped with a fabric filter and wet FGD, however, it is not equipped with an SCR. Although SO_3 generation rates and removal efficiencies in Unit 1 should be similar to the generation rates and removal efficiencies for the proposed Unit 3, adjustments were made to account for additional SO_2 to SO_3 oxidation in the SCR.

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SO_2 to SO_3 Conversion in the Boiler	1.0%
SO_2 to SO_3 Conversion in the SCR	1.2%
SO_3 removal in the Fabric Filter	40%
H_2SO_4 Removal in the Wet FGD	84%
Overall H_2SO_4 Removal Efficiency	90%

Based on a worst-case design fuel (i.e., fuel that results in the highest SO_2/SO_3 emission rate), the maximum potential H_2SO_4 emission rate is calculated to be 0.045 lb/mmBtu. Assuming the control efficiencies listed above, the system will achieve an overall H_2SO_4 control efficiency of approximately 90% with the fabric filter and wet FGD. Based on an overall control efficiency of 90%, the controlled H_2SO_4 emission rate will be reduced to 0.0044 lb/mmBtu (or approximately 1.5 ppmvd @ 3% O_2). Emission calculations are provided in Tables 1 and 2.

Table 1
Calculation of Maximum Uncontrolled Sulfuric Acid Mist Emissions

Parameter	Unit	Value
Full Load Heat Input to Boiler	mmBtu/hr	9,050
Primary Fuel Feed Rate	lb/hr	808,541
Sulfur Content	%	0.75
Potential SO_2 in Boiler Flue Gas	lb/hr	12,128
Potential SO_2 in Boiler Flue Gas	lbmole/hr	189.5
SO_2 to SO_3 Conversion in Boiler	%	1%
Potential SO_3 in Boiler Flue Gas	lbmole/hr	1.9
SO_2 Entering the SCR	lbmole/hr	187.6
SO_2 to SO_3 Conversion in SCR (estimate)	%	1.2%
SO_3 Generated Across SCR	lbmole/hr	2.27
Potential Flue Gas SO_3 (Exiting the SCR)	lbmole/hr	4.17
SO_3 to H_2SO_4 Conversion	%	100
Potential H_2SO_4 Emissions	lb/hr	408
Potential H_2SO_4 Emission Rate	lb/mmBtu	0.045

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Table 2
Calculation of Sulfuric Acid Mist Emission Controls

Parameter	Unit	Value
SO_3 Entering the Fabric Filter	lb/hr	333
SO_3 Removal in the Fabric Filter	%	40
SO_3 Entering the FGD	lb/hr	200
Potential H_2SO_4 in the FGD	lb/hr	245
H_2SO_4 Removal in the FGD	%	84%
Controlled H_2SO_4 Emissions	lb/hr	40
Controlled H_2SO_4 Emission Rate	lb/mmBtu	0.0044
H_2SO_4 Concentration in Stack Gas	ppmvd @ 3% O_2	1.5

Until recently, WESP technology has not been applied to the utility industry because of the high gas flow volumes and the relatively low acid mist concentrations associated with utility flue gas. WESP has been used successfully in industrial applications such as sulfuric acid plants and municipal waste combustion, which have significantly lower flue gas flow rates and significantly higher acid mist concentrations.

There is limited commercial operating experience upon which to base a conclusion regarding the technical feasibility and effectiveness of WESP on a large utility boiler fired on Utah bituminous coal. The proposed Unit 3 is a nominal 950-gross MW unit, which is significantly larger than any existing unit equipped with a WESP. Furthermore, the proposed primary fuel, Utah bituminous coal, has a sulfur content significantly lower than the sulfur content of fuels typically associated with WESP, such as petroleum coke and high sulfur eastern bituminous coal. In fact, the maximum H_2SO_4 concentration in the Unit 3 flue gas is already expected to be significantly below 10 ppmvd @ 3% O_2, a level generally associated with a controlled H_2SO_4 emission rate.

Furthermore, WESP has generally been used to reduce acid mist concentrations that have contributed to opacity at units firing high sulfur fuels. Sulfuric acid concentrations in the flue gas greater than approximately 5 – 10 ppm may contribute to visible plume from the stack. It is not expected that an acid mist concentration of 1.5 ppmvd @ 3% O_2 will contribute to opacity.

Even though a WESP system has not been proven to be technically feasible and capable of reducing H_2SO_4 emissions from a pulverized coal-fired unit similar to IPA's proposed Unit 3, the maximum control efficiency (based on the anticipated flue gas H_2SO_4 concentration) would not be expected to be greater than approximately 80% under optimal conditions. This control efficiency would result in a controlled H_2SO_4 emission

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rate of approximately 0.00088 lb/mmBtu,[3] reducing the flue gas H_2SO_4 concentration to approximately 0.30 ppmvd @ 3% O_2, and represents an overall control efficiency (with FF + wet FGD + WESP) of approximately 98%.

Economic Evaluation

Table 3 presents the projected capital costs and annual operating costs associated with building and operating a WESP system to control H_2SO_4 mist from a nominal 950-gross MW unit. Table 4 shows the average annual cost effectiveness for the WESP, assuming 70% post-wet FGD H_2SO_4 control. A more detailed summary of the cost evaluation is included in Attachment 1.

Table 3
H_2SO_4 Emission Control System
Cost Summary*

Control Technology	Total Capital Investment ($)	Total Capital Investment ($/kW)	Annual Capital Recovery Cost ($/year)	Annual Operating Costs ($/year)	Total Annual Costs ($/year)
WESP	$58,290,000	$63	$7,319,800	$6,857,100	$14,176,900

* Capital costs provided in Table 1 are based on the average purchased equipment cost provided by four WESP vendors plus typical cost factors attributable to pollution control equipment.

[3] Even though a WESP system has not been proven to be technically feasible and capable of reducing H_2SO_4 emissions from a pulverized coal-fired unit similar to IPA's proposed Unit 3, a control efficiency of 80% was assumed for this evaluation. Although WESP has been used in high sulfur applications (e.g., boilers fired with petroleum coke, Orimulsion™ or high sulfur eastern bituminous coals) there is limited commercial operating history of WESP upon which to base this conclusion. Furthermore, to the best of our knowledge, the WESPs in utility service have been designed to achieve a controlled H_2SO_4 concentration of approximately 5 to 10 ppmvd, and it is not known if a WESP system could actually achieve a controlled H_2SO_4 concentration below 1.0 ppm.. The H_2SO_4 control efficiencies and emission rates used in this economic analysis are based on engineering judgment, and may not be technically achievable, or available as a guaranteed emission rate from a WESP vendor.

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Table 4
H_2SO_4 Emission Control System
Cost Effectiveness

Control Technology	Total Annual Cost ($/year)	Annual Emission Reduction (tpy)	Average Annual Cost Effectiveness ($/ton)
WESP	$14,176,900	139*	$101,990

* Annual emissions were calculated based on a controlled emission rate of 0.0044 lb/mmBtu (174 tpy) with the FF plus wet FGD configuration, and 0.00088 lb/mmBtu (35 tpy) with the WESP configuration.

Conclusions

WESP has not been proven as a technically feasible control option to reduce H_2SO_4 emissions from a large pulverized coal-fired unit fired on low sulfur bituminous coal. Furthermore, even if WESP is considered to be technically feasible, it should be excluded from consideration as BACT based on economic impact. The cost effectiveness of a WESP system designed to reduce the post-wet FGD H_2SO_4 emission rate by 80% is approximately $102,000/ton, which exceeds the cost effectiveness guidelines used by UDAQ in prior BACT determinations.

Fabric filtration and wet FGD have been proposed as BACT for PM-10 and SO_2 control, respectively, because they provide the most stringent emission control. Based on stack tests on IPP Unit 1, this combination of control technologies is expected to reduce potential H_2SO_4 emissions by approximately 90%. Emission reduction is achieved in the fabric filter cake because of the alkalinity of the Utah coal, and additional control is achieved in the wet FGD. Assuming a control efficiency of 90%, the controlled H_2SO_4 emission rate will be 0.0044 lb/mmBtu (or approximately 1.5 ppmvd @ 3% O_2). It is not expected that an acid mist concentration of 1.5 ppmvd @ 3% O_2 will contribute to opacity from the proposed unit.

WESP is neither technically feasible nor economically feasible, and does not represent BACT, as defined in UAC R307-101-2, for the control of sulfuric acid mist from the proposed IPP Unit 3.

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Attachment
BACT Cost Evaluation

CAPITAL COSTS	Cost [$]		Basis
Direct Capital Costs			
Emission Control Device	$43,500,000		Cost based on the average $/kW estimate provided by equipment vendors for vertical flow WESP. Includes the cost of major components, ancillary equipment, duct work, foundations, mechanical erection for the ESP vessel, induced draft fans, and make-up water system.
Auxiliary Equipment (e.g., ductwork, fans, etc)	$0	0%	
Instrumentation	$0	0%	
Sales Tax	$0	0%	No Sales Tax for pollution control equipment in Utah.
Freight	$0	0%	included in control device cost
Total Purchased Equipment Cost	$43,500,000		
Direct Installation Costs			
Foundations and Supports	$0	0.0%	included in control device cost
Handling and Mechanical Erection	$0	0.0%	included in control device cost
Electrical	$0	0.0%	included in control device cost
Piping	$0	0.0%	included in control device cost
Insulation	$0	0.0%	included in control device cost
Painting	$0	0.0%	included in control device cost
Total Direct Installation Costs	$0		
Indirect Capital Costs			
Engineering	$4,350,000	10.0%	of purchased equipment cost (typical order-of-magnitude value)
Construction and Field Expenses	$2,175,000	5.0%	of purchased equipment cost (typical order-of-magnitude value)
Contractor Fees	$0	0.0%	included in Purchase and Direct costs
Start-Up	$870,000	2.0%	of purchased equipment cost (typical order-of-magnitude value)
Performance Tests	$870,000	2.0%	of purchased equipment cost (typical order-of-magnitude value)
Contingencies	$6,525,000	15.0%	of purchased equipment cost (typical order-of-magnitude value)
Total Indirect Capital Costs	$14,790,000		
Site Preparation	$0		
Buildings	$0		
Total Capital Costs			
Total Capital Investment	$58,290,000		
Total Capital Investment ($/kW)	$63.00		
Capital Recovery Factor = $i(1+i)^n / (1+i)^n - 1$	0.1256	20	life of equipment (years)
Annualized Capital Costs (Capital Recover Factor x Total Capital Investment)	**$7,319,800**	11%	pretax marginal rate of return on private investment

OPERATING COSTS			Basis
Operating & Maintenance Costs			
Variable O&M Costs			
Water Cost	$262,800		$1/1000 gal., approx. 500 gpm. Based on typical water flow to a WESP and assuming that approximately 75% of the water will be supplied from the wet FGD.
Solids and Wastewater Disposal	$25,000		Estimate, based on increased water flow and slight increase in solids generated for disposal.
Auxiliary Power Cost	$1,214,550		Assumed 0.5% auxiliary power requirement @ $30/MWh
Total Variable O&M Costs	$1,502,350		
Fixed O&M Costs			
Operating Labor	$70,000		1 additional operator @$70,000/operator/year
Supervisor Labor	$14,000	20.0%	of operating labor
Administrative Labor	$42,000	3.0%	of operating, supervisory, and maintenance labor
Maintenance Materials	$2,175,000	5.0%	of purchased equipment cost (assumed cost for WESP)
Maintenance Labor	$1,305,000	60.0%	of maintenance materials cost
Total Fixed O&M Cost	$3,606,000		
Indirect Operating Cost			
Property Taxes	$582,900	1%	of total capital investment. USEPA Cost Estimating Factor.
Insurance	$582,900	1%	of total capital investment. USEPA Cost Estimating Factor.
Administration	$582,900	1%	of total capital investment. USEPA Cost Estimating Factor.
Total Indirect Operating Cost	$1,748,700		
Total Annual Operating Cost	**$6,857,100**		
TOTAL ANNUAL COST			
Annualized Capital Cost	**$7,319,800**		
Annual Operating Cost	**$6,857,100**		
Total Annual Cost	**$14,176,900**		
TOTAL H2SO4 REMOVED (tons/year)	**139**		See FGD Summary Worksheet
COST EFFECTIVENESS ($/ton removed)	**$101,990**		

APPENDIX I-7

CO/VOC BACT

IPP Unit 3 Air Permit Application: Review of CO and VOC Permit Limits (revised)

IPP Unit 3 Air Permit Application
Review of CO and VOC Permit Limits (Revision 2)

PREPARED FOR: Milka Radulovic, UDAQ

PREPARED BY: CH2M HILL

DATE: March 26, 2004

The purpose of this memorandum is to provide additional information to support the CO and VOC BACT emission limits requested in the IPP Unit 3 permit application. This memorandum has been updated to incorporate the current draft Approval Order permit conditions and to update the analysis based on the recent addition of three other coal units in the "Recently Issued PSD Permits" list.

CO Limit

The BACT analysis in the IPP permit application concluded that combustion control was the appropriate control technology with an emission limit of 0.15 lb/MMBtu. This is equivalent to a boiler outlet concentration of 180 ppmvd at full load with the range of coals designed for the unit. It is expected that this will be the emission rate guarantee by boiler equipment vendors. IPP proposes to demonstrate compliance with this limit based on initial performance stack testing and the use of CEM or a CEM equivalent method, such as parametric monitoring, as determined by the Executive Secretary.

The table of CO limits for other recently issued pulverized coal-fired utility boilers PSD permits has been updated with three new units. They are shown in Table 1. Note that the Prairie State permit is still in draft form. Eight of the twelve facilities burn either Powder River Basin (PRB) western subbituminous coal or western bituminous coal. These facilities include Hawthorne, Springerville, Holcomb, Wygen, Roundup, Plum Point, Hardin and Council Bluffs. These facilities have CO permit limits between 0.15 and 0.16 lb/MMBtu. The remaining four facilities on the list burn eastern bituminous coals with significantly higher fuel heating values. These facilities include Thoroughbred, Elm Road, Longview and Prairie State. These facilities have CO permit limits between 0.10 and 0.12 lb/MMBtu. Five of the twelve units will use stack testing to demonstrate compliance with the limit; the other seven will utilize a CO CEM to demonstrate compliance.

To date, boiler vendors have supplied CO guarantees in the range of 0.15 – 0.16 lb/MMBtu for new pulverized coal boilers that burn western coals. The facilities that have lower permit limits are all designed to burn eastern bituminous coal. Of all the recently issued permits, only Hawthorne Unit 5 is operational and has demonstrated compliance with a 0.16 lb/MMBtu CO permit limit.

For the reasons stated above, IPP feels that a CO limit of 0.15 lb/MMBtu and the use of initial stack testing and CEM or CEM equivalent method for compliance demonstration is appropriate for IPP Unit 3. As referenced in the March 25, 2004 letter from CH2M HILL to UDAQ, IPP is agreeable to a 30-day block average CO limit of 1,357.5 lb/hr (0.15 lb/MMBtu at the maximum boiler heat input of 9,050 MMBtu/hr) and a short-term 8-hour CO emission limit of 3,000 lb/hr. The modeling conducted for IPP Unit 3 demonstrated that the CO impacts are well below the Class II modeling significance levels for both the 1-hour and 8-hour CO standards.

VOC Limit

The BACT analysis in the IPP permit application concluded that combustion control was the appropriate control technology with an emission limit of 0.0027 lb/MMBtu. It is expected that this will be the emission rate guarantee by boiler equipment vendors. IPP proposes to demonstrate compliance with this limit based on 3-hour average initial and annual stack tests utilizing EPA Reference Method 25 or 25A.

The table of VOC limits for other recently issued pulverized coal-fired utility boilers PSD permits has been updated with three new units. They are shown in Table 2. Note that the Prairie State permit is still in draft form. The twelve permits have limits between 0.0030 and 0.0200 lb/MMBtu depending on the boiler type and design coal. Nine of the twelve units will use initial stack testing to demonstrate compliance with the limit; the other three do not require compliance demonstration.

The IPP Unit 3 proposed VOC limit of 0.0027 lb/MMBtu is lower than any of the other recently issued permits. IPP feels that a VOC limit of 0.0027 lb/MMBtu and the use of initial and annual stack testing for compliance demonstration is appropriate.

TABLE 1
Recently Issued PSD Permits - CO Limits

Name	Type/Size	CO Limit	Comments
Hawthorne Unit 5 Missouri	Pulverized Coal 570 MW	0.16 lb/mmbtu	Combustion control. CEMS not required. Stack test used for compliance.
Springerville Units 3 and 4 Arizona	Pulverized Coal 450 MW each	0.15 lb/mmbtu (30 day rolling average)	Combustion control. CEMS used for compliance.
Holcomb Unit 2 Kansas	Pulverized Coal 660 MW	0.15 lb/mmbtu	Combustion control. CEMS not required. Stack test used for compliance. If CO and NOx limit cannot be met simultaneously, State will revise CO limit.
Thoroughbred Units 1 and 2 Kentucky	Pulverized Coal 750 MW each	0.10 lb/mmbtu (30 day rolling avg)	Combustion control. CEMS used for compliance.
Wygen Unit 2 Wyoming	Pulverized Coal 500 MW	0.15 lb/mmbtu	Combustion control. CEMS not required. Stack test used for compliance.
Bull Mountain Roundup Units 1 and 2 Montana	Pulverized Coal 390 MW each	0.15 lb/mmbtu	Combustion control. CEMS not required. Stack test used for compliance.
Plum Point Energy Station Unit 1 Arkansas	Pulverized Coal 550 – 800 MW	0.16 lb/mmbtu	Combustion control. CEMS used for compliance.
Rocky Mountain Power, Hardin Unit 1 Montana	Pulverized Coal 113 MW	0.15 lb/mmbtu	Combustion control. CEMS not required. Stack test used for compliance.
Council Bluffs Energy Center Unit 4 Iowa	Pulverized Coal 750 MW	0.154 lb/mmbtu (1 day avg) 5,177 tpy	Combustion control. CEMS used for compliance. If CO and NOx limit cannot be met simultaneously, State will revise CO limit.
Elm Road Generating Station, Units 1 and 2 Wisconsin	Pulverized Coal 600 MW each (6,180 mmbtu/hr)	0.12 lb/mmbtu (24-hr rolling avg)	Combustion control. CEMS used for compliance. Emission limit excludes startup and shutdown. Other limits: 742 lb/hr CO 24-hr rolling average, 2,400 lb/hr CO 1-hr average, 3,250 tons 12 month rolling total (includes all operation, startup and shutdown).
Longview Power Unit 1 West Virginia	Pulverized Coal 600 MW (6,114 mmbtu/hr)	0.11 lb/mmbtu (3-hr rolling avg)	Combustion control. CEMS used for compliance.
Prairie State Generating Station Units 1 and 2 Illinois	Pulverized Coal 750 MW each (7,450 mmbtu/hr)	0.12 lb/mmbtu (24 hour block avg)	Draft Permit Combustion control. CEMS used for compliance.

All the permits above, except Bull Mountain Roundup, exempt startup, shutdown and malfunction in the short term (1 hour, 3 hour, 24 hour and 30 day) emission limits.

TABLE 2
Recently Issued PSD Permits - VOC Limits

Name	Type/Size	VOC Limit	Comments
Hawthorne Unit 5 Missouri	Pulverized Coal 570 MW	0.0036 lb/mmbtu	Combustion control. Stack test used for compliance.
Springerville Units 3 and 4 Arizona	Pulverized Coal 450 MW each	0.06 lb/ton coal (3 hour average)	Combustion control. Stack test used for compliance.
Holcomb Unit 2 Kansas	Pulverized Coal 660 MW	0.0035 lb/mmbtu	Combustion control. Stack test used for compliance. If VOC and NOx limit cannot be met simultaneously, State will revise VOC limit
Thoroughbred Units 1 and 2 Kentucky	Pulverized Coal 750 MW each	0.0072 lb/mmbtu (30 day rolling avg)	Combustion control. Compliance with CO limit used to demonstrate compliance with VOC limit.
Wygen Unit 2 Wyoming	Pulverized Coal 500 MW	0.01 lb/mmbtu	Combustion control. Initial Stack test used for compliance.
Bull Mountain Roundup Units 1 and 2 Montana	Pulverized Coal 390 MW each	0.0030 lb/mmbtu	Combustion control. Stack tests not required.
Plum Point Energy Station Unit 1 Arkansas	Pulverized Coal 550 – 800 MW	0.02 lb/mmbtu	Combustion control. Initial Stack test used for compliance.
Rocky Mountain Power, Hardin Unit 1 Montana	Pulverized Coal 113 MW	0.0034 lb/mmbtu	Combustion control. Stack tests not required.
Council Bluffs Energy Center Unit 4 Iowa	Pulverized Coal 750 MW	0.0036 lb/mmbtu	Combustion control. Initial Stack test used for compliance.
Elm Road Generating Station, Units 1 and 2 Wisconsin	Pulverized Coal 600 MW each (6,180 mmbtu/hr)	0.0035 lb/mmbtu (24-hr rolling avg)	Combustion control. Initial Stack test used for compliance. Emission limit excludes startup and shutdown.
Longview Power Unit 1 West Virginia	Pulverized Coal 600 MW (6,114 mmbtu/hr)	0.004 lb/mmbtu (3 hr rolling avg)	Combustion control. Stack tests used for compliance.
Prairie State Generating Station Units 1 and 2 Illinois	Pulverized Coal 750 MW each (7,450 mmbtu/hr)	0.004 lb/mmbtu (3 hr block avg)	Draft Permit Combustion control. Stack tests used for compliance.

All the permits above, except Bull Mountain Roundup, exempt startup, shutdown and malfunction in the short term (1 hour, 3 hour, 24 hour and 30 day) emission limits.

APPENDIX I-8

Response to UDAQ BACT Questions

Generating Technology BACT Evaluation

Introduction

In December 2002, Intermountain Power Agency (IPA) submitted a Notice of Intent (NOI) to permit and construct a new nominal 950-gross MW (900-net MW) pulverized coal-fired unit at the Intermountain Power Project station near Delta, Utah. Subsequently, IPA provided the Utah Department of Environmental Quality – Division of Air Quality (UDAQ) additional technical information supporting the permit application. In the NOI, and subsequent supporting documents, IPA provided a comprehensive evaluation of the best available control technologies (BACT) to control emissions from the proposed pulverized coal-fired unit.

BACT is one element of the Prevention of Significant Deterioration (PSD) preconstruction permitting process, and is generally defined as an emissions limitation based on the maximum degree of reduction that can be achieved on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs.[1] Permitting agencies generally use the "top-down" BACT process to evaluate potential control technologies and establish appropriate BACT emissions limitations. The top-down BACT process is described in the U.S.EPA's New Source Review Workshop Manual, Draft October 1990 (the "NSR Manual").

Over the past few years, several PSD permit applications have been submitted to various permitting agencies proposing to construct pulverized coal-fired (PC) steam electric generating units. In a majority of these preconstruction permit reviews, the permitting agency applied the top-down BACT process to the source as defined by the applicant (e.g., PC steam electric generating unit).[2] The New Mexico Environment Department recently required an applicant proposing a PC unit to modify its BACT determination and evaluate the economic and environmental impacts of replacing the PC design with an Integrated Gasification Combined Cycle (IGCC) plant design. Similarly, the Illinois Environmental Protection Agency, recently requested an applicant proposing a circulating fluidized bed (CFB) boiler to consider IGCC in its BACT determination.

