State of Idaho
Department of Environmental Quality
Air Quality Division

AIR QUALITY PERMIT
STATEMENT OF BASIS

Permit to Construct No. P-2008.0066

Final

Southeast Idaho Energy, LLC

Power County Advanced Energy Center

American Falls, Idaho

Facility ID No. 077-00029

February 10, 2009

Cheryl A. Robinson, P.E.

Permit Writer

The purpose of this Statement of Basis is to satisfy the requirements of IDAPA 58.01.01.200, Rules for the Control of Air Pollution in Idaho, for issuing air permits.

Table of Contents

List of Tables

Acronyms, Units, and Chemical Nomenclature

acfm	actual cubic feet per minute
AFS	AIRS Facility Subsystem
AGR	acid gas removal
AIRS	Aerometric Information Retrieval System
AP-42	EPA's Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources, accessible at http://www.epa.gov/ttn/chief/ap42/
AQCR	Air Quality Control Region
AQMD	Air Quality Management District
ASTM	American Society for Testing and Materials
ASU	air separation unit
BACT	Best Available Control Technology
Btu	British thermal unit
CAA	Clean Air Act
CEMS	continuous emission monitoring system
CFR	Code of Federal Regulations
CH_4	methane
CI ICE	compression-ignition internal combustion engine (i.e., a diesel engine)
CO	carbon monoxide
CO_2	carbon dioxide
COS	carbonyl sulfide
CROMERR	Cross-Media Electronic Reporting Regulation
DEQ	Department of Environmental Quality
DRE	destruction removal efficiency
EPA	U.S. Environmental Protection Agency
^oF	degrees Fahrenheit
FR	Federal Register
GE	General Electric Company
g/hp-hr	grams per horsepower per hour
g/kW-hr	grams per kilowatt per hour
gpm	gallons per minute
gr/dscf	grain (1 lb = 7,000 grains) per dry standard cubic foot
H_2	hydrogen
H_2S	hydrogen sulfide
HAP	Hazardous Air Pollutant
HC	hydrocarbons
HP	high pressure (steam)
hp	horsepower
IDAPA	a numbering designation for all administrative rules in Idaho promulgated in accordance with the Idaho Administrative Procedures Act
IP	intermediate pressure (steam)
K	degrees Kelvin
KBR	KBR, Inc. (formerly Kellogg, Brown & Root)
km	kilometer
kPa	kilopascals
kW	kilowatt
LAER	lowest achievable emission rate
lb/hr	pound per hour
lb/MMBtu	pound per million British thermal units
LP	low pressure (steam)
m	meter(s)
MACT	Maximum Achievable Control Technology
$\mu g/m^3$	micrograms per cubic meter

MJ	megajoules
MMBtu	million British thermal units
MMBtu/hr	million British thermal units per hour
MW or MW_e	megawatts of electrical output
NESHAP	National Emission Standards for Hazardous Air Pollutants
NFPA	National Fire Protection Association
ng/J	nanograms per Joule
NH_3	ammonia
NMHC	nonmethane hydrocarbons
NO_2	nitrogen dioxide
NO_x	nitrogen oxides
NSPS	New Source Performance Standards
O_2	oxygen
PAH	polyaromatic hydrocarbon
PC	permit condition
PCAEC	Power County Advanced Energy Center
PEMS	predictive emission monitoring system
petcoke	petroleum coke
PM	particulate matter
$PM_{2.5}$	particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers
PM_{10}	particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers
POM	polucyclic organic matter
ppm	parts per million
ppmv	parts per million by volume
PSA	pressure swing adsorber
PSD	Prevention of Significant Deterioration
psi	pounds per square inch
psig	pounds per square inch gauge
PTC	permit to construct
PTE	potential to emit
RBLC	RACT/BACT/LAER Clearinghouse
RICE	reciprocating internal combustion engine
Rules	Rules for the Control of Air Pollution in Idaho
scf	standard cubic feet
SCR	selective catalytic reduction
SIC	Standard Industrial Classification
SIE	Southeast Idaho Energy, LLC
SIP	State Implementation Plan
SO_2	sulfur dioxide
SO_x	sulfur oxides
SRC##	emission source number
TAP	Toxic Air Pollutant
TCEQ	Texas Commission on Environmental Quality
TPD	tons per calendar day
TPH	tons per hour
TPY	tons per 12 consecutive calendar months
UAN	urea ammonium nitrate
UOP	UOP (a Honeywell company)
UTM	Universal Transverse Mercator
VOC	volatile organic compound
VOLs	volatile organic liquids

WP	Worley Parsons
WSA	wet gas sulfuric acid (process)
ZLDS	zero liquid discharge system

1. FACILITY INFORMATION

1.1 Facility Description

The Power County Advanced Energy Center (PCAEC) will be located in Power County, approximately 4 kilometers (km) southwest of American Falls and 45 km southwest of Pocatello. The facility will produce fertilizer products through the gasification of coal and petcoke. Gasification is a process in which carbon, hydrogen, and water react with oxygen in a large high-pressure vessel to form synthesis gas, or syngas. Syngas is primarily a mixture of carbon monoxide (CO), carbon dioxide (CO_2), and hydrogen (H_2). Sulfur compounds and water vapor are also present in the syngas. The CO_2 and H_2 components are the building blocks used to manufacture the fertilizer products. A pure H_2 stream is used to manufacture ammonia (NH_3), which is used to produce other nitrogen-based fertilizers.

The paragraphs in each permit section provide an overview of the facility, sources of emissions, and emission control technologies. For a more detailed discussion of the chemical processes and simplified block flow diagrams, please refer to Section 2 of the application submitted on April 29, 2008, and to Application Addenda Nos. 1, 2, 3, and 4.

1.2 Permitting History

This is the initial PTC for this facility.

2. APPLICATION SCOPE AND CHRONOLOGY

2.1 Application Scope

Southeast Idaho Energy, LLC (SIE) is proposing to construct a new facility to gasify coal and petcoke to produce ammonia, urea, and urea ammonium nitrate (UAN). The major components and proposed feed and product production rates are described in Section 1.1.

2.2 Application Chronology

April 29, 2008	Receipt of PTC application. The $1,000 PTC application fee submitted on July 24, 2007 for the P-2007.0151 application, which was withdrawn on April 29, 2008, was applied to this project.
July 3, 2008	Receipt of Addendum #1 to add an option for a Claus Sulfur Recovery Unit and Steam Superheater, with a modeling analysis for this option.
July 30-31, 2008	Receipt of Addendum #2, with revised modeling to reflect manufacturer guarantee for reduced particulate emissions from the cooling tower. The required certification for the submittal was received on August 11, 2008.
August 11, 2008	Application determined to be complete.
September 1, 2008	Preliminary draft permit and statement of basis issued for peer review and facility review.
September 5, 2008	Minor comments received from peer review.
September 8, 2008	Comments received from facility. Discussed by phone on September 9.

September 17, 2008	Draft permit and statement of basis to peer review, regional review, and facility review.
September 18, 2008	Comments received from facility.
September 19, 2008	Minor comments received from peer review. Regional office had no comments.
September 22, 2008	Draft permit and statement of basis posted on DEQ website.
September 22, 23, and 24, 2008	Informational meetings in Pocatello, American Falls, and Fort Hall.
September 24, 2008	Public comment period begins.
September 30, 2008	Receipt of $10,000 PTC processing fee.
October 9, 2008	Public hearing in American Falls.
October 14, 2008	Receipt of Sierra Club request to extend comment period by 60 days.
October 20, 2008	Information meeting and public hearing in Pocatello.
October 22, 2008	Notice published extending the comment period by 30 days, with Director approval, to November 24, 2008.
November 24, 2008	Public comment period ends.
December 5, 2008	Director notified that additional time beyond December 9, 2008 would be needed to respond to all comments. Proposed due date for decision on the permit was set to January 16, 2009.
December 10, 2008	Receipt of Addendum #3, which deleted the Haldor-Topsoe sulfuric acid plant option. A Claus sulfur recovery unit will be used to produce elemental sulfur.
December 24, 2008	DEQ requested additional information from SIE to provide additional clarification for responding to public comments. A response was requested within 14 days (i.e., by January 7, 2009).
January 7, 2009	DEQ approved SIE's email request to extend the due date for the response to January 9, 2009.
January 9, 2009	Receipt of Addendum #4, SIE response to DEQ's December 24, 2008 information request.
February 6, 2009	DEQ determines that an additional public comment period is not warranted.
February 10, 2009	Final permit issued.

3. TECHNICAL ANALYSIS

3.1 Emission Unit and Control Device

The information contained in Table 3.1 summarizes the design basis upon which the permit has been issued. Minimum capture efficiencies for control equipment reflect approximate control levels. See the summary of BACT limits in Table 4.12 of this statement of basis for a summary of specific emission limits.

Table 3.1 EMISSION UNIT AND CONTROL DEVICE INFORMATION

Emission Unit /ID No.	Description	Control Device/Emission Point
Feedstock Handling: Coal, Petcoke, and Fluxant		
Fluxant Handling	Railcar Unloading (see SRC01), or Truck Unloading (fugitives) Hopper to Fluxant Silo(s) (fugitives and silo vent [SRCxx]) Silo(s) to Rod Mill Hopper (fugitives) Note: SIE's application treated all fluxant handling emissions as fugitives. However, the permit requires a control device for silo filling, so a placeholder [SRCxx] has been used for that point source ID.	Fully enclosed storage silo(s), with <u>Silo vent baghouse/cartridge filter:</u> Mfr/Model: TBD PM/PM_{10} Control: 99% Covered conveyor(s) with enclosed transition points. Enclosed transition points include providing a connecting boot or equivalent for truck unloading. Water sprays or equivalent, minimum 75% control for fugitives. <u>Stack Parameters, Fluxant Silo Vent(s) Baghouse:</u> Stack Height: TBD Exit Diameter: TBD Orientation: TBD Exit flow rate: TBD Exit Velocity: TBD Exit Temperature: Ambient
Coal and Petcoke Handling <u>Railcar Unloading (SRC01)</u>	Manufacturer: TBD Model: TBD Max Capacity: 5,000 TPH max unloading rate Operations: 8,760 hr/yr	Rotary dumping system. Railcar unloading structure with restricted end door openings. Enclosure is at negative pressure during transfers. <u>High-efficiency Baghouse:</u> Mfr/Model: TBD PM/PM_{10} Control: 99% <u>Stack Parameters, SRC01:</u> Stack Height: 10.0 m (32.8 ft) Exit Diameter: 1.2 m (3.9 ft) Orientation: vertical Exit flow rate: 20,000 acfm Exit Velocity: 10 m/sec Exit Temperature: Ambient

Table 3.1 EMISSION UNIT AND CONTROL DEVICE INFORMATION

Emission Unit /ID No.	Description	Control Device/Emission Point
Railcar Hopper – Railcar Conveyor (SRC02) Railcar Conveyor to Silo Conveyors (SRC03) Silo Conveyor – Stacker Conveyors (SRC04)	Manufacturer: TBD Model: TBD Max Capacity: 5,000 TPH max rate (each) Operations: 8,760 hr/yr (each)	Covered conveyors with enclosed transition points. High-efficiency Baghouse (each): Mfr/Model: TBD PM/ PM_{10} Control: 99% Stack Parameters, SRC02, SRC03, and SRC04: Stack Height: 5.0 m (16.4 ft) (SRC02, SRC03) Stack Height: 2.0 m (6.6 ft) (SRC04) Exit Diameter: 1.2 m (3.9 ft) Orientation: vertical Exit flow rate: 20,000 acfm Exit Velocity: 10 m/sec Exit Temperature: Ambient
Coal and Petcoke Storage: Silos 1, 2, and 3 (SRC06, SRC07, and SRC05)	Manufacturer: Eurosilo or equivalent Model: TBD Max Fill Rate: 5,000 TPH (each) Operations: 8,760 hr/yr (each)	Baghouses (1 for each silo): Mfr/Model: TBD PM/PM_{10} Control: 99% Silo Vent Parameters SRC06, SRC07, SRC05: Vent Stack Height: 57.0 m Exit Diameter: 1.2 m (3.9 ft) Orientation: vertical Exit flow rate: 20,000 acfm Exit Velocity: 10 m/sec Exit Temperature: Ambient
Silo 1 Reclaimer to Reclaim Conveyor 1 (SRC08) Silo 2 Reclaimer to Reclaim Conveyor 2 (SRC09) Silo 3 Reclaimer to Reclaim Conveyor 3 (SRC10)	Manufacturer: TBD Model: TBD Max Capacity: 105 TPH max unloading rate (each) Operations: 8,760 hr/yr (each)	Covered conveyors with enclosed transition points. Baghouses (1 for each reclaimer): Mfr/Model: TBD PM/PM_{10} Control: 99% Stack Parameters: SRC08, SRC09, and SRC10 Stack Height: 53.0 m Exit Diameter: 1.2 m (3.9 ft) Orientation: vertical Exit flow rate: 20,000 acfm Exit Velocity: 10 m/sec Exit Temperature: Ambient
Reclaim Conveyor to Rod Mill Hopper #1 (SRC11) Reclaim Conveyor to Rod Mill Hopper #2 (SRC12)	Manufacturer: TBD Model: TBD Max Capacity: 105 TPH max unloading rate (each) Operations: 8,760 hr/yr	Covered conveyors with enclosed transition points. Baghouses (1 for each hopper): Mfr/Model: TBD PM/ PM_{10} Control: 99% Stack Parameters: SRC11 and SRC12 Stack Height: 10.0 m Exit Diameter: 1.2 m (3.9 ft) Orientation: vertical Exit flow rate: 20,000 acfm Exit Velocity: 10 m/sec Exit Temperature: Ambient

Table 3.1 EMISSION UNIT AND CONTROL DEVICE INFORMATION

Emission Unit /ID No.	Description	Control Device/Emission Point
Natural Gas-Fired Heaters		
ASU Regen Heater (SRC13)	Manufacturer: TBD Model: TBD Max Heat Input: 100,000 Btu/hr Fuel: Natural Gas Operations: 8,760 hr/yr	None Stack Parameters, SRC13: Stack Height: 4.0 m (13.1 ft) Exit Diameter: 0.05 m (0.16 ft) Orientation: vertical Exit flow rate: 37 acfm Exit Velocity: 9.0 m/sec Exit Temperature: 355 K (179.3^{o}F)
Gasifier Heater #1 and Gasifier Heater #2 (SRC14 and SRC15)	Manufacturer: TBD Model: TBD Startup: 25.5 MMBtu/hr avg (each) Standby: 9 MMBtu/hr avg (each) Fuel: Natural Gas Operations: 8,760 hr/yr (each)	None Gasifier Heater Vent #1 and Vent #2 Stack Parameters, SRC14, SRC15: Stack Height: 51.8 m (170 ft) Exit Diameter: 0.5 m (1.64 ft) Orientation: vertical Exit flow rate: 5,309 acfm Exit Velocity: 15.3 m/sec Exit Temperature: 811 K (1000.1^{o}F)
Diesel-Fired Emergency Generators		
2,000 kW (2 MW) Emergency Engine Generator (SRC25)	Manufacturer: Caterpillar or equivalent Model: TBD Max Rating: Nominal 2 MW output Displacement: < 10 liters per cylinder Emissions: Minimum EPA Tier 2 Fuel: Distillate fuel oil (Diesel) Operations: Maximum 100 hr/yr	None Emergency Generator Stack Parameters, SRC25: Stack Height: 10.1 m (33.0 ft) Exit Diameter: 0.6 m (2.0 ft) Orientation: vertical Exit flow rate: 15,136 acfm Exit Velocity: 24.5 m/sec Exit Temperature: 679 K (762.5^{o}F)
500 kW Emergency Engine Generator (Fire Pump) (SRC26)	Manufacturer: Caterpillar or equivalent Model: Nominal 500 kW output Displacement: < 10 liters per cylinder Emissions: EPA Tier 3 (for a gen set not meeting NFPA 20) 40 CFR 60, Subpart IIII (NFPA 20 fire pump) Fuel: Distillate fuel oil (Diesel) Operations: Maximum 100 hr/yr	None Firewater Pump Engine Generator Stack Parameters, SRC26: Stack Height: 4.6 m (15.0 ft) Exit Diameter: 0.3 m (1.0 ft) Orientation: vertical Exit flow rate: 3,842 acfm Exit Velocity: 24.9 m/sec Exit Temperature: 779 K (942.5^{o}F)
Gaseous Fuel-Fired Boilers		
Package Boiler (SRC24)	Manufacturer/Model: TBD Max Rating: 250 MMBtu/hr heat input Heat Release Rate: (High or Low, TBD) Operation: During startup and shutdown only Operations: 8,760 hr/yr at full rating (combined with Steam Superheater hours) Fuel: Natural Gas Sulfur Content: 2.0 gr/100 dscf	Low-NO_x burner and Flue Gas Recirculation (FGR) Purpose: NO_X reduction Efficiency: 95% control for NO_X Package Boiler Stack Parameters, SRC24: Stack Height: 33.5 m (110 ft) Exit Diameter: 1.8 m (5.9 ft) Orientation: vertical Exit flow rate: 52,282 acfm Exit Velocity: 10.3 m/sec Exit Temperature: 422 K (299.9^{o}F)

Table 3.1 EMISSION UNIT AND CONTROL DEVICE INFORMATION

Emission Unit /ID No.	Description	Control Device/Emission Point
Steam Superheater Boiler (SRC31)	Manufacturer/Model: TBD Max Rating: 250 MMBtu/hr heat input Heat Release Rate: (High or Low, TBD) Operations: 8,760 hr/yr at full rating (combined with Package Boiler hours) Fuel: Natural Gas (max 250 MMBtu/hr) Heat Content: ~1,020 Btu/scf Sulfur Content: 2.0 gr/100 dscf PSA Tailgas (max 250 MMBtu/hr) Heat Content: ~250 Btu/scf Sulfur Content: 25 ppmv	Low-NO_X burner and Selective Catalytic Reduction (SCR) Manufacturer/Model: TBD Purpose: NO_x reduction Efficiency: ~97% control for NO_X Ammonia slip: $\leq$ 10 ppmv (dry), corrected to 15% O_2 Steam Superheater Stack Parameters, SRC31: Stack Height: 33.50 m (109.9 ft) Exit Diameter: 1.8 m (5.9 ft) Orientation: vertical Exit flow rate: 52,282 acfm Exit Velocity: 10.3 m/sec Exit Temperature: 422 K (299.9^{o}F)
Gasifier Island		
Gasifier #1 and Gasifier #2 Gasifier and Quench Vessel	Manufacturer: GE Quench gasifier or equivalent Capacity: Up to 5,000 TPD coal/petcoke blend Feedstock: Maximum 6% sulfur coal/petcoke blend Coal/petcoke/fluxant wet slurry O_2 (from the ASU)	Control: No add-on controls. Fugitive (pipe/valve leak) emissions only. Fugitive emission BMPs for CO.
Syngas Cleanup Train:	Sour Water Scrubber (process equipment) Manufacturer/Model: TBD Scrubbing media: sour water Activated Carbon Beds (process equipment) Manufacturer/Model: TBD Purpose: Mercury removal Design Efficiency: 95% removal	Startup/Upsets: Amine Scrubber: Manufacturer/Model: TBD Feedstock: sour syngas from the carbon beds Purpose: Control sulfur compound emissions Scrubber Parameters: TBD Design Efficiency: 95% removal (as SO_2) Gasifier Flare: Flare type: smokeless (air or steam assist required only if unassisted flare produces smoke). Pilot fuel: natural gas Flare gas: sweet syngas Maximum capacity: ~900,000 lb/hr of sweet syngas Operations: 8,760 hr/yr on natural gas pilot Syngas flaring only during startup, shutdown, and upsets Design Efficiency: 98% for CO Gasifier Flare Stack Parameters, SRC16: Stack Height: 65.0 m (213.3 ft) Exit Diameter: 0.38 m (0.92 ft) Orientation: vertical Exit flow rate: 182 acfm Exit Velocity: 20.0 m/sec Exit Temperature: 1,273 K (1,832 ^{o}F) Normal Operations: No add-on controls. Fugitive (pipe/valve leak) emissions only. BMPs for fugitive CO from gasifier to last shift reactor.