[1] UAC R307-101-2

[2] See for example the PSD permit applications for: (1) KCP&L Hawthorne Facility in Missouri; (2) Thoroughbred Generating Facility in Kentucky; (3) Wygen II Project in Wyoming; (4) Roundup Power Project in Montana; and (5) Sunflower Electric – Holcomb Generating Project in Kansas. In each of these recent PSD permit applications, the permit applicant defined the source as a pulverized coal-fired unit, and applied the BACT process to identify the best available technologies to control emissions from a pulverized coal-fired unit.

IPA does not consider the BACT requirement as a process that should be used to define an emission source. Likewise, EPA has not historically considered the BACT requirement as a means to redefine the design of a source when considering available control alternatives (NSR Manual, page B.13). The BACT process, as described in the NSR Manual, should be applied to the source, as defined by the applicant, to identify the best available control technologies. All three electricity generating technologies (i.e., PC, CFB and IGCC) require unique engineering and design. Requiring Unit 3 to be designed using CFB or IGCC technology would completely redefine the scope of the proposed project.

Prior to proposing the new unit and submitting the NOI, IPA conducted an internal engineering review of potential electricity generating technologies. During the initial engineering review, IPA considered the technical and economic feasibility of PC, CFB, and IGCC power generation. In anticipation of questions that might arise during the permit review process, IPA is providing the following information:

I. Summary of the initial engineering review process IPA used to identify the most appropriate technology for Unit 3.

II. A full BACT analysis comparing the PC, CFB and IGCC technologies using, to the extent practicable, U.S.EPA's 5 step top-down BACT approach.

Based on the information included in this report, IPA has concluded that:

(1) PC is the only coal-fired generating technology that can reliably meet the design criteria established for the proposed Unit 3;
(2) IGCC and CFB are not feasible power generating options for Unit 3, as proposed;
(3) the BACT process should be used to identify the best emission control technologies available for the source as defined by the applicant, and should not be used to define or re-define the source;
(4) emissions from the proposed PC boiler will be lower than emissions actually achieved in practice at existing CFB and IGCC facilities, and virtually identical to emissions that might be achieved from the next generation CFB and IGCC plants; and
(5) the economic impacts associated with CFB and IGCC technologies are cost prohibitive.

Part I – INITIAL ENGINEERING REVIEW

1.0 Initial Engineering Review

During the initial planning stages of any power generation project, it is necessary for the proponent to define the scope of the project and initiate a conceptual design of the facility. Early in the Unit 3 planning process IPA initiated a conceptual design study. Technical, financial, environmental, and practical considerations were reviewed during the initial study to reach a conclusion as to the most appropriate design for IPP Unit 3. Items taken into consideration included: requisite generating capacity, reliability, availability, fuel availability, site characteristics (such as altitude), safety factors, operator training, redundancy/compatibility with existing IPP Unit 1 and Unit 2, and potential environmental impacts. Some of the more important project design criteria included:

- Unit 3 should be capable of generating a nominal 900-MW net output.

- Unit 3 would be a baseload unit, and therefore the unit must be designed with technologies capable of achieving a capacity factor of at least 90 percent.

- As a baseload unit, Unit 3 must be very reliable and must be capable of maintaining a very low forced outage rate. Therefore, Unit 3 must be designed with a highly reliable boiler and turbine, reliable emission control technologies, and reliable ancillary equipment.

- Based on projected fuel availability, Unit 3 boiler should be designed to fire Utah bituminous coal with an average maximum design coal sulfur content of 0.75%, and a design coal heating value of 11,193 Btu/lb.[3]

- To ensure flexibility in the fuel supply, the proposed boiler should be capable of burning a blend of Utah bituminous coal and western sub-bituminous coal.

- For safety considerations, operator training considerations, and O&M reliability, the boiler should be (to the extent practicable) compatible with the existing IPA coal-fired units.

- Unit 3 must be equipped with the best available emission control technologies, and emissions from the proposed unit must not cause or contribute to a violation of the applicable NAAQS or applicable Prevention of Significant Deterioration of Air Quality (PSD) increment.

[3] A detailed discussion of the proposed design fuel has been provided to UDAQ in a paper titled: "*Intermountain Power Project Unit 3 Coal Supply*".

Part I – INITIAL ENGINEERING REVIEW

2.0 Unit 3 – Initial Design Basis

The Delta, Utah station currently has two operating PC units. The site was originally designed to support four units with a total electricity output of approximately 3000 MW. Units 1 & 2 are nominal 950 MW-gross units firing Utah bituminous coal. These units have been in service for approximately 15 years, and have proven to be reliable and efficient generating units with capacity factors above 90%, and availability records of 98% to 99%.

The existing units served as a starting point for the conceptual design of Unit 3. The conceptual design included a review of the cycle and steam conditions, and a preliminary review of fuel availability and potential pollution control technologies. The conceptual design also identified potential interface points with existing equipment and site facilities and a preliminary capital cost estimate. The Unit 3 conceptual design criteria included:

- Turbine-Generator: 950 MW-gross tandem compound, 6-flow subcritical.
- Main Steam Condition at Turbine: 2520 lb. and 1050 °F.
- Reheat Steam Temperature: 1050 °F.
- Feedwater Heater Cycle: HARP-Cycle (8-heater).
- Steam Generator: Pulverized coal with low NO_X combustion system, over-fire air, and selective catalytic reduction.
- Pollution Control Equipment: fabric filter and wet limestone flue gas desulfurization with forced oxidation.
- Cooling System: Mechanical draft cooling towers with multi-pressure condenser.
- Equipment Sizing and Sparing: Same philosophy as Units 1 & 2 to support the demonstrated high reliability.

The conceptual design also included interface with the following existing systems and site facilities:

- coal unloading, storage, and reclaim;
- cooling tower make-up water supply;
- cycle make-up water supply;
- fly ash handling;
- bottom ash handling;
- limestone for the FGD;
- FGD waste handling;
- wastewater treatment; and
- 345 kV Switchyard tie-in.

Part I – INITIAL ENGINEERING REVIEW

Using the existing units as the starting point for the Unit 3 conceptual design offered the following advantages:

- Proven reliability.
- High efficiency, with HARP cycle.
- Low emissions when equipped with BACT emission control technologies.
- Fuel flexibility.
- Potential sale of waste products, fly ash, bottom ash, and gypsum.
- Good turndown capability and load following.
- Plant operators will be familiar with the Unit 3 design, based on operating Units 1 and 2.
- Commonality of space parts and maintenance practices will promote reliability and safety.
- Commonality of burning the same fuel as Units 1 and 2 will promote economic generation.

3.0 Alternative Steam Generation Options

Once the design criteria for Unit 3 were established, alternative electricity generating technologies were evaluated. Consideration was given to both CFB and IGCC technologies. Technical and economic variables evaluated during the technical review process included:

- size of existing steam generation equipment;
- heat rate and unit performance;
- availability/reliability;
- demonstrated performance on Utah bituminous coal;
- potential air emissions;
- capital costs;
- operating costs;
- maintenance costs;
- waste products; and
- water usage.

Table 1 summarizes the design basis for each technology used during the initial design phase of the project.

Part I – INITIAL ENGINEERING REVIEW

Table 1
Generating Technologies
Initial Design Basis

	Proposed PC Unit #3	**CFB Boiler**	**IGCC**
Gross Output (MW)	950 (1 boiler and 1 turbine)	975 (3 boilers and 1 turbine)	1014 (4 gas turbines, 4 HRSGs, and 1 steam turbine) Note: the CT's are derated by approximately 16% due to the site elevation of 4646 ft.
Net Output (MW's)	900	900	912
Plant Heat Rate (Btu/kW-Hr)	~ 9700	~9,900	~9700 - 9800
Capital costs	Base	Base + \$55 x 10^6	Base + \$500 x 10^6
Anticipated Emission Rates (lb/mmBtu – 30 day average)			
SO_2	0.10	0.10	0.12
NO_X	0.07	0.09	0.09
Particulate (filterable)	0.015	0.015	0.011
Mercury	55- 75% controlled based on ICR database	55- 75% controlled based on ICR database	Unknown, based on DOE report possibly 30%

4.0 Circulating Fluidized Bed (CFB) Steam Generator

4.1 CFB Description

In a CFB boiler, coal or other fuels are burned in a bed of inert particulate matter, which is suspended or "fluidized" by the combustion air. The combustion temperature of the bed is maintained at approximately 1600 °F, which precludes the coal ash from melting and fouling heat transfer surfaces in the boiler, and reduces the amount of NOx produced in the combustion process. The steaming rate is primarily controlled by manipulating the bed velocity. By reducing the velocity, less heat-transfer surface is exposed to the bed. When air is shut off, heat transfer is halted providing the capability for quick turndown. Steaming rate and turndown in a CFB can also be controlled by reducing the amount of bed material or by regulating the fuel feed rate.

CFB boilers can burn low-quality fuels such as culm, gob, and petroleum coke, and can also burn chipped tires and biomass.

Part I – INITIAL ENGINEERING REVIEW

CFB units typically use a refractory-lined combustor bottom section with fluidizing nozzles on the floor above the wind box; an upper combustor section, usually with waterwalls; a transition piece, including a hot-solids separator and reentry downcomer; and a convective boiler section. Long residence times in the boiler bed will increase combustion efficiency and improve absorption of SO_2. The main disadvantage of a CFB is its need for greater fan power to maintain high bed velocities.

In a CFB, a sorbent (usually limestone) is added to the combustion bed to react with SO_2 generated by combustion of sulfur in the fuel. The CFB boiler with limestone injection can achieve SO_2 removal efficiencies of approximately 90% to 92% at relatively high calcium-to-sulfur molar ratios. Post-combustion FGD systems are typically not required, however, a couple of recently permitted CFB boilers have been designed with a post-combustion polishing scrubber. A polishing scrubber typically consists of a fly ash (or lime) reinjection system, and can increase the overall SO_2 removal efficiency and improve limestone utilization. A CFB boiler designed with a polishing scrubber may achieve an overall SO_2 removal efficiency of 95 – 97%, depending on the fuel sulfur content. CFB boilers produce a dry, inert by-product, which is easily disposed, but generally not salable.

In order to meet low NOx emission requirements, selective noncatalytic reduction (SNCR) can be implemented. SNCR involves the injection of ammonia into the boiler. SNCR is a relatively simple control system, and does not require catalyst to promote the NOx reduction reaction. Depending on the fuel and flue gas characteristics, SNCR technology has demonstrated a NOx reduction efficiency of approximately 25 – 35% resulting in controlled NOx emission rates of 0.90 - 0.10 lb/mmBtu.

The CFB steam cycle and auxiliary equipment is basically equivalent to that used for a PC unit. Supercritical steam conditions are not used with fluidized beds because of a concern of pressure-part erosion by the fluidized material.

4.2 Size Range and Turndown

CFB plants range in size from 100 MW to 300 MW. The largest operating CFBs are at the Jacksonville Electric Authority (JEA) Northside Generating Station. JEA's CFB boilers are rated at 296 MW each, and are designed to burn 100% bituminous coal, 100% petroleum coke, and blends of each.

CFB boiler turndown is typically 30% to 40% load, depending on the fuel characteristics.

It is likely that at least three CFB boilers would be required to meet the steam requirements of one 950 MW-gross steam turbine. Each CFB boiler would need to be rated for 325 MW to allow for the higher auxiliary power requirements and achieve a net output of approximately 900 MW. A gross rating of 325 MW represents a scale-up in boiler design of approximately 10%. For purposes of the initial technology evaluation, a scale-up of less than 10% was considered acceptable. Each boiler would have its own fans, air heaters, SO_2 polishing system, and baghouse. The CFB units would utilize a common chimney with three individual liners.

4.3 Capital Costs

Capital costs for the CFB design where developed based on S&L's database of recent coal-fired CFB plant estimates. The baseline Unit 3 conceptual design cost estimate was adjusted by deleting the cost of the PC boiler (including the boiler and SCR), the baghouse, and wet-FGD, and replacing these costs with the costs associated with three CFB boilers. The baseline capital cost for the CFB configuration was estimated to be approximately $1,189/kW-gross, which is approximately $51,000,000 above the PC configuration.

4.4 Air Emissions

Based on a review of recently permitted CFB units, and emissions achieved in practice at existing CFB boilers, it is expected that a new CFB unit could achieve the following emission rates:

> SO_2: 0.05 to 0.08 lb/mmBtu (30-day rolling average) achieved with in-bed SO_2 reduction with limestone followed by dry SO_2 polishing scrubber and baghouse.
>
> NO_X: 0.09 – 0.10 lb/mmBtu (30-day rolling average) based on using SNCR in the CFB. SCR technology is not considered technically feasible on a CFB boiler due to the potential fouling of the catalyst by the CFB flue gas chemistry.
>
> PM10[4]: 0.012 - 0.015 lb/mmBtu achieved using baghouse technology.

4.5 Advantages

Advantages of designing Unit 3 using CFB boilers include:

- The need for an expensive post-combustion FGD system is probably eliminated.
- SNCR represents BACT for NOx control. SNCR is cheaper than the SCR technology used for NO_X control on PC units.

[4] As used throughout this evaluation, unless otherwise noted the term "PM10" refers to filterable particulate matter with an aerodynamic diameter less than 10 microns measured using USEPA Methods 201/201A.

- CFB offer the flexibility to burn a wide array of fuels.
- CFB technology has been designated a "clean coal combustion" technology, and may be viewed as a favorable technology with respect to environmental issues

4.6 Disadvantages

The disadvantages of CFB plants include:

- Higher capital costs.
- CFB boilers generate larger quantities of solid waste compared to a PC plant designed with wet limestone scrubbing.
- CFB boiler design results in a significant increase in auxiliary power requirements due to fan power requirements.
- It is unlikely that a CFB boiler equipped with SNCR will be able to achieve a controlled NOx emission rate below approximately 0.09 lb/mmBtu.
- Solid waste generated from SO_2 and particulate matter removal is generally not salable.

5.0 Integrated Gasification Combined Cycle (IGCC)

5.1 IGCC Description

In an IGCC facility coal (or other solid fuel) is converted into a low- or medium-Btu synthesis gas ("syngas") that can be used to fuel a combustion turbine. Originally, the IGCC process was conceived to take advantage of an inexpensive and abundant fuel source (i.e., coal) in an efficient combined cycle plant. IGCC has good fuel flexibility, and oil or natural gas may be fired in the combustion turbine when syngas is unavailable. Gasifiers can also utilize blended feed stocks provided suitable design considerations are incorporated.

Coal can be fed to the gasifier using various systems, including water slurry feed (wet), nitrogen carrier feed (dry), paste feed, and lockhopper solids. The gasifier may be of the fixed-bed, fluid-bed, or entrained-flow type. Syngas from the gasifier must be cleaned prior to combustion to remove particulates and sulfur compounds. Cleaned syngas is burned in a turbine combustor.

Because the gasification process is energy-intensive, integration of the power block with the gasification plant will maximize plant efficiency. This may involve supplying air to the gasification plant from the combustion turbine compressor and supplying process heat to the gasification system from the HRSG.

Part I – INITIAL ENGINEERING REVIEW

There are currently two IGCC plants operating in the U.S. designed specifically to generate electricity from gasified coal and/or petroleum coke – Polk and Wabash River. Based on information available from U.S. Department of Energy (DOE)[5] both plants have failed to demonstrate syngas availability of 80%, and neither plant has ever operated at an annual capacity factor higher than 77%, including periods when they operated on oil or natural gas with no attempt to use coal. Table 2 provides a summary of the actual capacity factors and heat rates achieved in practice at Polk and Wabash River. Data summarized in Table 2 were obtained from the U.S. EPA's Acid Rain emissions scorecard (http://www.epa.gov/airmarkets/emissions/index.html) and Resource Data International's PowerDat database:

Table 2
IGCC Actual Capacity Factors and Heat Rates

	Polk Power Station IGCC		Wabash River IGCC	
	Capacity Factor	Net Heat Rate	Capacity Factor	Net Heat Rate
Year	%	Btu/kWh	%	Btu/kWh
1996	11.54	n/a	--	--
1997	45.38	n/a	34.95	11,716
1998	62.37	n/a	52.44	11,341
1999	70.20	9,877	32.88	10,225
2000	77.01	10,378	44.54	8,746
2001	63.46	10,725	36.08	9,244

[5] Technical information for the two operating IGCC facilities was obtained from the following documents:

Wabash River Coal Gasification Repowering Project – Final Technical Report, Prepared by Wabash River Energy Ltd., Work Performed Under Cooperative Agreement DE-FC21-92MC29310 for the U.S. Department of Energy, August 2000 ("Wabash River Final Report").

Wabash River Coal Casification Repowering Project: A DOE Assessment, U.S. Depart of Energy, DOE/NETL-2002/1164, January 2002 ("Wabash River DOE Assessment").

Tampa Electric Polk Power Station Integrated Gasification Combined Cycle Project – Final Technical Report, Prepared by Tampa Electric Company, Work Performed Under Cooperative Agreement DE-FC-21-91MC27363, August 2002 ("Polk Final Report").

The Wabash River IGCC has always operated at annual capacity factors below 60% and the Polk IGCC has usually operated at annual capacity factors below 70%. A capacity factor below approximately 90% would seriously jeopardize the economics of the IPA Unit 3 project.

A third IGCC power plant, Pinon Pine, was constructed in Nevada in1996, and was the only IGCC plant that has used Western coal. The Pinon Pine IGCC plant never operated successfully. As stated in the Final Report for the Pinon Pine demonstration project:

> "During the reporting period of the Pinon Pine IGCC Project, the Gasifier was started up a total of eighteen (18) times. Each start-up failed due to design or equipment flaws. Each subsequent start-up attempt after a failure was not performed until the problem that halted the preceding start-up was addressed. Although this project was to demonstrate the potential for commercial operation of the air blown KRW Gasifier, hot desulfurization, and hot particulate removal, the goal of achieving sustained operation has not yet been accomplished."
> *Final Technical Report to the U.S. Department of Energy – Pinon Pine IGCC Project, January 2001.*

The U.S. DOE recently issued its own assessment of the project which concluded:

> "A protracted effort was made to bring the facility on stream, but a series of equipment problems resulted in aborting all startup attempts. Sustained integrated operation of the gasifier and hot-gas cleanup facilities was never achieved…. Attempts to start the IGCC plant were discontinued in 2001, and the gasifier is being mothballed."
> *Pinon Pine IGCC Power Project, A DOE Assessment, December 2002.*

5.2 Size Range and Turndown

There have been very few IGCC plants built for commercial applications in a utility-sized generating station. A rough estimate of the maximum size range for an IGCC facility based on "F" technology combustion turbines would be approximately 540 MW using a 2 x 2 x 1 (i.e., 2 combustion turbines, 2 HRSGs, and 1 steam turbine) configuration. Multiple trains could be added for an incremental increase in output should a larger plant be required.

Because the plant site is at an elevation of 4646 feet, the combustion turbines would have to be derated. The four-on-one configuration that would normally provide 1148 MW–gross, would only achieve an output of 1014 MW. This derating will impact the combustion turbine emission rates on a lb/MW-hr basis, and increase costs on a $/MW-net basis.

Turndown of a gasifier is technically possible, however base load is preferred due to complexity of the gasification process. IGCC plants usually install multiple gasifier trains for reliable operation. The combustion turbines can achieve part-load operation down to 50 – 70% until emissions (NOx and CO) increase significantly.

5.3 Capital Costs

Capital costs for the IGCC configuration where developed based on information obtained from a gasifier equipment vendor, and confirmed by comparing costs developed to costs included in the Polk and Wabash River final reports. The baseline Unit 3 conceptual design cost prepared by S&L was adjusted by deleting the cost of the PC boiler (including the boiler and SCR), the baghouse, and wet-FGD, and replacing these costs with the costs associated with an IGCC including the gasifiers, air separation unit, gas cleanup equipment, sulfuric acid plant, combustion turbine, HRSG, and steam turbine. The baseline capital cost for the IGCC configuration was estimated to be approximately $1,511/kW-gross, which is approximately $630,000,000 above the PC configuration.

5.4 Air Emissions

The combustion of low- or medium-Btu syngas in a combustion turbine can result in an inherently low NOx emission rate. Furthermore, sulfur compounds can be removed from the syngas prior to combustion to reduce the SO_2 emission rate. However, because the syngas has a lower heating value than fuels such as natural gas, the combustor must be specially modified, and additional fuel must be burned to generate the same heat input to the combustion turbine.

Table 3 provides a summary of the actual NOx and SO_2 emission rates that have been achieved in practice at Polk and Wabash River. Emissions data presented in Table 3 were obtained from the U.S.EPA Emissions Scorecard, available at http://www.epa.gov/airmarkets/emissions/index.html.

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Table 3
Actual Annual Average Emission Rates

	Polk Power Station IGCC					Wabash River IGCC			
Year	**NOx**		**SO_2**			**NOx**		**SO_2**	
	lb/ mmBtu	**ton/ year**	**lb/ mmBtu**	**ton/ year**		**lb/ mmBtu**	**ton/ year**	**lb/ mmBtu**	**ton/ year**
1996	0.15	165	0.135	149					
1997	0.12	453	0.220	935		0.150	515	0.266	1,051
1998	0.10	537	0.224	1,321		0.140	534	0.167	851
1999	0.09	578	0.180	1,183		0.150	359	0.132	461
2000	0.10	586	0.146	918		0.140	387	0.173	657
2001	0.10	504	0.153	818		0.170	307	0.143	449

Based on information presented in Table 3, and assuming some incremental advancements in gasifier and gas cleanup technologies, it is expected that a new IGCC unit may achieve the following emission rates:

SO_2: 0.10 – 0.12 lb/mmBtu (30-day rolling average). The actual SO_2 emission rate will depend on the extent of gas cleanup.

NO_X: 0.09 – 0.10 lb/mmBtu (30-day rolling average) based on the combustion of a low – to medium-Btu syngas.

PM10: 0.011 - 0.012 lb/mmBtu depending on the extent of syngas cleanup.

5.5 Advantages

The initial perceived advantages of IGCC plants include:

- Reduced emissions from the gasifier plant.
- Fuel flexibility with suitable design considerations.
- Federal Government grants may be available to offset high capital costs.
- Ability to burn syngas in a high efficiency combustion turbine to generate electricity.

5.6 Disadvantages

The disadvantages of IGCC plants include:

- High capital costs and difficulty obtaining firm EPC pricing due to technology risks.

- Actual emissions from operating IGCC plants are essentially equal to the actual emission rates that have been achieved in practice at PC and CFB units.
- Vendor predictions for availability are in the range of 75% to 85%.
- Spare gasifier train would be needed to achieve acceptable availability, but at an increased cost.
- Significant complexities in operating a process plant, sulfuric acid plant, and power plant.
- Generated electrical output set by available combustion turbine frame sizes.
- Only suitable for base loaded application. Design for multiple fuels and turndown flexibility adds to design and operating complexity.
- Relying on backup fuel like oil/gas adds to complexity of combustor design and results in burning a high-cost fuel.

6.0 Conclusions – Electricity Generating Technologies

During the initial planning stages of any electricity generating project, it is necessary to define the project criteria including, among other things; requisite generating capacity, reliability, availability, fuel availability, site characteristics, safety factors, and potential environmental impacts. Based on a review of several technical, financial, and practical considerations, IPA determined that the appropriate design for the proposed Unit 3 is a 900 MW-net baseload unit capable of firing Utah bituminous coal. Based on a technical review of the potentially available electricity generating configurations (e.g., PC, CFB, and IGCC) IPA concluded that the most appropriate generating technology, and, in fact, the only technically feasible and commercially available technology capable of meeting all the project specifications, was a large single-boiler PC unit equipped with the best available control technologies.