Table 3.1 EMISSION UNIT AND CONTROL DEVICE INFORMATION

Emission Unit /ID No.	Description	Control Device/Emission Point
Syngas Cleanup Train:	Acid Gas Removal Unit AGR Stream 1: H_2S and CO_2 Claus Sulfur Recovery Unit: Manufacturer/Model: TBD Tailgas: Hydrotreater to Sour Shift inlet	None (no emission points). Fugitive (pipe/valve leak) emissions only.
Syngas Cleanup Train:	Acid Gas Removal Unit AGR Stream 2: CO_2 Vent (CO, H_2S, and COS/VOCs)	Thermal Oxidizer: Mfr/Model: CSM Worldwide or equivalent Maximum Capacity: 300,000 lb/hr CO_2 Burner Type: Direct-fired Rating: 9 MMBtu/hr Fuel: Natural gas Catalyst: Type: Low-Temperature Life: ~ 3-5 years Cleaning Frequency: ~ 6 months Cleaning Method: offsite regeneration Operations: 8,760 hr/yr Design Efficiency: 95% for CO, COS, and H_2S AGR CO_2 Vent Stack Parameters, SRC17 Stack Height: 52.0 m (171 ft) Exit Diameter: 1.34 m (4.4 ft) Orientation: vertical Exit flow rate: 54,000 acfm Exit Velocity: 18.0 m/sec Exit Temperature: 359 K (186.5^{o}F)
Syngas Cleanup Train:	Acid Gas Removal Unit AGR Stream 3: Syngas Syngas Stream: H_2 (90 mole%), CO_2 (5 mole%), CO, methane, inerts, and < 1 ppm H_2S and COS	None. Fugitive (pipe/valve leak) emissions only.
Syngas Cleanup Train:	Pressure Swing Adsorber (PSA)	None. Fugitive (pipe/valve leak) emissions only.
Ammonia and Urea Plants		
Ammonia Synthesis Loop and Refrigeration System	Capacity: ~2,000 tons per day (ammonia)	Process Flare: Flare type: smokeless (air or steam assist required only if unassisted flare produces smoke(. Pilot fuel: natural gas Flare gas: Ammonia system purge gases and urea process off-gases Process Flare Stack Parameters, SRC21: Stack Height: 52.0 m (171 ft) Exit Diameter: 0.43 m (1.4 ft) Orientation: vertical Exit flow rate: 252 acfm Exit Velocity: 20.0 m/sec Exit Temperature: 1,273 K (1,832 ^{o}F) Fugitive (pipe/valve leak) emissions.

Table 3.1 EMISSION UNIT AND CONTROL DEVICE INFORMATION

Emission Unit /ID No.	Description	Control Device/Emission Point
Urea Process	Stamicarbon or equivalent. Urea reactor vessel, steam stripper, decomposers, evaporator(s), ammonia receiver/condenser, carbamate absorber/condensers, multi-stage compressor(s), pumps, valves, piping, and instrumentation. Capacity: 2,400 tons per day (liquid solution)	Process Flare: Flare type: smokeless (air or steam assist required only if unassisted flare produces smoke). Pilot fuel: natural gas Flare gas: Ammonia system purge gases and urea process off-gases Process Flare Stack Parameters, SRC21: - see above Urea Melt Plant: None Urea Melt Plant Vent Stack Parameters, SRC23: Stack Height: 34.0 m (112 ft) Exit Diameter: 1.22 m (4.0 ft) Orientation: vertical Exit flow rate: 136,900 acfm Exit Velocity: 55.3 m/sec Exit Temperature: 318 K (112.7 ^{o}F) Fugitive (pipe/valve leak) emissions.
Urea Granulation	Manufacturer: Uhde or equivalent. Capacity: 1,800 tons per day granulated urea Wet Scrubber (process equipment) Manufacturer/Model: TBD Purpose: PM/PM_{10} capture and recycling Scrubber Parameters: TBD Design Efficiency: 98%	None. Granulation Vent Stack Parameters, SRC19: Stack Height: 40 m (131ft) Exit Diameter: 1.8 m (6.0 ft) Orientation: vertical Exit flow rate: 296,500 acfm Exit Velocity: 53.3 m/sec Exit Temperature: 323 K (121.7^{o}F) Fugitive (pipe/valve leak) emissions.
Granulated Urea Storage, Transfers, and Loadout	Humidity-controlled warehouse storage	Negligible fugitive PM/PM_{10} emissions only.
Nitric Acid and Ammonium Nitrate/Urea Ammonium Nitrate Plants		
Nitric Acid Plant	Manufacturer/Provider: Weatherly or equivalent Capacity: ~575 TPD of nitric acid	SCR: Manufacturer/Model: TBD Operating Parameters: TBD Efficiency: 98% for NO_x (max. 50 ppmv) Ammonia slip: $\leq$ 10 ppmv (dry), corrected to 15% O_2 Nitric Acid Tailgas Stack Parameters, SRC20: Stack Height: 58.0 m (190 ft) Exit Diameter: 1.16 m (3.8 ft) Orientation: vertical Exit flow rate: 60,500 acfm Exit Velocity: 27.1 m/sec Exit Temperature: 400 K (260.3 ^{o}F) Fugitive (pipe/valve leak) emissions.

Table 3.1 EMISSION UNIT AND CONTROL DEVICE INFORMATION

Emission Unit /ID No.	Description	Control Device/Emission Point
Ammonium Nitrate/UAN Plant	Manufacturer/Provider: Weatherly or equivalent Capacity: ~715 TPD of ammonium nitrate ~1,600 TPD of UAN A wet scrubber is integral to the process, but must recover and recycle a minimum of 90% of PM/PM_{10} present within the process.	None. AN Neutralizer Vent Stack Parameters, SRC29: Stack Height: 16.0 m (52.5 ft) Exit Diameter: 0.3 m (1.0 ft) Orientation: vertical Exit flow rate: 14,123 acfm Exit Velocity: 91.4 m/sec Exit Temperature: 344 K (159.5 ^{o}F) Fugitive (pipe/valve leak) emissions.
Diesel, Ammonia, Nitric Acid, and UAN Tank Storage		
Emergency Engine Generator Fuel Tank	Tank 19, Diesel Storage Tank Contents: #2 Diesel fuel Capacity: 3,000 gallons Turnovers: 1 per year Type: Horizontal Shell length: 10.0 ft Shell Diameter: 7.50 ft Paint: Gray/Light Paint Condition: Good	None. Tank vent(s)
Emergency Fire Pump Engine Fuel Tank	Tank 18, Diesel Storage Tank Contents: #2 Diesel fuel Capacity: 500 gallons Turnovers: 1 per year Type: Horizontal Shell length: 5.0 ft Shell Diameter: 5.0 ft Paint: Gray/Light Paint Condition: Good	None. Tank vent(s)
Ammonia Storage Tanks (2)	Capacity: 204,000 barrels (each) (6.426 million gallons each) Type: Vertical fixed roof Insulated atmospheric pressure tanks Size: Shell height 41 ft, Diameter 45 ft Service Equipment: Ammonia compressors Fuel: Electric utility	Ammonia Storage Flare Flare type: smokeless (air or steam assist required only if unassisted flare produces smoke). Pilot fuel: natural gas Ammonia Storage Flare Parameters, SRC27: Stack Height: 18.29 m (60.0 ft) Exit Diameter: 0.20 m (0.66 ft) Orientation: vertical Exit flow rate: 129 acfm Exit Velocity: 20.0 m/sec Exit Temperature: 1,273 K (1,832^{o}F)
Nitric Acid Storage Tank	Capacity: 16,000 barrels (504,000 gallons) Type: Vertical fixed roof Atmospheric pressure tank Size: Shell height 45 ft, Diameter 50 ft	None. Tank vent(s)
UAN Storage Tanks (4)	Contents: UAN Capacity: 110,000 barrels (each) (4.5 million gallons each) Type: Vertical fixed roof Atmospheric pressure tanks Size: Shell height 42 ft, Diameter 130 ft	None. Tank vent(s)

Table 3.1 EMISSION UNIT AND CONTROL DEVICE INFORMATION

Emission Unit /ID No.	Description	Control Device/Emission Point
Zero Liquid Discharge System (ZLDS) and Cooling Tower		
Zero Liquid Discharge System (ZLDS)	Plant wastewater treatment system cooling tower Manufacturer: SPX Cooling Technologies or equivalent Type: TBD Cooling Water Flow Rate: 985 gpm TDS: 50,000 mg/L	Drift/mist eliminators PM/PM_{10} limited to max 0.001% of total circulating water flow ZLDS Stack Parameters, SRC30: Stack Height: 8.0 m (26.4 ft) Exit Diameter: 2.3 m (7.54 ft) Orientation: vertical Exit flow rate: 235,387 acfm Exit Velocity: 27.1 m/sec Exit Temperature: 317 K (110.9 ^oF)
Cooling Tower	Plant water cooling system. Manufacturer: SPX Cooling Technologies or equivalent Type: Mechanical Draft Cooling Tower Cooling Water Flow Rate: 121,000 gpm TDS: 5,000 mg/L	Drift/mist eliminators PM/PM_{10} limited to max 0.0005% of total circulating water flow Cooling Tower Stack Parameters, SRC22: Stack Height: 13.0 m (42.6 ft) Equivalent Exit Diameter: 22.6 m (74.1 ft) Orientation: vertical Exit flow rate: 1,289,000 acfm Exit Velocity: 8.3 m/sec Exit Temperature: 303 K (85.7 ^oF)
Slag and Solid Byproduct Handling		
Slag Storage and Handling	Gasifier slag is transferred wet to the storage pile.	Fugitives Storage pile enclosed on 3 sides. BMPs for fugitive PM/PM_{10}.
Granular Urea Storage	Storage in humidity-controlled warehouse.	None.
Elemental Sulfur Storage	Storage tank(s)	None.

3.2 Emissions Inventory

DEQ reviewed the emissions inventory submitted by the applicant and determined that it represented reasonable estimated emissions for all sources. Detailed information for the emissions inventory is included in Appendix B to this statement of basis.

3.2.1 Uncontrolled Emissions

Using the information provided by the applicant, DEQ calculated the uncontrolled emission rates for the project scope including all addenda to the application. The uncontrolled emission rates shown in Table 3.2 and were based on the following assumptions:

- Feedstock delivery and handling was based on no control equipment and operations at maximum capacity for 8,760 hours per year.
- The controlled emissions from the ASU Regen heater and the gasifier heaters were based on operating 8,760 hours per year. Uncontrolled emissions equal the controlled emissions.
- Emissions from the 2 MW and 500 kW emergency generators were based on operating at maximum capacity for 8,760 hours per year.

- No 95% control for NO_x emissions from the combined operations of the package boiler and steam superheater boiler. Each boiler was presumed to operate at maximum capacity for 8,760 hours per year.
- The syngas cleanup train is an integral part of the process, not control equipment. This includes the quench, sour water scrubber, and activated carbon beds. Uncontrolled emissions equal the controlled emissions.
- Controlled emissions from the gasifier flare during steady state operations were based on burning the natural gas pilot for 8,760 hours per year. Uncontrolled emissions equal the controlled emissions.
- Controlled emissions from the process flare and ammonia flare operations were based on burning the natural gas pilot for 8,760 hours per year, and burning purge gases based on the maximum proposed production capacity for these processes. Uncontrolled emissions equal the controlled emissions.
- No 95% thermal oxidizer control for CO or COS from the AGR CO_2 vent.
- SIE's controlled emissions of H_2S from the AGR CO_2 vent did not take credit for any destruction in the thermal oxidizer. Uncontrolled emissions equal the controlled emissions.
- No 98% SCR control for NO_x from the nitric acid plant tailgas vent.
- The wet scrubber is an integral part of the AN neutralizer process, not control equipment. Uncontrolled emissions equal the controlled emissions.
- The wet scrubber is an integral part of the urea granulation process, not control equipment. Uncontrolled emissions equal the controlled emissions.
- Uncontrolled drift/mist from the cooling tower and zero liquid discharge system cooling tower were based on a drift/mist rate of 0.02% of the total circulating flow (AP-42, Table 134.-1 (1/95)).

A summary of uncontrolled emissions from each source is included in Appendix B to this statement of basis.

Table 3.2 UNCONTROLLED EMISSIONS ESTIMATES OF CRITERIA POLLUTANTS

Emissions Source	PM_{10}	SO_2	NO_x	CO	VOC	LEAD
	T/yr	T/yr	T/yr	T/yr	T/yr	T/yr
Point Sources	473	19	4,429	947	12.4	0.0012
Fugitive Sources	3	---	---	31	2.2E-04	---
TOTAL	**476**	**19**[a]	**4,429**	**978**	**12.4**	**0.0012**

[a] The uncontrolled emissions of SO_2 are less than the controlled emissions because uncontrolled emissions do not include using the thermal oxidizer on the AGR CO_2 vent, which converts H_2S and COS to SO_2.

The uncontrolled facility-wide emission rates of HAPs shown in Table 3.3 were based on the same assumptions described above. As shown in the table the uncontrolled emission rates of all HAPs is less than 25 tons per year. However, the proposed project is a synthetic minor source for HAPs because the uncontrolled emissions of COS are greater than 10 tons per year. A summary of uncontrolled HAP/TAP emissions from each source is included in Appendix B to this statement of basis.

Table 3.3 UNCONTROLLED EMISSIONS OF HAPS

Hazardous Air Pollutants and Toxic Air Pollutants	Uncontrolled Emissions (TPY)	Notes
2-Methylnaphthalene	2.80E-05	Compound is a PAH HAP, a subset of Polycyclic Organic Matter (POM)
Acetaldehyde	2.69E-03	
Acrolein	8.42E-04	
Arsenic	2.33E-04	
Benzene	8.54E-02	
Cadmium	1.28E-03	
Chromium	1.63E-03	
Cobalt	9.81E-05	
Carbonyl sulfide (COS)	16.3	
Dichlorobenzene	1.40E-03	
Fluoranthene	3.57E-06	Compound is part of the 15-PAH group (POM)
Fluorene	3.27E-06	Compound is part of the 15-PAH group (POM)
Formaldehyde	9.60E-02	
Hexane	2.10	
Lead	5.84E-04	
Manganese	4.44E-04	
Mercury	3.04E-04	
Naphthalene	1.46E-02	
Nickel	2.45E-03	
Polyaromatic Hydrocarbons (PAH)	2.27E-02	PAH HAP (POM)
Phenanthrene	1.98E-05	PAH HAP (POM)
Pyrene	5.84E-06	PAH HAP (POM)
Toluene	3.40E-02	
Xylene	2.06E-02	
TOTAL	**18.66**	

Uncontrolled facility-wide emission rates of state-regulated TAPs shown in Table 3.3 were based on the same assumptions described above. The first step in evaluating TAPs emissions is a comparison of the uncontrolled emission rates with the applicable screening emission level (EL) listed in Section 585 or 586 of the Rules. No further analysis is required for a TAP if the uncontrolled emissions are less than the EL. For TAPs with uncontrolled emission rates in excess of the ELs, the next step is to compare the controlled emissions with the ELs (see Table 3.6).

Table 3.4 UNCONTROLLED TAPs EMISSIONS SUMMARY

Toxic Air Pollutant	HAP?	TAP Averaging Period	Uncontrolled Emission Rate (lb/hr)	IDAPA Screening EL (lb/hr)	Emissions Exceed EL?
Noncarcinogenic TAPs					
Ammonia (NH_3)	No	24-hour	139	1.2	Yes
Carbonyl sulfide (COS)	Yes	24-hour	3.72	0.027	Yes
Chromium (total, presumed as Cr II and III)	Yes	24-hour	3.73E-04	3.3E-02	No
Coal dust. Sources: Coal handling.[a]	No	24-hour	Not estimated	0.133	Presume Yes
Cobalt	Yes	24-hour	6.18E-08	3.3E-03	No
Crystalline silica. Sources: Coal and sand fluxant handling	No	24-hour	Not estimated	0.667	Presume Yes
Dichlorobenzene	Yes	24-hour	3.20E-04	20	No

Table 3.4 UNCONTROLLED TAPs EMISSIONS SUMMARY

Toxic Air Pollutant	HAP?	TAP Averaging Period	Uncontrolled Emission Rate (lb/hr)	IDAPA Screening EL (lb/hr)	Emissions Exceed EL?
Hexane	Yes	24-hour	0.48	12	No
Hydrogen sulfide (H_2S)	No	24-hour	0.44	0.933	No
Lead	Yes	---	1.33E-04	---	---
Manganese	Yes	24-hour	1.01E-04	6.7E-02	No
Mercury	Yes	24-hour	6.93E-05	1.0E-03	No
Nitric acid (HNO_3)	No	24-hour	0.94	0.333	Yes
Nitrous oxide (N_2O) Source: Nitric acid unit tailgas vent	No	24-hour	See Comment 59	6	See Comment 59
Toluene	Yes	24-hour	7.76E-03	25	No
Xylene	Yes	24-hour	4.71E-03	29	No
Carcinogenic TAPs					
Acetaldehyde	Yes	Annual	6.15E-04	3.0E-03	No
Acrolein	Yes	Annual	1.92E-04	1.70E-02	No
Arsenic	Yes	Annual	5.33E-05	1.5E-06	Yes
Benzene	Yes	Annual	1.95E-02	8.0E-04	Yes
Cadmium	Yes	Annual	2.93E-04	3.7E-06	Yes
Fluoranthene (PAH HAP)	Yes	Annual	8.16E-07	9.1E-05	No
Fluorene (PAH HAP)	Yes	Annual	7.46E-07	9.1E-05	No
Formaldehyde	Yes	Annual	2.19E-02	5.1E-04	Yes
2-Methylnaphthalene (PAH)	Yes	Annual	6.40E-06	9.1E-05	No
Naphthalene	Yes	Annual	3.33E-03	3.33	No
Nickel	Yes	Annual	5.6E-04	2.7E-05	Yes
Phenanthrene (PAH)	Yes	Annual	4.53E-06	9.1E-05	No
Polyaromatic hydrocarbons (PAHs)	Yes	Annual	5.17E-03	9.1E-05	Yes
POM, as defined in Rules Section 586 Sum of: benzo(a)pyrene, benzo(a)anthracene, benzo(b)fluoranthene, benzo(k)fluoranthene, dibenzo(a,h)anthracene, chrysene, indenol(1,2,3,-cd), pyrene, and benzo(a)pyrene	Yes	Annual	1.33E-06	2.0E-06	No

Compliance for N_2O emissions can be demonstrated using the uncontrolled ambient impact. If ambient impact from 300 ppmv N_2O emissions is scaled for an uncontrolled N_2O emission rate of 3500 ppmv, the “uncontrolled” ambient impact would be 0.47 mg/m^3. See the response to Comment 59 in the Response to Comments document for additional discussion. No further analysis for N_2O is required.

3.2.2 Controlled Emissions (Potential to Emit)

The controlled steady state emission rates (the potential to emit [PTE]) shown in Table 3.5 were based on the assumptions shown in Table 3.1 and in the emission inventory included in Appendix B to this statement of basis. Key assumptions used in estimating the PTE include:

- The sulfuric acid plant has been deleted from the project scope (Addendum No. 3).
- The natural gas-fired ASU regen heater operates at 0.1 MMBtu/hr, and the gasifier heaters each operate at 9 MMBtu/hr for 8,760 hours per year.
- The 2 MW and 500 kW diesel-fired emergency engine generators are each limited to 100 hours per year of operation for routine maintenance and testing.