The addition of 900 MW-net can be reliably and cost-effectively accomplished with PC technology. Furthermore, emissions from a modern PC unit equipped with BACT control technologies (including combustion controls, SCR, baghouse, and wet FGD) will be lower than emissions achieved in practice at existing CFB and IGCC facilities, and are essentially equal to projected emissions from the next generation CFBs and IGCCs. CFB technology cannot currently meet the stringent NOx emission rate achieved with a PC+SCR, and CFB technology would require at least three boilers, substantially adding to the total cost of the project. IGCC technology is still considered a developing technology. There are currently only two IGCC units in the U.S. that gasify coal or petroleum coke solely for the generation of electric power. Both of these facilities received substantial funds from the U.S.DOE, and both facilities continue to experiment with process improvements. Finally, actual emission rates achieved in practice at the IGCC facilities exceed the emissions proposed for Unit 3.

Part I – INITIAL ENGINEERING REVIEW

Part II – PC/CFB/IGCC BACT DETERMINATION

Introduction

In its NOI, IPA provided UDAQ with a comprehensive evaluation of the best emission control technologies available to control emissions from the proposed pulverized coal-fired unit. BACT is one element of the PSD preconstruction permitting process. Permitting agencies generally use the "top-down" BACT process to evaluate potential control technologies and establish appropriate BACT emissions limitations. The top-down BACT process is described in the U.S.EPA's New Source Review Workshop Manual, Draft October 1990 (the "NSR Manual").

BACT is defined as:

> an emissions limitation and/or other controls to include design, equipment, work practice, operation standard or combination thereof, based on the maximum degree of reduction of each pollutant subject to regulation under the Clean Air Act and/or the Utah Air Conservation Act emitted from or which results from any emitting installation, which the Air Quality Board, on a case-by-case basis taking into account energy, environmental and economic impacts and other costs, determines is achievable for such installation through application of production processes and available methods, systems and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant….
> UAC R307-101-2.

During the BACT analysis, which is done on a case-by-case and pollutant-by-pollutant basis, the permitting authority evaluates the environmental, energy, and economic costs and benefits associated with alternative control technologies and then specifies an emissions limitation for the source that reflects the maximum degree reduction achievable for each regulated pollutant.[6] Because the BACT process is conducted on a pollutant-specific basis, BACT is generally used to evaluate control systems with potential application to the source as proposed by the applicant. Historically, BACT has not been used as a means of redefining the proposed emissions source.[7]

With respect to evaluating the environmental/economic impacts of various electricity generating technologies, the top-down BACT process may not be practical because the competing technologies are mutually exclusive. For example, an applicant could not propose a source using CFB technology to control SO_2 emissions and PC+SCR to control NOx. The applicant must propose either a PC, CFB or IGCC design.

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[6] NSR Manual, page B.2.
[7] NSR Manual, page B.13.

Part II – PC/CFB/IGCC BACT DETERMINATION

Although IPA does not consider the BACT requirement as a process that should be used to define or re-define a proposed source, IPA is providing a complete BACT evaluation of the three competing electricity generating technologies. IPA will follow, to the extent possible, the 5-step top-down BACT evaluation process described in the NSR manual to evaluate the environmental and economic impacts associated with PC, CFB and IGCC generating technologies.

BACT EVALUATION

STEP 1: IDENTIFY ALL CONTROL TECHNOLOGIES

The electricity generating technologies included in this BACT evaluation include pulverized coal (PC), circulating fluidized bed (CFB) combustion, and integrated gasification combined cycle (IGCC).

STEP 2: ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

A technical evaluation of the CFB and IGCC generating technologies is provided below.

2.1 Integrated Gasification Combined Cycle

2.1.1 IGCC Process Description[8]

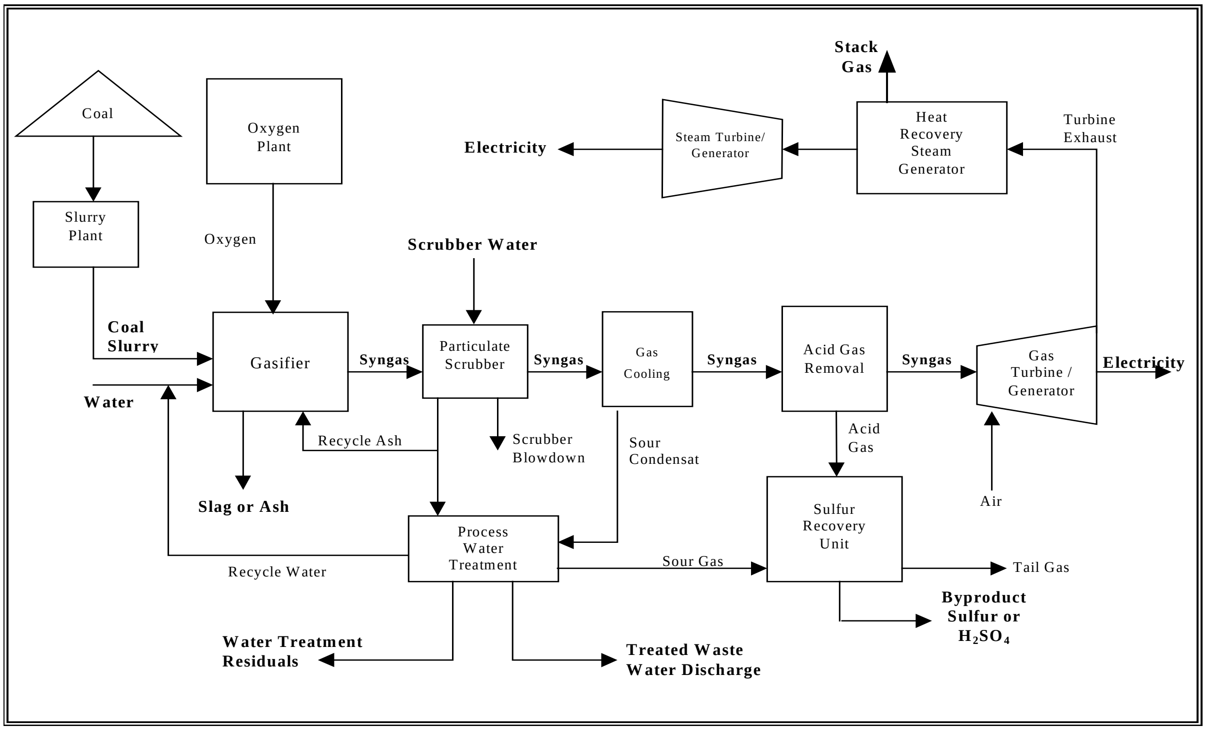
Integrated Gasification Combined Cycle (IGCC) power systems use a gasifier to convert coal (or other carbon-based solids) into a synthesis gas (syngas) consisting of a mixture of carbon monoxide (CO), hydrogen (H_2), carbon dioxide (CO_2) and traces of other gases. Syngas from the gasifier is cleaned of particulates, sulfur, and other contaminants prior to being combusted in a gas-fired combustion turbine. Heat from the turbine exhaust gas is extracted in a heat recovery steam generator (HRSG) to produce steam to drive a steam turbine/generator.

Figure 1 is a simplified schematic diagram of a typical IGCC plant. The main elements of an IGCC plant are discussed below in more detail.

[8] A majority of the technical information in this section, including Figure 1, was taken from: "Major Environmental Aspects of Gasification-Based Power Generation Technologies," Final Report, U.S. Department of Energy – Office of Fossil Energy, December 2002 ("Major Environmental Aspects of Gasification").

Part II – PC/CFB/IGCC BACT DETERMINATION

Figure 1
ICGG Schematic of Generic IGCC Power Plant*



* Diagram adapted from: Major Environmental Aspects of Gasification, page 1-5.

2.1.1.1 Air Separation Plant

Gasification processes require an oxidant to react with the coal and maintain the temperature required for gasification. The oxidant reacts with the coal to produce carbon monoxide. The typical air separation unit (ASU) cryogenically separates ambient air into its major constituents, oxygen (O_2) and nitrogen (N_2). Most of the O_2 is needed in the gasification plant for the production of syngas. A small percentage of the O_2 is used in the sulfuric acid plant. Most of the N_2 goes to the power plant's combustion turbine to dilute the fuel gas for NOx abatement. This diluent N_2 also increases the combustion turbine's power production as it expands through the turbine.

2.1.1.2 Gasification Plant

The gasification processes generally uses one-fifth to one-third of the theoretical oxygen (substoichiometric) to partially oxidize the combustible constituents of the feedstock. The major combustible products of gasification are CO and H_2, with a

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small fraction of the carbon completely oxidized to CO_2 and a small amount of methane (CH_4) may also be present.

The minor and trace components of coal are also transformed in the gasification reactor. Under the substoichiometric reducing conditions of gasification, most of the fuel's sulfur converts to hydrogen sulfide (H_2S), but some (3-10%) also converts to carbonyl sulfide (COS). Nitrogen bound in the fuel generally covets to gaseous nitrogen (N_2) and ammonia (NH_3) and a small amount of hydrogen cyanide (HCN). Most of the chlorine in the fuel converts to hydrogen chloride (HCl) gas. Trace elements associated with both organic and inorganic components of the coal, such as mercury and arsenic, are released during gasification and partition between the ash fractions and gaseous emissions. The typical gasifier gas composition is shown in Table 1.

Table 1
Typical Gasifier Gas Composition*

Constituent	Volume %
H_2	25 – 30
CO	30 – 60
CO_2	5 – 15
H_2O	2 – 30
CH_4	0 – 5
H_2S	0.2 – 1
COS	0 – 0.1
N_2	0.5 – 4
Ar	0.2 – 1
NH_3 + HCN	0 – 0.3
Ash/Slag/PM	
Heating Value	170 – 350 Btu/scf

* Major Environmental Aspects of Gasification, page 1-7.

2.1.1.3 Particulate Removal and Sulfur Removal

Syngas exiting a gasifier contains ash particulate that must be removed prior to combustion in the combustion turbine. Particulate matter can be removed by hot barrier filters (located upstream of the high temperature heat recovery devices) or warm-gas water scrubbers located downstream of the heat recovery system. Warm gas particulate removal via wet scrubbing is typically employed. In water scrubbers, the particulate is removed as a slurry which must be dewatered.

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Particulate-laden water is sent to a water handling system, which separates the solids for recycle to the gasifier for disposal.

The gasifier's raw gas also contains carbonyl sulfide (COS) and hydrogen sulfide (H_2S), both of which must be removed for the combustion turbine to achieve a low SO_2 emission limit. COS is not readily removed unless it is first converted to H_2S by hydrolysis. A hydrolysis unit reacts COS with water in the presence of a catalyst to form CO_2 and H_2S. The cooled syngas is then sent through an acid gas removal process to remove most of the H_2S and some of the CO_2.

Acid gas removal processes treat the syngas via contact with chemical or physical solvents to capture the H_2S. Amine solvents, such as methyldiethanolamine (MDEA) react to form a chemical bond between the acid gas and the solvent. The rich amine from the absorber is sent to a stripper where it is stripped of acid gas. The amine can be recycled and the recovered acid gases sent to a sulfur recovery process for conversion into sulfuric acid or elemental sulfur.

2.1.1.4 Combustion Turbine and Heat Recovery Steam Generator

The cleaned syngas is used to fuel a combustion turbine. The combustion turbine drives an electric generator and produces heat (exhaust) to generate steam in a Heat Recovery Steam Generator (HRSG) for a steam turbine. The low-Btu syngas produced by gasification require modifications to the combustion turbine's burners. GE has found that the flame speed of the hydrogen component of the gasifier system is too fast to be compatible with their low NOx combustor designs. Therefore, GE currently uses diffusion combustion systems with inert diluent injection for NOx control. Most IGCC plants also saturate the syngas with water to minimize NOx formation.

The exhaust temperature from the combustion turbine is generally about 1100 ^{o}F. This excess heat can be used in a HRSG to produce steam. The steam is supplied to a steam turbine to generate additional electric power.

2.1.1.5 Water Treatment

Process water produced within the gasification process is treated to remove dissolved gases before being recycled to the slurry production area or being discharged to a wastewater outfall.

2.1.2 Commercial Experience with IGCC

Gasification has been employed on a worldwide basis for the refining and chemical industries. Although there are numerous gasifiers operating commercially worldwide, there is far less experience with commercial operation of IGCC plants. The largest market for IGCC systems has been in the petroleum refining and petrochemical industries using petroleum residual feedstocks and co-production of power, steam and hydrogen for the refinery.

There have been five large-scale IGCC power generation plants built in the U.S. that have used coal and/or petroleum coke as the primary feed stock. A list of the five large-scale U.S. IGCC plants is provided in Table 2. The first two, Cool Water and LGTI were first-generation IGCC projects. Cool water was originally funded by a consortium of industrial partners, with guaranteed product price support from the U.S. Synthetic Fuels Corporation (SFC, which no longer exists). The LGTI facility was supported by a price guarantee contract offered to Dow Chemical by the SFC. Both of these IGCC plants were shut down once the duration of the price guarantee period expired.[9]

The next three plants listed in Table 2 are second-generation IGCC systems. DOE's Clean Coal Technology (CCT) Demonstration Project co-funded the construction and initial operation of Tampa Electric's Polk Power Station, PSI Energy's Wabash River Generation Station, and the Pinion Pine IGCC Project (a joint venture between DOE and Sierra Pacific Resources). In addition to the three U.S. demonstration projects, there are currently two large-scale demonstration plants located overseas. The NUON/Demkolec/Willem-Alexander plant in Buggenum, The Netherlands, and the ELCOGAS/Puertollano Plant in Puertollano, Spain. The Buggenum plant is fully owned by the Netherlands utilities. The Puertollano project is owned by utilities from Spain and France, and was funded under the EU's Thermie-Programme.

Table 2
IGCC Power Generation Plants in the U.S.*

Plant Name	Plant Location	Output (MWe)	Feedstock	Operation Status
Texaco Cool Water	Daggett, CA	125	Bituminous Coal	1984 – 1988
Dow Chemical/Destec LGTI Project	Plaquemine, LA	160	Subbituminous Coal	1987 – 1995
Tampa Electric Polk Plant	Polk County, FL	250	Bituminous Coal	1996 – Present
PSI Energy/Global Energy Wabash River Plant	West Terra Haute, IN	262	Bituminous Coal and Petroleum Coke	1995 - Present
Pinion Pine	Reno, NV	100	Western Bituminous Coal	1996 – 2001

* Information in Table 2 is from Major Environmental Impacts of Gasification, page 1-20.

9 See, Major Environmental Aspects of Gasification, page 1-19.

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2.1.3 Availability and Reliability

Availability, reliability, and emissions information for the two operating IGCC power plants is based on information available in the following documents:

> *Wabash River Coal Gasification Repowering Project – Final Technical Report*, Prepared by Wabash River Energy Ltd., Work Performed Under Cooperative Agreement DE-FC21-92MC29310 for the U.S. Department of Energy, August 2000 ("Wabash River Final Report").
>
> *Wabash River Coal Casification Repowering Project: A DOE Assessment*, U.S. Depart of Energy, DOE/NETL-2002/1164, January 2002 ("Wabash River DOE Assessment").
>
> *Tampa Electric Polk Power Station Integrated Gasification Combined Cycle Project – Final Technical Report*, Prepared by Tampa Electric Company, Work Performed Under Cooperative Agreement DE-FC-21-91MC27363, August 2002 ("Polk Final Report").

2.1.3.1 Polk Power Station IGCC

The Polk Power Plant completed six years of operation in September 2002. In its final technical report, Tampa Electric reported that the longest gasifier runs of 46.3 and 48.1 days occurred at Polk in the year 2000 (Polk Final Report, page 2-4). Key availability factors reported by Tampa Electric are summarized in Table 3. Availability is defined in the Tampa Electric final report as the percent of time during each period that the unit was in service or in reserve shutdown.

Table 3
Polk IGCC Key Availability Factors*

	Gasifier In Service	IGCC In Service	Total In Service	Combined Cycle Availability	On-Peak Availability
1996	27.5	17.2	32.9	47.8	
1997	50.4	45.6	59.3	64.8	
1998	63.3	60.8	74.4	88.7	
1999	69.9	68.3	81.1	92.7	
2000	80.1	78.0	84.0	88.7	94.9
2001	65.4	64.2	76.1	90.6	97.7

* Information in Table 3 is from the Polk Final Report, page 2-2.

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Tampa Electric also evaluated the availability of each of the three main systems at the Polk IGCC Power Plant (air separation unit, gasification and power block). The availability of each of these systems in years 4 and 5 of operation is shown in Table 4.

Table 4
Polk IGCC Subsystem Availability*

	ASU			**Gasification**			**Power Block**	
	Year 4	**Year 5**		**Year 4**	**Year 5**		**Year 4**	**Year 5**
In-Service	80.5	73.3		77.8	71.0		81.0	81.4
Reserve Shutdown	13.4	17.2		10.9	13.2		5.6	12.5
Availability	**93.9**	**90.4**		**88.6**	**84.2**		**86.6**	**93.9**
Planned Outage	1.1	1.1		5.8	7.7		4.8	3.1
Unplanned Outage	5.01	8.5		5.6	8.2		8.7	3.0
Unavailability	6.1	9.6		11.4	15.9		13.5	6.1
Total	100	100		100	100		100	100

* Information in Table 4 is from the Polk Final Report, page 2-6.

2.1.3.2 Wabash River IGCC

Commercial operation of the Wabash River facility began late in 1995. Both the gasification and combined-cycle plants successfully demonstrated the ability to run at capacity and within environmental compliance parameters. However, numerous operating problems adversely impacted plant reliability and the first year of operation resulted in only a 22% availability factor (Wabash River Final Report, page ES-3). Plant reliability was hindered by frequent failure of the ceramic filter elements in the particulate removal system and high chloride content in the syngas. The high chlorides contributed to exchanger tube failures in the low temperature heat recovery area, COS hydrolysis catalyst degradation and mechanical failures of the syngas recycle compressor. Ash deposits in the post gasifier pipe spool created high system pressure drop, which forced the plant off line and required significant downtime to remove.

In 1997 the Wabash River availability factor was 44% and in 1998 the availability factor improved to 60%. In 1998 and 1999 a high percentage of coal interruptions and downtime were caused by the air separation unit. In 1999, failure of a blade in the compressor section of the combustion turbine required a complete rotor rebuild that idled the project for 100 days. Run-time in 1999 was also impacted by a syngas leak in the piping system of the particulate removal system, a main exchanger leak in the air separation unit, a plugged taphole, and failure of a ceramic test filter in the particulate removal system. Consequently the availability factor for the project in 1999 dropped to 40% (Wabash River Final Report, page ES-4). Wabash River reported that improvements were seen in the third quarter of 1999, and that the gasification block operated continuously without any interruption for 54 days.

2.1.3.3 Pinion Pine IGCC

A third IGCC power project, the Pinon Pine IGCC Project started operation in 1996 but never achieved operability. In its final technical report to the DOE, Sierra Pacific Resources stated:

> During the reporting period of the Pinon Pine IGCC Project, the Gasifier was started up a total of eighteen (18) times. Each start-up failed due to design or equipment flaws. Each subsequent start-up attempt after a failure was not performed until the problem that halted the preceding start-up was addressed. Although this project was to demonstrate the potential for commercial operation of the air blown KRW Gasifier, hot desulfurization, and hot particulate removal, the goal of achieving sustained operation has not yet been accomplished.

(See, *Final Technical Report to the U.S. Department of Energy – Pinon Pine IGCC Project*, January 2001).

In its own assessment of the project, DOE concluded:

> A protracted effort was made to bring the facility on stream, but a series of equipment problems resulted in aborting all startup attempts. Sustained integrated operation of the gasifier and hot-gas cleanup facilities was never achieved…. Attempts to start the IGCC plant were discontinued in 2001, and the gasifier is being mothballed.

(See, *Pinon Pine IGCC Power Project, A DOE Assessment*, December 2002).

2.1.3.4 Capacity Factor

Capacity factor measures the amount of electricity actually produced compared with the maximum output achievable. Based on information available from the U.S.EPA's Acid Rain emissions database and Resource Data International's PowerDat database, the capacity factors achieved at Polk and Wabash River for the years 1996 through 2001 are shown in Table 5.

Table 5
Polk and Wabash River Capacity Factors

	Polk Power Station IGCC		**Wabash River IGCC**
Year	**Capacity Factor (%)**		**Capacity Factor (%)**
1996	11.54		
1997	45.38		34.95
1998	62.37		52.44
1999	70.2		32.88
2000	77.01		44.54
2001	63.46		36.08

It can be seen that Wabash River has always operated at annual capacity factors below 60%, and Polk Power Station has usually operated at annual capacity factors below 70%. The IPA Unit 3 PC unit is expected to operate at an annual capacity factor of approximately 90%, and a capacity factor significantly lower than this would seriously jeopardize the economics of the project.

2.2 Circulating Fluidized Bed (CFB)

2.2.1 CFB Process Description

Circulating Fluidized Bed (CFB) is an electric power generation process that controls the formation of gaseous pollutants by controlling coal combustion parameters and by injecting a sorbent (typically crushed limestone) into the combustion chamber. CFB combustion was initially developed to reduce the cost of pollution control and allow the use of low-quality fuels (e.g., high sulfur coals, culm, petroleum coke, etc.).

In a CFB, the solid fuel is burned in a bed of hot combustible particles suspended by an upward flow of combustion air. The fuel and limestone (used as the SO_2 sorbent) forms the combustion bed. Bed temperature is usually maintained at around 1550 -

1750 ^oF because this temperature is optimal for the chemical processes needed to capture SO_2 and control NO_x formation. Efficient combustion in the CFB is achieved because of the relatively long residence time of fuel in the bed and good gas/solids contact.

CFB units use a refractory-lined combustor bottom section with fluidizing nozzles on the floor above the wind box; an upper combustor section (usually with waterwalls); a transition piece including a hot-solids separator and re-entry downcomer; and a convective boiler section. Steam is generated in tubes placed along the walls of the combustor and superheated in tube bundles placed downstream of the particulate separator. The steam flows to a turbine/generator, where electric power is produced. In addition to the boiler and turbine, a CFB generating unit will have the following process systems:

- post-combustion air quality control systems generally including selective non-catalytic reduction, polishing scrubber and fabric filter;
- fuel handling system;
- limestone preparation system;
- solid waste management system.

2.2.2 Commercial Experience with CFB

The Clean Coal Technology (CCT) Demonstration Program, sponsored by the DOE, involves a series of demonstration projects that provide data for design, construction, operation and technical/economic evaluation of full-scale coal utilization processes for the world energy market. Among the technologies being demonstrated in the CCT program is fluidized bed combustion (FBC), including CFB technologies.

Five FBC demonstration projects are included in the CCT Program under Advanced Electric Power Generation: (1) the JEA Large-Scale CFB Combustion Demonstration Project; (2) the Nucla CFB Demonstration Project; (3) the Tidd PFBC Demonstration Project, (4) the McIntosh Unit 4A PCFB Demonstration Project; and (5) the McIntosh Unit 4B Topped PCFB Demonstration Project. The JEA project represents a scale-up of previous CFB installations. The Nucla project, completed in 1992, had a capacity of 100 MW (net) and the Tidd project, completed in 1995, had a capacity of 70 MW (net). At a nominal design capacity of 300 MW gross (265 MW net) the JEA project is the largest scale demonstration of FBC technology to date.

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The JEA project involved the construction and operation of a new 300 MW gross CFB boiler fired with coal fuel blends to repower an existing steam turbine (JEA Unit 2). In parallel with this project, JEA replaced their Unit 1 oil/gas fired boiler with an identical CFB unit (JEA Unit 1). The boilers were designed to burn fuel blends consisting of coal and petroleum coke.