- The emissions from the 250 MMBtu/hr package boiler and 250 MMBtu/hr steam superheater boiler, combined, do not exceed the emissions from a single gas-fired 250 MMBtu/hr boiler operated at maximum capacity for 8,760 hours per year. Low-NO_x burners and FGR (for the package boiler) and SCR (for the steam superheater boiler) provide a minimum of 95% control for NO_x when burning natural gas, and 97% control for NO_x when burning PSA tailgas.
- The syngas cleanup train is an integral part of the process. This includes the quench, sour water scrubber, and activated carbon beds. The carbon beds must be designed for a minimum 95% control efficiency for mercury.
- Controlled emissions from the gasifier flare during steady state operations were based on burning the natural gas pilot for 8,760 hours per year.
- Controlled emissions from the process flare and ammonia flare operations were based on burning the natural gas pilot for 8,760 hours per year, and burning purge gases based on the maximum proposed production capacity for these processes.
- A thermal oxidizer with a nominal 9 MMBtu/hr natural gas-fired heater provides 95% control for CO and COS from the AGR CO_2 vent. This is an increase from the 90% control estimated by SIE in their April 2008 application.
- The emissions inventory presumes no control for H_2S in the thermal oxidizer.
- An SCR unit controls NO_x emissions from the nitric acid plant tailgas vent to a maximum of 50 ppmv.
- The wet scrubber that is an integral part of the AN neutralizer process captures and recycles 90% of the PM/PM_{10} in the process.
- The wet scrubber is an integral part of the urea granulation process captures and recycles 98% of the PM/PM_{10} in the process.
- High-efficiency drift/mist eliminators limit PM/PM_{10} emissions to 0.0005% of the total circulating flow from the cooling tower, and 0.001% of the total circulating flow from the ZLDS cooling tower. For the cooling tower, this represents a reduction in emissions estimated by SIE in their April 2008 application, which were based on drift/mist of 0.001% of the total circulating flow.

The April 2008 application PTE totals for point sources, fugitive sources, and total facility-wide emissions are included in the table for comparison. As shown in the table, the deletion of the sulfuric acid plant and increased efficiency of controls for the cooling tower and AGR CO_2 vent resulted in significantly lower PTE for the proposed project compared to the April 2008 emission estimates. This is important to note because SIE demonstrated compliance with the applicable National Ambient Air Quality Standards (NAAQS) based on the higher emission rates contained in the April 2008 application. See the discussion in Section 3.3 of this statement of basis.

Table 3.5 CONTROLLED EMISSIONS ESTIMATES OF CRITERIA POLLUTANTS (POTENTIAL TO EMIT)

Emissions Unit	PM_{10}		SO_2		NOx		CO		VOC		LEAD
	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	
Point Sources Affected by this Permitting Action											
Feedstock Handling: Coal, Petcoke, and Fluxant											
Railcar Unloading (SRC01)	0.0435	0.004	---	---	---	---	---	---	---	---	---

Table 3.5 CONTROLLED EMISSIONS ESTIMATES OF CRITERIA POLLUTANTS (POTENTIAL TO EMIT)

Emissions Unit	PM_{10}		SO_2		NOx		CO		VOC		LEAD
	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	
Railcar Hopper to Conveyor (SCR02)	0.041	0.004	---	---	---	---	---	---	---	---	---
Railcar Conveyor to Silo Conveyor (SRC03)	0.041	0.004	---	---	---	---	---	---	---	---	---
Silo Conveyor to Stacker Conveyor (SRC04)	0.041	0.004	---	---	---	---	---	---	---	---	---
Silo 1 Vent (SRC06)	0.041	0.004	---	---	---	---	---	---	---	---	---
Silo 2 Vent (SRC07)	0.041	0.004	---	---	---	---	---	---	---	---	---
Silo 3 Vent (SRC05)	0.041	0.004	---	---	---	---	---	---	---	---	---
Silo 1 Reclaimer – Reclaim Conveyor (SRC08)	0.0008	0.004	---	---	---	---	---	---	---	---	---
Silo 2 Reclaimer – Reclaim Conveyor (SRC09)	0.0008	0.004	---	---	---	---	---	---	---	---	---
Silo 3 Reclaimer – Reclaim Conveyor (SRC10)	0.0008	0.004	---	---	---	---	---	---	---	---	---
Reclaim Conveyor to Rod Mill Hopper #1 (SRC11)	0.0008	0.004	---	---	---	---	---	---	---	---	---
Reclaim Conveyor to Rod Mill Hopper #2 (SRC12)	0.0008	0.004	---	---	---	---	---	---	---	---	---
Fluxant Silo Filling	0.0025	0.0005									
Natural Gas-Fired Heaters											
ASU Regen Heater (SRC13)	0.0007	0.0033	0.0001	0.0003	0.005	0.021	0.008	0.036	0.001	0.005	---
Gasifier Heater Vent #1 (SRC14)	0.067	0.294	0.053	0.232	0.882	3.865	0.741	3.246	0.049	0.213	---
Gasifier Heater Vent #2 (SRC15)	0.067	0.294	0.053	0.232	0.882	3.865	0.741	3.246	0.049	0.213	---
Diesel-Fired Emergency Engine Generators											
2 MW Emergency Generator (SRC25)	0.154	0.008	0.979	0.049	31.841	1.592	1.713	0.086	0.650	0.032	
500 kW Emergency Generator (Fire Pump), (SRC26)	0.027	0.001	0.256	0.013	8.477	0.424	0.591	0.030	0.015	0.0007	
Gaseous Fuel-Fired Boilers											
Package Boiler (SRC24)	1.25	5.48	1.43	6.26	5.00	21.90	18.50	81.03	1.00	4.38	0.0001 lb/hr 0.0006 T/yr
Steam Superheater Boiler (SRC31)											

Table 3.5 CONTROLLED EMISSIONS ESTIMATES OF CRITERIA POLLUTANTS (POTENTIAL TO EMIT)

Emissions Unit	PM_{10}		SO_2		NOx		CO		VOC		LEAD
	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	
Gasification Island											
Gasifier Flare (SRC16) Steady State	0.011	0.048	0.008	0.036	0.100	0.438	0.509	2.230	0.014	0.061	---
Selexol AGR CO2 Vent (SRC17)	---	---	3.76	16.49	0.88	3.86	8.66	37.95	---	---	---
Sulfuric Acid Vent (SRC18) - Deleted from Project Scope	---	---	---	---	---	---	---	---	---	---	---
Ammonia and Urea Plants											
Process Flare (SRC21)	0.06	0.25	0.008	0.037	1.31	5.76	1.30	5.69	0.044	0.194	---
Urea Melt Plant Vent (SRC23)	---	---	---	---	---	---	---	---	---	---	---
Urea Granulation Vent (SRC19)	9.00	39.42	---	---	---	---	---	---	---	---	---
Urea Granulation Loadout	---	---	---	---	---	---	---	---	---	---	---
Nitric Acid and Ammonium Nitrate/UAN Plants											
Nitric Acid Unit – Tailgas (SRC20)	---	---	---	---	15.33	67.16	---	---	---	---	---
Ammonium Nitrate Neutralizer Vent (SRC29)	1.49	6.52	---	---	---	---	---	---	---	---	---
Diesel, Ammonia, Nitric Acid, and UAN Tank Storage											
Ammonia Storage Flare (SRC27)	0.005	0.024	0.004	0.018	0.050	0.219	0.255	1.115	0.010	0.043	---
Process Water Cooling Towers											
Cooling Tower (SRC22)	1.51	6.63	---	---	---	---	---	---	---	---	---
ZLDS System (SRC30)	0.25	1.08	---	---	---	---	---	---	---	---	---
Total, Point Sources FINAL 2009	**14.2**	**60.1**	**6.6**	**23.4**	**64.8**	**109.1**	**33.0**	**134.7**	**1.8**	**5.1**	**0.0001 lb/hr 0.0006 T/yr**
Total, Point Sources SIE April 2008 Application	**15.4**	**66.7**	**8.6**	**32.3**	**68.8**	**126.7**	**48.5**	**202.6**	**1.8**	**5.1**	**0.0001 lb/hr 0.0006 T/yr**
Process Fugitive/Volume Sources Affected by this Permitting Action											
Fluxant Handling											
Fluxant Unloading (from trucks)	0.054	0.010	---	---	---	---	---	---	---	---	---

Table 3.5 CONTROLLED EMISSIONS ESTIMATES OF CRITERIA POLLUTANTS (POTENTIAL TO EMIT)

Emissions Unit	PM_{10}		SO_2		NOx		CO		VOC		LEAD
	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	
Fluxant Hopper to Fluxant Silos	0.0081	0.0015	---	---	---	---	---	---	---	---	---
Fluxant Silos to Rod Mill Hopper	0.0003	0.0015	---	---	---	---	---	---	---	---	---
Slag Handling											
Slag Dewatering to Slag Storage Pile	0.0049	0.0215	---	---	---	---	---	---	---	---	---
Slag Storage Pile	0.0196	0.0859	---	---	---	---	---	---	---	---	---
Slag Storage Truck Loading	0.0049	0.0215	---	---	---	---	---	---	---	---	---
Gasification and Syngas Cleanup Process Fugitives											
Valves – gas	---	---	---	---	---	---	3.43	15.03	---	---	---
Valves – Lt Liquid	---	---	---	---	---	---	0.032	0.139	---	---	---
Pump Seals – Lt Liquid	---	---	---	---	---	---	0.00	0.00	---	---	---
Compressor Seals	---	---	---	---	---	---	1.80	7.86	---	---	---
Pressure Relief Valves	---	---	---	---	---	---	0.66	2.87	---	---	---
Connectors	---	---	---	---	---	---	1.10	4.83	---	---	---
Open-Ended Lines	---	---	---	---	---	---	0.007	0.03	---	---	---
Sampling Connections	---	---	---	---	---	---	0.06	0.26	---	---	---
Ammonia, Urea, and UAN Process Fugitives											
Valves – gas	---	---	---	---	---	---	---	---	---	---	---
Valves – Lt Liquid	---	---	---	---	---	---	---	---	---	---	---
Pump Seals – Lt Liquid	---	---	---	---	---	---	---	---	---	---	---
Compressor Seals	---	---	---	---	---	---	---	---	---	---	---
Pressure Relief Valves	---	---	---	---	---	---	---	---	---	---	---
Connectors	---	---	---	---	---	---	---	---	---	---	---
Open-Ended Lines	---	---	---	---	---	---	---	---	---	---	---
Sampling Connections	---	---	---	---	---	---	---	---	---	---	---
Fuel Storage Tanks											
2 MW Generator Diesel Tank (TNK19)	---	---	---	---	---	---	---	---	2.4E-05	1.1E-04	---
500 kW Generator Diesel Tank (TNK18)	---	---	---	---	---	---	---	---	2.4E-05	1.1E-04	---
Total Fugitives FINAL 2009	**0.09**	**0.14**	---	---	---	---	**7.08**	**31.0**	**4.8E-05**	**2.2E-04**	---
Total Fugitives, SIE April 2008 Application	**0.43**	**0.20**	---	---	---	---	**7.08**	**31.0**	**4.8E-05**	**2.2E-04**	---

Table 3.5 CONTROLLED EMISSIONS ESTIMATES OF CRITERIA POLLUTANTS (POTENTIAL TO EMIT)

Emissions Unit	PM_{10}		SO_2		NOx		CO		VOC		LEAD
	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	
Potential to Emit for this Permitting Action											
TOTAL PTE, FINAL 2009	**14.3**	**60.2**	**6.6**	**23.4**	**64.8**	**109.1**	**40.1**	**165.7**	**1.8**	**5.1**	**0.0006 T/yr**
TOTAL PTE, SIE April 2009 Application	**15.8**	**66.9**	**8.6**	**32.3**	**68.8**	**126.7**	**55.6**	**233.6**	**1.8**	**5.1**	**0.0006 T/yr**
Difference in PTE from 2008 Application to 2009 Final	**-9.8%**	**-9.9%**	**-23.7%**	**-27.6%**	**-5.8%**	**-13.9%**	**-27.9%**	**-29.1%**	**0.0%**	**0.0%**	**0.0%**

"---" = pollutant is not emitted or is emitted in negligible amounts

As described in Section 3.2.1 above, further evaluation is needed for TAPs with uncontrolled emissions in excess of the applicable EL. The comparison of the controlled emission rate with the EL for TAPs carried through from Table 3.4 is shown in Table 3.6. The controlled facility-wide emission rates of TAPs shown in this table were based on the same assumptions described above for steady-state operations. Modeling is required for emissions of toxic air pollutants that exceed the applicable EL (see Section 3.3 for a discussion of the modeling results).

The final column in this table summarizes the potential to emit for federally-regulated HAP. The total emissions of federally-regulated HAPs is shown at the bottom of the table. A summary of controlled HAP/TAP emissions from each source is included in Appendix B to this statement of basis.

Table 3.6 CONTROLLED HAPs/TAPs EMISSIONS SUMMARY (POTENTIAL TO EMIT)

Toxic Air Pollutant	HAP?	Averaging Period	Emission Rate (lb/hr)	IDAPA Screening EL (lb/hr)	Modeling Required?	HAPs PTE (T/yr)
Noncarcinogenic TAPs						
Ammonia (NH_3)	No	24-hour	139	1.2	Yes	---
Carbonyl sulfide (COS)	Yes	24-hour	0.186	0.027	Yes	0.81
Chromium (total, presumed as Cr II and III)	Yes	---	3.73E-04	---	---	1.63E-03
Coal dust. Sources: Coal handling.[a]	No	24-hour	> 0.133	0.133	No[a]	---
Cobalt	Yes	---	2.24E-05	---	---	9.81E-05
Crystalline silica. Sources: Coal and sand fluxant handling [a]	No	24-hour	0.440	0.667	No[a]	---
Dichlorobenzene	Yes	---	3.20E-04	---	---	1.40E-03
Hexane	Yes	---	4.80E-01	---	---	2.10
Hydrogen sulfide (H_2S)	No	---	0.44	---	---	---
Lead	Yes	---	1.33E-04	---	---	5.84E-04
Manganese	Yes	---	1.01E-04	---	---	4.44E-04
Mercury	Yes	---	6.93E-05	---	---	3.04E-04
Nitric acid (HNO_3)	No	24-hour	0.936	0.333	Yes	---
Nitrous oxide (N_2O) Source: Nitric acid unit tailgas vent	No	---	88	---	---	---
Toluene	Yes	---	7.76E-03	---	---	4.31E-03
Xylene	Yes	---	4.71E-03	---	---	2.35E-04
Carcinogenic TAPs						
Acetaldehyde	Yes	---	6.15E-04	---	---	3.07E-05
Acrolein	Yes	---	1.92E-04	---	---	9.61E-06

Table 3.6 CONTROLLED HAPs/TAPs EMISSIONS SUMMARY (POTENTIAL TO EMIT)

Toxic Air Pollutant	HAP?	Averaging Period	Emission Rate (lb/hr)	IDAPA Screening EL (lb/hr)	Modeling Required?	HAPs PTE (T/yr)
Arsenic	Yes	Annual	5.33E-05	1.5E-06	Yes	2.33E-04
Benzene	Yes	Annual	1.95E-02	8.0E-04	Yes	3.40E-03
Cadmium	Yes	Annual	2.93E-04	3.7E-06	Yes	1.28E-03
Fluoranthene (PAH HAP)	Yes	---	8.16E-07	---	---	3.57E-06
Fluorene (PAH HAP)	Yes	---	7.46E-07	---	---	3.27E-06
Formaldehyde	Yes	Annual	2.19E-02	5.1E-04	Yes	8.76E-02
2-Methylnaphthalene (PAH)	Yes	---	6.40E-06	---	---	2.80E-05
Napththalene	Yes	---	3.33E-03	---	---	8.71E-04
Nickel	Yes	Annual	5.60E-04	2.7E-05	Yes	2.45E-03
Phenanthrene (PAH)	Yes	---	4.53E-06	---	---	1.98E-05
Polyaromatic hydrocarbons (PAHs)	Yes	Annual	5.17E-03	9.1E-05	Yes	2.6E-04
POM, as defined in Rules Section 586 Sum of: benzo(a)pyrene, benzo(a)anthracene, benzo(b)fluoranthene, benzo(k)fluoranthene, dibenzo(a,h)anthracene, chrysene, indenol(1,2,3,-cd), pyrene, and benzo(a)pyrene	Yes	---	1.33E-06	---	---	5.84E-06
					TOTAL HAPs PTE .	**3.02**

[a] See the response to Comment 55 in the Response to Comments document for a more detailed discussion.

3.3 Ambient Air Quality Impact Analysis

DEQ reviewed in detail the ambient air quality impact analyses submitted by the applicant but did not rerun any of the modeling. For PSD projects, applicants are required to provide information as required for potential impacts on air quality from criteria pollutants emitted by the facility, air quality impacts from growth associated with the facility, and potential impacts to visibility, soils, and vegetation. Because the maximum impacts from the proposed project were below significant, however, a number of these requirements do not apply.

A detailed discussion of DEQ's modeling review and an evaluation of the applicant's submittal regarding additional impacts for a project subject to PSD is included in Appendix C to this statement of basis.

DEQ determined that the ambient air quality impact analysis submitted demonstrated to DEQ's satisfaction that emissions from the facility, as represented by the applicant in the permit application, will not:

- Cause or significantly contribute to a violation of any air quality standard in the attainment or unclassified Class II area surrounding the facility. This means that the ambient impacts from point sources at the PCAEC are less than the significant contribution levels defined in IDAPA 58.01.01.006, as shown in Table 3.7. These values reflect the modeled ambient impacts submitted with the April 29, 2008 application, and are conservative (i.e., likely overestimate the ambient impacts from the proposed project) because:
    - As a result of increasing the efficiency of the drift/mist eliminators on the cooling tower (see Addendum No. 2 to the application), the PM/PM_{10} emissions from this source dropped by half, and the following emissions were eliminated from the project:

      1.5 lb/hr and 6.7 T/yr of PM/PM_{10}.

- As a result of deleting the sulfuric acid plant from the project scope (see Addendum No. 3 to the application), the following emissions were eliminated from the project:

  6.8 lb/hr and 29.9 T/yr of CO; 4.0 lb/hr and 17.6 T/yr of NO_x, and 2.2 lb/hr and 9.8 T/yr of SO_2.

- As a result of increasing the destruction efficiency from 90% to 95% for the AGR CO_2 thermal oxidizer (see Addendum No. 4 to the application), the following emissions were eliminated from the project:

  8.7 lb/hr and 38 T/yr of CO; 0.19 lb/hr and 0.8 T/yr of COS, and a decrease in H_2S emissions (not calculated).

  This change also resulted in a small increase in SO_2 emissions of 0.2 lb/hr and 0.9 T/yr.

The comparison of the criteria pollutant emission rates from the April 2008 application and the permitted emission rates shown in Figure 3.1 illustrates that the project emissions have been reduced for these criteria pollutants compared to the values modeled in the original application.

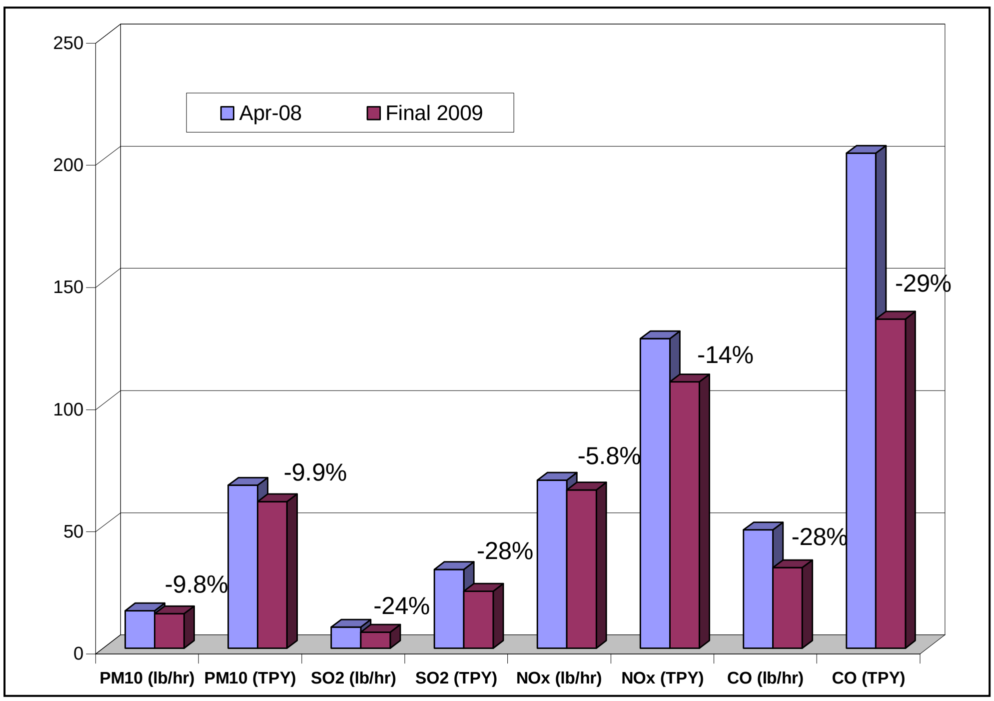

Figure 3.1 COMPARISON OF APRIL APPLICATION AND 2009 PERMIT PTE

- Cause or significantly contribute to a violation of any air quality standard in the existing PM_{10} nonattainment area located on Shoshone-Bannock tribal lands to the east of the proposed PCAEC.
- Be required to include the impacts from other nearby sources in the modeling analysis. As discussed in Section 4.4 of this statement of basis, the PCAEC project is subject to Prevention of Significant Deterioration (PSD) review, which includes potentially needing to evaluate the combined impact from the proposed facility (in this case, the PCAEC) and other nearby major emissions sources (in this case, the ConAgra/Lamb Weston plant located just to the north of the proposed PCAEC). Because the predicted ambient impacts from the PCAEC are below significant, however, modeling the combined impacts from these two facilities was not required.

Table 3.7 RESULTS OF SIGNIFICANT IMPACT ANALYSES

Pollutant	Averaging Period	Maximum Modeled Concentration[a] ($\mu g/m^3$)[b]	Significant Contribution Level ($\mu g/m^3$)	Percentage of Significant Contribution Level	Is a Full Impact Analysis Required?	Must Modeling Include Co-Contributing Sources?
PM_{10}	24-hour	4.92	5.0	98%	No	No
	Annual	0.69	1.0	69%	No	No
SO_2	3-hour	17.88	25.0	72%	No	No
	24-hour	3.13	5.0	63%	No	No
	Annual	0.21	1.0	21%	No	No
NO_2	Annual	0.91	1.0	91%	No	No
CO	1-hour	308.63	2,000.0	15%	No	No
	8-hour	45.18	500.0	9%	No	No

[a] Values are modeling results obtained from the applicant's modeling analysis submitted on April 29, 2008.
[b] Micrograms per cubic meter

- Exceed any 24-hour average applicable ambient concentration (AAC) or annual-average applicable ambient concentration for carcinogens (AACC) for state-regulated toxic air pollutants (TAPs). The toxic air pollutants that were required to be modeled are listed in Table 3.6. Note that these values reflect the modeled TAPs impacts submitted with the April 29, 2008 application, except for ammonia, COS, and H_2S, as follows:
  - The NO_x emissions from the steam superheater proposed as part of the project in Addendum No. 1 will be controlled using selective catalytic reduction (SCR) rather than implementing flue gas recirculation (FGR) as proposed for the package boiler. A stream of ammonia is used in the SCR unit operations, so the ambient impact for ammonia for the operating scenario using a Claus sulfur recovery unit is slightly increased, from 40.09 µg/m3 to 40.63 µg/m3, compared to the operating scenario using a sulfuric acid plant.
  - As noted above, the increase in the thermal oxidizer destruction efficiency results in a decrease of COS and H_2S emissions.

Table 3.8 RESULTS OF TAPs ANALYSES

Toxic Air Pollutant	Averaging Period	Maximum Modeled Concentration ($\mu g/m^3$)[a]	AAC/AACC[b] ($\mu g/m^3$)	Percent of AAC/AACC
Noncarcinogenic TAPs				
Ammonia	24-hour	40.63[c]	900	4.5%
Carbonyl sulfide	24-hour	0.20	20	1.0%
Coal dust[d]	24-hour	< 5[d]	10	< 50%
Nitric acid	24-hour	0.69	250	0.3%
Nitrous oxide (N_2O) [e]	24-hour	470 [e]	4,500	10.4%
Sulfuric acid	24-hour	0.34	50	0.7%
Carcinogenic TAPs				
Arsenic	Annual	0.00	2.3E-04	0% (Negligible)
Benzene	Annual	9.0E-05	1.2E-01	0.08%
Cadmium	Annual	2.0E-05	5.6E-04	3.6%
Formaldehyde	Annual	1.3E-03	7.7E-02	1.7%
Nickel	Annual	4.0E-05	4.2E-03	1.0%
Polyaromatic hydrocarbons (PAHs)	Annual	1.0E-05	1.4E-02	0.07%

a. Micrograms per cubic meter

b Acceptable ambient concentration for non-carcinogens/acceptable ambient concentration for carcinogens

c Ammonia impact is slightly higher for the Claus elemental sulfur plant scenario. The Haldor-Topsoe wet sulfuric acid plant scenario maximum impact was 40.09 $\mu g/m^3$, 24-hour average.

d Compliance is demonstrated based on comparison with facility-wide modeling results. See the response to Comment 55 in the Response to Comments document for additional discussion

e Compliance is demonstrated using the uncontrolled ambient impact. See the response to Comment 59 in the Response to Comments document for additional discussion.

- Cause an unacceptable visibility impact on nearby mandatory Class I areas. Class I areas are places where visibility has been determined to be an important value, and includes international parks, national wilderness areas, national memorial parks, and national parks that were in existence as of August 7, 1977, when the Clean Air Act Amendments of 1977 were promulgated. The nearest mandatory Class I area to the proposed PCAEC site is the Craters of the Moon National Monument, located about 46 miles (74 km) away at its nearest point. As discussed in Section 4.4 of this statement of basis, the PCAEC project is subject to Prevention of Significant Deterioration (PSD) review, which includes potentially needing to evaluate the visibility impacts from the project's emissions on Class I areas.

  As discussed in the modeling memo contained in Appendix C to this statement of basis, the federal land managers did not require a Class I analysis (additional analysis using a long-range dispersion model) or a visibility analysis. This determination was made based on the relatively low emissions of pollutants that cause regional haze and the distance to the nearest boundary of a Class I area. As described in the modeling memo, the emissions used to make this determination included emissions from steady-state operation plus predicted emissions from 50 startups.

  DEQ concurred with this decision but did request that the applicant run a screening visibility analysis. The analysis confirmed that it was unlikely that emissions from the proposed PCAEC project would be visible from the Craters of the Moon National Monument.

4. REGULATORY REVIEW

4.1 Attainment Designation (40 CFR 81.313)

The facility is located in Power County which is designated as attainment or unclassifiable for PM_{10}, $PM_{2.5}$, CO, NO_2, SO_X, and Ozone. Reference 40 CFR 81.313.

4.2 Permit to Construct (IDAPA 58.01.01.201)

The proposed project does not meet the permit to construct exemption criteria contained in Sections 220 through 223 of the Rules. A PTC is therefore required.

4.3 Tier II Operating Permit (IDAPA 58.01.01.401)

The proposed project does not meet the criteria contained in Section 401 of the Rules. A Tier II operating permit is therefore not required.

4.4 Title V Classification (IDAPA 58.01.01.300, 40 CFR Part 70)

The proposed project has the potential to emit (PTE) greater than 100 tons per year each of CO and NO_x. In accordance with Section 008 of the Rules, the proposed PCAEC is a **major Title V facility**. In accordance with Section 313.01.b of the Rules, SIE must submit a complete application to DEQ for an initial Tier I operating permit within 12 months of becoming a Tier I source or commencing operation.

4.5 PSD Classification (40 CFR 52.21)

Federal Prevention of Significant Deterioration (PSD) requirements are incorporated by reference in Sections 200 and 107. The proposed project belongs to two of the 28 “designated facility” categories defined in Section 006 of the Rules: 1) the project is a fuel conversion plant because it converts coal into a synthetic gas (syngas) in a chemical process, and 2) the project is a chemical process plant because it processes syngas to make ammonia and other chemicals. The PTE for this proposed project is greater than 100 tons per year each for CO and NO_x. The proposed project is therefore **a major PSD facility** as defined in 40 CFR 52.21(b)(1)(i)(a) because it is a designated facility that has the potential to emit more than 100 tons per year of any regulated NSR pollutant. Because the proposed project is a major PSD facility for NO_x, it is also considered major for ozone, in accordance with 40 CFR 52.21(b)(1)(ii).

Fugitive emissions must be included when determining the PTE because the proposed project is included in two of the 28 categories listed in 40 CFR 52.21(b)(1)(iii).

4.6 NSPS Applicability (40 CFR 60)

Note: This section has been revised to reflect changes promulgated by the EPA and published as a final rule on January 28, 2009 to New Source Performance Standard (NSPS) Subpart Db.[1]

40 CFR 60 Subpart Db ....NSPS for Industrial, Commercial, and Institutional Steam Generating Units

40 CFR 60.40b(a), Applicability.

The Package Boiler and Steam Superheater will each commence construction after June 19, 1984 and after February 28, 2005. Each boiler will be rated at a nominal 250 megawatts per hour (MW/hr) heat input, so will have a heat input capacity of greater than 29 MW/hr (100 MMBtu/hr). Each of these boilers will be subject to Subpart Db provisions that apply to affected facilities that have been

[1] January 28, 2009, 74 FR 5072.

constructed after February 28, 2005. In accordance with 60.40b(j), because these boilers will be constructed after June 19, 1986, and are subject to Db, neither of the boilers is subject to Subpart D (Standards of Performance for Fossil-Fuel-Fired Steam Generators, §60.40).

60.41b, Definitions.

Annual capacity factor means the ratio between the actual heat input to a steam generating unit from the [natural gas and PSA tailgas], as applicable, during a calendar year and the potential heat input to the steam generating unit had it been operated for 8,760 hours during a calendar year at the maximum steady state design heat input capacity.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see 60.17), coal refuse, and petroleum coke. Coal-derived synthetic fuels, including but not limited to solvent refined coal, **gasified coal not meeting the definition of natural gas,** coal-oil mixtures, coke oven gas, and coal-water mixtures, are also included in this definition for the purposes of this subpart.

Gaseous fuel means any fuel that is a gas at ISO conditions. This includes, but is not limited to, natural gas and gasified coal (including coke oven gas).

Natural gas means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or

(2) Liquefied petroleum gas…; or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 34 and 43 megajoules (MJ) per dry standard cubic meter (910 and 1,150 Btu per dry standard cubic foot).

Is the PSA Tailgas "coal" for the purposes of Subpart Db?

The proposed project is proposing to use tailgas from the pressure swing adsorber (PSA) as fuel in one or more gas-fired boilers. Coal/petcoke are gasified to produce a synthetic gas, which is passed through a scrubber and carbon beds to remove contaminants. The syngas then passes through a sour shift reactor to maximize the amount of hydrogen available for ammonia production. Next, acid gases and CO_2 are removed from the syngas using Selexol technology. From the Selexol unit, the hydrogen-rich syngas goes to a pressure swing adsorber (PSA) unit. The PSA unit separates the hydrogen from the other syngas components, producing a stream of very pure hydrogen for use in ammonia production. The remaining syngas components, primarily nitrogen, hydrogen, CO, CO_2, argon, and methane, and trace amounts of sulfur compounds, exit the PSA in the "tailgas" stream.

The heat content of the PSA tailgas is described in the application as about 250 Btu per standard cubic foot (Btu/scf). The PSA tailgas is expected to be quite dry, so the heat content can be expected to be in the range of 250 Btu per dry scf. This heat content does not fall within the range of 910 to 1,150 Btu per dry standard cubic foot, and hence cannot be considered to be "natural gas."

Based on the process description provided in the application, although the syngas from the gasifiers goes through several processes before exiting the PSA unit, the PSA tailgas is still a coal-derived synthetic fuel. A previous EPA determination[2] that coke oven gas should be considered "coal" notes that the definition of coal in 60.41b is intended to be very broad, based on the use of the phrase "including but not limited to."

DEQ therefore has determined that the PSA tailgas is a coal-derived synthetic fuel and is regulated both as "coal" and as a "gaseous fuel," for the purposes of Subpart Db.

<u>60.42b, Standard for Sulfur Dioxide</u>.

60.42b(a) and (b). These sections apply only to boilers that commenced construction, reconstruction, or modification on or before February 28, 2005, so are not applicable to the proposed project.

60.42b(c) Does not apply because neither the package boiler nor the steam superheater will use an emerging technology for the control of SO_2 emissions.

60.42b(d) applies only to boilers that commenced construction, reconstruction, or modification on or before February 28, 2005, so are not applicable to the proposed project

60.42b(e) does not apply because neither boiler is subject to SO_2 emission limits and/or percent reduction requirements. See 60.42b(k)(2).

60.42b(f) does not apply because the annual capacity factor for oil for this boiler is not limited to 10 percent or less, and boiler fuels are not restricted to only very low sulfur fuel oil.

60.42b(g) which requires that the SO_2 emission limits and percent reduction requirements apply at all times, including periods of startup, shutdown, and malfunction does not apply because neither boiler is subject to SO_2 emission limits and/or percent reduction requirements. See 60.42b(k)(2).

60.42b(h) does not apply because the boilers are not subject to (c) of this section.

60.42b(i) does not apply because the boilers are not subject to (a), (b), or (c) of this section.

60.42b(j) does not apply because the boilers will not burn very low sulfur oil. 60.42b(k)(1) Does not apply. The boilers are exempt from the limits listed in (k)(1) per (k)(2).

60.42b(k)(2). Units firing only very low sulfur oil, gaseous fuel, a mixture of these fuels, or a mixture of these fuels with any other fuels with a potential SO_2 emission rate of 140 ng/J (0.32 lb/MMBtu) heat input or less are exempt from the SO_2 emissions limit in paragraph 60.42b(k)(1). As shown in Table 4.1, the SO_2 emission rate for natural gas and for the PSA tailgas to be used as fuel in these boilers is less than 0.32 lb/MMBtu. In addition, natural gas and PSA tailgas each are a "gaseous fuel" as defined in 40 CFR 60.41b. **These boilers are therefore exempt from the SO_2 emission limits listed in paragraph (k)(1), and by extension, these boilers are not subject to the SO_2 emission limits listed in paragraph (k)(1).**

[2] EPA Applicability Determination, Control No. 0000130, Subpart Db – Coke Oven Gas & Furnace Oven Gas Applicability, October 8, 1999, accessible at http://cfpub.epa.gov/adi. See Appendix D of this Statement of Basis.

Table 4.1 POTENTIAL SO_2 EMISSION RATES FOR NATURAL GAS AND PSA TAILGAS

Fuel	**Sulfur Content (as SO_2)**	**Conversion Factors**	**Approximate SO_2 Emission Rate (lb/MMBtu)**	**Approximate Percent of 0.32 lb/MMBtu Limit**
Natural Gas	2.0 gr/100 dscf	x 1 lb/7000 gr x scf/1020 Btu [a] x 10^6 Btu/MMBtu x (64 lb-mol SO_2/32.065 lb-mol S)=	0.006	1.9%
PSA Tail Gas	25 ppmv	(25 lb-mol SO_2/1x10^6 lb-mol gas) x (64 lb SO_2/lb-mol SO_2) x (lb-mol gas/379 scf) x (1 scf/250 Btu) x (1x 10^6 Btu/MMBtu) =	0.017	5.3%

[a] Presume scf is equal to dscf for these estimates. Most pipeline quality gas tariff agreements require that gas be delivered with negligible moisture content. Source for 1,020 Btu/scf: EPA AP-42, Section 1.4 (7/98).

Note: The maximum total sulfur content in natural gas is set in natural gas tariff agreements that must be approved by the Federal Energy Regulatory Commission (FERC). EPA rules contained in **40 CFR 72.2** define pipeline natural gas as “a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions, and which is provided by a supplier through a pipeline. **Pipeline natural gas contains 0.5 grains or less of total sulfur per 100 standard cubic feet.** Additionally, pipeline natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1100 Btu per standard cubic foot.”

60.43b, Standard for Particulate Matter.

The following paragraphs in 60.43b do not apply because the boilers:

(a)(1), (2), (3), (4) Will not be constructed before February 28, 2005.

(b) Do not combust oil.

(c) Do not combust wood.

(d) Do not combust municipal-type solid wastes.

60.43b(a)(1) applies when the boilers burn only coal (i.e., PSA tailgas) or has an annual capacity factor for natural gas of 10 percent or less, and limits the PM emissions to 22 ng/J (0.051 lb/MMBtu) for these cases.

60.43b(e) applies, and requires that for the purposes of this section, the annual capacity factor is determined by dividing the actual heat input to the steam generating unit during the calendar year from the combustion of coal (PSA tailgas), wood, or municipal-type solid waste, and other fuels, as applicable, by the potential heat input to the steam generating unit if the steam generating unit had been operated for 8,760 hours at the maximum heat input capacity. However, none of the limits in 60.43b that apply to these boilers are based on the annual capacity factor, so while this provision applies, it will not be used by the permittee.

Paragraph 60.43b(f). On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal (PSA tailgas), oil, wood, or mixtures of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. If the permittee elects to install, calibrate, maintain, and operate a continuous emission monitoring system

(CEMS) for measuring PM emissions according to the requirements of this subpart and are subject to a federally enforceable PM limit of 0.030 lb/MMBtu or less are exempt from this opacity standard.

The permit limits the PM emissions to a maximum of 1.3 lb/hr operating as a maximum heat input of 250 MMBtu/hr. This is equivalent to a limit of 0.0052 lb/MMBtu.

This opacity limit applies any time the boiler combusts coal (PSA tailgas) or a mixture of coal (PSA tailgas) and other fuels (i.e., natural gas).

60.43b(g) applies to all facilities subject to PM and the opacity standards under this subpart, and requires that these standards apply at all times, except during periods of startup, shutdown, and malfunction.

60.43b(h): The limits and alternative limits in (h)(1) and (h)(2) apply because these boilers will be built after February 28, 2005 and will combust coal (i.e., PSA tailgas). The limits apply only when the boilers are burning tailgas or a mixture of tailgas and natural gas.

(h)(1) Except as provided in paragraphs (h)(2), (h)(3), (h)(4), (h)(5) and (h)(6) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 13 ng/J (0.030 lb/MMBtu) heat input.

(h)(2) As an alternative to meeting the requirements of paragraph (h)(1) of this section, the owner or operator of an affected facility for which modification commenced after February 28, 2005, may elect to meet the requirements of this paragraph. On and after the date on which the initial performance test is completed or required to be completed under §60.8, no owner or operator of an affected facility that commences modification after February 28, 2005 shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of both:

(i) 22 ng/J (0.051 lb/MMBtu) heat input derived from the combustion of coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels; and

(ii) 0.2 percent of the combustion concentration (99.8 percent reduction) when combusting coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels.