In addition to the CFB combustor, the JEA CFBs are equipped with supplementary pollution control systems including selective non-catalytic reduction to control NOx, a polishing scrubber to further reduce SO_2, and a fabric filter to control particulate matter emissions.

DOE Topical Report Number 22 (issued in March 2003) summarized the initial results of the JEA CFB Demonstration Project. Based on information in Topical Report Number 22, JEA Unit 2 has:

> operated at full load, achieving rated output in May 2002. The unit can maintain operation on both coal and coal fuel blends. However, satisfactory operation on 100% petroleum coke has not yet been demonstrated…. Initial results indicate that the JEA plant is capable of meeting emissions guarantees when operating on both coal and coal fuel blends." See, Topical Report Number 22, page 23.

2.3 Technical Evaluation - Conclusions

2.3.1 IGCC Technical Conclusions

Given the reliability issues that have been observed at Polk and Wabash, and given the operational problems experienced at Pinion Pine, it appears unlikely that an IGCC facility could be designed to achieve 900 MW-net output, and achieve a capacity factor of 90%. Although IGCC is a technically feasible electricity generating technology, it is not the appropriate technology, at this time, for a 900 MW-net baseload facility.

Furthermore, it is likely that there would be significant technical issues associated with scaling an IGCC facility to achieve the proposed 900 MW-net power requirements. Wabash River's IGCC is the largest operating IGCC at 262 MW net. Based on "F" combustion turbine technology, the maximum size range for an IGCC facility would be approximately 540 MW using a 2 x 2 x 1 configuration (e.g., 2 combustion turbines, 2 HRSGs and 1 steam turbine). Multiple trains could be added for an incremental increase in plant output. Because the plant site is at an elevation of 4,646 feet, the combustion turbines would be derated at this elevation. Because of this derating, a 4 x 4 x 1 configuration that normally provides 1148 MW-gross would provide approximately 1014 MW-gross.

Based on actual operating information from existing IGCC facilities, it appears that IGCC technology is neither technically feasible nor commercially available for the proposed IPA Unit 3 project as proposed (e.g., 950 MW-gross baseload unit). However, for purposes of completeness, IPA will continue with the environmental and economic impact analyses.

2.3.2 CFB Technical Conclusions

For purposes of this evaluation it has been concluded that CFB boiler technology is a technically feasible and commercially available technology. Although CFB boiler vendors have represented that they have designs for CFB boilers larger than 300 MW-gross, the largest CFBs in operation in the U.S. are the JEA CFBs at approximately 300 MW-gross. Therefore, at least three CFB boilers will be required to meet the steam requirements of the 950 MW-gross steam turbine proposed for IPA Unit 3. Each CFB boiler would need to be rated for 325 MW-gross to allow for the higher auxiliary power requirements and achieve a net output of approximately 900 MW. A 325 MW-gross design represents a scale-up in boiler design of less than 10% from the JEA CFBs, which is considered technically acceptable.

STEP 3: RANK THE REMAINING CONTROL TECHNOLOGIES BY CONTROL EFFECTIVENESS

In order to evaluate the effectiveness of each generating technology, in terms of emission reductions, expected emissions from an IGCC and CFB facility are evaluated below.

3.1 IGCC Emissions

3.1.1 IGCC Emissions Achieved in Practice

Table 6 presents a summary of actual NOx and SO_2 emission rates that have been achieved in practice at the Polk and Wabash River IGCC power plants. Both of these facilities have been operating for more than 5 years under DOE's CCT program. Emissions data presented in Table 6 were obtained from the U.S.EPA Emissions Scorecard, available at http://www.epa.gov/airmarkets/emissions/index.html.

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Table 6
Actual Annual Average Emission Rates

	Polk Power Station IGCC					Wabash River IGCC			
Year	**NOx**		**SO2**			**NOx**		**SO2**	
	lb/ mmBtu	**ton/ year**	**lb/ mmBtu**	**ton/ year**		**lb/ mmBtu**	**ton/ year**	**lb/ mmBtu**	**ton/ year**
1996	0.15	165	0.135	149					
1997	0.12	453	0.220	935		0.150	515	0.266	1,051
1998	0.10	537	0.224	1,321		0.140	534	0.167	851
1999	0.09	578	0.180	1,183		0.150	359	0.132	461
2000	0.10	586	0.146	918		0.140	387	0.173	657
2001	0.10	504	0.153	818		0.170	307	0.143	449

The emission rates shown in Table 6 are annual average emission rates achieved at each plant. Emission rates were calculated by dividing the total annual mass emissions reported by each plant by each plant's reported heat input.

It is more difficult to determine actual emission rates achieved in practice for PM10, CO and VOC because these emissions are not subject to continuous emissions monitoring and are not reported to the U.S.EPA Acid Rain Database. PM10, CO and VOC emission rates are typically determined with a stack test conducted at the time of the initial compliance testing and possibly annually thereafter, depending on permit-specific testing requirements. Permitted emission rates, and emission rates observed during stack testing, are summarized in Table 7. Data summarized in Table 7 is based on information presented in the Polk and Wabash River final technical reports.

Table 7
IGCC PM10, CO, and VOC Emission Rates

Pollutant	**Polk IGCC(1)**			**Wabash River IGCC(3)**	
	Permit Limit	**Measured Emissions**	**Permit Limit(2)**	**1997**	**1998**
	lb/hr	**lb/MWh**	**lb/mmBtu**	**lb/mmBtu**	**lb/mmBtu**
PM10	17	0.037	0.007	0.012	0.011
CO	99		0.041	0.056	0.033
VOC	3		0.0012	0.002	0.0021

(1) Polk IGCC permit limits obtained from the Polk Final Report, page 3-5.
(2) Polk emission rates (lb/mmBtu) were calculated based on a heat input of 2433 mmBtu/hr.
(3) Total air emissions based on all sources monitored or calculated at the Wabash River site during the years of 1997 and 1998, Wabash River Final Report, page ES-6.

3.1.2 Recently Proposed IGCC Emission Rates

Two recently permitted IGCC projects, Lima Energy and Kentucky Pioneer Energy have proposed emission limits lower than the emission rates actually achieved in practice at Polk or Wabash River. Both of these facilities have been permitted, but construction has not begun on either facility. The IGCC design at both facilities incorporate innovative technologies that have not been demonstrated in practice. A DOE Fact Sheet states that the goal of the Kentucky Pioneer Energy project is to "demonstrate and assess the reliability, availability, and maintainability of a utility-scale IGCC system using a high-sulfur bituminous coal… in a oxygen-blown, fixed-bed slagging gasifier."[10] Summarized in Table 8 are the emission limits included in each permit.

Table 8
Lima Energy and Kentucky Pioneer Energy Permit Limits*

	Lima Energy	**Kentucky Pioneer**
State	OH	KY
Net Size	520 MW	520 MW
SO_2 Emission Limit	38.6 lb/hr/turbine 0.021 lb/mmBtu	0.032 lb/mmBtu
NOx	178 lb/hr/turbine 0.097 lb/mmBtu	0.0735 lb/mmBtu
PM10**	18 lb/hr/turbine 0.010 lb/mmBtu	0.011 lb/mmBtu
CO	251 lb/hr/turbine 0.137 lb/mmBtu	0.032 lb/mmBtu
VOC	15 lb/hr/turbine 0.0082 lb/mmBtu	0.0044 lb/mmBtu

* Permit limits for both facilities were provided in terms of maximum lb/hr. Emission rates in lb/mmBtu were estimated base on the maximum heat input to the plant.
** PM10 emission rates for the proposed IGCC units are for filterable PM only. See, OEPA Final Permit to Install, Application No. 03-13445, 3/26/2002, page 49 (requiring compliance with the particulate emission rate demonstrated using USEPA Method 5).

Neither the Lima nor Kentucky Pioneer IGCC facilities have been constructed, therefore, there is no operating history to determine their ability to meet the permitted emissions limits. Furthermore, these facilities have proposed to incorporate innovative technologies that have not been demonstrated in practice. U.S.EPA's NSR

[10] See, http://www.lanl.gov/projects/CCCT/index.html

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Manual states that a technology is considered available "if it has reached the licensing and commercial sales stage of development" (NSR Manual at B.18). At this time, the gasifier technologies proposed in the Lima Energy and Kentucky Pioneer projects have not been demonstrated and are not commercially available, and the emission rates have not been demonstrated in practice.

3.1.3 Other IGCC Emissions

In addition to emissions from the IGCC combustion turbine/HRSG, an IGCC plant has additional air emission sources. The Polk and Wabash River facilities have two significant emission sources not present with the CFB or PC facility design:

1. Tail Gas Incinerator to convert trace acid gas components in tank vents to oxide forms (SO_2, NOx, H_2O and CO_2); and

2. Flare to combust syngas during startup/shutdown periods and during turbine malfunctions.

Emissions from these additional sources can be significant. For example, the Polk permit includes an SO_2 emission limit of 33 tpy from the sulfuric acid plant, and Polk reported typical emissions from the sulfuric acid plant of 29 tpy (see, Polk Final Report, page 3-3). However, for this comparison, only emissions from the CT/HRSG have been included.

3.2 CFB Emissions

CFB technology offers the potential for the lowest NO_x emissions from commercially available boiler designs due to inherently lower combustion temperatures. At the low combustion temperatures in a CFB, the formation of thermal NO_x is essentially eliminated, however, nearly all of the fuel nitrogen will be converted to nitrogen oxides. Based on information available from CFB vendors, it is anticipated that a CFB boiler will consistently achieve a NO_x emission level of approximately 0.15 lb/mmBtu.

Recently permitted CFB boilers have been permitted with selective non-catalytic reduction (SNCR) for supplemental NOx control. SNCR involves the direct injection of ammonia (NH_3) or urea ($CO(NH_2)_2$) at flue gas temperatures of approximately 1600 - 1900 ºF. The ammonia or urea reacts with NO_x in the flue gas to produce N_2 and water. Mixing of the reactant and flue gas within the reaction zone is an important factor to SNCR performance. The SNCR system must be designed to deliver the reagent in the proper temperature window, and allow sufficient residence time of the reagent and flue gas in that temperature window. In addition to

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temperature, mixing, and residence time, several other factors influence the performance of an SNCR system including reagent-to-NO_x ratio and fuel sulfur content.

Both urea- and ammonia-based SNCR systems have been applied to new coal-fired and petroleum coke-fired CFB boilers. SNCR systems have been designed to achieve NO_x reduction efficiencies of approximately 40 - 60% on coal-fired boilers. The actual NO_x reduction efficiency will depend on several site-specific factors, including the flue gas characteristics, NO_x concentration in the flue gas, reagent-to-NO_x ratio, and the acceptable ammonia slip level. Based on SNCR performance at existing CFB units, it is anticipated that a new CFB boiler could consistently achieve a permitted NO_x emission rate of 0.09 lb/mmBtu.

SO_2 control is inherent to the operation of a CFB. In a CFB boiler, crushed limestone ($CaCO_3$) is fed to the combustor and becomes part of the solid medium that makes up the combustion bed. Within the combustion zone lime (CaO) is formed by calcining the limestone. SO_2 formed during the combustion process combines with the calcined lime to form gypsum ($CaSO_4$), a stable byproduct. The theoretical minimum Ca/S ratio required for the removal of a given sulfur concentration is 1/1, assuming 100% utilization of the sorbent. However, the actual removal efficiency that can be achieved in practice for a given unit is dependent on several factors including the size and porosity of the calcinated lime, temperature of the combustion bed, residence time within the combustion bed, mixing, and uncontrolled SO_2 concentration. In practice, it has been found that approximately 50% of the SO_2 will be removed at a Ca/S ratio of 1. As the Ca/S ratio increases a greater amount of SO_2 will be removed, but with diminishing return.

Ash reinjection systems, or polishing scrubbers, are modified dry FGD processes developed to increase utilization of unreacted lime (CaO) in the CFB ash and further reduce the SO_2 concentration in the flue gas.[11] In an ash reinjection system, a portion of the unit's ash is collected and re-introduced into a reaction vessel located ahead of the fabric filter inlet duct. The ash may or may not be hydrated prior to reinjection depending of the unit's design.

The JEA CFBs are permitted to achieve a controlled SO_2 emission rate of 0.2 lb/mmBtu (24-hour block average) and 0.15 lb/mmBtu (30-day rolling average) with with limestone injection and a polishing scrubber. One CFB facility, AES – Puerto Rico, was recently permitted with limestone injection plus a dry scrubber, and a controlled SO_2 emission rate of 0.022 lb/mmBtu. This emission rate was based on

[11] The actual design of an ash reinjection system is vendor specific, and ash reinjection systems may be referred to as flash dryer absorbers, hydrated ash reinjection, or polishing scrubbers. All system designs will achieve essentially the same control efficiency.

emission calculations, assuming a fuel sulfur content of 1.0% and an overall control efficiency of approximately 98.9%. An emission rate of 0.022 lb/mmBtu is equivalent to approximately 8.4 ppmvd @ 7% O_2. Based on discussions with representatives of U.S.EPA Region II, the AES-Puerto Rico unit has been constructed, however, compliance testing is not yet complete and there is no information available to determine whether the facility is able to meet its proposed SO_2 emission rate. Based on emission rates achieved in practice at JEA, and emission rates recently proposed in CFB PSD permit applications, it is assumed that a new CFB unit designed with a polishing scrubber would be permitted to achieve a controlled SO_2 emission rate of 0.05 – 0.08 lb/mmBtu.

Particulate matter emissions from a CFB boiler are generally controlled with a fabric filter located downstream of the ash reinjection system. The JEA CFBs were constructed with fabric filters and permitted with a PM10 emission limit of 0.011 lb/mmBtu.

Attachment A to this report includes a detailed summary of permitted and proposed emission rates from recently permitted CFB boilers and CFB boilers included in the U.S.EPA's RBLC Database.

3.3 Comparison of Technologies

3.3.1 Technical Comparison

Table 9 provides a brief comparison of the three power generating technologies.

Part II – PC/CFB/IGCC BACT DETERMINATION

Table 9
Power Generating Technology Comparison

	IGCC	PC	CFB
Process Description	Coal is partially oxidized in the gasification unit to produce a syngas. The high-pressure syngas is combusted and expanded in a combustion turbine to produce power. Heat is recovered from the turbine exhaust gas to produce electricity in a steam turbine.	Pulverized coal is combusted in a boiler where the heat is directly transferred to produce high-pressure steam that is expanded in a steam turbine to produce power.	Air-suspended coal is combusted together with limestone for sulfur control. Heat is directly transferred to produce high-pressure steam that is expanded in a steam turbine to produce power.
Coal Sulfur Conversion and Sulfur Dioxide Control	Sulfur is primarily converted to H_2S and some COS in the synfuel. In the syngas cleanup process, COS is hydrolized to H_2S, and H_2S is removed from the syngas in an amine-based scrubber. Sulfur can be recovered as sulfuric acid or elemental sulfur.	Sulfur is converted to SO_2 in the combustion process and exits the boiler with the flue gas. SO_2 is removed from the flue gas with post-combustion control technologies including wet flue gas desulfurization (FGD).	Sulfur is converted to SO_2 in the combustion process and is captured by an in-bed sorbent such as limestone. Residual SO_2 exits the boiler in the flue gas, and can be recovered with post-combustion control systems such as hydrated ash reinjection and dry scrubbing.
Coal Nitrogen Conversion and NOx Control	Coal nitrogen is converted to ammonia and nitrogen in the gasifier. Ammonia is removed from the syngas prior to combustion in the combustion turbine. NOx generated in the combustion turbine is controlled with diluent gas injection and water sprays. Post-combustion NOx controls are currently not technically feasible with syngas.	Converted to NOx in the combustion process and exits boiler with flue gas. NOx formation in the boiler can be minimized with combustion controls including low NOx burners and overfired air. NOx in the boiler flue gas can be further reduced with post-combustion controls such as selective catalytic reduction.	Converted to NOx in the combustion process. NOx formation in the CFB boiler is relatively low because of the reduced combustion temperature in the fluidized bed. Post-combustion control such as selective noncatalytic reduction can be used to further reduce NOx emissions.
Particulates	Most of the coal ash is recovered as slag or bottom ash from the gasifier. A small portion of the ash is entrained with the synfuel, and removed in the gas cleanup process.	Approximately 80% of the coal ash is entrained in the flue gas as fly ash. The remaining ash is recovered as bottom ash. Fly ash is removed from the flue gas with post-combustion controls such as electrostatic precipitation and fabric filters.	Ash and spent sorbent (limestone) entrained in the flue gas is collected in a control device such as a cyclone and returned to the boiler. Solids are collected as bottom ash or fly ash. Fly ash from the boiler is collected in a post-combustion control system such as a fabric filter.

* Adapted from: Major Environmental Aspects of Gasification, page 1-29.

3.3.2 Comparison of Emission Rates

Table 10 includes a comparison of the anticipated BACT emission limits for each technology, and a summary of the lowest emissions limits proposed for future IGCC and CFB facilities. The anticipated BACT emission limits are based on: (1) commercially available control technologies for each generating configuration; (2) emission rates achieved in practice; (3) a reduction in some controlled emission rates based on foreseeable improvements in control technologies; and (4) inclusion of an incremental margin above the lowest achievable emission rates to account for natural fluctuations in control systems and to ensure compliance.

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Table 10
Comparison of Emission Limits for Each Generating Technology

Pollutant	Unit	PC (IPA Proposed Emission Rate)	IGCC		CFB	
			BACT	Lowest Proposed	BACT	Lowest Proposed
NOx	lb/mmBtu	0.07 (30-day average) LNB/OFA + SCR	0.09 (30-day average)	0.0735 (30-day average)	0.09 (30-day average)	0.09 (30-day average)
			Post combustion SCR is not currently considered technically feasible with IGCC. Therefore, NOx emission rates are based on combustion of low-Btu syngas		CFB + SNCR	
SO_2	lb/mmBtu	0.10 (30-day average) Wet Limestone FGD	0.12 (30-day average)	0.032 (30-day average)	0.05* (30-day average)	0.022 (30-day avearge)
			IGCC syngas cleanup		CFB with limestone injection and polishing scrubber or dry FGD	
PM10 (filterable)	lb/mmBtu	0.015 Fabric Filter	0.011	0.011	0.015	0.012
			IGCC syngas cleanup		CFB with Fabric Filter	

* Based on a review of the RBLC Database, the SO_2 BACT emission limit for a CFB boiler is currently in the range of 0.10 – 0.12 lb/mmBtu. However, one facility recently proposed a controlled SO_2 emission rate of 0.05 lb/mmBtu utilizing a CFB boiler and polishing scrubber. Although the new facility has not yet been permitted, an emission rate of 0.05 lb/mmBtu will be used in this evaluation to provide a conservative comparison of the electricity generating technologies.

2.3.3 Comparison of Annual Mass Emissions

In addition to comparing emission rates (i.e., lb/mmBtu heat input), it is necessary to compare annual mass emissions from each type of facility. Potential annual emissions are calculated by multiplying the permitted emission rate (lb/mmBtu) by the maximum heat input to the combustion unit (mmBtu/hr) and the annual hours of operation. Table 11 provides an estimate of the heat input needed to achieve 900 MW-net output with each technology, and Table 12 provides an estimate of the annual mass emissions from each type of facility based on the emission rates in Table 10, the heat inputs in Table 11, and assuming a 90% annual capacity factor.
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Part II – PC/CFB/IGCC BACT DETERMINATION

Table 11
Heat Input to Achieve 900 MW-net Output

<table>
<tr><th>Parameter</th><th>Unit</th><th>IGCC</th><th>CFB</th><th>PC</th><th>Notes</th></tr>
<tr><td>Baseline Heat Input From Coal Feed</td><td>mmBtu/hr</td><td>2,433</td><td>5,536</td><td>9,050</td><td rowspan="3">IGCC baseline information obtained from: Polk-Final Report page 6-1.

CFB baseline information obtained from: S&L heat balances recently prepared for a 2x250 MW-net CFB project.

PC baseline information obtained from S&L heat balances prepared for IPA Unit 3. See, NOI Appendix C.

Baseline plant heat rates are in line with reported heat rates each technology. The CFB heat rate is typically higher because of the additional auxiliary power requirements.</td></tr>
<tr><td>Baseline Net Power Output</td><td>MW</td><td>252.5</td><td>510.8</td><td>924.3</td></tr>
<tr><td>Baseline Plant Heat Rate</td><td>Btu/net kWh</td><td>9,636</td><td>10,838</td><td>9,790</td></tr>
<tr><td>Unit 3 Net Output</td><td>MW</td><td>900</td><td>900</td><td>900</td><td></td></tr>
<tr><td>Heat Input to Achieve 900 MW-net Output</td><td>mmBtu/hr</td><td>9,713</td><td>9,754</td><td>8,841</td><td>Example Calculations:
CFB:
5,536 x (900 / 510.8) = 9,754
IGCC:
[2,433 x (900 / 252.5)] x 1.12 = 9,713
IGCC: heat input increased by 12% to account for CT derating at site altitude.</td></tr>
</table>

Table 12
Comparison of Annual Mass Emissions

Pollutant	Unit	PC	IGCC		CFB	
			BACT	Lowest Proposed	BACT	Lowest Proposed
NOx	tpy	2,440	3,446	2,814	3,461	3,461
SO2	tpy	3,485	4,595	1,225	1,923	846
PM10	tpy	523	421	421	577	461

3.3.4 NOx

Based on the information and assumptions discussed above, a PC plant equipped with state-of-the-art combustion controls (LNB+OFA) and post-combustion SCR provides the most stringent NOx emissions control. IPA has proposed a BACT emission limit of 0.07 lb/mmBtu using combustion controls and SCR. This emission rate is lower than the NOx emission rate proposed as BACT at recently permitted CFB units, and below the NOx emission rate achieved in practice (or proposed) with IGCC. The most stringent NOx emission rate proposed for a new IGCC is 0.0735 lb/mmBtu at the Kentucky Pioneer Energy Project. Although this emission rate has not been demonstrated, it is still higher than the NOx emission rate proposed for IPA Unit 3 and would result in increased annual NOx emissions of approximately 374 tons/year.

3.3.5 SO_2

Based on the information and assumptions discussed above, the combination of PC with wet FGD provides the most stringent SO_2 emissions control based on emission rates achieved in practice. IPA has proposed a BACT emission limit of 0.10 lb/mmBtu using PC technology and wet FGD.

An emission rate of 0.10 lb/mmBtu is lower than the SO_2 emission rate imposed on several recently permitted CFBs (see, Attachment A). Assuming an identical emission rate, the CFB facility will result in increased annual emissions because of the additional auxiliary power requirement of the CFB design which results in more fuel burned to achieve the same net power output. One facility has recently proposed an SO_2 BACT emission rate of 0.05 lb/mmBtu. A CFB boiler capable of achieving an emission rate of 0.05 lb/mmBtu would reduce annual SO_2 emissions (compared to the PC case) by approximately 1,562 tpy. Although the new facility has not yet been permitted, the economic effectiveness of a CFB unit designed to achieve a controlled SO_2 emission rate of 0.05 lb/mmBtu is evaluated below. One CFB was recently permitted with an SO_2 emission rate of 0.022 lb/mmBtu. This emission rate would also result in a reduction in annual SO_2 emissions, however, this emission rate has not been demonstrated in practice. For completeness purposes, the cost effectiveness of a CFB unit capable of achieving a controlled SO_2 emission rate of 0.022 lb/mmBtu will also be evaluated.

IGCC developers have proposed very low SO_2 emissions rates, however, based on actual emissions from operating plants the SO_2 emission rate from an IGCC facility may be approximately 0.12 lb/mmBtu. The Lima IGCC Project and Kentucky Pioneer IGCC projects have proposed SO_2 emission rates of 0.021 and 0.032 lb/mmBtu, respectively. However, these emission rates have not been demonstrated in practice, and are significantly below the actual emissions rates at Polk and Wabash River. For completeness purposes, the cost effectiveness of an IGCC unit capable of achieving a controlled SO_2 emission rate of 0.021 lb/mmBtu will be evaluated.

3.3.6 PM10

Based on the information and assumptions discussed above, it appears that the IGCC technology will provide the most stringent PM10 emissions control. In an IGCC most of the coal ash is recovered as slag or bottom ash from the gasifier. Ash entrained in the syngas is removed in the gas cleanup process prior to burning the syngas in the combustion turbine. In appears that both Polk and Wabash have achieved PM10 emission rates around 0.011 lb/mmBtu.

PM10 emissions from a CFB boiler or PC boiler should be essentially the same because both will be equipped with a fabric filter for particulate matter control. The actual control efficiency achieved by a fabric filter will be site-specific, and depends on specific variables such as permeability of the filter cake, the loading and nature of the particulate matter (e.g., irregular-shaped or spherical), air/cloth ratio, particle size distribution and, to some extent, the frequency of the cleaning cycle. Fabric filters have been used successfully with both CFB and PC boilers, and have demonstrated the ability to consistently achieve very high collection efficiencies.

Although the PM10 emission rate varies between the three generating technologies it is important to note that all three technologies are very effective at controlling PM10 emissions. Potential uncontrolled particulate matter emissions from the proposed unit are 8.58 lb/mmBtu, or approximately 300,000 tons/year (depending on the generating technology used). Therefore, control efficiencies will vary from 99.82 – 99.86% with the fabric filter on the PC and CFB units, respectively, to approximately 99.87% with the IGCC.

3.4 Control Effectiveness Conclusions

Part II – PC/CFB/IGCC BACT DETERMINATION

Without taking into account the reliability and cost issues associated with IGCC and CFB technologies, there are no environmental impacts associated with a PC unit that should eliminate it from consideration as an appropriate power generating technology. In fact, a PC unit equipped with SCR will result in the lowest controlled NOx emission rate, and a PC unit equipped with wet FGD will result in an SO_2 emission rate lower than the SO_2 emission rate currently achieved in practice at existing IGCC facilities, and essentially equal to the SO_2 emission rate from a CFB equipped with a polishing scrubber. Finally, fabric filtration is a very effective particulate matter control technology, achieving greater than 99.8% reduction in potential PM10 emissions.

CFB technology may achieve a PM10 emission rates essentially equal to, or possibly slightly below, the PM10 emission rate achieved with the PC system. However, CFB boilers are not as efficient as PC boilers because of the significant increase in auxiliary power requirements. Therefore annual PM10 emissions from either source will be essentially the same. CFB technology designed with a polishing scrubber may be able to achieve a controlled SO_2 emission rate below the emission rate achievable with a PC equipped with wet FGD. One applicant recently proposed a CFB with a controlled SO_2 emission rate of 0.05 lb/mmBtu. Although this unit is not yet permitted, the cost effectiveness of a CFB unit capable of achieving a controlled SO_2 emission rate of 0.05 lb/mmBtu is evaluated below. Finally, it is likely that the controlled NOx emission rate from a CFB boiler will be higher than the controlled NOx emission rate from a PC boiler equipped with SCR. Based on emission calculations, NOx emissions will increase approximately 1,021 tons/year with the CFB configuration.

IGCC technology holds the promise of reduced emission rates, however, IGCC technology is still in the development/demonstration stage. Redesigning Unit 3 as an IGCC unit would completely redefine the scope of the IPP Unit 3 project. Based on emission rates achieved in practice, an IGCC facility will result in increased emissions of NOx and SO_2. Although future improvements in IGCC technology, gas-cleanup technologies, and SCR catalysts may result in lower emission rates, these improvements are still in the developmental stage and lower emission rates have not been achieved in practice. Based on emission rates actually achieved in practice, emission calculations predict that NOx and SO_2 emissions would increase by approximately 1,006 and 1,109 tons/year, respectively, while PM10 emissions may decrease by approximately 102 tons/year.

STEP 4: EVALUATE MOST EFFECTIVE CONTROLS AND DOCUMENT RESULTS

The effectiveness of each generating technology, with respect to emissions, was evaluated in Step 3. Provided in Step 4 is an evaluation of the economic impact associated with each generating technology.

Part II – PC/CFB/IGCC BACT DETERMINATION

U.S.EPA has standardized cost-estimating methods to evaluate add-on emission control systems.[12] However, there are no standardized methodologies available to compare the costs associated with competing source technologies. Therefore, in order to compare the relative cost effectiveness of each technology, S&L developed a total annual cost for each facility by estimating the total capital required to construct each facility, and the associated operations and maintenance (O&M) costs. To the extent possible, cost estimating methodologies described in the U.S.EPA OAQPS Cost Control Manual were utilized. More detailed summaries of the cost estimates developed for this BACT evaluation are included in Attachment B.

[12] See, OAQPS Control Cost Manual, 5th ed., U.S. Environmental Protection Agency, EPA 453/B-96-001, February 1996.

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4.1 Capital Costs

Capital costs include all the costs required to purchase equipment needed to construct each facility, including the costs of associated control systems, labor and materials for installing the equipment, engineering costs, and contingencies. The capital cost estimate presented for the PC option represents the proposed 900 MW-net Unit 3. Capital costs for the CFB and IGCC designs were developed based on S&L's internal database of recent coal-fired CFB plant designs, information from CFB and IGCC vendors, and information presented in the DOE Final Reports for Polk and Wabash River. Unit 3 baseline design costs were adjusted by deleting the PC boiler (including the SCR), the fabric filter, and the wet FGD, and replacing those costs with the appropriate costs for the CFB and IGCC designs.

Summarized in Table 13 are the estimated capital costs for each generating technology.

Table 13
Generating Technology Capital Costs

		PC	CFB	IGCC
Total Capital Investment	MM$	$1,108	$1,159	$1,738
Total Capital Investment	$/kW-gross	$1,166	$1,189	$1,511

5.2 O&M Costs

S&L developed annual O&M costs based on engineering calculations, information available from existing units, and information included in the Polk and Wabash River final reports. Variable O&M costs (including catalyst costs, limestone, water, ammonia, etc.) were estimated based on engineering calculations and estimated utilization rates. Fixed O&M costs, including maintenance materials and labor, were estimated based on a review of information available from existing operating facilities. Summarized in Table 14 are the estimated fixed and variable O&M costs for each generating faciltiy.

Table 14
Generating Technology – Annual O&M Costs

		PC	CFB	IGCC
Total Variable O&M Cost	MM$/yr	$15.689	$15.546	$13.333
Total Variable O&M Cost	$/MWh-net	$2.21	$2.19	$1.78
Total Fixed O&M Cost	MM$/yr	$8.188	$27.700	$50.678
Total Fixed O&M Costs	$/MWh-net	$1.15	$3.90	$6.77

Part II – PC/CFB/IGCC BACT DETERMINATION

The annual O&M cost estimates indicate that there will be a significant difference in the fixed O&M costs (including maintenance materials and supplies, and operating labor) between the PC facility and the CFB and IGCC facilities. The reason for this difference is the fact that the facility will realize certain economies if the new unit is similar in design to the two existing units. The addition of a third PC unit would require minimal new operating labor. Furthermore, there will be commonality between maintenance materials, supplies, and inventory, and operating/maintenance labor can be shared between the three units. Operating labor for the CFB or PC design increases dramatically because the technologies are unique, and would require specific operators and operator training. Furthermore, maintenance materials and supplies would be unique to the new units, and there would be very little redundancy between the new unit and the existing units. Fixed maintenance costs for the IGCC units are particularly high because the IGCC facility consists of several unit operations including an air separation unit, gasifier, gas cleanup system, sulfuric acid plant, combustion turbine, heat recovery steam generator, and steam turbine.

4.3 Total Annual Costs

Total annual costs consist of the variable O&M costs, fixed O&M costs, and an annual capital recovery cost. To calculate the annual capital recovery cost, S&L used the Equivalent Uniform Annual Cash Flow (EUAC) method described in U.S.EPA's OAQPS Control Cost Manual as follows:

CRC = Capital Recovery Factor (CRF) x Total Capital Investment

Where;

$CRF = i(1+i)^n / (1 + i)^n - 1$

n = the control system economic life (a life of 30 years was used for each generating technology)

i = interest rate: a pretax marginal rate of return on private investment

Summarized in Table 15 are the total annual costs associated with each generating technology.

Table 15
Generating Technology – Total Annual Costs

	PC	CFB	IGCC
Capital Recovery Cost	$122,465,600	$128,102,500	$192,099,000
Total Annual Operating Cost	$46,037,400	$66,427,100	$116,150,800
Total Annual Cost	$168,503,000	$194,529,600	$308,249,800

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4.4 Cost Effectiveness

The cost effectiveness of each control technology was evaluated on a pollutant-specific basis. The PC configuration was used as the baseline configuration. If an alternate generating technology resulted in reduced annual emissions, the average annual cost effectiveness of the generating system was calculated as follows:

$$CE_{Avg} = (TAC_{Tech} - TAC_{PC}) / (E_{Tech} - E_{PC})$$

Where:

TAC_{Tech} = Total Annual Cost of the Alternative Technology
TAC_{PC} = Total Annual Cost of the PC Configuration
E_{Tech} = Annual Emissions from the Alternative Technology
E_{PC} = Annual Emissions from the PC Configuration

Summarized in Tables 16 through 18 are the average annual cost effectiveness, on a pollutant-specific basis for each electricity generating configuration. To ensure a complete review of potential emission reductions, a cost effectiveness evaluation was conducted for both the anticipated BACT emission rate (based on emissions actually achieved in practice) and the lowest proposed emission rate for each technology.

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Table 16
Annual Cost Efficiency
NOx Control

Pollutant	NOx				
Capacity Factor	0.90				
Control Technology	Heat Input to Achieve 900 MW-net Output (mmBtu/hr)	Expected BACT Emission Rate (lb/MMBtu)	Expected Emissions (ton/year)	Emission Reduction Efficiency for BACT Analysis (%)	Expected Emissions Reduction (ton/year)
Baseline Emissions Pulverized Coal Facility + BACT	8841	0.07	2,440	--	--
Circulating Fluidized Bed Design based on most likely BACT emission rate.	9754	0.09	3,461	-41.8%	(1,021)
Circulating Fluidized Bed Design based on lowest proposed emission emission rate.	9754	0.09	3,461	-41.8%	(1,021)
IGCC Design with BACT based on best emission rate achieved in practice	9713	0.09	3,446	-41.3%	(1,006)
IGCC Design with BACT based on lowest proposed future emission rate.	9713	0.0735	2,814	-15.4%	(375)

Control Technology	Emissions (tpy)	Tons of NOx Removed (tpy)	Total Capital Investment ($)	Annual Capital Recovery Cost ($/year)	Total Annual Operating Costs ($/year)	Total Annual Costs ($)	Incremental Annual Cost Increase ($/ton)	Incremental Control Efficiency ($/ton)
Baseline Emissions Pulverized Coal Facility + BACT	2,440		$1,108,000,000	$122,465,600	$46,037,400	$168,503,000		
Circulating Fluidized Bed Design based on most likely BACT emission rate.	3,461	(1,021)	$1,159,000,000	$128,102,500	$66,427,100	$194,529,600	**$26,026,600**	NA - Results in Annual Emissions Increase
Circulating Fluidized Bed Design based on lowest proposed emission emission rate.	3,461	(1,021)	$1,159,000,000	$128,102,500	$66,427,100	$194,529,600	**$26,026,600**	NA - Results in Annual Emissions Increase
IGCC Design with BACT based on best emission rate achieved in practice	3,446	(1,006)	$1,738,000,000	$192,099,000	$116,150,800	$308,249,800	**$139,746,800**	NA - Results in Annual Emissions Increase
IGCC Design with BACT based on lowest proposed future emission rate.	2,814	(375)	$1,738,000,000	$192,099,000	$116,150,800	$308,249,800	**$139,746,800**	NA - Results in Annual Emissions Increase

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Table 17
Annual Cost Efficiency
SO2 Control

Pollutant	SO2				
Capacity Factor	0.90				
Control Technology	Heat Input to Achieve 900 MW-net Output (mmBtu/hr)	Expected BACT Emission Rate (lb/MMBtu)	Expected Emissions (ton/year)	Emission Reduction Efficiency for BACT Analysis (%)	Expected Emissions Reduction (ton/year)
Baseline Emissions Pulverized Coal Facility + BACT	8841	0.10	3,485	--	--
Circulating Fluidized Bed Design based on most likely BACT emission rate.	9754	0.05	1,923	44.8%	1,563
Circulating Fluidized Bed Design based on lowest proposed emission emission rate.	9754	0.022	846	75.7%	2,639
IGCC Design with BACT based on best emission rate achieved in practice	9713	0.12	4,595	-31.8%	(1,110)
IGCC Design with BACT based on lowest proposed future emission rate.	9713	0.032	1,225	64.8%	2,260

Control Technology	Emissions (tpy)	Tons of S02 Removed (tpy)	Total Capital Investment ($)	Annual Capital Recovery Cost ($/year)	Total Annual Operating Costs ($/year)	Total Annual Costs ($)	Incremental Annual Cost Increase ($/ton)	Incremental Control Efficiency ($/ton)
Baseline Emissions Pulverized Coal Facility + BACT	3,485		$1,108,000,000	$122,465,600	$46,037,400	$168,503,000		
Circulating Fluidized Bed Design based on most likely BACT emission rate.	1,923	1,563	$1,159,000,000	$128,102,500	$66,427,100	$194,529,600	**$26,026,600**	$ 124,490
Circulating Fluidized Bed Design based on lowest proposed emission emission rate.	846	2,639	$1,159,000,000	$128,102,500	$66,427,100	$194,529,600	**$26,026,600**	$ 73,707
IGCC Design with BACT based on best emission rate achieved in practice	4,595	(1,110)	$1,738,000,000	$192,099,000	$116,150,800	$308,249,800	**$139,746,800**	NA - Results in Annual Emissions Increase
IGCC Design with BACT based on lowest proposed future emission rate.	1,225	2,260	$1,738,000,000	$192,099,000	$116,150,800	$308,249,800	**$139,746,800**	$ 136,401

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Table 18
Annual Cost Efficiency
PM10 Control

Pollutant	PM10				
Capacity Factor	0.90				
Control Technology	Heat Input to Achieve 900 MW-net Output (mmBtu/hr)	Expected BACT Emission Rate (lb/MMBtu)	Expected Emissions (ton/year)	Emission Reduction Efficiency for BACT Analysis (%)	Expected Emissions Reduction (ton/year)
Baseline Emissions Pulverized Coal Facility + BACT	8841	0.015	523	--	--
Circulating Fluidized Bed Design based on most Likely BACT emission rate.	9754	0.015	577	-10.3%	(54)
Circulating Fluidized Bed Design based on lowest proposed emission rate.	9754	0.012	461	11.7%	61
IGCC Design with BACT based on best emission rate achieved in practice	9713	0.011	421	19.4%	102
IGCC Design with BACT based on lowest proposed future emission rate.	9713	0.011	421	19.4%	102

Control Technology	Emissions (tpy)	Tons of PM10 Removed (tpy)	Total Capital Investment ($)	Annual Capital Recovery Cost ($/year)	Total Annual Operating Costs ($/year)	Total Annual Costs ($)	Incremental Annual Cost Increase ($/ton)	Incremental Control Efficiency ($/ton)
Baseline Emissions Pulverized Coal Facility + BACT	523		$1,108,000,000	$122,465,600	$46,037,400	$168,503,000		
Circulating Fluidized Bed Design based on most Likely BACT emission rate.	577	(54)	$1,159,000,000	$128,102,500	$66,427,100	$194,529,600	**$26,026,600**	NA - Results in Annual Emissions Increase
Circulating Fluidized Bed Design based on lowest achievable emission rate proposed.	461	61	$1,159,000,000	$128,102,500	$66,427,100	$194,529,600	**$26,026,600**	$ 3,170,036
IGCC Design with BACT based on best emission rate achieved in practice	421	102	$1,738,000,000	$192,099,000	$116,150,800	$308,249,800	**$139,746,800**	$ 3,034,157
IGCC Design with BACT based on lowest proposed future emission rate.	421	102	$1,738,000,000	$192,099,000	$116,150,800	$308,249,800	**$139,746,800**	$ 3,034,157

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4.5 Economic Evaluation – Conclusions

Based on an evaluation of the potential emission rates and the costs associated with each electricity generating technology, there is no basis to eliminate the PC design (including SCR, fabric filter and wet FGD) as BACT for Unit 3. When comparing the proposed IPP Unit 3 emission limits to emission rates currently achieved in practice by CFB and IGCC units, the PC configuration will result in the lowest annual emissions of NOx and SO_2.

One CFB unit has recently been proposed with an SO_2 emission limit of 0.05 lb/mmBtu. Assuming the BACT emission limit for a CFB unit equipped with a polishing scrubber is 0.05 lb/mmBtu, and assuming that IPP Unit 3 could be replaced with CFB technology, annual SO_2 emission may be reduced by approximately 1,563 typ. However, the incremental SO_2 cost effectiveness of the CFB technology would be approximately $124,490/ton. Likewise, the IGCC configuration may reduce annual PM10 emissions by approximately 102 tpy, however, the incremental cost effectiveness associated with this reduction in PM10 emissions is approximately $3,000,000/ton.

Furthermore, when comparing the proposed PC emission limits to <u>the lowest proposed emission limits</u> for either the CFB or IGCC, the PC still represents BACT. For example, the lowest proposed SO_2 emission limit for a CFB facility is 0.022 lb/mmBtu. Assuming that the CFB design could consistently achieve an emission rate of 0.022 lb/mmBtu, the annual SO_2 emissions from the project would be reduced by approximately 2,639 tons/year compared to the proposed PC emission rate of 0.10 lb/mmBtu. However, the incremental cost effectiveness of this reduction in SO_2 emissions would be approximately $73,700/ton, and the CFB facility would result in increased NOx emissions of approximately 1,021 tons/year.

Likewise, the lowest proposed SO_2 emission rate for an IGCC facility is 0.032 lb/mmBtu. Assuming that the IGCC facility could consistently achieve an emission rate of 0.032 lb/mmBtu, the annual SO_2 emissions from the project would be reduced by approximately 2,260 ton/year compared to the proposed PC emission rate of 0.10 lb/mmBtu. However, the incremental cost effectiveness of this reduction in SO_2 emissions would be approximately $136,400/ton, and the IGCC facility would result in increased NOx emissions of approximately 375 to 1,006 tons/year (depending on the IGCC NOx emission rate).

STEP 5: SELECT BACT

Based on a review of the technical feasibility, potential controlled emission rates, and economic impacts of PC, CFB, and IGCC generating technologies, the PC configuration with SCR, fabric filter and wet FGD represents BACT for the proposed 900 MW-net Unit 3.

Part II – PC/CFB/IGCC BACT DETERMINATION

Attachment A
Recent CFB BACT Determinations

Part II – PC/CFB/IGCC BACT DETERMINATION

Attachment A
Recent CFB BACT Determinations
SO_2

Permit Date	Facility Name	SO_X Limits (lb/mmBtu)	Controls Used	Notes
Pending	Indeck-Elwood Energy Center	0.18 (30-day rolling)	CFB with limestone injection. Minimum of 92% reduction	BACT-PSD Permit Application is under review by IEPA
11/21/01	AES BV Partners	0.14 (annual average) 0.21 (30-day rolling)	CFB with limestone injection and hydrated ash re-injection system (or equivalent).	PA-SIP
5/4/01	Kentucky Mountain Power LLC	0.13	CFB with limestone injection and hydrated ash re-injection system.	BACT-PSD
8/15/00	EnviroPower of Illinois	0.25	CFB with limestone injection and supplementary injection of lime or other sorbent material using a hydrated ash reinjection system	Maximum 0.25 lb/mmBtu and 92% reduction if emissions are 0.20 lb/mmBtu or greater. Note: Facility has been permitted but construction/ operation has not begun.
7/14/99	JEA Northside Generating Station	0.2	CFB with limestone injection	BACT-PSD
12/24/98	Archer Daniels Midland Company	0.7	Limestone injection and fabric filter	BACT-PSD 92% control
9/18/98	AES Puerto Rico	0.022	CFB with limestone injection and dry scrubber and limit on sulfur content of fuel.	BACT-PSD Sulfur content of fuel limited to 1.0%, SO_2 emissions limited to 8.40 ppmvd @ 7% O_2
8/25/98	Choctaw Generation Limited	0.25	CFB with limestone injection	BACT-PSD Lignite fuel
9/3098	Archer Daniels Midland Company	0.36 (30-day rolling)	CFB with limestone injection	BACT-PSD 92% control
6/20/97	Toledo Edison Bayshore Plant	0.73	CFB with limestone injection	BACT-Other Coal and Pet-Coke Fired 90% control efficiency
7/25/95	York County Energy Partners	0.25	CFB with lime injection and fuel spec. (<2% sulfur in coal)	BACT-PSD 92% control efficiency
4/14/95	Northhampton Generating Company	0.129	CFB with lime injection	BACT-PSD Anthracite Culm fuel 92% control efficiency
8/11/94	Archer Daniels Midland Company	0.7	CFB with limestone injection followed by fabric filter	BACT-PSD 90% control efficiency
7/11/94 4/30/93	Energy New Bedford	0.23	CFB with limestone injection and fuel spec (<3.5% sulfur)	BACT-PSD
6/3/94	AES Warrior Run, Inc.	0.21 (3-hour)	CFB with limestone injection	BACT-PSD 95% control efficiency
4/30/93	Taunton Energy Center	0.23	CFB with limestone injection	BACT-PSD 70% control efficiency
1/25/93	North Branch Energy Partners	0.49	CFB with limestone injection	BACT-PSD 46% control efficiency

Part II – PC/CFB/IGCC BACT DETERMINATION

Attachment A
Recent CFB BACT Determinations
NOx

Permit Date	Facility Name	State	Heat Input (mmBtu/hr)	NO_X Limit (lb/mmBtu)	Controls Used	Remarks
Pending	Indeck-Elwood Energy Center	IL	~2925	0.10	SNCR	BACT-PSD 30-day rolling average Permit Application is under review by IEPA
11/21/01	AES BV Partners	PA	2155	0.15	SNCR	PA-SIP Determination
5/4/01	Kentucky Mountain Power LLC	KY	2 units at 2550 each	0.07 Note: Emissions above 0.07 are allowed at operating loads below 95% as long as mass emissions do not exceed 75 lb/hr.	SNCR	BACT-PSD Permit issued, but construction/operation has not begun. Permit includes provisions for a NOx optimization study.
8/15/00	EnviroPower of Illinois	IL		0.125	SNCR	BACT-PSD coal and mine tailings Permit issued but construction has not started.
7/14/99	JEA Northside Generating Station	FL	2764	0.09	SNCR	BACT-PSD 30-day rolling average
12/24/98	Archer Daniels Midland (Boiler 9 & 10)	IL	1500	0.12	SNCR	BACT-PSD
9/18/98	AES Puerto Rico	PR	2 @ 2461.5	0.10	SNCR	BACT-PSD Approximately 53 ppmvd @ 7% O_2
8/25/98	Choctow Generating Limited Partnership	MS	2475.8	0.2	CFB	Lignite fired CFB
6/30/98	Archer Daniels Midland (Boiler #5 and #6)	IA	1500	0.07	SNCR	30-day rolling average
6/20/97	Toledo Edison Co. Bayshore Plant	OH	1764	0.2	CFB	NSPS Permit Petroleum Coke
7/25/95	York County Energy Partners	PA	2500	0.125	SNCR	LAER Evaluation
4/14/95	Northampton Generating Co.	PA	1164	0.1	Thermo DeNox (SNCR)	BACT – PSD Anthracite Culm Fuel
8/11/94	Archer Daniels Midland Company (Boiler 7&8)	IA	1500	0.12	SNCR	
7/11/94	Energy New Bedford	MA	1671	0.15	SNCR	
6/3/94	AES Warrior Run, Inc.	MD	2070	0.1	Thermal DeNOx (SNCR)	
8/3/93	Archer Daniels Midland Company	IA	551.5	0.07	SNCR	30-day average
4/30/93	Taunton Energy Center	MA	1604.4	0.15	SNCR	
4/30/93	Energy New Bedford	MA	3342	0.15	SNCR	