(h)(3) Does not apply because the boilers do not combust wood.

(h)(4) Does not apply because the boilers do not combust wood.

(h)(5) Does not apply because the boilers do not combust only oil and/or coke oven gas, or mixtures of fuels not subject to a PM standard under 60.43b.

(h)(6) Does not apply because the boilers do not combust only oil.

<u>60.44b, Standard for NO_x.</u>

60.44b(a) applies to all units subject to Subpart Db, except as provided in paragraphs (k) and (l).

A high heat release rate is defined in 60.41b as a heat release rate greater than 70,000 Btu/hr-ft^3.

The applicant's regulatory analysis presumes that these boilers will be subject to NO_x emission limits for a low heat release rate when burning natural gas. For boilers, the heat release rate is the heat input rate in Btu/hr per cubic foot of furnace volume. For a nominal 250 MW heat input rate, a boiler volume less than 3,571 cubic feet (e.g., a boiler roughly 13.5 feet in diameter and 25 feet high) would result in a heat release rate greater than 70,000 Btu/hr-ft^3. **Because the boilers have not yet been ordered for this project, DEQ's analysis includes requirements for both low and high heat release rate boilers with a nominal heat input rating of 250 MW.** Table 4.2 lists the applicable NO_x limits when burning only natural gas or PSA tailgas.

60.44b(b) applies when simultaneously combusting mixtures of coal (PSA tailgas) and natural gas in the boilers. The NOx limit when burning a mix of PSA tailgas and natural gas shall be determined by the formula shown in Table 4.2.

60.44b(k) exempts boilers rated at 250 MW or less from the NO_x emission limits in this subpart if the boiler (j)(1) combusts only natural gas…, (j)(2) has a combined annual capacity factor of 10 percent or less for natural gas…, that is a federally enforceable limit. The annual capacity factor for natural gas is not limited for these boilers, so 60.44b(k) does not apply.

60.44b(l)(1) does not apply because the boilers are not subject to a federally enforceable provision that limits the annual capacity factor for coal (PSA tailgas) or natural gas to 10 percent or less.

60.44b(l)(2) applies because the boilers will be constructed after July 9, 1997; the boilers may have a **low heat release rate**; and are expected to combust natural gas in excess of 30 percent of the heat input (see below) on a 30-day rolling average from the combustion of all fuels. The NO_x limit shall be determined by the formula shown in Table 4.2.

Estimate for the minimum heat input of natural gas when burning a mix of tailgas and natural gas:

(185 MMBtu/hr on natural gas)/(185 MMBtu/hr on natural gas + 65 MMBtu/hr on tailgas) = 74 percent

Table 4.2 NOx EMISSION RATE LIMITS

Boiler Fuel	**Applicable Regulation**	**NO_x Emission Limit (expressed as NO_2)**
When burning only natural gas	60.44b(a)(1)(i) Low heat release rate	43 ng/J (0.10 lb/MMBtu)
When burning only natural gas	60.44(a)(1)(ii) High heat release rate	86 ng/J (0.20 lb/MMBtu)
When burning only PSA tail gas	60.44b(a)(3)(vi) Coal-derived synthetic fuels	210 ng/J (0.50 lb/MMBtu)
When burning a mix of natural gas and PSA tail gas	60.44b(b)	$E_n = \frac{(EL_g x H_g) + (EL_c x H_c)}{(H_g + H_c)}$ Where (example uses lb/MMBtu values): E_n = NO_x emission limit (expressed as NO_2) in lb/MMBtu, EL_g = Natural gas emission limit: 0.10 lb/MMBtu (low heat release rate), or 0.20 lb/MMBtu (high heat release rate), EL_c = Coal (PSA tailgas) emission limit: 0.50 lb/MMBtu, H_g = 30-day* heat input from combustion of natural gas, and H_c = 30-day* heat input from combustion of coal (PSA tailgas). *Example for the normal natural gas/tailgas mix for the steam superheater:* E_n = (0.10 x 185 MMBtu/hr) + (0.5 x 65 MMBtu/hr)/(250 MMBtu/hr)

Table 4.2 NOx EMISSION RATE LIMITS

Boiler Fuel	Applicable Regulation	NO_x Emission Limit (expressed as NO_2)
		E_n = 0.204 lb NO_x/MMBtu *Per 44b(i), emission limits in this subpart are determined on a rolling 30-day average
When burning a mix of natural gas and PSA tail gas, and natural gas Comprises > 30% of the 30-day heat input	60.44b(l)(2) Low heat release rate	$E_n = \frac{(0.10\,xH_{go}) + (0.20\,xH_r)}{(H_{go} + H_r)}$ Where: E_n = NO_x emission limit in lb/MMBtu, H_{go} = 30-day heat input from combustion of natural gas [or oil], and H_r = 30-day heat input from combustion of any other fuel. *Example for the normal natural gas/tailgas mix for the steam superheater:* E_n = (0.10 x 185 MMBtu/hr) + (0.2 x 65 MMBtu/hr)/(250 MMBtu/hr) E_n = 0.126 lb NO_x/MMBtu

The following paragraphs in 60.44b do not apply because the boilers:

(c) Are not limited to an annual capacity factor of 10 percent or less for coal (tailgas) or a mixture of coal (tailgas) with natural gas.

(d) Are not limited to an annual capacity factor of 10 percent or less for natural gas.

(e) Do not combust byproduct/waste and are not limited to an annual capacity factor of 10 percent or less for natural gas.

(f) Do not combust byproduct/waste and are not limited to an annual capacity factor of 10 percent or less for natural gas.

(g) Combust hazardous waste with natural gas or oil.

60.44b(h) applies to all affected facilities subject to Db (i.e., the package boiler and steam superheater), and requires that the NO_x standards apply at all times, including periods of startup, shutdown, or malfunction.

60.44b(i) applies to all affected facilities except for facilities subject to (j). Paragraph 60.44(j) does not apply because the boilers are not limited to an annual capacity factor of 10 percent or less for natural gas. Compliance with the Subpart Db NO_x emission limits for the package boiler and steam superheater shall be determined on a 30-day rolling average.

60.44b(k) does not apply because the package boiler and steam superheater are not limited to an annual capacity factor of 10 percent or less for natural gas.

60.45b, Compliance and Performance Test Methods and Procedures for SO_2.

60.45b(a) applies to all affected facilities subject to an SO_2 standard under Subpart Db. The SO_2 standards under 60.42b apply at all times.

The boilers are exempt from the SO_2 standards based on limiting the potential SO_2 emission rate of the fuel. However, the requirement to demonstrate compliance within the timeframe specified by 60.8 still applies.

60.45(b)(j). The owner or operator of an affected facility that only combusts very low sulfur oil, natural gas, or a mixture of these fuels with any other fuels not subject to an SO_2 standard is not subject to the compliance and performance testing requirements of this section if the owner or operator obtains fuel receipts as described in 60.49b(r).

60.45(b)(k). The owner or operator of an affected facility seeking to demonstrate compliance under 60.42b(d)(4), 60.42b(j), 60.42b(k)(2) and 60.42b(k)(3) (when not burning coal) shall follow the applicable procedures under 60.49b(r).

The exemption from SO_2 emission limits under this subpart was based on 60.42b(k)(2), so the procedures under 60.49b(r) will apply.

<u>60.49b(r).</u> The owner or operator of an affected facility who elects to use the fuel based compliance alternatives in §60.42b or §60.43b shall either:

(1) (this provision does not apply because the boilers will not combust very low sulfur fuel oil); or

(2) The owner or operator of an affected facility who elects to demonstrate compliance based on fuel analysis in §60.42b or §60.43b **shall develop and submit a site-specific fuel analysis plan to the Administrator (this means Idaho DEQ, as this NSPS has been delegated) for review and approval no later than 60 days before the date you intend to demonstrate compliance.** Each fuel analysis plan shall include a minimum initial requirement of weekly testing and each analysis report shall contain, at a minimum, the following information:

- (i) The potential sulfur emissions rate of the representative fuel mixture in ng/J heat input;
- (ii) The method used to determine the potential sulfur emissions rate of each constituent of the mixture. For…natural gas a fuel receipt or tariff sheet is acceptable;
- (iii) The ratio of different fuels in the mixture; and
- (iv) The owner or operator can petition the Administrator (i.e., Idaho DEQ) to approve monthly or quarterly sampling in place of weekly sampling.

<u>60.46b, Compliance and Performance Test Methods and Procedures for PM and NO_x.</u>

60.46b(a) The PM emission standards and opacity limits under 60.43b apply at all times except during periods of startup, shutdown, or malfunction. The NO_x emission standards under 60.44b apply at all times.

60.46b(b) Compliance with the PM emission standards under 60.43b shall be determined through performance testing as described in paragraph (d) of this section, except as provided in paragraph (i) of this section.

(d) To determine compliance with the PM emission limits and opacity limits under 60.43b, the…permittee…shall conduct an initial performance test as required under 60.8, and shall conduct subsequent performance tests as requested by the Administrator (in this case Idaho DEQ), using the following procedures and reference methods…

(i) Does not apply because the boilers will not burn coke oven gas.

60.46b(j) allows the facility to install, calibrate, maintain, and operate a PM CEMS and record the PM CEMS output instead of conducting PM testing with Methods 5, 5B, or 17. If a PM CEMS is used, compliance shall be determined in accordance with requirements contained in 60.46b(j)(1) through (j)(13).

60.46b(j)(14) After July 1, 2011, within 90 days after completing a correlation testing run, the owner or operator of an affected facility shall either successfully enter the test data into EPA's WebFIRE data base located at http://cfpub.epa.gov/oarweb/index.cfm?action=fire.main or mail a copy to: United States Environmental Protection Agency; Energy Strategies Group; 109 TW Alexander DR; Mail Code: D243-01; RTP, NC 27711.

PM performance testing must be conducted for any boiler that will burn PSA tailgas or a mixture of PSA tailgas and natural gas, in accordance with the procedures and reference methods in 60.46b(d). If a PM CEMS is used in lieu of conducting Methods 5, 5B, or 17, compliance shall be determined in accordance with 60.46b(j)(1) through (j)(13), with reporting as required in 60.46b(j)(14).

60.46b(c) Compliance with the NO_x emission standards under 60.44b shall be determined through performance testing under paragraph (e) or (f), or under paragraphs (g) or (h) of this section.

(e) To determine compliance with the emission limits for NO_x required under 60.44b, the…permittee…shall conduct the performance test as required under 60.8 using the continuous monitoring system required by 60.48b(b). *(Note that 48b(b) allows (g), which authorizes using a NO_x CEMS or DEQ-approved continuous NO_x PEMS.)*

(e)(1) For the initial compliance test, NO_x from the steam generating unit are monitored for 30 successive steam generating unit operating days and the 30-day average emission rate is used to determine compliance with the NO_x emission standards under 60.44b. The 30-day average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 30-day test period.

(e)(2) Following the date on which the initial performance test is completed or is required to be completed under 60.8, whichever date comes first, the owner or operator of a facility which combusts coal (i.e., PSA tailgas)...shall determine compliance with the NO_x emission standards under 60.44b on a continuous basis through the use of a 30-day rolling average emission rate. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly NO_x emission data for the preceding 30 steam generating unit operating days.

(e)(3) Does not apply because neither boiler will have a heat input capacity greater than 73 MW (250 MMBtu/hr).

(e)(4) Following the date on which the initial performance test is completed or required to be completed under 60.8, whichever date comes first, the owner of operator of an affected facility that has a heat input capacity of 73 MW (250 MMBtu/hr) or less and that combusts natural gas,…shall upon request determine compliance with the NO_x standards under 60.44b through the use of a 30-day performance test. During periods when performance tests are not requested, NO_x emissions data collected pursuant to 60.48b(g)(1) [using a NO_x CEMS] or 60.48b(g)(2) [using an approved NO_x PEMS] are used to calculate a 30-day rolling average emission rate on a daily basis and used to prepare excess emission reports, but will not be used to determine compliance with the NO_x emission standards. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly NO_x emission data for the preceding 30 steam generating unit operating days.

(e)(5) Does not apply because the boilers do not combust residual oil.

(f) Does not apply because the combustion units are not duct burners.

(g) Does not apply because the boilers are not limited to an annual capacity factor of 10 percent or less for natural gas as required to meet (j)(3).

(h) Does not apply because the boilers are not limited to an annual capacity factor of 10 percent or less for natural gas as required to meet (j)(3).

60.47b, Emission Monitoring for SO_2.

60.47b(a). Except as provided in paragraphs (b) and (f) of this section, the owner or operator of an affected facility subject to the SO_2 standards under 60.42b shall install, calibrate, maintain, and operate CEMS for measuring SO_2 concentrations and either O_2 or CO_2 concentrations…

Per 60.42b(k)(2), the boilers are not subject to SO_2 emissions standards or percent reduction standards under 60.42b. The requirements of 60.47b therefore do not apply.

60.48b, Emission Monitoring for PM and NO_x.

60.48b(a). Except as provided in paragraph **(j)** of this section, the owner or operator of an affected facility subject to the opacity standard under 60.43b shall install, calibrate, maintain, and operate a continuous opacity monitoing system (COMS) for measuring the opacity of emissions discharged to the atmosphere and record the output of the system.

(j)(2) **A COMS is not required** because the boilers will burn only…gaseous fuels with potential SO_2 emissions rates of 26 ng/J (0.060 lb/MMBtu) or less and do not use a post-combustion technology to reduce SO_2 or PM emissions. (FGR and/or SCR is used to reduce NO_x emissions only). The owner or operator must maintain fuel records of the sulfur content of the fuels burned, as described under 60.49b(r).

60.48b(b). Except as provided under paragraphs (g), (h), and (i) of this section, the owner or operator of an affected facility subject to a NO_x standard under 60.44b shall…install, calibrate, maintain, and operate CEMS for measuring NO_x and O_2 (or CO_2) emissions discharge to the atmosphere, and shall record the output of the system…

(g) The owner or operator of an affected facility that has a heat input capacity of 73 MW (250 MMBtu/hr) or less, and that has an annual capacity factor for…natural gas,…greater than 10 percent shall:

(1) **NO_x CEMS**. Comply with the provisions of paragraphs (b), (c), (d), (e)(2), (e)(3), and (f) of this section (install a NOx CEMS for measuring NO_x and O_2 (or CO_2); or

(2) **NO_x PEMS**. Monitor steam generating unit operating conditions and predict NO_x emission rates as specified in a plan submitted pursuant to 60.49b(c). EPA has delegated authority to Idaho for this NSPS, so this predictive emissions monitoring system (PEMS) plan shall be submitted to Idaho DEQ for approval rather than to the EPA.

(h) Does not apply because the emissions are not from a duct burner.

(i) Does not apply because the boilers are not limited to an annual capacity factor of 10 percent or less for natural gas as required to meet (j)(3).

A NO_x CEMS or PEMS is therefore required for both the package boiler and the steam superheater.

60.49b, Reporting and Recordkeeping Requirements.

60.49b(a) applies, and requires the permittee to submit notification of the date of initial startup, as provided in §60.7. Information to be included in the notification is listed in 60.49b(a).

60.49b(b) applies, and requires the permittee to submit performance test data from the initial performance test(s) and the performance evaluation of the CEMS using the applicable performance specifications in 40 CFR 60, Appendix B. The reporting requirements for facilities described in 60.44b(j) or (k) do not apply because the boiler(s) are not subject to a limit on the capacity factor for natural gas.

60.49b(c) applies only if the facility elects to use a PEMS instead of a CEMS for monitoring NO_x emissions.

60.49b(d) applies, and requires recording and maintaining records of the type and amount of fuel combusted, and calculation of the annual capacity factor.

60.49b(e) does not apply because the boilers do not burn residual oil.

60.49b(f) applies, and requires maintaining records of opacity when burning PSA tailgas in the boiler(s).

60.49b(g) applies, and requires daily recordkeeping for NO_x emissions.

60.49b(h) applies because the boiler(s) are subject to the opacity standard when burning PSA tailgas or a mixture of PSA tailgas and natural gas, and because continuous NO_x monitoring is required (CEMS or PEMS). Excess emissions reporting for opacity and for NO_x is therefore required.

60.49b(i) applies because the boilers are subject to continuous NO_x monitoring, and requires that NO_x excess emission reports include the information listed in paragraph (g).

60.49b(j), (k), (l), (m), and (n) do not apply because the boiler(s) are not subject to the SO_2 standards under 60.42b.

60.49b(o) requires that all records under this section be maintained by the permittee for a period of 2 years. DEQ PTC General Provision 7 is more stringent, and requires maintaining these records for a period of 5 years.

60.49b(p) and (q) do not apply because the boiler(s) are not subject to a limit on the capacity factor for natural gas.

60.49b9(r) applies because **sulfur content monitoring for natural gas and PSA tailgas is needed to demonstrate that the potential SO_2 emission rate is less than 140 ng/J (0.32 lb/MMBtu), i.e., that the boiler(s) are exempt from SO_2 standards per 60.42b(k)(2), and 26 ng/J (0.060 lb/MMBtu) or less to demonstrate that a COMS is not required per 60.48b(j)(2).**

60.49b(s), (t), (u), (x), and (y) do not apply because these are facility-specific standards approved for individual facilities.

60.49b(v) allows quarterly electronic submittal of required reports, subject to approval by the permitting authority. DEQ's application to implement EPA's Cross-Media Electronic Reporting Regulation (CROMERR) has not yet been approved, so DEQ cannot accept electronic submittals.

60.49b(w) specifies that the reporting period for reports required under this subpart is each 6 month period, and requires that hard copy reports be postmarked by the 30^{th} day following the end of the reporting period.

40 CFR 60.1 through 60.19, NSPS General Provisions. The NSPS General Provisions are given by 40 CFR Part 60 Subpart A. The General Provisions which apply to the boiler project have been added to the permit. The following requirements in this subpart do not apply: 60.18.

40 CFR 60 Subpart G ....Standards of Performance for Nitric Acid Plants.

60.70 Applicability and designation of affected facility.

60.70(a) The provisions of this subpart are applicable to each nitric acid production unit, which is the affected facility.

60.70(b) Any facility under paragraph (a) of this section that commences construction or modification after August 17, 1971, is subject to the requirements of this subpart.

60.71 Definitions.

60.71(a) *Nitric acid production unit* means any facility producing weak nitric acid by either the pressure or atmospheric pressure process.

60.71(b) *Weak nitric acid* means acid which is 30 to 70 percent in strength.

Subpart G applies because the nitric acid plant proposed for this project will be constructed after August 17, 1971 and will produce nitric acid at a concentration of about 57 percent.

60.72 Standard for nitrogen oxides.

60.72(a) On and after the date on which the performance test required to be conducted by 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:

(1) Contain nitrogen oxides, expressed as NO_2, in excess of 1.5 kg per metric ton of acid produced (3.0 lb per ton), the production being expressed as 100 percent nitric acid.

(2) Exhibit 10% opacity or greater.

60.73 Emission monitoring.

60.73(a) The source owner or operator shall install, calibrate, maintain, and operate a continuous monitoring system for measuring nitrogen oxides (NO_x). The pollutant gas mixtures under Performance Specification 2 and for calibration checks under 60.13 of this part shall be nitrogen dioxide (NO_2). The span value shall be 500 ppm of NO_2. Method 7 shall be used for the performance evaluations under 60.13(c). Acceptable alternative methods to Method 7 are given in 60.74(c).

A CEMS is required for monitoring NO_x emissions from the nitric acid plant.