Part II – PC/CFB/IGCC BACT DETERMINATION

Attachment A
Recent CFB BACT Determinations
PM-10

Permit Date	Facility Name	PM-10 Limits (lb/mmBtu)	Controls Used	Comments
Pending	Indeck-Elwood Energy Center	0.015	Fabric Filter	BACT-PSD Permit Application is under review by IEPA
11/21/01	AES BV Partners	0.02	Fabric Filter	PA-SIP
5/4/01	Kentucky Mountain Power LLC	0.015	Fabric Filter	BACT-PSD
8/15/00	EnviroPower of Illinois	0.015	Fabric Filter	BACT-PSD
7/14/99	JEA Northside Generating Station	0.011 (3 hr. avg.)	Proposed fabric filter or electrostatic precipitator	BACT-PSD
12/24/98	Archer Daniels Midland Company (boilers 9 & 10)	0.025	Fabric Filter	BACT-PSD 99% control efficiency
8/18/98	AES Puerto Rico	0.015	ESP	BACT-PSD
8/25/98	Choctaw Generation Limited	0.015	Baghouse	BACT-PSD Lignite fuel
9/3098	Archer Daniels Midland Company (boilers 5 & 6)	0.015 (3 hr. avg.)	Fabric Baghouse	BACT-PSD 99% control efficiency
6/20/97	Toledo Edison Bayshore Plant	0.03	Fabric Filter	NSPS 99% control efficiency
7/25/95	York County Energy Partners	0.011	Fabric Filter Research Cottrell with Ryton bags	BACT-PSD 99.95% control
4/14/95	Northhampton Generating Company	0.01	Fabric Filter Manufactured by Brandt	BACT-PSD 99.98% control
8/11/94	Archer Daniels Midland Company (boilers 7 & 8)	0.025	Fabric Filter	BACT-PSD 99% control efficiency
6/3/94	AES Warrior Run, Inc.	0.015	Fabric Filters	BACT-PSD
4/30/93	Energy New Bedford Co-Generation Facility	0.018	Fabric Filters	BACT-PSD
4/30/93	Taunton Energy Center	0.018	Fabric Filter	BACT-PSD 99% control efficiency
1/25/93	North Branch Energy Partners	0.02	Fabric Collector	BACT-Other 99.97% control

Part II – PC/CFB/IGCC BACT DETERMINATION

Attachment B
Economic Evaluation
Summary of Total Annual Costs

Part II – PC/CFB/IGCC BACT DETERMINATION

Economic Evaluation - Summary of Total Annual Costs – Pulverized Coal

CAPITAL COSTS	Cost [$]		Basis
Total Capital Costs			
Total Capital Investment	$1,108,000,000		Total Capital Investment based on site-specific cost estimate prepared by Sargent & Lundy LLC. PC costs were estimated based on information obtained from vendors for the IPA project and similar coal-fired projects. The Total Capital Cost estimate includes: (1) equipment costs for the boiler (including the SCR), steam turbine, fabric filter, and wet FGD; (2) auxiliary equipment, duct work, fans, instrumentation and freight; (3) direct installation costs such as foundations and supports, mechanical erection, electrical, piping, insulation and painting; and (4) indirect capital costs such as engineering, construction and field expenses, contractor fees, start-up and performance testing and contingencies. The cost estimate assumes multiple lump sum contracts, and additional contingency costs would be needed if the project were awarded as an EPC contract.
Total Capital Investment ($/kW-net)	$1,231		
Total Capital Investment ($/kW-gross)	$1,166		
Capital Recovery Factor = $i(1+i)^n / (1+i)^n - 1$	0.1105	30	life of equipment (years)
Annualized Capital Costs (Capital Recover Factor x Total Capital Investment)	**$122,465,600**	10.5%	pretax marginal rate of return on private investment
OPERATING COSTS			**Basis**
Operating & Maintenance Costs (based on 90% capacity factor)			
Variable O&M Costs			
Limestone	904,000		Limestone feed rate of 19,116 lb/hr (100% baseload case) @ $12/ton and 90% capacity factor.
Ammonia	2,536,000		Based on aqueous ammonia feed rate of 3,217 lb/hr (100% baseload case) @ $200/ton and 90% capacity factor.
SCR Catalyst	1,125,000		Based on $1250/MW-net per year catalyst replacement cost.
Water	294,000		Based on cooling water make-up rate of 3,110 gpm (100% baseload case) @ $0.20/1000 gallons and 90% capacity factor.
Waste Disposal	7,282,000		Based on: Flyash @ 73,791 lb/hr; bottom ash @ 18,480 lb/hr; and FGD waste @ 30,888 lb/hr. Total solid waste generation rate of 123,159 lb/hr @ $15/ton disposal cost and 90% capacity factor.
Other Variable O&M	3,548,000	$ 0.50	Assumes $0.50/MWh to account for other variable O&M including start-up fuel, cleaning chemicals, dibasic acid, cleaning costs, etc.
Total Variable O&M Cost	$15,689,000		
Total Variable O&M Cost ($/MWh-net)	$2.21		
Fixed O&M Costs			
Operating Labor			
Plant Manager's Office	$151,200		Assumed that the incremental increase to manage Unit 3 would require the addition of 2 plant management employees at an average salary (including benefits) fo $75,600/yr.
Operations	$1,890,000		Assumed that the operation of Unit 3 would require the addition of 25 operations employees at an average salary (including benefits) of $75,600/yr.
Maintenance Labor	$1,551,200	40.0%	Assuming 40% of the maintenance materials & supplies cost.
Maintenance Materials & Supplies	$3,878,000	0.35%	Assuming 0.35% of the Total Capital Equipment Cost, taking into account economies of scale associated with materials common to all 3 Units.
Administrative and General	$718,000	20.0%	Assuming 20% of the management, operations, and maintenance labor cost.
Total Fixed O&M Cost	$8,188,400		
Total Fixed O&M Cost ($/MWh-net)	$1.15		
Indirect Operating Cost			
Property Taxes	$11,080,000	1%	Property taxes, insurance, and administrative charges (including sales, research & development, accounting and other home office expenses) based on % of total capital investment, per USEPA guidelines, page 2-32.
Insurance	$11,080,000	1%	
Administration	$11,080,000	1%	
Total Indirect Operating Cost	$22,160,000		
Total Annual Operating Cost	**$46,037,400**		
Total Annual Operating Cost ($/MWh-net)	$6.49		
Total Annual Operating Cost (% of Total Capital)	4.2%		
TOTAL ANNUAL COST			
Annualized Capital Cost	**$122,465,600**		
Annual Operating Cost	**$46,037,400**		
Total Annual Cost	**$168,503,000**		

Part II – PC/CFB/IGCC BACT DETERMINATION

Economic Evaluation - Summary of Total Annual Costs – Circulating Fluidized Bed

CAPITAL COSTS	Cost [$]		Basis
Total Capital Costs			
Total Capital Investment	$1,159,000,000		Total Capital Investment based on site-specific information prepared for IPA Unit 3 based on labor costs, mechanical erection, and material handling costs at Delta, UT. CFB costs were based on information prepared by Sargent & Lundy LLC for a 550 MW (net) CFB project scaled-up to meet a net output of 900 MW. The Total Capital Cost estimate includes: (1) equipment costs for the CFB boilers, ash separation system, SNCR, dry FGD and fabric filter; (2) auxiliary equipment, duct work, fans, instrumentation and freight; (3) direct installation costs such as foundations and supports, mechanical erection, electrical, piping, insulation and painting; and (4) indirect capital costs such as engineering, construction and field expenses, contractor fees, start-up and performance testing and contingencies. The cost estimate assumes multiple lump sum contracts, and additional contingency costs would be needed if the project were awarded as an EPC contract.
Total Capital Investment ($/kW-net)	$1,288		
Total Capital Investment ($/kW-gross)	$1,189		
Capital Recovery Factor = $i(1+i)^t / (1+i)^t - 1$	0.1105	30	life of equipment (years)
Annualized Capital Costs (Capital Recover Factor x Total Capital Investment)	**$128,102,500**	10.5%	pretax marginal rate of return on private investment
OPERATING COSTS			**Basis**
Operating & Maintenance Costs (based on 90% capacity factor)			
Variable O&M Costs			
Limestone	1,958,000		Based on limestone consumption rate of 13,800 lb/hr (per CFB) @ $12/ton and 90% capacity factor.
Ammonia	449,000		Based on aqueous ammonia consumption rate of 190 lb/hr (per CFB) @ $200/ton and 90% capacity factor.
SCR Catalyst	0		NA
Water	108,000		Based on water consumption rate of 380 gpm (per CFB) @ $0.20/1000 gallons and 90% capacity factor.
Waste Disposal	9,484,000		Based on solid waste generation rate of 40,100 lb/hr (per CFB) including fly ash, bottom ash, and spent limestone sorbent @ $20/ton and 90% capacity factor.
Other Variable O&M	3,547,800	$ 0.50	Assumes $0.50/MWh to account for other variable O&M including start-up fuel, cleaning chemicals, cleaning costs, etc.
Total Variable O&M Cost	$15,546,800		
Total Variable O&M Cost ($/MWh-net)	$2.19		
Fixed O&M Costs			
Operating Labor			
Plant Manager's Office	$823,500		Assumes that the installation of three new CFB boilers will require 10 additional senior management employees, including an operations manager, purchasing manager, safety & training manager, environmental manager, and administrative assistants. Senior management at an average annual salary (including benefits) of $96,000 and junior management at 76,500/year.
Operations	$5,821,200		Assumes that the installation of three new CFB boilers will require a total of 77 additional opertions employees (approximately 25/shift + 2) at an average annual salary (including benefits) of $75,600/year.
Maintenance Labor	$5,331,600	40.0%	Assuming 40% of the maintenance materials & supplies cost.
Maintenance Materials & Supplies	$13,329,000	1.15%	Assuming 1.15% of the Total Capital Equipment Cost. This percentage is higher than the percentage for the PC because of the differences between the CFB units and the existing PC units.
Administrative and General	$2,395,000	20.0%	Assuming 20% of the management, operations, and maintenance labor cost.
Total Fixed O&M Cost	$27,700,300		
Total Fixed O&M Cost ($/MWh-net)	$3.90		
Indirect Operating Cost			
Property Taxes	$11,590,000	1%	Property taxes, insurance, and administrative charges (including sales,
Insurance	$11,590,000	1%	research & development, accounting and other home office expenses) based
Administration	$11,590,000	1%	on % of total capital investment, per USEPA guidelines, page 2-32.
Total Indirect Operating Cost	$23,180,000		
Total Annual Operating Cost	**$66,427,100**		
Total Annual Operating Cost ($/MWh-net)	$9.36		
Total Annual Operating Cost (% of Total Capital)	5.7%		
TOTAL ANNUAL COST			
Annualized Capital Cost	**$128,102,500**		
Annual Operating Cost	**$66,427,100**		
Total Annual Cost	**$194,529,600**		

Part II – PC/CFB/IGCC BACT DETERMINATION

Economic Evaluation - Summary of Total Annual Costs – IGCC

CAPITAL COSTS	Cost [$]		Basis
Total Capital Costs			
Total Capital Investment	$1,738,000,000		Total Capital Investment based on site-specific labor costs, mechanical erection, and material handling costs developed for Delta, UT. IGCC costs were estimated based on information obtained from a gasifier equipment vendor (for a confidential client), and confirmed by comparison to capital costs reported by Polk and Wabash River. The Total Capital Cost estimate includes: (1) equipment costs for gasifier, air separation unit, gas cleanup equipment, sulfuric acid plant, combustion turbine, HRSG, and steam turbine; (2) auxiliary equipment, duct work, fans, instrumentation and freight; (3) direct installation costs such as foundations and supports, mechanical erection, electrical, piping, insulation and painting; and (4) indirect capital costs such as engineering, construction and field expenses, contractor fees, start-up and performance testing and contingencies. The cost estimate assumes multiple lump sum contracts, and additional contingency costs would be needed if the project were awarded as an EPC contract.
Total Capital Investment ($/kW-net)	$1,829		
Total Capital Investment ($/kW-gross)	$1,511		
Capital Recovery Factor = $i(1+i)^t / (1+i)^t - 1$	0.1105	30	life of equipment (years)
Annualized Capital Costs (Capital Recover Factor x Total Capital Investment)	**$192,099,000**	10.5%	pretax marginal rate of return on private investment
OPERATING COSTS			**Basis**
Operating & Maintenance Costs (based on 90% capacity factor)			
Variable O&M Costs			
Limestone	$ -		NA
Ammonia	$ -		NA
SCR Catalyst	$ -		NA
Catalysts and Chemicals	$ 3,800,000	$ 4	Water treatment, flocculent, acid gas removal, COS and Sulfuric Acid Plant Catalysts. $4/kW-net based on information presented in Polk Final Report, page 4-7.
Water	$ 72,000		Assuming 760 gpm @ $0.20/1000 gallons and 90% capacity factor
Waste Disposal	$ 1,971,000		Assuming 50,000 lb/hr slag and ash @ $10/ton disposal and 90% capacity factor.
Other Variable O&M	$ 7,490,000	$ 1.00	Assumed $1.00/MWh to account for miscellaneous variable costs associated with the air separation unit, gasifier, gas cleanup, sulfuric acid plant, CT/HRSG, and steam turbine. Costs include additional fuel costs, start-up fuel, chemicals and packaging.
Total Variable O&M Cost	$13,333,000		
Total Variable O&M Cost ($/MWh)	$1.78		
Fixed O&M Costs			Note: The O&M Costs are based on a % of Total Capital Cost, Polk Final Report, section 4-2. In general, the percentages used were reduced (compared to the Polk costs) to account for future improvements and economy of scale. However, the CT O&M costs were increased based on operating history at the Polk and Wabash River facilities.
O&M - General Maintenance and ASU	$4,345,000	0.25%	Includes building, structure, and site maintenance; safety and general supplies, and waste disposal (except slag).
O&M - Gaification	$8,690,000	0.50%	Includes coal slurry operations, high temperature gas cooling, slag and fines handling, gas cleanign, and sulfuric acid plant.
O&M - Power Block, Common and Plant Water Systems	$12,166,000	0.70%	Includes maintenance costs associated with the power block (combustion turbines, HRSGs, steam turbines, etc.)
Sustaining Capital - Small Projects	$4,345,000	0.25%	Includes replacement of worn capital equipment and minor improvements
Operating Labor			
Plant Manager's Office	$651,000		Assumes that the operation of two new IGCC modules will require the addition of 8 management employees. Senior management assumed at an average annual salary (including benefits) of $96,000/year, and junior management assumed at $75,6000/yr. This estimate appears to be conservative based on information presented in the Polk Final Report, page 4-8.
Operations	$5,140,800		Assumes that the installation of two new IGCC modules will require a total of 68 additional opertions employees (approximately 22/shift + 2) at an average annual salary (including benefits) of $75,600/year.
Maintenance Labor	$11,818,000	40.0%	of maintenance materials cost
Total Maintenance Materials and Supplies	$29,546,000		Sum of maintenance and materials costs for each IGCC plant component listed above.
Administrative and General	$3,521,960	20.0%	Assumed 20% of operating, superviosry and maintenance labor. See, USEPA Cost Estimating Methodology, Dec. 1995, Chapter 2, page 2-31.
Total Fixed O&M Cost	$50,677,760		
Total Fixed O&M Cost ($/kW-net)	$6.77		
Indirect Operating Cost			
Property Taxes	$17,380,000	1%	Property taxes, insurance, and administrative charges (including sales, research & development,
Insurance	$17,380,000	1%	accounting and other home office expenses) based on % of total capital investment, per USEPA
Administrative Charges	$17,380,000	1%	guidelines, page 2-32.
Total Indirect Operating Cost	$52,140,000		
Total Annual Operating Cost	**$116,150,800**		
Total Annual Operating Cost ($/MWh-net)	$15.51		
Total Annual Operating Cost (% of Total Capital)	6.7%		Note: this percentage is in-line with the 6.8% reported by Wabash River in their final Technical Report, page 7-6.
TOTAL ANNUAL COST			
Annualized Capital Cost	**$192,099,000**		
Annual Operating Cost	**$116,150,800**		
Total Annual Cost	**$308,249,800**		

Intermountain Power Proejct Unit 3 Permit Application: Response to UDAQ Questions

IPA
Intermountain Power Agency

July 28, 2003

Utah Department of Environmental Quality
Division of Air Quality
Milka Radulovic, Permit Engineer
150 North 1950 West
P.O. Box 144820
Salt Lake City, UT 84114-4820

RE: **Intermountain Power Project Unit 3 Permit Application**
Response to UDAQ Questions

Dear Milka:

We have attached our responses to the following NSR comments: a document provided by you in a meeting on June 19, 2003, that summarized "questions and comments on the IPP Unit 3 NOI not addressed yet"; four e-mail comment memos from you to Steve Sands, CH2MHILL on June 19, June 20, June 30 (clarifications and questions to June 30 IPSC response letter), and July 14, 2003 (follow-up to summarize discussions of June 30 e-mail) concerning the IPP Unit 3 permit application.

Our records indicate that with the information attached, plus the information provided to you in our June 30, 2003 response entitled "Intermountain Power Project Unit 3 Permit Application Response to UDAQ Questions", we have now provided responses to every NSR review question that you have asked to date relating to the IPP Unit 3 permit application. Please note that we are developing separate responses to modeling issues that DAQ has raised.

If you have any questions or require any additional information, please call me directly at (801) 938-1315.

Sincerely,

Lance C. Lee

Lance C. Lee

IPP Unit 3 Feasibility Manager

c: Mr. Stephen Sands (CH2M HILL)
Mr. Reed T. Searle

10653 South River Front Parkway, Suite 120, South Jordan, Utah 84095
(801) 938-1333 Fax (801) 938-1330

Intermountain Power Project Unit 3 Permit Application Response to UDAQ Comments

PREPARED FOR: Milka Radulovic, UDAQ

PREPARED BY: CH2M HILL

DATE: July 28, 2003

The purpose of this memorandum is to provide Intermountain Power Service Corporation's responses to a document provided by Milka Radulovic in a meeting on June 19, 2003, that summarized "questions and comments on the IPP Unit 3 NOI not addressed yet", four additional e-mail comment memos sent from Milka Radulovic, Utah Department of Air Quality (UDAQ) to Steve Sands, CH2MHILL on June 19, June 20, June 30 (clarifications and questions to June 30 IPSC response letter), and July 14, 2003 (follow-up to summarize discussions of June 30 e-mail) concerning the IPP Unit 3 permit application. All UDAQ comments are shown in *italic font* and the IPSC responses are shown in normal font.

June 19, 2003 Document provided by Milka Radulovic, UDAQ to Steve Sands, CH2MHILL, in a meeting on June 19, 2003

This document was titled:

"Questions and comments on the IPP Unit 3 NOI not addressed yet"

1. UDAQ Comment: *Calculation methods description and tools if not done by the EPA's AP-42 emission factors compilation for all submitted calculations.*

   IPSC Response: An electronic copy of the emission calculations workbook was provided to Milka Radulovic, DAQ, by e-mail from Steve Sands on June 26, 2003 at 4:49 pm.

2. UDAQ Comment: *What is the basis for the change of particulate loadings in the 5/14/03 NOI from the dated 12/16/02 NOI?*

   IPSC Response: The change in particulate loadings from the 12/16/02 NOI and the 5/14/03 NOI Addendum were based on a correction to the worst-case design coal average maximum ash content. The worst-case design coal average maximum ash content was changed from 9.2 to 12 percent by weight in the design and in Table 2-1 in the December submittal, however, initial loading calculations were based on an ash content of 9.2 percent by weight. Particulate loading calculations were inadvertently not updated prior to initial NOI submission.

3. UDAQ Comment: *Baghouse FF cost analysis didn't include all the pollutants for which NOI claimed reduction.*

IPSC Response: The cost analysis that was performed for PM_{10} control indicated that proper technologies were proposed as BACT for PM_{10}. Footnote 1 of the WESP technology discussion presented in Section 4 of Appendix I addresses H_2SO_4 removal. We are unaware of any regulatory need to perform cost analysis for other non-PSD pollutants when evaluating the proper level of BACT control technology for PM_{10}.

4. UDAQ Comment: *Startups (cold and hot) and shutdowns emissions and durations.*

IPSC Response: This information will be provided in a separate submittal developed to present the results of the Unit 3 analysis that was performed to model the impacts of startup emissions on the NAAQS.

5. UDAQ Comment: *Scrubber units' capacity clarification.*

IPSC Response: A response to a similar comment was previously addressed in our June 30, 2003 response to DAQ. For completeness, the June 30, 2003 response is repeated in this response as follows: Under normal operating conditions based on the design worst case coal, each scrubber module will handle 50% to 67% of the flue gas flow. However, in the event that one scrubber module is taken out of service, the other module would be capable of receiving 100% of the flue gas flow and achieving the 0.10 lb/MMBtu outlet SO_2 emission rate based on a 30 day rolling average. Additional discussion on this issue is in the Appendix I SO_2 control white papers.

6. UDAQ Comment: *Is the worst-case coal analysis provided in the NOI (used for emissions calculations and analysis) based on the blending of bituminous and subbituminous coal?*

IPSC Response: The primary coal proposed for IPP Unit 3 would fall into the category of bituminous coal. The worst-case coal analysis is not based on a particular coal or a particular blend of bituminous coals and subbituminous coals. The worst-case coal analysis is based on worst-case pollutant producing characteristics of all coals and coal types (primarily bituminous) for which Unit 3 is being designed to burn. As has been previously discussed with DAQ, it is difficult to predict specific coals or blends that may be available to burn over the life of the project (see coal technology discussion presented in Section 1 of Appendix I). As a result, a worst-case analysis of the types of coals that Unit 3 will be designed to burn was performed. This worst-case Unit 3 design coal analysis serves as a basis for Unit 3 emission calculations.

7. UDAQ Comment: *Since in the Section 4.4 H_2SO_4 and HF emissions limits are crossed, what else is proposed as a limit to support BACT for these two pollutants?*

IPSC Response: A response to a similar comment was previously addressed in our June 30, 2003 response to DAQ. For completeness, the June 30, 2003 response is repeated in this response as follows: Estimated stack emissions are 39.7 lb/hr H_2SO_4 and 4.7 lb/hr HF. An SO_2 limit of 0.10 lb/MMBtu on a 30 day rolling average will ensure that both H_2SO_4 and HF are controlled at 90% or above. IPSC feels that individual permit limits for these two pollutants are not required. IPSC is willing to perform performance testing related to these two pollutants to demonstrate the emission rates and control efficiencies. A number of other state regulatory agencies have determined that individual limits are not required for H_2SO_4 and HF if proper FGD operation is demonstrated. Examples include Hawthorne Unit 5 in Missouri and Hardin Unit 1 in Montana.

8. UDAQ Comment: *Forms in the Appendix A update*

IPSC Response: As discussed in the meeting on July 8, 2003, IPSC formally requests a withdrawal of Form 19. Responses to DAQ questions are intended to clarify and/or provide additional information to assist DAQ in drafting the permit. If after review of the responses provided, DAQ requires updates to specific NOI forms, please let us know what you want so that we can provide.

9. UDAQ Comment: *Why are the Unit 3 Hg emissions so much higher than Units 1 & 2 Hg emissions? What kind of coal was used in both Hg tests at IPP (with reference to the Hg content, HCl)? What was the LOI?*

IPSC Response: Mercury emissions from Units 1 and 2 are based on test data. The Unit 3 mercury emissions are conservatively based on the mercury content of coals proposed for IPP Unit 3. The mercury content of the coals proposed for Unit 3 range from as low as 0.02 ppm by weight to 0.15 ppm by weight. The mercury and HCl content of coals used by IPP Units 1 and 2 in both mercury tests is not relevant to the range of coals that IPP Unit 3 will be designed to burn over the life of the plant. Because Unit 3 is not yet constructed, boiler test data is not available, thus emission estimates were based on worst-case design coal mercury content information. The LOI content in the fly ash anticipated from Unit 3 cannot be predicted until a final boiler design is selected. However, based on ash salability, we expect a vendor guarantee LOI content less than 5 percent.

10. UDAQ Comment: *Why are the Unit 3 PM_{10} emissions for the cooling towers so much smaller than Units 1&2 cooling tower PM_{10} emissions?*

IPSC Response: A response to a similar comment was previously addressed in our June 30, 2003 response to DAQ. For completeness, the June 30, 2003 response is repeated in this response as follows: There are two reasons for the difference. The 2001 Units 1 and 2 cooling tower PM_{10} emission estimates were based on the AP-42 Section 13.4-1 method utilizing average flow, average TDS and a drift eliminator control efficiency of 0.002%. All PM drift was considered to be PM_{10}. However, based on the 2001 paper, *Calculating Realistic PM_{10} Emissions from Cooling Towers*, J. Reisman, G. Frisbie, only about 5% of the drift would be PM_{10} based on a TDS of 15,000 mg/l. Thus, in the Unit 3 NOI permit application, the cooling tower PM_{10} emissions for Units 1 and 2 were revised to a total of 19.7 tons including the helper towers. The Unit 3 cooling tower PM_{10} emission calculation was based on the same revised method but a BACT drift eliminator control efficiency of 0.0005% (gallons of drift per gallon of cooling water flow) was used. Please reference the calculations and notes in Appendix C – Emission Calculations.

11. UDAQ Comment: *Could you provide calculations and rational for the 1.34 lb/MMBtu of SO2.*

IPSC Response: A response to a similar comment was previously addressed in our June 30, 2003 response to DAQ. For completeness, the June 30, 2003 response is repeated in this response as follows: The uncontrolled emission rate of 1.34 lb/MMBtu SO_2 is based on the worst case design bituminous coal with a coal sulfur content of 0.75 percent. The calculation is as follows:

Uncontrolled SO_2 (lb/MMBtu) = Annual Coal Throughput (lb/hr) * Coal Sulfur Percent * [2 moles SO_2/1 mole S] / Maximum Boiler Heat Input (MMBtu/hr)
= 808,504 * 0.0075 * 2 / 9,050
= 1.34 lb/MMBtu

12. UDAQ Comment: *Inconsistencies in the NOI, such as*

- *Ammonia slip listed in Appendix C calculations 3 ppmvd, but in the emission table 2-4 as 5 ppmvd*
- *Table 2-9 lists 20,072 lb/hr and page 2-22 lists 20,066 lb/hr*
- *Section 6.2 gives description that Unit 3 will have two-scrubber modules each designed to treat 67% of maximum fuel flow. In the technical discussion, Appendix A (NOI dated May 14, 03) part IV it is stated that FGD vessels are being designed to treat 100% of gas flow.*
- *Table 3-2 footnote a reference SO_2 emissions at 100% load. As shown in the calculations SO_2 emissions are done for 105% boiler load. This information should be in the section 6.2 and any other applicable place.*
- *Section 2.3 WFGD should include mercury*
- *Section 1.2 should reference the NESHAP and Acid Rain Regulations*

IPSC Response: In meetings since submittal of the NOI Addendum, it has been discussed that clarifications should be made via follow-up responses as opposed to a second NOI update and complete re-submittal. The rational provided by DAQ was that if the public requests copies of the NOI, it is easier for DAQ to provide follow-up correspondence than an entire NOI update. If DAQ would like to see changes to the NOI, please let us know. Clarifications to the issues identified in Comment 12 are as follows:

- The SCR is expected to operate with an average ammonia slip of 2 ppmvd @ 3% O_2. The design guarantee from the vendor is expected to be 5 ppmvd at 3% O_2. The ammonia emission rate based on 5 ppmvd at 3% O_2 would be 21.7 lb/hr.
- Limestone consumption at full load (105%) is expected to be 20,072 lb/hr.
- FGD vessels are being designed to treat 100% of gas flow.
- Emission calculations were based on 105% boiler load conditions throughout the document.
- Section 6.4.3.4 discusses mercury removal in the WFGD.
- NESHAP and Acid Rain Regulations are addressed in Section 5.

June 19, 2003 6:11 p.m. E-mail from Milka Radulovic, UDAQ to Steve Sands, CH2MHILL

1. UDAQ Comment: *Basis for the efficiencies used in the cost analysis for the comparison between the proposed fabric filters and Gorterx bag. In addition, there will be addition or comment why the cost analysis did not reflect the emissions reduction difference for all the rest of pollutants for which control the baghouses were used to present their controlled values.*

   IPSC Response: The basis for the efficiencies included technology reviews from sources including the EPA RBCL database, EPA's NSR bulletin board, BACT guideline – South Coast Air Quality Management District, control technology vendors, technical journals and web sites, and other recently issued federal/state/local NSR permits. The Technology discussion that was developed as Section 3 of Appendix I includes justification beyond that provided in Section 6.3.7 of the NOI. The cost analysis that was performed for PM_{10} control indicates that proper technologies have been proposed as BACT for PM_{10}. We are not aware of any regulatory requirement to perform cost analysis for other non-PSD pollutants when evaluating the proper level of BACT control technology for PM_{10}.

2. UDAQ Comment: *In the MACT case by case you will provide reference for Hg content in the coal.*

   IPSC Response: The Unit 3 mercury emissions are conservatively based on the mercury content of coals proposed for IPP Unit 3. The mercury content of the coals proposed for Unit 3 range from as low as 0.02 ppm by weight to 0.15 ppm by weight. Because Unit 3 is not yet constructed, boiler test data is not available, thus emission estimates were based on worst-case design coal mercury content the range of coals that IPP Unit 3 will be designed to burn over the life of the plant.

3. UDAQ Comment: *You will also comment on the Waygen Unit 2 PM10 limit of 0.012 lb/MMBtu shown in the Table 6-7, NOI May 14, 2003. Also, comment on the Springerville's future limit.*

   IPSC Response: This Wygen PM10 limit of 0.012 lb/MMBtu was evaluated for applicability to IPP Unit 3. In addition to information provided in the PM_{10} BACT Analysis in 6.3.7, a detailed technology discussion and incremental cost analysis of alternatives for improving the fabric filter control efficiency for Unit 3 was presented in Section 3 of Appendix I. The incremental cost analysis specific to IPP Unit 3 demonstrated a cost effectiveness of $14,026/ton of PM_{10} removed to go from fabric filters at 0.015 lb/MMBtu to fabric filters at 0.012 lb/MMBtu. The conclusion of the analysis is that fabric filters at a 0.015 lb/MMBtu emission rate is BACT for IPP Unit 3.

   BACT is defined under R307-101-2 as "an emission limitation and/or other controls to include design, equipment, work practice, operation standard or combination thereof, based on the maximum degree or reduction of each pollutant subject to regulation under the Clean Air Act and/or the Utah Air Conservation Act emitted from or which results from any emitting installation, which the Air Quality Board, **on a case-by-case basis taking into account energy, environmental and economic impacts and other costs, determines is achievable for such installation…"**

IPP Unit 3 is located in a PM_{10} attainment area and economic impacts need to be considered when evaluating proposed BACT controls. This is not a LAER situation where cost effectiveness is not a factor in the decision. IPSC has sufficiently demonstrated fabric filters with a 0.015 lb/MMBtu emission rate as BACT for IPP Unit 3.

On the future Springerville permit, we spoke to Arizona DEQ. According to Arizona DEQ, the limit on Springerville permit has not changed from the 0.015 lb/MMBtu limit that was originally issued.

June 20, 2003 1:09 p.m. E-mail from Milka Radulovic, UDAQ to Steve Sands, CH2MHILL

1. UDAQ Comment: *Page 6-14, second line from the bottom has 174 lb/hr rate for H_2SO_4. Correct value should be 39.7 (39.2) lb/hr.*

   IPSC Response: The correct value should be 39.7 lb/hr.

2. UDAQ Comment: *Appendix H, page 9 of 16 does not lists FF for fugitive emissions control (transfer points).*

   IPSC Response: DAQ is correct to point out that a baghouse (fabric filter) is a potential control technology for controlling PM10 fugitive emission from transfer points. As presented in Section 6.3.9.5 of the BACT analysis, fabric filters are proposed as BACT for control of fugitive emissions from all enclosed material handling transfer points associated with Unit 3.

3. UDAQ Comment: *Table 6-1, page 6-9, in the table title a reference to the superscript "a" should be removed.*

   IPSC Response: We disagree with this comment. Refer to 40 CFR 60.43a(a)(2) as a basis for the applicability of the superscript "a".

4. UDAQ Comment: *The value of 220.9 lb/hr for total PM_{10} (filterable & condensable) should includes 2.7 lb/hr $(NH_4)_2SO_4$. Is this correct?*

   IPSC Response: This is correct. The 2.7 lb/hr $(NH_4)_2SO_4$ is included in the value of 220.9 lb/hr for total PM_{10} (filterable & condensable).

5. UDAQ Comment: *For the Tables 6-2 and 6-7, footnote is incorrect; Project Bull Mountain Round Unit 1, Montana does not have in the permit limit exclusion for the startups, shutdowns, and malfunction.*

   IPSC Response: The footnotes in Tables 6-2 and 6-7 should be changed to read "All of the permits above, except Bull Mountain Roundup, exempt startup, shutdown, and malfunction in the short term (3 hour, 24 hour, and 30 day) emission limits. Plum Point is a draft permit."

6. UDAQ Comment: *Table 6-6, NO_x emission limit of 0.07 lb/MMBtu is for 24-hour average. This is more stringent emission limit that needs to be addressed.*

IPSC Response: The NO_X emission rate proposed as BACT for IPP Unit 3 is 0.07 lb/MMBtu based on a 30-day rolling average. It is not appropriate to specify an emission rate with an averaging period shorter than 30-days for an attainment area pollutant that is regulated only by an annual health based NAAQS standard. IPSC has performed air quality modeling analysis for NO_X. The Unit 3 impacts are well below the modeling significance level for NO_X.

IPSC does not see any regulatory reason for specifying an emission limit with an averaging period shorter than 30-days for NO_X. As discussed in the technology discussion in Section 2 of Appendix I, data from existing coal-fired boilers indicate that the most aggressive NO_X emission rate currently achieved at any existing PC-boiler with a 30-day averaging period is in the range of 0.10 lb/MMBtu. As discussed in Section 6.2.4 and 6.3.5, SCR is a relatively new technology with limited long-term operating history and, to date, no actual operating experience demonstrated on Utah bituminous coals.

7. UDAQ Comment: *The references provided for the short-term limits address an injunctive relief as result of the source NOV case on the existing units. Short-term limits in the IPP will be based on NAAQS or increment consumption criteria.*

IPSC Response: The only short term emission limits that have been proposed by IPSC include a 30-day rolling average for NO_X and SO_2 and a 3-hour rolling average for total PM and PM_{10} (filterable). Representative emission rates over shorter term periods were used in the modeling of NAAQS, increment consumption, and AQRV analysis. Any permit limits with averaging periods shorter than those proposed by IPSC should be discussed prior to making decisions on the proper averaging periods that should be specified as permit limits.

8. UDAQ Comment: *In your discussion Wygen Project, Wyoming (table 6-7) has 0.012 lb/MMBtu limit for PM_{10}. Did you look at this limit as being applicable to IPP?*

IPSC Response: This limit was evaluated for applicability to IPP Unit 3. In addition to information provided in the PM_{10} BACT Analysis in 6.3.7, a detailed technology discussion and incremental cost analysis of alternatives for improving the fabric filter control efficiency for Unit 3 was presented in Section 3 of Appendix I. The incremental cost analysis specific to IPP Unit 3 demonstrated a cost effectiveness of $14,026/ton of PM_{10} removed to go from fabric filters at 0.015 lb/MMBtu to fabric filters at 0.012 lb/MMBtu. The conclusion of the analysis is that fabric filters at a 0.015 lb/MMBtu emission rate is BACT for IPP Unit 3.

BACT is defined under R307-101-2 as "an emission limitation and/or other controls to include design, equipment, work practice, operation standard or combination thereof, based on the maximum degree or reduction of each pollutant subject to regulation under the Clean Air Act and/or the Utah Air Conservation Act emitted from or which results from any emitting installation, which the Air Quality Board, **on a case-by-case basis taking into account energy, environmental and economic impacts and other costs, determines is achievable for such installation…"**

IPP Unit 3 is located in a PM_{10} attainment area and economic impacts need to be considered when evaluating proposed BACT controls. This is not a LAER situation where cost effectiveness is not a factor in the decision. IPSC has sufficiently demonstrated fabric filters with a 0.015 lb/MMBtu emission rate as BACT for IPP Unit 3.

9. UDAQ Comment: *Table 2-3 gives reference to 100% load. The rest of the NOI says 105%.*

   IPSC Response: Information Table 2-3 should reference 105% load.

10. UDAQ Comment: *BACT for VOC and CO should incorporate reference table with recently issued PSD projects, as it was done for PM_{10}, NO_x.*

    IPSC Response: The summary information reference tables for PM_{10}, NO_X, and SO_2 were developed to assist DAQ in performing a review of the BACT analysis. Appendix F Table F-1 and F-2 contain summary information from the RBCL database for CO and VOC, respectively.

June 30, 2003 6:36 p.m. E-mail from Milka Radulovic, UDAQ to Steve Sands, CH2MHILL

This e-mail contained clarifications and questions to the IPSC Response letter e-mailed to Milka on June 26, 2003, and formally submitted to DAQ on June 30, 2003. UDAQ Comments, IPSC Responses, UDAQ Follow-up Comments, and IPSC Follow-up Responses are included below.

April 24, 2003 1:25 p.m. E-mail from Milka Radulovic, UDAQ to Steve Sands, CH2MHILL

1. UDAQ Comment: *The ammonia slip of 2 ppmvd at 3% O2 listed in the IPP calculations (NOI Appendix C) and the likely limit of 5 ppmvd or less referenced in the NOI Section 6.2.4.4 (and the NOx draft document) do not match. Which one is the proposed limit?*

   IPSC Response: Based on preliminary engineering design data, the SCR is expected to operate with an average ammonia slip of 2 ppmvd @ 3% O_2. However, the design guarantee from the selected vendor is expected to be 5 ppmvd at 3% O_2. IPSC is not requesting a permit limit for ammonia slip since it is neither a criteria or hazardous air pollutant.

   UDAQ Follow-up Comment: *My comment to the above response is that for the NOI consistency (between the text and calculations) the calculations in the NOI Appendix C, need to be changed to reflect the 5 ppmvd at 3% O2 as being the worst case.*

   IPSC Follow-up Response: The ammonia emission rate based on 5 ppmvd at 3% O_2 is 21.7 lb/hr.

3. UDAQ Comment: *6-2 table in the NOI lists emission rates for LNB with OFA as 0.32-0.33 lb/MMBtu. However a limit of 0.35 lb/MMBtu was considered in the proposed 0.07 lb/MMBtu emission (80% NOx reduction with SCR) Was this in error?*

IPSC Response: The original Table 6-2 is Table 6-5 in the May 14, 2003 addendum. Based on the permitted emission rates from other permits and data in the RBLC, LNB's with Overfire Air were in the range of 0.15 – 0.33 lb/MMBtu NO_x and LNB's alone were in the range of 0.32 to 0.39 lb/MMBtu NO_x. The value of 0.35 lb/MMBtu for the LNB's and Overfire Air for IPP Unit 3 is based on the design coal for the unit. In order to achieve an outlet emission rate of 0.07 lb/MMBtu NO_x the SCR will be designed for a minimum of 80% removal. NO_x emissions and controls are discussed in further detail in the Appendix I white paper.

UDAQ Follow-up Comment: *Since the emission rate proposed for NOx is not in 0.15 to 0.33 lb/MMBtu range, the IPSC needs to address this concern.*

IPSC Follow-up Response: In a follow-up telephone conversation on July 8, 2003, to clarify this concern, Milka Radulovic, DAQ, indicated to Steve Sands, CH2MHILL, that additional explanation of why the value of 0.35 lb/MMBtu was outside the range of 0.15 – 0.33 lb/MMBtu NO_x for LNB's with Overfire Air of permitted emission rates from other permits and data in the RBLC. As indicated in the response above, the value of 0.35 lb/MMBtu for the LNB's and Overfire Air for IPP Unit 3 is based on the design coal for the unit. There is also additional discussion on NO_x emissions and controls provided in the Appendix I white paper that was submitted on May 14, 2003, as part of the NOI Addendum.

IPSC has not proposed LNB's and Overfire Air with a value of 0.35 lb/MMBtu as BACT for IPP Unit 3. Rather, IPSC has proposed LNB's, Overfire Air and SCR with a value of 0.07 lb/MMBtu as BACT for IPP Unit 3. This represents the most stringent combination of control technologies available for coal fired boilers. As Table 6-6 of the NOI Addendum indicates, the proposed outlet emission rate of 0.07 lb/MMBtu for NO_x is at the low end of the range of NO_x emissions (0.07 – 0.09 lb/MMBtu) associated with any PSD permit recently issued.

April 29, 2003 12:01 p.m. E-mail from Milka Radulovic, UDAQ to Steve Sands, CH2MHILL

2. UDAQ Comment: *At the AWMA Mega Symposium in Chicago, 2001, it was stated that 3-5% of H2SO4 would cause white plum. In addition, in the H2SO4 reduction discussion, there was no reference to any alkaline sorbents injection methods.*

IPSC Response: As discussed above, the expected H_2SO_4 concentration of 1.5 ppmvd @ 3% O_2 will not contribute to opacity. This is significantly lower than 3 to 5 percent. The wet limestone FGD system will have high H_2SO_4 removal (84%) with an overall system removal efficiency of 90%. Additional discussion is provided in the wet ESP white paper in Appendix I.

UDAQ Follow-up Comment: *In my original email of April 29, 2003, I listed an incorrect units designation. I listed 3-5% when the correct value should have been 3-5 ppm. Is IPSC's response of "As discussed above, the expected H_2SO_4 concentration of 1.5 ppmvd @ 3% O_2 will not contribute to opacity. This is significantly lower than 3 to 5 percent" still valid with this corrected question. Please refer to my e-mail to Steve Sands dated June 17, 2003*

IPSC Follow-up Response: The corrections sent by e-mail from Milka Radulovic, DAQ, to Steve Sands, CH2MHILL, on June 17, 2003 at 4:21 are as follows:

"I have small corrections in my recently sent e-mails
First dated 04/24/03, Item 3, should reference the table 6-2, not 4-3 Second dated 04/29/03, Item 1, 3-5 should be ppmvd not % Third dated 06/09/03, Item 4, should have 39.2 lb/hr not 42.4"

The response is valid since 1.5 ppmvd @ 3% O_2 is significantly lower than 3-5 ppmvd. IPSC does not anticipate that this expected H_2SO_4 concentration will contribute to opacity.

5. UDAQ Comment: *In the coal analysis, there were no data for chlorine, nitrogen, Hg or nay other constituent. Also, fly ash analysis was not included.*

IPSC Response: Data on the design coal analysis and fly ash analysis is shown in the Sargent & Lundy design data spreadsheet at the end of the Appendix C emission calculations. The fuel ultimate analysis on Page 1 of the spreadsheet shows a nitrogen content of 1.26% and a chlorine content of 0.03%. The mercury content of the bituminous coal proposed for IPP Unit 3 ranges from as low as 0.02 ppm by weight to 0.15 ppm by weight.

UDAQ Follow-up Comment: *Your reply did not consider my corrections, which I e-mailed to Steve Sands, CH2MHIL, on 4/29/03 at 5:52 pm. Also, what is the LOI content in the fly ash?*

IPSC Follow-up Response: The corrections sent by e-mail from Milka Radulovic, DAQ, to Steve Sands, CH2MHILL, on 4/29/03 at 5:52 are as follows:

"I found ash and coal analysis in the Appendix C. No reference to Mercury content."

Clarification noted. In our response above, we simply reiterated that coal analysis was provided in Appendix C and provided the range of expected Mercury concentrations. The LOI content in the fly ash anticipated from Unit 3 cannot be predicted until a final boiler design is selected. However, based on ash salability, we expect a vendor guarantee LOI content less than 5 percent.

June 9, 2003 7:16 p.m. E-mail from Milka Radulovic, UDAQ to Steve Sands, CH2MHILL

1. UDAQ Comment: *The NOI dated December 14, 2002; page 2-12, baghouse inlet particulate loading was shown as 59.515 lb/hr (6.58 lb/MMBtu). In the May 14, 2003 addendum it is shown as 77.616 lb/hr (8.58 lb/MMBtu). Please provide the rational and/or calculations for these numbers.*

IPSC Response: The initial baghouse inlet loading was based on a coal ash content of 9.2%. As discussed in the Appendix I coal supply white paper (May 14, 2003 addendum), the coal is anticipated to have an average maximum ash content of 12.0%. Thus, Table 2-5 was revised to show the higher particulate inlet loading. The calculation is as follows:

Inlet Particulate Loading = [Heat Input (MMbtu/hr)/Coal Heating Value (Btu/lb)] * Percent Ash in Coal * Percent Ash as Flyash
= [9,050E+6/11,193] * 12.0% * 80%
= 77,620 lb/hr

The higher inlet particulate loading also resulted in the increase of the baghouse design collection efficiency from 99.77% to 99.83%.

UDAQ Follow-up Comment: *So to make it clear, the number of 6.59 lb/MMBtu has to be corrected to 8.58 lb/MMBtu for the consistency with the rest of NOI information - 12% fly ash content in the coal and assumption that 80% of the total ash is emitted as fly (as shown in the December 16, 2002 NOI and May 14, 2003 NOI)*

The baghouse efficiency change (increase) was the next step needed to meet the proposed PM10 limit of 0.015 lb/MMBtu. Now I have additional question:: Why the efficiency increase from 99.77% to 99.83%, has changed? Was the reason for it the back calculation to meet the proposed limit?

IPSC Follow-up Response: After this issue was discussed on July 14, 2003, an additional clarification was provided by Milka Radulovic to Steve Sands an e-mail from Milka Radulovic on 7/8/03 at 5:43. Please refer to complete response provided under July 8, 2003 e-mail comment.