60.73(b) The owner or operator shall establish a conversion factor for the purpose of converting monitoring data into units of the applicable standard (kg/metric ton, lb/ton). The conversion factor shall be established by measuring emissions with the continuous monitoring system concurrent with measuring emissions with the applicable reference method tests…The conversion factor shall be reestablished during any performance test under 60.8 or any continuous monitoring system performance evaluation under 60.13.

The permittee is required to establish and update the conversion factor during performance tests or CEMS evaluations.

60.73(c) applies, and requires the permittee to record the daily production rate and hours of operation.

60.73(d) applies, and requires that for the purpose of reports required under 60.7(c), periods of excess emissions that shall be reported are defined as any 3-hour period during which the average NO_x

emissions (arithmetic average of three contiguous 1-hour periods) as measured by a continuous monitoring system exceed the standard under 60.72(a).

60.74 Test methods and procedures.

60.74(a) applies, and requires that when conducting performance tests required in 60.8, the permittee shall use reference methods and procedures in 40 CFR 60, Appendix A or other methods and procedures as specified in Subpart G, except as provided in 60.8(b). Acceptable alternative methods and procedures are given in paragraph (c) of this section.

> 60.8(b) …unless the Administrator (1) specifies or approves, in specific cases, the used of a reference method with minor changes in methodology, (2) approves the use of an equivalent method, (3) approves the use of an alternative method the results of which he has determined to be adequate for indicating whether a specific source is in compliance, (4) waives the requirement for a source test because the owner or operator of a source has demonstrated by other means to the Administrator's satisfaction that the affected facility is in compliance with the standard, or (5) approves shorter sampling times and smaller sample volumes when necessitated by process variables or other factors. Nothing in this paragraph shall be construed to abrogate the Administrator's authority to require testing under section 114 of the Act.
>
> **The permittee is required to conduct performance tests using approved methods and procedures.**

40 CFR 60 Subpart J............................Standards of Performance for Petroleum Refineries.

Is the Claus sulfur recovery unit proposed as an optional control device subject to Subpart J?

60.100 Applicability, designation of affected facility, and reconstruction.

60.100(a) The provisions of this subpart are applicable to the following affected facilities in petroleum refineries:…all Claus sulfur recovery plants except Claus plants with a design capacity for sulfur feed of 20 long tons per day (LTD) or less. The Claus sulfur recovery plant need not be physically located within the boundaries of a petroleum refinery to be an affected facility, provided it processes gases produced within a petroleum refinery.

60.100(b) …any Claus sulfur recovery plant under paragraph (a) of this section which commences construction, reconstruction, or modification after October 4, 1976, and on or before May 14, 2007.

> The Claus sulfur recovery unit proposed as option #1 for controlling sulfur compounds from the Selexol acid gas removal unit is not located in a petroleum refinery and does not process gases produced within a petroleum refinery. In addition, the Claus sulfur recovery unit would be constructed after May 14, 2007, **so is therefore not subject to Subpart J**.

40 CFR 60 Subpart Ja...........................Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007.

Is the Claus sulfur recovery unit proposed as an optional control device subject to Subpart Ja?

60.100a Applicability, designation of affected facility, and reconstruction.

60.100a(a) The provisions of this subpart are applicable to the following affected facilities in petroleum refineries:…sulfur recovery plants. The sulfur recovery plant need not be physically located within the boundaries of a petroleum refinery to be an affected facility, provided it processes gases produced within a petroleum refinery.

60.101a Definitions. *Sulfur recovery plant* means all process units which recover sulfur from HS_2 [sic] and/or SO_2 at a petroleum refinery.…For example, a Claus sulfur recovery plant includes: Reactor furnace and waste heat boiler, catalytic reactors, sulfur pits, and, if present, oxidation or reduction control systems, or incinerator, thermal oxidizer, or similar combustion device….

The Claus sulfur recovery unit proposed as option #1 for controlling sulfur compounds from the Selexol acid gas removal unit is not located in a petroleum refinery and does not process gases produced within a petroleum refinery, **so is therefore not subject to Subpart Ja**.

40 CFR 60 Subpart Kb.........................New Source Performance Standards (NSPS) of Performance for Volatile Organic Liquid Storage Vessels (including petroleum liquid storage vessels) for which Construction, Reconstruction, or Modification Commenced after July 23, 1984.

40 CFR 60.110b, Applicability and designation of affected facility.

60.110b(a) Except as provided in paragraph (b) of this section, the affected facility to which this subpart applies is each storage vessel with a capacity greater than or equal to 75 cubic meters (m^3) that is used to store volatile organic liquids (VOLs) for which construction, reconstruction, or modification is commenced after July 23, 1984.

60.111b Definitions

Volatile organic liquid (VOL) means any organic liquid which can emit volatile organic compounds (as defined in 40 CFR 51.100) into the atmosphere.

40 CFR 51.100(s) *Volatile organic compounds (VOC)* means any compound of carbon, excluding carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, and ammonium carbonate, which participates in atmospheric photochemical reactions.

60.110b(b) This subpart does not apply to storage vessels with a capacity greater than or equal to 151 m^3 storing a liquid with a maximum true vapor pressure less than 3.5 kilopascals (kPa) or with a capacity greater than or equal to 75 m^3 but less than 151 m^3 storing a liquid with a maximum true vapor pressure less than 15.0 kPa.

A typical maximum true vapor pressure for #2 diesel fuel is about 0.067 kPa.
The 2 MW engine diesel storage tank is a 3,000gallon tank (11.36 m^3)
The 500 kW engine diesel storage tank is a 500-gallon tank (1.89 m^3)

The two diesel fuel storage tanks do not have capacities greater than 75 m^3, so Subpart Kb does not apply to these storage tanks.

Ammonia, nitric acid, sulfuric acid, and UAN are not volatile organic liquids, so Subpart Kb does not apply to these storage tanks.

40 CFR 60, Subpart Y...........................Standards of Performance for Coal Preparation Plants

60.250 Applicability and designation of affected facility.

60.250(a) The provisions of this subpart are applicable to any of the following affected facilities in coal preparation plants which process more than 181 Mg (200 tons) per day: Thermal dryers, pneumatic coal-cleaning equipment (air tables), coal processing and conveying equipment (includes breakers and crushers), coal storage systems, and coal transfer and loading systems. (b)…that commences construction or modification after October 24, 1974…

Although no upper limit was provided in the application, the coal and petcoke grinder and rod mill can process as much as 5,000 tons per day of coal/petcoke to produce the slurry feed to the gasifier.

The proposed project coal preparation plant is being constructed after 1974 and can process more than 200 tons per day, and is therefore subject to Subpart Y.

60.251 Definitions.

60.251(a) *Coal preparation plant* means any facility (excluding underground mining operations) which prepares coal by one or more of the following processes: breaking, crushing, screening, wet or dry cleaning, and thermal drying.

The grinding mill and the rod mill are a *coal preparation plant* for the purposes of this subpart.

60.251(c) *Coal* means all solid fossil fuels classified as anthracite, bituminous, subbituminous, or lignite by ASTM Designation D388-77, 90, 91, 95, or 98a.

Petcoke does not meet ASTM Designation D388, which defines coals by rank.

60.251(e) *Thermal dryer* means any facility in which the moisture content of bituminous coal is reduced by contact with a heated gas stream which is exhausted to the atmosphere.

60.251(f) *Pneumatic coal-cleaning equipment* means any facility which classifies bituminous coal by size or separates bituminous coal from refuse by application of air stream(s).

Proposed coal sources for the proposed project include the West Elk mine near Somerset, Colorado and the Sufco mine near Salinas, Utah, both of which are located in the western bituminous region. However, coal crushing at the proposed project will be done using grinding equipment and a rod mill. Neither process uses air tables to separate coal by size. Because the crushed coal will be mixed with water to form a slurry, the proposed project will not require a thermal dryer to reduce the moisture content of the coal.

60.251(g) *Coal processing and conveying equipment* means any machinery used to reduce the size of coal or to separate coal from refuse, and the equipment used to convey coal to or remove coal and refuse from the machinery. This includes, but is not limited to, breakers, crushers, screens, and conveyor belts.

60.251(h) *Coal storage system* means any facility used to store coal except for open storage piles.

60.251(i) *Transfer and loading system* means any facility used to transfer and load coal for shipment.

60.252 Standards for Particulate Matter.

60.251(a) and (b) limit PM emissions from a thermal dryer and pneumatic coal cleaning equipment (air tables). The proposed project uses neither of these, so these provisions do not apply.

60.251(c) On and after the date on which the performance test required to be conducted by §60.8 is completed, an owner or operator subject to the provisions of this subpart shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal, gases which exhibit **20 percent opacity** or greater.

40 CFR 60, Subpart VVa......................Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006

60.489a. Process units that produce, as intermediates or final products, chemicals listed in 60.489 are covered under this subpart. The applicability date for process units producing one or more of these chemicals is November 8, 2006.

The proposed project will commence construction after November 8, 2006, produces no chemicals listed in 60.489 as intermediate products, but produces one chemical (urea, CAS No. 57-13-6) as a final product. The proposed project's urea process is an affected facility subject to this NSPS.

60.480a(1) The provisions of this subpart apply to affected facilities in the synthetic organic chemicals manufacturing industry.

60.480a(2) The group of all equipment (defined in 60.481a) within a process facility is an affected facility.

60.481a, Definitions:

Equipment means each pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, valve, and flange or other connector in VOC service and any devices or systems required by this subpart.

In VOC service means that the piece of equipment contains or contacts a process fluid that is at least 10 percent VOC by weight. (The provisions of 60.485a(d) specify how to determine that a piece of equipment is not in VOC service.)

All equipment that comes into contact with a liquid or gas containing at least 10% VOC would therefore be an affected facility.

An EPA applicability determination memo[3] drew a distinction between the manufacture of liquid urea and solid urea in Section 5.1 of EPA Document Number EPA-450/3-80-033b, VOC Fugitive Emissions in Synthetic Organic Chemicals Manufacturing Industry Background Information for Promulgated Standards. In that document, EPA "recognized that plants which do not produce urea solids would not have a formaldehyde addition step, and, therefore, would have no potential for fugitive emissions of VOC."

While fugitive leaks of urea are possible throughout the process, EPA considers the "formaldehyde addition step" in producing granular urea to be the sole cause of potential fugitive VOC emissions from urea productions processes. This equipment should be considered to be in VOC service.

60.480a(b) Any affected facility under paragraph (a) of this section that commences construction,…after November 7, 2006, shall be subject to the requirements of this subpart.

The proposed project will commence construction after November 7, 2006.

60.480a(d) The exemptions in this section do not apply because the proposed project's design capacity for urea is more than 1,102 ton/yr, it does not produce heavy liquid chemicals only from heavy liquid feed or raw materials, it does not produce beverage alcohol, and it *does* have equipment in VOC service.

60.480a(e) Alternative means of compliance – (1) Option to comply with part 65 [the Consolidated Federal Air Rule for SOCMI]….

The applicant has not requested to use this alternative means of compliance.

60.480a(f) does not apply because the proposed project did not start a new affected source prior to November 16, 2007.

60.481a, Definitions. These will not be repeated here.

60.482-1a, Standards: General

[3] EPA Applicability Determination, Control No. 0600015, Liquid Urea Manufacturing Operations, November 1, 2005.

60.482-1a(a) Each owner or operator subject to the provisions of this subpart shall demonstrate compliance with the requirements of 60.482-1a through 60.482-10a…for all equipment within 180 days of startup.

60.486a, Recordkeeping Requirements

60.487a, Reporting Requirements

60.487a(a) Each owner or operator subject to the provisions of this subpart shall submit semiannual reports to the Administrator beginning 6 months after the initial startup date.

60.487a(b) The initial semiannual report to the Administrator shall include the following….

60.487a(c) All semiannual reports to the Administrator shall include the following, summarized from the information in 60.486a….

60.487a(d) An owner or operator electing to comply with the provisions of 60.483-1a or 60.483-2a shall notify the Administrator of the alternative standard selected 90 days before implementing either of the provisions….

60.487a(e) An owner or operator shall report the results of all performance tests in accordance with 60.8 of the General Provisions. The provisions of 60.8(d) do not apply to affected facilities subject to the provisions of this subpart except that an owner or operator must notify the Administrator of the schedule for the initial performance tests at least 30 days before the initial performance tests.

The requirement to comply with the applicable provisions of this subpart has been included in the permit.

60.487a(f) The requirements of paragraphs (a) through (c) of this section remain in force until and unless EPA, in delegating enforcement authority to a state under section 111(c) of the CAA, approves reporting requirements or an alternative means of compliance surveillance adopted by such state. In that event, affected sources within the state will be relieved of the obligation to comply with the requirements of paragraphs (a) through (c) of this section, provided they comply with the requirements established by the state.

At this time, Idaho DEQ does not have in place any different requirements applicable to affected facilities under this subpart.

40 CFR 60, Subpart IIII ....Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (CI ICE)

40 CFR 60.4200 ....Am I subject to this subpart?

60.4200(a)(2)(i). The nominal 2 MW emergency engine generator is subject to this subpart because the permittee will commence construction (will order the engine) after July 11, 2005, and the engine generator will be manufactured (the date ordered from the manufacturer) after April 1, 2006.

60.4200(a)(2)(i). The nominal 500 kW emergency engine generator (for fire pump service) is subject to this subpart because the permittee will commence construction (will order the engine) after July 11, 2005, and the engine generator will be manufactured (the date ordered from the manufacturer) after April 1, 2006.

Note: The 500 kW emergency engine used in the application to provide representative emissions information for service as a fire pump is not a "fire pump," which is defined in §60.4200(a)(2)(ii) as a "certified National Fire Protection Association (NFPA) fire pump engine." The Caterpillar spec sheet for this generator set includes no information that this generator meets NFPA 20, Standard for Centrifugal Fire Pumps, but notes that this generator set meets "EPA Tier 2 and Low Emission" standards for this size engine. As shown in Table 4.3, the emission standards for NFPA 20 fire pump engines ordered from the manufacturer in 2008 or earlier are higher than for similarly sized non-fire pump engines. Fire pump emission standards for engines ordered in 2009 or later are the same as for similarly sized non-fire pump emergency generator engines, except that there is no standard for CO emissions from these fire pump engines.

Table 4.3 COMPARISON OF ENGINE EMISSION STANDARDS

Emission Unit	**Regulation**	**NO_x** (g/kW-hr)	**HC** (g/kW-hr)	**NMHC + NO_x** (g/kW-hr)	**CO** (g/kW-hr)	**PM** (g/kW-hr)
NFPA-certified fire pump engine, Ordered in 2008 or earlier.	40 CFR 60, Subpart IIII, Table 4 130 $\leq$ kW $\leq$ 560	---	---	10.5	3.5	0.54
NFPA-certified fire pump engine, Ordered in 2009 or later. Emissions certification required for 2009+		---	---	4.0	---	0.20
Emergency Engine Generator, 500 kW	40 CFR 89.112, Table 1 450 $\leq$ kW $\leq$ 560: Tier 3, beginning with Model Year 2006	---	---	4.0	3.5	0.20

HC = hydrocarbons, NMHC = nonmethane hydrocarbons

40 CFR 60.4201, 4202, and 4203 ....What…must I meet…if I am a stationary CI internal combustion engine manufacturer?

These sections are not applicable because the permittee is not a stationary CI ICE manufacturer.

40 CFR 60.4204 ....What emission standards must I meet for non-emergency engines if I am an owner operator of a stationary CI internal combustion engine?

This section is not applicable because the 2MW and 500 kW engines are emergency engines.

40 CFR 60.4205 ....What emission standards must I meet for emergency engines if I am an owner operator of a stationary CI internal combustion engine?

60.4205(b) Owners and operators of 2007 model year and later emergency stationary CI ICE with a <u>displacement of less than 30 liters per cylinder</u> that are <u>not fire pump engines</u> must comply with the emission standards for new nonroad CI engines in 60.4202, for all pollutants, for the same model year and maximum engine power for their 2007 model year and later emergency stationary CI ICE.

60.4202(a)(2) For engines with a maximum engine power greater than or equal to 37 kW (50 hp), the certification emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants beginning in model year 2007.

60.4202(b)…applies to emergency generators rated at more than 2,237 kW (3,000 hp).

60.4202(c)…applies to generators with displacement greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder.

As shown in Table 4.4, the nominal 2 MW (2,000 kW) and 500 kW engine generators used by the applicant to provide representative emission characteristics for these sources each have a displacement of less than 10 liters per cylinder, are not fire pump engines, and are rated between 37 kW and

2,237 kW. Therefore these engines would be subject to the emission standards of 40 CFR 89.112 and 89.113.

Table 4.4 EMISSION STANDARDS APPLICABLE TO PCAEC EMERGENCY GENERATOR SETS

PCAEC Generator Set	Engine Displacement/ No. of Cylinders[a]	Applicable Requirement and Compliance Demonstration	40 CFR 89.112, Table 1		
			NMHC $+NO_X$	CO	PM
2 MW engine	69.00 L / ≥8 cyl (8.6 L/cylinder)	kW > 560 Tier 2, beginning with model year 2006	6.4 g/kW-hr	3.5 g/kW-hr	0.20 g/kW-hr
Caterpillar spec: CAT C15 ATAAC		Tier 2 compliant			
500 kW engine	15.20 L/ 6 cyl (2.5 L/cylinder)	450 ≤ kW ≤ 560 Tier 3, beginning with model year 2006	4.0 g/kW-hr	3.5 g/kW-hr	0.20 g/kW-hr
Caterpillar Spec: CAT C15 ATAAC		Tier 2 and Low Emissions	5.74 g/hp-hr (7.70g/kW-hr)[b]	0.4 g/hp-hr (0.54 g/kW-hr)[b]	0.018 g/hp-hr (0.024 g/kW-hr)[b]

L = liters

[a] Caterpillar engine specification sheets (See Appendix D of the application)

[b] g/hp-hr x 1 hp/0.7457 kW = g/kW-hr

The smoke emission standards in 89.113 include opacity limits for the emergency engine generators that are not fire pump engines during acceleration and lugging modes, and the methods of measurement.

Note that the 500 kW engine generator used to provide representative emission parameters for this project does not meet the minimum required emission standard.

40 CFR 60.4206 ....How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?

The permittee shall operate and maintain stationary CI ICE that achieve the emission standards as required in 60.4205 according to the manufacturer's written instructions, over the life of the engine.

40 CFR 60.4207 ....What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?

60.4207(a), beginning October 1, 2007, the permittee shall use diesel fuel that meets the requirements of 40 CFR 80.510(a).

60.4207(b), beginning October 1, 2010, the permittee shall use diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel.

40 CFR 60.4208 ....What is the deadline for importing or installing stationary CI ICE produced in the previous model year?

The permittee shall not install or import a diesel generator after the dates listed in 60.4208 that does not meet the applicable emission standards of Subpart IIII. Permit Condition 5.6 includes the requirements of this section.

40 CFR 60.4209 ....What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?

60.4209(a). The permittee shall install a non-resettable hour meter prior to startup of the engine. 60.4209(b), installation of a backpressure monitor for a diesel particulate filter, does not apply because the two proposed generators are emergency generators.

40 CFR 60.4210 ....What are my compliance requirements if I am a stationary CI internal combustion engine manufacturer?

This section is not applicable because the permittee is not a stationary CI ICE manufacturer.

40 CFR 60.4211 ....What are my compliance requirements if I am an owner operator of a stationary CI internal combustion engine?

60.4211(a). The emergency generator shall be operated according to the manufacturer's written instructions. In addition, the permittee shall only change those settings that are permitted by the manufacturer. The permittee is also required to meet the requirements of 40 CFR 89, 94 and/or 1068, as applicable.

40 CFR 89, Control of Emissions from New and In-Use Nonroad Compression-Ignition Engines.

40 CFR 94, Control of Emissions from Marine Compression-Ignition Engines. The engine generators proposed for use at the PCAEC are not marine engines, so these requirements do not apply.

40 CFR 1068, General Compliance Provisions for Nonroad Programs. [Requirements do not apply]

60.4211(c). Because the emergency generator is model year 2007 or later, and is subject to the emission standards specified in 60.4205(b), the permittee shall comply by purchasing an engine certified to the emission standards in 60.4205(b) and installing and configuring the engine according to the manufacturer's specifications.

60.4211(e). The emergency generator may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended. Maintenance checks and readiness testing of such units is limited to 100 hours per year. There is no time limit on the use of emergency stationary ICE in emergency situations. Because the emergency generator is meeting the requirements of 40 CFR 60.4205 but not 60.4204, any operation other than emergency operation, and maintenance and testing as permitted in this section, is prohibited.

40 CFR 60.4212 ....What test methods and other procedures must I use if I'm an owner or operator of a stationary CI internal combustion engine with a displacement of less than 30 liters per cylinder?

Owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests pursuant to this subpart must do so according to paragraphs (a) through (d) of this section, in accordance with 60.4214.

40 CFR 60.4213 ....What test methods and other procedures must I use if I am an owner or operator of a stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder?

This section is not applicable because the emergency generators each have a displacement of less than 30 liters per cylinder.

40 CFR 60.4214 .... What are my notifications, reporting, and recordkeeping requirements if I am and owner or operator of a stationary CI internal combustion engine?

60.4214(b). Because the stationary CI ICE is an emergency stationary ICE, the permittee is not required to submit an initial notification. Because the model year of the emergency generator is before 2011, additional recordkeeping requirements are not applicable.

40 CFR 60.4215 .... What requirements must I meet for engines used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands?

These requirements do not apply to this facility because it is located in Idaho.

40 CFR 60.4216 .... What requirements must I meet for engines used in Alaska?

These requirements do not apply to this facility because it is located in Idaho.

40 CFR 60.4217 .... What requirements must I meet if I am an owner or operator of a stationary internal combustion engine using special fuels?

These requirements do not apply to this facility because diesel fuel will be used in the emergency generators, and the use of special fuels has not been requested.

40 CFR 60.4218 .... What part of the general provisions apply to me?

All 40 CFR 60, Subpart A general provisions apply to this facility except as specified in Table 8 to Subpart IIII of Part 60—Applicability of General Provisions to Subpart IIII. In particular, notification and recordkeeping requirements are:

60.7(a)(1), the “initial notification” for the construction date does not apply, per 60.4214(a).
60.7(a)(3), notification of the initial startup date, appears to be applicable.

40 CFR 60.4219 .... What definitions apply to this subpart?

This section contains the definitions and supporting tables for this subpart.

4.7 NESHAP Applicability (40 CFR 61)

The proposed project is not included in any of the source categories subject to a National Emission Standard for Hazardous Air Pollutants (NESHAP).

4.8 MACT Applicability (40 CFR 63)

The uncontrolled emissions of all HAPs from the proposed project are less than 25 tons per year, but at 16.3 tons per year the uncontrolled emissions of carbonyl sulfide (COS) exceed 10 tons per year. The permit requires that COS emissions from the AGR CO_2 vent be controlled by a thermal oxidizer with a minimum design destruction efficiency of 95% for CO, COS, and H_2S, reducing the COS emissions from this source to 0.8 tons per year. The PCAEC is therefore a synthetic minor area source for HAPs, and is not subject to any Maximum Achievable Control Technology (MACT) standard applicable to major HAP sources.

The applicability of area source MACTs is described below.

40 CFR 63 Subpart ZZZZ....................NESHAP for Stationary Reciprocating Internal Combustion (RICE) Engines

40 CFR 63.6585 ....Am I subject to this subpart?

You are subject to this subpart if you own or operate a stationary RICE at a major or area source of HAP emissions, except if the stationary RICE is being tested at a stationary RICE test cell/stand.

63.6585(a). The two emergency diesel engine generators proposed for this project are stationary RICE because they are internal combustion engines that use reciprocating motion to convert heat energy into mechanical work and they are not mobile. Mobile RICE include nonroad engines as defined in 40 CFR 1068.30, engines used to propel a motor vehicle or a vehicle used solely for competition.

> 1068.30 A nonroad engine means …(2) An internal combustion engine is not a nonroad engine if:…(ii) The engine is regulated by a federal New Source Performance Standard (NSPS) promulgated under section 111 of the Act (42 U.S.C. 7411)…
>
> Both of the emergency engine generators proposed for this project are regulated under an NSPS, specifically 40 CFR 60, Subpart IIII.
>
> The 2 MW and 500 kW emergency engine generators are therefore stationary RICE.

63.6590(a)(2)(iii). A stationary RICE located at an area source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2008.

> The proposed project is an area source of HAPs, and both of the emergency engine generators proposed for this project will be constructed after June 12, 2008.
>
> The 2 MW and 500 kW emergency engine generators are therefore new stationary RICE.

63.6590(c). Stationary RICE subject to Regulations under 40 CFR Part 60 [is A]n affected source that is a new…stationary RICE located at an area source,…and..must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII, for compression engines. **No further requirements apply for such engines under this part**.

4.9 CAM Applicability (40 CFR 64)

SIE must address Compliance Assurance Monitoring (CAM) applicability in their application for an initial Tier I permit (see Section 4.5). CAM requirements, if applicable, will be included in the Tier I permit.

4.10 CAA 112(r), 40 CFR 68, Chemical Accident Prevention, Risk Management Plan

Under the Clean Air Act Amendments of 1990, the Chemical Accident Prevention Provisions required EPA to develop rules and guidance for facilities that produce, handle, process, distribute, or store more than threshold amounts of chemicals defined as extremely hazardous substances. Under the rule, contained in 40 CFR 68, companies of all sizes that use certain flammable and toxic substances must develop a Risk Management Plan (RMP), and submit the RMP to EPA. An initial RMP must be submitted by dates specified in the rule and must be revised as needed and resubmitted every five years. RMP must include a(n):

- Hazard assessment that details the potential effects of an accidental release, an accident history of the last five years, and an evaluation of worst-case and alternative accidental releases;
- Prevention program that includes safety precautions and maintenance, monitoring, and employee training measures; and

- Emergency response program that spells out emergency health care, employee training measures and procedures for informing the public and response agencies (e.g., the fire department) should an accident occur.

The proposed project will be required to prepare a Risk Management Plan (RMP) in accordance with 40 CFR 68 because it will produce, handle, or store more than the threshold planning quantity (TPQ) of ammonia listed in 40 CFR 68.130, as shown in Table 4.5. Other chemicals that may exceed the threshold planning these requirements include hydrogen sulfide, carbonyl sulfide, and hydrogen. As part of developing the RMP, SIE must determine which chemicals at the PCAEC are subject to RMP requirements

Table 4.5 TOXIC SUBSTANCES THAT WILL OR MAY BE REQUIRED IN PCAEC'S RMP

Toxic Substance	Threshold Planning Quantity	Estimated Production at PCAEC
Ammonia (concentration of 20% or greater),	20,000 pounds	100 to 500 short tons per day (200,000 to 1,000,000 pounds per day)
Hydrogen sulfide (H_2S)	10,000 pounds	(TBD) pounds per day produced in the Selexol AGR unit
Carbonyl sulfide (COS)	10,000 pounds	(TBD) pounds per day produced in plant processes.
Hydrogen (H_2)	10,000 pounds	(TBD) pounds per day produced in the Selexol AGR unit.

In accordance with 40 CFR 68.150, SIE will be required to submit the RMP no later than the date on which one of these substances is first present above a threshold quantity in a process (i.e., essentially at the initial startup for processes that produce these substances).

4.11 BACT Determination (40 CFR 51.116)

Best available control technology (BACT) is defined in 40 CFR 52.21(b)(12) as "an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under (the) Act which would be emitted from" the proposed stationary source.

For each regulated new source review (NSR) pollutant subject to BACT, a BACT determination defines any inherently lower-emitting processes or practices, add-on control technology, and emission limits. BACT is based on the maximum degree of pollution reduction that DEQ determines on a case-by-case basis is achievable taking into account energy, environmental, economic, and other factors. No technology or emission limit may be approved that is less stringent than the NSPS found in 40 CFR 60 or any NESHAP found in 40 CFR 61.

"Top-Down Methodology." BACT is demonstrated on a case-by-case basis using a "top-down" methodology in which available control technology options are identified based on knowledge of the source and previous regulatory decisions for other identical or similar sources. These alternatives are then ranked in descending order of control effectiveness, i.e., the "top" option is the most stringent and typically represents the lowest achievable emission rate (LAER). The feasibility or appropriateness of each alternative as BACT is based on technical feasibility and economic, energy, and environmental impacts. If the top control alternative is selected as BACT, no further analysis is required. If the top control alternative is technically infeasible or is otherwise rejected as inappropriate after considering site-specific impacts, it is rejected and the next most stringent alternative is then considered. This process continues until a control alternative is determined to be technically feasible and without adverse economic, energy, and environmental impact. This alternative is then selected as BACT.

BACT Cost Threshold. SIE used a cost threshold of $10,000 per ton of pollutant reduction for evaluating the economic feasibility of a control option. This means that an option was considered economically feasible if the cost-per-ton was less than $10,000. BACT cost thresholds are determined on a case-by-case basis, but are expected to be in approximately the same range for similar types of projects. Setting a high cost-per-ton threshold results in including more costly control options. BACT cost thresholds used in California[4] were presumed to be representative. As shown in Table 4.6, the cost threshold used for the PCAEC BACT analysis is higher than the "representative" thresholds for CO and PM_{10}. For NO_x emissions, SIE selected the "top control" for all sources except the package boiler, so cost analyses were not required. DEQ determined that the $10,000/ton threshold for NO_x emissions from the package boiler was appropriate because the boiler will be operated only during startup and shutdown.

Table 4.6 BACT COST THRESHOLD COMPARISON

Pollutant	Cost Threshold ($/ton)	PCAEC Threshold ($/ton)	Comments
NO_x	24,500	10,000	
SO_2	3,900	10,000	PCAEC is not subject to BACT for SO_2.
CO	300	10,000	
VOC	17,500	10,000	PCAEC is not subject to BACT for VOCs.
PM_{10}	5,700	10,000	

BACT Limits

Work Practices in lieu of an Emission Limit. If DEQ "determines that there is no economically reasonable or technologically feasible way to accurately measure the emissions, and hence to impose an enforceable emissions standard, [the source may be required] to use design, alternative equipment, work practices or operational standards to reduce emissions of the pollutant to the maximum extent."[5]

BACT Opacity Limits. The parenthetical reference to a visible emission standard was included in the BACT definition in 1978 (43 FR 26380, June 19, 1978). This makes clear that an emissions limitation may include a visible emission standard, but does not require that an opacity limit be set. A review of the listings in the EPA's RACT/BACT/LAER Clearinghouse[6] shows that PM BACT entries that list an opacity limit in addition to an emission limit are not typical. The 1990 Draft NSR Workshop Manual[5] mentions opacity only once (see p. H-6), suggesting that where "continuous, quantitative measurements are infeasible, surrogate parameters must be expressed in the permit. Examples of surrogate parameters include: mass emissions/opacity correlations,…" The correlation between the mass of particulates emitted and opacity can vary widely depending on the particle size (e.g., emissions of large particles can mean that a significant mass of pollutants may be emitted while observed opacity levels are quite low).

4.11.1 Regulated NSR Pollutants Subject to BACT at the PCAEC

All new major stationary sources and all major modifications must conduct an analysis to ensure that BACT is specified for each pollutant that exceeds the PSD "significant" thresholds. "Significant" emission rates are defined in federal rules contained in 40 CFR 52.21(b)(23)(i), and are also listed

4 Yolo-Solano Air Quality Management District, accessible at http://www.eea-inc.com/rrdb/DGRegProject/States/Newsite/CADistricts/Yolo.html

5 October 1990, Draft, New Source Review Workshop Manual, Prevention of Significant Deterioration and Nonattainment Permitting, EPA.

6 EPA RACT/BACT/LAER Clearinghouse, available at http://cfpub.epa.gov/rblc/bl02.cfm

(except for $PM_{2.5}$ and emissions of NO_x for ozone) in Section 006 of the Rules. For any regulated NSR pollutant not included in that list, the emission of any amount is considered "significant." As shown in Table 4.7 below, the potential emissions of CO, NO_x, PM, and PM_{10} from the PCAEC are "significant." Each of these NSR pollutants is therefore subject to BACT requirements. Consequently, the BACT determination must separately address air pollution controls and limits for CO, NO_x, PM, and PM_{10} for each emissions unit or pollutant emitting activity at the PCAEC.

Table 4.7 PSD APPLICABILITY FOR REGULATED NSR POLLUTANTS

Pollutant	Significant Emission Rate (Tons per Year (TPY))	PCAEC Potential to Emit (Tons per Year)		Is Pollutant Subject to PSD/BACT?
		April 2008 Application	Feb 2009 Permit	
Carbon monoxide (CO)	100	203	135	Yes
Nitrogen oxides (NO_x), as nitrogen dioxide (NO_2)	40	127	109	Yes
Sulfur oxides, as sulfur dioxide (SO_2) [b]	40	32.3	23.4	No
Particulate matter (PM)	25	>66.7	>60.1	Yes
PM_{10}	15	66.7[a]	60.1	Yes
$PM_{2.5}$	10 TPY of direct PM2.5 emissions; 40 TPY of SO_2 emissions; 40 TPY of NO_x emissions, unless demonstrated not to be a $PM_{2.5}$ precursor	See Comment 25 in in the Response to Comments document.		See Comment 25 in in the Response to Comments document.
Ozone	40 TPY of volatile organic compounds (VOCs) or 40 TPY of NO_x	5.1 (VOCs) or 127 (NO_x)	5.1 (VOCs) or 109 (NO_x)	No Yes
Lead (elemental)	0.6	6.0E-04	6.0E-04	No
Fluorides, excluding hydrogen fluoride	3	Negligible [c]	Negligible [c]	No
Sulfuric acid mist	7	3.7	- 0 - [d]	No
Hydrogen sulfide (H_2S)	10	2.3	1.9	No
Total reduced sulfur,[e] including H_2S	10	2.3	1.9	No
Reduced sulfur compounds, including H_2S	10	2.3	1.9	No
Class I and II ODS	---	- 0 - [f]	- 0 - [f]	No

[a] Does not reflect the reduction in emissions associated with revised estimates for the cooling tower.

[b] Sulfur dioxide is the measured surrogate for the criteria pollutant sulfur oxides. Sulfur oxides were made subject to regulation explicitly through the proposal of 40 CFR 60, Subpart J as of August 17, 1989.

[c] Fluorides are not expected to be emitted (see the response to Comment 57 in the Response to Comments document).

[d] Addendum No. 3 to the PCAEC application, received on December 10, 2008, deleted the sulfuric acid plant option.

[e] Total reduced sulfur means the total concentration of sulfur from H_2S, methyl mercaptan (CH_3SH), dimethyl sulfide ($(CH_3)_2S$), and dimethyl disulfide (CH_3 $SSCH_3$). Mercaptans are not expected to be emitted (see the response to Comment 58 in the Response to Comments document).

[f] Federal and state regulations require capture and recycling of these materials when recharging or servicing equipment containing any Class I or II ozone depleting substance (ODS).

4.11.2 DEQ Review of Applicant's Proposed BACT

In a PSD application, the applicant provides a BACT analysis and proposes BACT. DEQ's responsibility is to review the applicant's BACT analysis and determine whether the applicant's analysis, proposed control technologies, and limits, represent BACT. As part of this review, DEQ:

- Conducted online reviews of recent BACT determinations for comparable processes at other facilities listed in the following databases: EPA's RBLC,[6] and California's South Coast Air Quality Management District (AQMD)[7] and Bay Area AQMD.[8]
- Reviewed general information in the technical literature and information on other similar projects that have been proposed or have recently been permitted. For example, DEQ reviewed recent BACT determinations for a very similar facility in Kansas, the Coffeyville Resources Nitrogen Fertilizers plant,[9] and BACT determinations for the proposed Rentech gasification project in Illinois,[10] and other sources as noted below.
- As noted in the applicant's BACT analysis, SIE also reviewed European guidance for best available pollution controls for the production of urea and UAN. DEQ also reviewed this guidance.

FEEDSTOCK HANDLING

a. Coal and Petcoke Handling (SRC01 – 12)

BACT is required for emissions of PM/PM_{10} from coal and petcoke railcar unloading, conveying, and storage at a maximum capacity of 5,000 tons per hour (120,000 tons per day).

Proposed BACT Technology and Limits: SIE proposed an enclosure kept under negative pressure for railcar unloading, covered conveyors and enclosed transfer points, silo storage of coal and petcoke, and high efficiency (99%) baghouse controls on all emission points, asserting that these controls constituted LAER. SIE's proposed pound-per-hour PM and PM_{10} emission limits are shown in Table 4.8, based on using state-of-the-art feedstock handling equipment.

BACT Technology and Limits: DEQ reviewed the RBLC listings for process type 90.011, Coal Handling/ Processing/Preparation/Cleaning, as well as an April 28, 2008 proposed rule change to NSPS Subpart Y, Standard of Performance for Coal Preparation Plants.[11] In the discussion for the proposed rule, EPA noted that no emerging pollution prevention measures or PM control technologies had been identified for controlling emissions from coal handling. The proposed rule suggests that the current "best demonstrated technology" is enclosures in conjunction with wet or chemical suppression or venting to a fabric filter.

The April 28, 2008 proposed rule change to NSPS Subpart Y, Standard of Performance for Coal Preparation Plants suggests that emissions using the current "best demonstrated technology" should be limited to:

- Opacity limit of 5% (reduced from the current Subpart Y opacity limit of 20%); and

---

[7] South Coast Air Quality Management District, California, http://www.aqmd.gov/bact/index.html
[8] Bay Area Air Quality Management District, California, http://www.baaqmd.gov/pmt/bactworkbook/default.htm
[9] August 6, 2007, Kansas Department of Health and Environment, Air Emission Source Construction Permit, Source ID 1250079, Coffeyville Resources Nitrogen Fertilizer Facility, Coffeyville, Kansas.
[10] September 14, 2007, Illinois EPA, Construction Permit, ID No. 085809AAA, Rentech Energy Midwest Corporation, East Dubuque, Illinois.
[11] April 28, 2008, EPA Proposed Rule, NSPS Subpart Y, 73 FR 22901.

- An emission limit of 0.011 g/dscm (0.0050 gr/dscf) for PM emissions vented to a stack for coal processing and conveying equipment, coal storage systems, and transfer and loading systems processing coal other than bituminous coals.

As shown in Table 4.8, the PM and PM_{10} emission limits proposed by SIE are considerably lower than 0.005 gr/dscf. DEQ included a 5% opacity limit and SIE's proposed pound per hour emission limits in the draft permit as BACT.

Table 4.8 PM and PM_{10} BACT EMISSION LIMITS FOR COAL AND PETCOKE HANDLING

Source	PM		PM_{10}	
	Proposed and Draft Permit BACT (lb/hr)	**Equivalent Grain Loading (g/dscf)[a]**	**Proposed and Draft Permit BACT (lb/hr)**	**Equivalent Grain Loading (g/dscf)[a]**
SRC01, Railcar Unloading	0.09	0.0009	0.044	0.0004
SRC02 - SRC07 Conveyor transfers and silo filling	0.09	0.0009	0.04	0.0004
SRC08 – SRC12 Reclaim conveyor transfers	0.002	0.00002	0.001	0.00001

[a] Grain loading was calculated by DEQ based on an elevation of 4560 ft above MSL, exit flows of 20,000 acfm, 30% moisture, and exhaust temperature of 68°F.