4. UDAQ Comment: *H_2SO_4 emissions in the NOI May 14, 2003, table 4-2 the hourly emission rate is shown for H_2SO_4 as 39.7.lb/hr. In the modeling CALPUFF input data SO_4 is given as 42.4 lb/hr on annual and 24 hour basis. Is this correct?*

IPSC Response: Yes, both values are correct. The SO_4 emission rate in CALPUFF included the H_2SO_4 (39.7 lb/hr) plus the ammonium sulfate, $(NH_4)_2SO_4$ (2.7 lb/hr) for at total of 42.4 lb/hr.

UDAQ Follow-up Comment: *In my original email of June 9, 2003, I listed an incorrect number. I listed 42.4 lb/hr when the correct value should have been 39.2 ppm. Is IPSC's response still valid with this corrected question? Please refer to my e-mail sent to Steve on June 17, 03.*

IPSC Follow-up Response: The corrections sent by e-mail from Milka Radulovic, DAQ, to Steve Sands, CH2MHILL, on June 17, 2003 at 4:21 are as follows:

"I have small corrections in my recently sent e-mails
First dated 04/24/03, Item 3, should reference the table 6-2, not 4-3 Second dated 04/29/03, Item 1, 3-5 should be ppmvd not % Third dated 06/09/03, Item 4, should have 39.2 lb/hr not 42.4"

The values provided in the response above are still valid.

June 11, 2003 1:23 p.m. E-mail from Milka Radulovic, UDAQ to Steve Sands, CH2MHILL

1. UDAQ Comment: *Table 4-1, IPSC's NOI (May 14, 2003), needs a clarification that the emissions from the Unit 1 or 2 represent only the emissions from the boilers 1 &2, not boiler associated equipment and fugitive emissions points.*
-In the table VOC are listed as 12.7 tons per year (tpy). Does this number represent HAPs and non-HAP VOC? If it includes HAPs, what is the HAP portion in it?
-Lead emissions from the UDAQ emission inventory list from Boiler #1 and 2 are ~0.059 tpy (total 0.09 tpy). The table lists for Boiler 3 0.7 tpy. Why are the emissions so much higher for the Boiler 3 (~18 times)?
-Table 6-8 has lead listed as 0.11 tpy. Which one is correct : 0.07 or 0.11 tpy.

IPSC Response: As noted, the Table 4-1 actual emissions for Units 1 and 2 are for the main boilers only.

Units 1 and 2 reported an average of 12.70 tons/year of VOC for the years 2000 and 2001. 12.65 tons is from coal combustion and 0.05 tons is from fuel oil combustion. The coal combustion VOC emissions were calculated based on individual HAPs that are also VOC's. Thus, the HAP portion is 100%. The fuel oil combustion is based on an AP-42 of 0.2 lb/1000 gallons.

Units 1 and 2 reported an average of 0.09 tons/year of lead for the years 2000 and 2001. The coal combustion lead emissions are based on the use of the AP-42 Section 1.1-16 emission factor formula using a coal ash factor of 8.64%, a coal trace metal lead concentration of 7.1 ppm and a PM actual emission factor of 0.0073 lb/MMBtu. To be conservative from a BACT analysis standpoint, the Unit 3 potential to emit lead emissions in the criteria calculation sheet were based on a AP-42 Section 1.1-18 emission factor of 4.2E-04 lb/ton. The calculation is as follows:

Unit 3 lead emissions, tpy = 4.2E-04 * 3,541,246 tons coal/year * 1 ton/2000 lb
= 0.74 tons/year.

Table 6-8 lists the annual HAP emission estimates. Lead is listed as 0.11 tons. This value is based on the use of the AP-42 Section 1.1-16 emission factor formula using a coal ash factor of 12.0%, a coal trace metal lead concentration of 6.5 ppm and a PM guaranteed emission factor of 0.015 lb/MMBtu. A lead emission rate of 0.11 tons/year is expected to be more representative of the actual Unit 3 emissions. However, as discussed above, and since the PSD significance level for lead is 0.6 tons, a conservative calculation was used in estimating criteria emissions.

UDAQ Follow-up Comment: *For the NOI consistency, please provide lead emissions number for tons per year using one AP-42 table (Table 1.1-16 Emission Factors for Trace Metals from Coal Combustion and Table 1.1-18 Emission Factors for Trace Metals from Controlled Combustion) with rational why is the specific table selected. Therefore, Tables 3-2 (lists 0.7 tpy of lead) and Table 6-8 (lists 0.11 tpy of lead) list the same number.*

IPSC Follow-up Response: The best estimate of lead emissions for the Unit 3 main boiler is the use of the AP-42 Table 1.1-16 emission factor. Based on a coal ash factor of 12%, a coal trace metal lead concentration of 6.5 ppm, and a PM emission factor of 0.015 lb/MMBtu, the estimated lead emissions are 0.026 lb/hr or 0.11 tons per year.

2. UDAQ Comment: *Table 4-2 footnote "[a]" reference the emissions at 100 % load. SO_2 emissions are actually from the 105% boiler design load. Please provide exact reference to the load in the referenced emissions.*

IPSC Response: Noted. The intent of the footnote is to point out that the hourly, daily and annual criteria emissions for Unit 3 are at the maximum design heat input (9,050 MMBtu/hr) for 8,760 hours/year.

UDAQ Follow-up Comment: *My comment is that for the consistency, 105% of the design load should be referenced in all places with the same definition: maximum design heat load or full load (as given in the calculations, the Appendix I).*

IPSC Follow-up Response: All PTE emissions information in the NOI is based on 105% load which should be defined as maximum design heat load or full load from this point forward.

8. UDAQ Comment: *Addendum Appendix A, Form 19 for the natural gas boiler needs to be updated with information submitted in the NOI.*

IPSC Response: There is not a specific UDAQ application form for a coal-fired boiler thus Form 19 was completed for the Unit 3 main boiler with information known to date. There will be no natural gas or fuel oil boiler as part of the project.

UDAQ Follow-up Comment: *I agree the form addresses NG and oil fired boilers. However, since you opted to submit it with signature, you need to put the same data as in the body of the NOI (Heat input, oil, and if needs to add a page with specific data not covered in the form.*

IPSC Follow-up Response: As discussed in the meeting on July 8, 2003, IPSC formally requests a withdrawal of Form 19 that was included with signature in the December 2002 NOI submittal and the May 14, 2003 NOI Addendum submittal. As DAQ accurately points out, Form 19 is only applicable to NG and oil fired boilers. This form is not applicable to coal fired boilers and should not have been submitted as part of the application.

June 11, 2003 7:20 p.m. E-mail from Milka Radulovic, UDAQ to Steve Sands, CH2MHILL

1. UDAQ Comment: *In the May 14, 03 NOI, page 6-37 the value of 0.42 tpy of Mercury emission is listed. Could you provide calculation for this number. It says that is based on ICR test data and coal trace analysis. The published value based on the testing at the IPP*

plant (I believe based on the earlier testing performed at the plant) shows the emissions of 0.0045 tpy for the plant.

IPSC Response: The EPA database for ICR mercury data can be referenced at http://www.epa.gov/ttn/atw/combust/utiltox/mercury/int2sgar.pdf. The mercury testing conducted last month at IPP has not yet been quality assured and finalized but initially seems to support the original results. EPA currently reports IPP mercury emissions at 28 lb/yr or 0.014 tons/yr.

The estimated uncontrolled mercury emissions for Unit 3 are 0.42 tons per year. The calculation is as follows:

Uncontrolled Hg (tpy)	=	Annual Coal Throughput (tpy) * (1 – Coal Moisture) * Coal Mercury Concentration (ppm dry weight basis)
	=	3,541,252 * (1 – 0.0826) * 0.13/1,000,000
	=	0.422 tpy
Controlled Hg (tpy)	=	Uncontrolled Hg (tpy) * (1 - Collection Efficiency %)
	=	0.422 * (1 – 77.65%)
	=	0.094 tpy

UDAQ Follow-up Comment: *Just to clarify, for the 0.0045 tpy of IPP mercury emissions I used these EPA's web sites*

http://www.epa.gov/ttn/atw/combust/utiltox/stxstate2.pdf
http://www.epa.gov/ttn/atw/combust/utiltox/pltxplt3.pdf
http://www.epa.gov/ttn/atw/combust/utiltox/rawdata1.pdf (June, 2001)
http://www.epa.gov/ttn/atw/combust/utiltox/icrdata.xls (January 2002)

IPSC Follow-up Response: Noted. However, as previously stated, the 0.0045 tpy is not the data that EPA currently shows for IPP. The correct and current information that EPA has on file for IPP Units 1 and 2 is contained in the link provided in our earlier response.

June 13, 2003 1:49 p.m. E-mail from Milka Radulovic, UDAQ to Steve Sands, CH2MHILL

1. UDAQ Comment: *Table 2-1 is for the worst case coal - bituminous. The lines above the table (page 2-7) states that the boiler will be designed to use blend of sub-bituminous and bituminous. Shouldn't the table reflect this?*

IPSC Response: The Unit 3 emission estimates, BACT analysis and air quality modeling have to be based on the worst case design coal from a pollutant emission rate standpoint. The permit application and all supporting information is based on the design coal summarized in Table 2-1 and discussed further in the Appendix I white paper on coal supply. However, in order to guarantee a supply of acceptable coals, the unit will be designed with flexibility to burn other bituminous and sub-bituminous coals.

UDAQ Follow-up Comment: *Let me ask the question: Why is this case (bituminous) the worst case and what are expected changes in any emissions presented in the IPP NOI when bituminous and subbituminous coals are blended? Mercury?*

IPSC Follow-up Response: The primary coal proposed for IPP Unit 3 would fall into the category of bituminous coal. The worst-case coal analysis is not based on a particular coal or a particular blend of bituminous coals and subbituminous coals. The worst-case coal analysis is based on worst-case pollutant producing characteristics of all coals and coal types (primarily bituminous) for which Unit 3 is being designed to burn. As has been previously discussed with DAQ, it is difficult to predict specific coals or blends that may be available to burn over the life of the project (see coal technology discussion presented in Section 1 of Appendix I). As a result, a worst-case analysis of the types of coals that Unit 3 will be designed to burn was performed. This worst-case Unit 3 design coal analysis serves as a basis for Unit 3 emission calculations.

The Unit 3 mercury emissions are conservatively based on the mercury content of coals proposed for IPP Unit 3. The mercury content of the coals proposed for Unit 3 range from as low as 0.02 ppm by weight to 0.15 ppm by weight. Because Unit 3 is not yet constructed, boiler test data is not available, thus emission estimates were based on worst-case design coal mercury content the range of coals that IPP Unit 3 will be designed to burn over the life of the plant.

July 8, 2003 5:43 p.m. E-mail from Milka Radulovic, UDAQ to Steve Sands, CH2MHILL

This e-mail was a follow-up e-mail to a telephone conversation between Steve Sands, CH2MHILL and Milka Radulovic, UDAQ. Item 1 below is a clarification of the UDAQ Follow-up Comment 1 to the June 9 IPSC Response 1 summarized in the June 30, 2003 6:36 p.m. e-mail from Milka Radulovic, UDAQ to Steve Sands, CH2MHILL described above.

1. UDAQ Clarification to Follow-up Comment 1 (from response to Comment 1 on June 9 e-mail): *As we talked today, my question about back calculations is based on the text in the IPP NOI page 6-21, under the Fabric Filters, second paragraph which says:*

   "Fabric filtration is a constant-emission control device. Pressure drop across the filters, inlet particulate loading, or changes in gas volumes may change the rate of filter cake buildup, but will not change the final emission rate. Actual performance of a fabric-filter depends on specific items such as air/cloth ratio, permeability of the filter cake, the loading and nature of the particles (e.g., irregular-shaped or spherical), particle size distribution, and to some extent, the frequency of the cleaning cycle. "

   If the statement in this paragraph correct, why the baghouse efficiency has increased?

IPSC Response: DAQ is correct, the removal efficiency was back calculated. The statements in the NOI are also correct. The outlet emission rate (0.015 lb/MMBtu) does not change with inlet loading. This outlet emission rate is driven by the physical design of the baghouse and the type of fabric filter technology that is implemented. The removal efficiency, however, is a function of inlet loading and when the inlet loading increased due to the increase in the worst case design coal average maximum ash content, the removal efficiency increased slightly to reflect the change.

2. UDAQ Comment*: To establish the worst case scenario for the emissions from the Unit 3 and if the new mercury MACT applicability shall include fuel subcategory (bituminous, subbituminous, lignite), please provide what is the worst scenario for the IPP proposed coal blend (i.e. max percent of subbituminous coal in the blend and its characteristics relevant for the air emissions).*

IPSC Response: IPSC will comply with the final mercury MACT once promulgated. The worst-case coal analysis is not based on a particular coal or a particular blend of bituminous coals and subbituminous coals. The worst-case coal analysis is based on worst-case pollutant producing characteristics of all coals and coal types (primarily bituminous) for which Unit 3 is being designed to burn. As has been previously discussed with DAQ, it is difficult to predict specific coals or blends that may be available to burn over the life of the project (see coal technology discussion presented in Section 1 of Appendix I). As a result, a worst-case analysis of the types of coals that Unit 3 will be designed to burn was performed. This worst-case Unit 3 design coal analysis serves as a basis for Unit 3 emission calculations.

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APPENDIX I-9

Mercury MACT

IPP Unit 3 Air Permit Application: Review of Mercury Permit Conditions (revised)

IPP Unit 3 Air Permit Application
Review of Mercury Permit Conditions (revised)

PREPARED FOR: Milka Radulovic, UDAQ

PREPARED BY: CH2M HILL

DATE: September 8, 2003

The purpose of this memorandum is provide additional information to support the Mercury MACT analysis (Section 6.4) in the IPP Unit 3 permit application.

The uncontrolled annual emissions for the proposed IPP Unit 3 are 0.42 tons per year based on ICR test data and coal trace analysis data. The maximum achievable control efficiency is 77.65 percent based on the proposed baghouse and wet limestone scrubber design. This results in an estimated controlled mercury emission rate of 0.0215 lb/hr, 2.37 lb/10^{12} Btu heat input, or 0.09 tons per year. IPP believes that a permit emission limit for mercury is not required by the 40 CFR Part 63 case by case MACT rule, thus none is requested. The proposed unit will comply with Federal MACT standards for coal-fired boilers when promulgated.

The Division has requested that IPP supply information from other recently issued PSD permits concerning any permit conditions related to mercury. Nine PSD applications for pulverized coal-fired units have been issued since 1999. A summary of relevant mercury permit conditions follows this introduction.

The only facility with a lower proposed mercury emission rate or higher mercury removal efficiency is the permit issued for MidAmerican CBEC Unit 4 in Council Bluffs, Iowa. The MidAmerican permit analysis estimated that the proposed lime spray dryer and fabric filter would remove 35% of the uncontrolled mercury from the coal. The Iowa Department of Natural Resources established a permit limit that was based on 80% mercury removal with the addition of an activated carbon injection system.

The IPP Mercury MACT analysis differs from the analysis conducted for MidAmerican in several key areas. MidAmerican Unit 4 is designed to burn PRB subbituminous coal. IPP Unit 3 will burn western bituminous coals. Based on the ICR database, subbituminous coals with lime spray dryer/fabric filter, as proposed at MidAmerican, 35% mercury control is achievable. The IPP design with western bituminous coal and fabric filter/wet limestone FGD will result in 77.65% mercury control (as demonstrated during IPP stack testing). The MidAmerican project is to start construction this month. Because the start of construction was before the issuance of the proposed federal MACT standards for utility coal-fired boilers, IDNR was uncomfortable with deferring a MACT determination. IPP will not start construction of Unit 3 until after the MACT standards are proposed. Thus, IPP feels that that the request to delay the issuance of a mercury emission limitation in the permit until the federal MACT standards are proposed, is appropriate.

Kansas City Power and Light, Hawthorne Unit 5, Missouri

At the time this PSD permit was issued (8/17/1999), a Case by Case MACT determination was not required per 40 CFR Part 63. The facility is major for HAPs. The applicant's only requirement was to submit estimated HAP emissions. The estimated net emissions increase of Mercury emissions was 0.05 tons/year.

Tucson Electric Power, Springerville Units 3 and 4, Arizona

The State of Arizona Department of Environmental Quality (ADEQ) performed a MACT analysis for this application during the permit review process. ADEQ set a mercury lb/MMBtu limit based on the range of mercury in the design coals for Units 3 and 4 and the mercury removal efficiency demonstrated across the lime spray dryers and baghouses on the existing Units 1 and 2. Units 3 and 4 will utilize similar controls. The permit has the following conditions related to Mercury.

III.A Unit 3 and Unit 4 Emission Limits and Standards

Condition 10 Mercury Emission Standard

a. The Permittee shall not cause to be discharged into the atmosphere from the stack of Unit 3 and Unit 4 any gases which contain mercury in excess of 0.0000069 lb per million Btu heat input derived from the combustion of fuel. Compliance with this emission limit shall be determined using a three hour averaging period.

b. The mercury emission standard in Specific Condition III.A.10.a above shall apply at all times except during periods of startup, shutdown or malfunction.

III.D Unit 3 and Unit 4 Testing Requirements

Condition 10 Mercury

a. The Permittee shall perform initial and annual performance tests on Unit 3 and Unit 4 to determine compliance with the mercury emission limitation in Specific Condition III.A.10.a of Attachment "B".

b. Each performance test for mercury shall be performed using EPA Reference Method 29.

c. The Permittee shall develop and submit to the Director a site-specific test plan in accordance with the provisions of 40 CFR 63.7(c) at least 60 days prior to each scheduled performance test required by Specific Condition III.D.10.a above.

Sand Sage Power, LLC, Holcomb Unit 2, Kansas

Sand Sage Power provided information in the permit application to the State of Kansas Department of Health & Environment (KDHE) that the facility was a minor source of HAPs thus a MACT analysis was not required. There is not a mercury emission limitation in the permit. Within 180 days after initial startup of the Holcomb Unit 2 boiler, the permittee will be required to conduct performance tests to verify that HAP emissions do not exceed 10 tons per year of any individual HAP or 25 tons per year of combined HAPs.

Thoroughbred Generation Company LLC, Thoroughbred Units 1 and 2, Kentucky

Thoroughbred conducted a case by case MACT determination. The State of Kentucky Department for Environmental Protection issued a permit with the following Mercury permit conditions.

Section B Emission Points, Emission Units, Applicable Regulations, and Operating Conditions

Condition 2 Emission Limitations

k. Pursuant to Regulations 401 KAR 51:017, mercury emissions shall not exceed 0.00000321 lb/MMBtu from each unit based on a quarterly average.

m. Pursuant to 40 CFR 63.43(d) case-by-case MACT determination, each pulverized coal fired steam electric generating unit, shall not exceed the following hazardous air pollutants (HAP) emission limitations listed below:

Mercury 0.1047 tons/year per unit

Condition 3 Testing Requirements

e. Case-by-Case MACT Requirements
Pursuant to 40 CFR 63.43(g)(2)(ii), case-by-case MACT determination, the permittee shall demonstrate compliance with the applicable emissions limitations for the following HAPs in the table below:

Mercury Method 29

f. Pursuant to 40 CFR 63.43(g)(2)(ii) case-by-case MACT determination, the permittee shall demonstrate compliance with these emission limitations within 60 days after achieving the maximum production rate at which the facility will be operated, but not later than 180 days after initial startup of these emission units.

g. Pursuant to Regulation 401 KAR 52:020, Section 10, during the initial compliance test, the permittee shall take a sample of the fuel "as fired" and analyze it to determine the HAP content in the fuel. This information shall be used to establish a correlation between the sample's HAP content and HAP emissions for monitoring purposes. The permittee shall demonstrate compliance with these emissions limits annually to validate the correlation between grab samples HAP content and HAP emissions.

Black Hills Corporation, Wygen Unit 2, Wyoming

Black Hills conducted a case by case MACT determination. The State of Wyoming Department for Environmental Quality (WDEQ) determined that the proposed air pollution controls (Low NO_x burners, SCR, Lime Spray Dryers and Baghouses) were MACT for mercury and other HAPs. WDEQ did not place a permit limitation on mercury but estimated emissions were 0.0000122 lb/MMbtu or 0.275 tons per year. The following condition related to mercury is in the WDEQ issued permit.

Condition 10 The following testing shall be performed and a written report of the results submitted within 90 days after initial start-up:

D. PC Boiler exhaust shall be tested prior to control devices and at the PC Boiler Stack to determine emissions of metals (antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, mercury, nickel and selenium) and control efficiencies using EPA Method 29 or equivalent methods. Results of the tests shall be reported in the units of lb/hr and control efficiencies.

Roundup Power, Roundup Unit 1, Montana

The State of Montana Department of Environmental Quality (MDEQ) deferred the MACT determination until after the construction permit was issued. Therefore there are no emission limitations or conditions related to Mercury in the permit. It is felt that they will wait until the Federal MACT standards are proposed for coal-fired units.

Plum Point Energy Associates, LLC, Plum Point Unit 1, Arkansas

The final permit was issued by the Arkansas Department of Environmental Quality (ADEQ) on August 20, 2003. ADEQ determined that the MACT standard for Mercury will be to control emissions to 12.8 lb/trillion Btu using a SCR/dry scrubber/fabric filter control equipment combination. The controls are estimated to remove 34.2% of the uncontrolled mercury emissions. There are no specific testing or compliance demonstration conditions in the permit.

Rocky Mountain Power, Hardin Unit 1, Montana

Rocky Mountain Power provided information in the permit application to the State of Montana Department of Environmental Quality (MDEQ) that the facility was a minor source of HAPs thus a MACT analysis was not required. There is not a mercury emission limitation in the permit.

MidAmerican Energy, Council Bluffs Energy Center Unit 4, Iowa

MidAmerican Energy submitted a MACT analysis as part of the permit application. The facility is major for HAPs. The State of Iowa Department of Natural Resources (IDNR) determined that MACT was 80% mercury removal of the uncontrolled mercury emissions with the addition of activated carbon injection. The lime spray dryer and baghouse account for approximately 35% mercury removal with the remaining 45% (of the 80%) from the activated carbon injection system. The mercury emission limit is based on the uncontrolled mercury emission rate (worst case design coal) times the 80% removal efficiency. The specific conditions related to mercury in the permit are as follows:

Condition 10b 112 Emission Limits

Mercury 1.7×10^{-6} lb/MMBtu, average of three test runs

Condition 14 Operating Limits

I. The minimum activated carbon feed rate shall be 10 pounds per million cubic feet of exhaust gas or a rate specified for one of the trials of the optimization study required under condition M of this section. Deviation from the minimum 10 pounds per million cubic feet of exhaust gas shall only occur for the duration of a given trial. At the end of each trial, the injection rate must be returned to a minimum of 10 pounds per million cubic feet.

M. Optimization studies are required for the control of SO_2, NO_x and Hg. These studies shall evaluate the affects of increased activated carbon injection, increased injection of slurry in the spray dryer absorber, and the optimization of the operation of the SCR unit.

P. A compliance test for mercury must be conducted once annually.

(1) Stack test must be performed according to method outlined in section 12 of this permit.

(2) A test report must be submitted to the Department according to the schedule outlined in Section 8 of this permit.

(3) Testing must be completed once every calendar year with a minimum of nine months between each test.

Condition 15 Operating Condition Monitoring

M. The following information must be kept concerning the activated carbon injection system.

(1) A continuous record of the activated carbon feed rate in pounds per million cubic feet of exhaust gas.

(2) A copy of the approved optimization protocol.

(3) A record of the time each trial of the optimization study begins and ends and enough information to identify which trial is being undertaken during that period.

P. A copy of the final test results for each compliance test for mercury shall be maintained.

Condition 17 Notice of MACT Approval Information