Based on this review, DEQ concurred that SIE's proposed emission controls represent the "top control," and evaluation of other alternatives was therefore not required. The pound per hour PM and PM_{10} limits shown in Table 4.8 are BACT for coal and petcoke handling.

b. Fluxant Handling (SRCxx)

BACT is required for emissions of PM/PM_{10} from fluxant railcar or truck unloading, conveying, and storage at a maximum rate of 250 tons per hour and 6,000 tons per day. Fluxant may include materials such as limestone and sand.

Proposed BACT Technology and Limit: SIE proposed water sprays to reduce the emissions of PM/PM_{10} from fluxant handling by 75%, and addressed all fluxant handling emissions as fugitive emissions.

BACT Technology and Limits: DEQ determined that for railcar unloading and subsequent transfers and storage, fluxant handling is essentially the same materials handling process described for coal and petcoke feedstock handling. Based on this comparison, and a review of BACT technology determinations for lime and limestone handling (RBLC process type 90.019), DEQ determined that the "top control" technology for fluxant handling included covered conveyors and enclosed transfer points (this would include a boot or similar connection for truck unloading), fluxant storage in a silo or equivalent storage method, and a high efficiency (99%) baghouse or cartridge filter on the silo vent(s).

BACT for fugitives control requires the use of water sprays to reduce emissions by a minimum of 75% (i.e., negligible visible fugitive emissions).

Although the costs would likely be prohibitively high to install an unloading facility for railcar unloading of only 250 tons per hour of fluxant, emissions from railcar unloading of fluxant will be reduced when using the railcar unloading facility for coal and petcoke which includes a negative pressure enclosure and rotary dumper (or equivalent).

DEQ set a secondary limit of 0.002 pounds per hour for PM/PM_{10} emissions from the silo (or equivalent) stack, based on an uncontrolled emission factor for transferring 250 tons per hour of sand into a silo[12] and a baghouse efficiency of 99%. Conservatively assuming (i.e., assumptions that increase the grain loading estimate) a nominal exhaust flow of 10,000 acfm and 95% humidity and an elevation of 4,560 feet, a 0.002 lb/hr emission rate corresponds to a grain loading of 0.00055 gr/dscf, a factor of ten lower than the suggested limit for coal handling in the proposed rule change to NSPS Subpart Y.

A separate opacity limit was not imposed for this source because, unlike coal handling, the fluxant handling is not subject to a specific opacity limit under any NSPS.

Because of the difficulty in measuring fugitive emissions for this source, work practices have been imposed instead of an emission limit: the use of water sprays as needed and periodic fugitive emissions inspections (see draft Permit Conditions 2.5 and 2.5.1 through 2.5.4).

Based on this review, DEQ determined that the emission controls determined to be BACT represent the "top control," and evaluation of other alternatives was therefore not required. The PM and PM_{10} limits of 0.002 lb/hr for the fluxant silo baghouse stack are BACT for this source. Work practices specified in Permit Conditions 2.5, 2.5.1-2.5.4 and 3.6 are BACT for controlling fugitive emissions from fluxant handling.

c. Slag Handling (FUG)

BACT is required for emissions of PM/PM_{10} from slag handling.

Proposed BACT Technology and Limit: SIE proposed storing the slag in a 3-sided bunker.

BACT Technology and Limits: Based on observations of slag handling at a Coffeyville, Kansas gasification facility during a June 2008 site visit by the DEQ permit engineer, and an understanding that the slag from the PCAEC will be similar in size and consistency, significant PM/PM_{10} emissions are not expected from slag handling and storage. The typical particle size is relatively large, the slag will be wet when first added to the storage pile, and the storage pile will be enclosed in a 3-sided bunker.

Fugitive emissions from transfers from dewatering to the slag storage pile, wind erosion of the slag storage pile, and slag storage truck loading were estimated by SIE to be 0.26 tons per year for PM (0.0455, 0.172, and 0.0455 tons per year), and 0.13 tons per year (0.0215, 0.086, and 0.0215 tons per year) for PM_{10}. The annual emissions from this heater based on operating continuously, i.e., for 8,760 hours per year are shown in the table below. In order to meet the BACT economic threshold of $10,000 per ton of pollutant reduction, the maximum annual cost for a control measure or control device for each pollutant subject to BACT could not exceed the values shown in the table. A brief review of the control equipment cost estimates contained in Section 4 of the application demonstrates that equipment and operational costs are typically more than $100,000. Requiring add-on control equipment for these relatively small fugitive emission sources is therefore not reasonable.

Table 4.9 EMISSIONS OF PM/PM_{10} FROM SLAG STORAGE

Pollutant	Steady State Emissions (TPY)	Control Option Cost Threshold ($)
PM	0.26	$2,600
PM_{10}	0.13	$1,300

Based on this review, DEQ determined storage in a 3-sided bunker and work practices to reduce fugitive emissions are BACT for slag handling.

[12] Maricopa County Air Quality Department, Emission Inventory Help Sheet for Concrete Batch Plants, http://www.maricopa.gov/aq/divisions/planning_analysis/docs/2007_helpsheets/07_concrete.pdf

NATURAL GAS-FIRED PROCESS HEATERS

d. ASU Regen Heater (SRC13)

BACT is required for emissions of CO, NO_x, PM and PM_{10} from this small combustion source.

Proposed BACT Technology and Limit: SIE proposed to operate the heater exclusively on natural gas, and to use good combustion practices to ensure emissions are kept as low as possible.

BACT Technology and Limit: Natural gas is the "top control" option for using clean fuels in fuel-burning equipment to reduce emissions of PM/PM_{10}.

The natural gas-fired ASU regen heater at the PCAEC will be sized to operate at 100,000 Btu per hour (0.1 MMBtu/hr). The annual emissions from this heater based on operating continuously, i.e., for 8,760 hours per year are shown in the table below. In order to meet the BACT economic threshold of $10,000 per ton of pollutant reduction, the maximum annual cost for a control measure or control device for each pollutant subject to BACT could not exceed the values shown in the table. A brief review of the control equipment cost estimates contained in Section 4 of the application demonstrates that equipment and operational costs are typically more than $100,000. Requiring add-on control equipment for this small natural gas-fired heater is therefore not reasonable.

Table 4.10 ASU REGEN HEATER EMISSIONS OF POLLUTANTS SUBJECT TO BACT

Pollutant	AP-42, Section 1.4 Emission Factor (lb/MMBtu)	Steady State Emissions 0.1 MMBtu/hr x 8,760 hr/yr (TPY)	Control Option Cost Threshold (Annual $/ton reduced)
PM/PM_{10}	7.45E-03	0.003	$30
NO_x	9.80E-02	0.043	$430
CO	8.42E-02	0.037	$370

Because of the expense of conducting a source test to measure emissions from such a small combustion source, work practices have been imposed instead of an emission limit. The draft permit requires *Good Combustion Control*. Combustion controls generally include the following: high temperatures, sufficient excess air, sufficient residence times and good air/fuel mixing. Combustion efficiency is directly related to the ''three T's'' of combustion: time, temperature and turbulence. These components of combustion efficiency are designed into boilers and other gas-fired furnaces to maximize fuel efficiency and to reduce fuel cost. A fourth important parameter is the level of oxygen in the combustor, often referred to as the excess air or excess oxygen level. Combustion control is accomplished primarily through good combustion principals in design and operation.

DEQ determined that burning natural gas exclusively is the "top control" and good combustion practices are BACT for CO, NO_x, PM, and PM_{10} for the ASU Regen Heater.

e. Gasifier Heater #1 and #2 (SRC14 and 15)

BACT is required for emissions of CO, NO_x, PM and PM_{10} from these relatively small combustion sources, which are part of a proprietary technology heating system for the gasifiers.

Proposed BACT Technology and Limit: SIE proposed to operate the heaters exclusively on natural gas, and to use good combustion practices to ensure emissions are kept as low as possible.

BACT Technology and Limit: Natural gas is the "top control" option for using clean fuels in fuel-burning equipment to reduce emissions of PM/PM_{10}..

The natural gas-fired gasifier heaters at the PCAEC will be sized to operate at 9 MMBtu/hr while on standby and 25 MMBtu/hr during startup conditions. As noted on p. 1-19 of the application, preheating the gasifiers from a cold start requires about 40 hours. In the table below, annual emissions associated with preheating each gasifier were very conservatively estimated by DEQ based on 50 startups per year. In order to meet the BACT economic threshold of $10,000 per ton of pollutant reduction, the maximum annual cost for a control measure or control device for each pollutant subject to BACT could not exceed the values shown in the table. A brief review of the control equipment cost estimates contained in Section 4 of the application demonstrates that equipment and operational costs are typically more than $100,000. Requiring add-on control equipment for these relatively small natural gas-fired heaters is therefore not reasonable.

Table 4.11 GASIFIER HEATER EMISSIONS OF POLLUTANTS SUBJECT TO BACT

Pollutant	AP-42, Section 1.4 Emission Factor	Steady State Emissions 9 MMBtu/hr x 8,760 hr/yr	Cost Threshold	Startup Emissions 25 MMBtu/hr x 40 hr x 50 startups	Cost Threshold
	(lb/MMBtu)	(TPY)	($)	(TPY)	($)
PM/PM_{10}	7.45E-03	0.294	$2,940	0.186	$1,860
NO_x	9.80E-02	3.865	$38,650	2.45	$24,500
CO	8.42E-02	3.246	$32,460	2.15	$21,500

Because of the expense of conducting a source test to measure emissions from such small combustion sources, work practices have been imposed instead of an emission limit. The draft permit requires *Good Combustion Control*. Combustion controls generally include the following: high temperatures, sufficient excess air, sufficient residence times and good air/fuel mixing. Combustion efficiency is directly related to the ‘‘three T’s’’ of combustion: time, temperature and turbulence. These components of combustion efficiency are designed into boilers and other gas-fired furnaces to maximize fuel efficiency and to reduce fuel cost. A fourth important parameter is the level of oxygen in the combustor, often referred to as the excess air or excess oxygen level. Combustion control is accomplished primarily through good combustion principals in design and operation.

DEQ determined that burning natural gas exclusively and good combustion practices are BACT for CO, NO_x, PM, and PM_{10} for the gasifier heaters.

STARTUP EQUIPMENT

f. Startup and Shutdown: Gasifier Flare (SRC16)

BACT is required for emissions of CO, NO_x, PM and PM_{10}.

<u>Proposed BACT Technology and Limit</u>: The off-specification syngas produced during startup and shutdown cannot be used in the fertilizer production process. SIE proposed to flare syngas during startup and shutdown, using a flare that complies with 40 CFR 60.18, uses steam or air-assist if needed to operate as a “smokeless” flare (i.e., PM/PM_{10} emissions are negligible), and is designed for a minimum 98% destruction efficiency for CO. Work practices listed in 40 CFR 60.18 were proposed in lieu of an emission limit.

<u>BACT Technology and Limit</u>: Based on the description of the production process, DEQ concurred that the off-specification syngas cannot be routed to the AGR and used in the fertilizer production process. Because the heat content of the syngas may vary widely until the process reaches steady-state conditions, DEQ also determined that the off-specification syngas could not reasonably be burned in the process heaters or boilers.

DEQ reviewed the RBLC database for process type 19.310, Chemical Plant Flares, as well as 40 CFR 60.18 (control device and work practice requirements for flares referenced in an applicable NSPS) and 40 CFR 63.11 (control device and work practice requirements for flares referenced in an applicable MACT). A smokeless flare designed for at least 98% destruction of CO and operated in accordance with 40 CFR 60.18 is the "top control" option for flaring.

Testing of flares in the field has been described as "nearly impossible."[13] In accordance with 1990 NSR PSD Workbook guidance, if "there is no economically reasonable or technologically feasible way to accurately measure the emissions, and hence to impose an enforceable standard, [the reviewing agency] may require the source to use design, alternative equipment, work practices or operational standards to reduce emissions of the pollutant to the maximum extent." For this reason, emission standards for flares were not set in the draft permit; emissions for the gasifier flare are kept as low as possible by following the work practices specified in Permit Condition 7.5.1.

DEQ determined that a smokeless flare designed and operated in accordance with 40 CFR 60.18 with a natural gas pilot is the "top control" technology, and combined with work practices specified in 40 CFR 60.18 are BACT for CO, NO_x, PM, and PM_{10} for the gasifier flare.

g. Startup and Shutdown: Package Boiler (SRC24)

BACT is required for emissions of CO, NO_x, PM and PM_{10} for this combustion source.

Proposed BACT Technology and Limit: The 250 MMBtu package boiler will be used only during startup and shutdown. SIE proposed using good combustion practices to control CO to a maximum of 18.5 lb/hr (0.074 lb/MMBtu at maximum capacity), a low-NO_x burner and flue gas recirculation (FGR) to control NO_x to a maximum emission level of 5.0 lb/hr (0.02 lb/MMBtu at maximum capacity), and natural gas fuel and good combustion practices to control PM/PM_{10} to a maximum emission level of 1.3 lb/hr (0.0052 lb/MMBtu at maximum capacity).

BACT Technology and Limit:

CO. As shown in Table 4-17 of the application, catalytic oxidation is the "top control" technology for controlling CO from a boiler. SIE evaluated the incremental cost effectiveness of catalytic oxidation compared to using good combustion practices, and demonstrated that catalytic oxidation could be ruled out on an economic basis.

DEQ reviewed the RBLC lowest emission rate determinations for natural gas-fired industrial boilers and furnaces over the past decade. The range of lowest CO emission rates over this period was 0.030 to 1.47 lb/MMBtu for smaller boilers and from 0.01 to 1.13 lb/MMBtu for boilers larger than 250 MMBtu/hr. A BACT limit of 0.0008 lb/MMBtu from a 2001 permit in New York was dropped from consideration because it appears to be an outlier. The CO emission limit in the draft permit (equivalent to 0.074 lb/MMBtu) is contained within the lowest 4% of this range of values.

NO_x. As shown in Table 4-13 of the application, SCR is the "top control" technology for controlling NO_x for natural gas-fired boilers. SIE evaluated the incremental cost effectiveness of SCR compared to using a low-NO_x burner and FGR, and demonstrated that SCR could be ruled out on an economic basis presuming that the package boiler operated continuously. With the design decision to use a Claus sulfur recovery unit instead of a wet sulfuric acid plant (Addenda Nos. 1 and 4 to the application), the package boiler is proposed for use only during startup and shutdown. The reduction in annual operations—and

[13] 2006, Industrial-Scale Flare Testing, *Environmental Management*, American Institute of Chemical Engineers, May 2006, accessible at http://www.johnzink.com/products/flares/pdfs/05CEP_FlareTesting.pdf

commensurate reduction in the predicted emissions from this boiler—means that SCR would be at an even greater economic disadvantage compared to using a low-NO_x burner and FGR.

As described in the BACT analysis submitted in Addendum No. 1 to the application, recently permitted boilers had a NO_x emission rate range of 0.011 to 0.7 lb/MMBtu. As part of the review of the proposed BACT limits, DEQ had also queried the RBLC database for the "lowest emission rate" final determination for natural gas-fired industrial boilers (less than or equal to 250 MMBtu/hr and greater than 250 MMBtu/hr) over the past decade. The query returned the same information reported by the applicant: a range of 0.011 to 0.7 lb/MMBtu for NO_x emission limits for the smaller boilers, and a range of 0.007 to 0.61 lb/MMBtu for the larger boilers. The NO_x emission limit in the draft permit (equivalent to 0.02 lb/MMBtu) is contained within the lowest 2% of this range of values.

PM/PM_{10}. Natural gas is the "top control" option for using clean fuels in fuel-burning equipment to reduce emissions of PM/PM_{10}. Further evaluation of alternative technologies was not required.

As part of the review of the proposed BACT limits, DEQ queried the RBLC database for the "lowest emission rate" final determination for natural gas-fired industrial boilers (less than or equal to 250 MMBtu/hr and greater than 250 MMBtu/hr) over the past decade. The query returned a range of 0.0066 to 0.24 lb/MMBtu for PM emission limits for the smaller boilers, and a range of 0.005 to 0.10 lb/MMBtu for the larger boilers. The PM/PM_{10} emission limit in the draft permit (equivalent to 0.0054 lb/MMBtu) is contained within the lowest 0.2% of this range of values.

Based on DEQ's review of the applicant's submittal and other sources, DEQ determined that a low-NO_x burner and FGR is BACT for the package boiler. The emission limits proposed by SIE are also BACT, as follows: 0.074 lb/MMBtu for CO, 0.02 lb/MMBtu for NOx, and 0.0052 lb/MMBtu/hr for PM/PM_{10}.

STEADY-STATE OPERATIONS

h. Steam Superheater Boiler (SRC31)

BACT is required for emissions of CO, NO_x, PM and PM_{10} for this combustion source.

Proposed BACT Technology and Limit: The 250 MMBtu steam superheater boiler will be used during startup, steady-state operations, and shutdown. SIE proposed using good combustion practices to control CO to a maximum of 18.5 lb/hr (0.074 lb/MMBtu at maximum capacity), a low-NO_x burner and selective catalytic reduction (SCR) to control NO_x to a maximum emission level of 5.0 lb/hr (0.02 lb/MMBtu at maximum capacity), and natural gas/PSA tailgas and good combustion practices to control PM/PM_{10} to a maximum emission level of 1.3 lb/hr (0.0052 lb/MMBtu at maximum capacity).

BACT Technology and Limit:

CO. As shown in Table 4-17 of the application and the same table in Addendum No. 1 to the application, catalytic oxidation is the "top control" technology for controlling CO from a boiler. SIE evaluated the incremental cost effectiveness of catalytic oxidation compared to using good combustion practices, and demonstrated that catalytic oxidation could be ruled out on an economic basis.

The CO limit of 0.074 lb/MMBtu was demonstrated to be BACT for the 250 MMBtu/hr package boiler (see above). The same limit applies to the steam superheater boiler.

NO_x. As shown in Table 4-13 of the application, SCR is the "top control" technology for controlling NO_x for natural gas-fired boilers. The steam superheater boiler may burn up to 100% of the PSA tailgas produced, an increase from the 40% PSA tailgas originally proposed to be combusted in the package boiler. Because the PSA tailgas contains much more hydrogen than natural gas, SIE presumed that the

NO_x emissions will be higher, and adjusted the NO_x control emission rates upward in consultation with their technology providers. For example, at 97% efficiency, NO_x emissions when burning natural gas were estimated at 0.011 lb/MMBtu; this was increased to 0.02 lb/MMBtu for burning PSA tailgas. SIE selected SCR as a technically feasible technology that could provide NO_x emissions equal or better than the emissions already modeled for the package boiler.

The NO_x limit of 0.02 lb/MMBtu was demonstrated to be BACT for the 250 MMBtu/hr package boiler (see above). The same limit applies to the steam superheater boiler.

PM/PM_{10}. Natural gas is the "top control" option for using clean fuels in fuel-burning equipment to reduce emissions of PM/PM_{10}. Based on the process description, PM/PM_{10} emissions from combusting the PSA tailgas can reasonably be expected to be similar or less than emissions on natural gas. Further evaluation of alternative technologies was not required.

The PM/PM_{10} limit of 0.0052 lb/MMBtu was demonstrated to be BACT for the 250 MMBtu/hr package boiler (see above). The same limit applies to the steam superheater boiler.

Based on DEQ's review of the applicant's submittal and other sources, DEQ determined that the applicant proposed BACT for the steam superheater boiler: good combustion practices for CO, a low-NO_x burner and SCR for NO_x, and natural gas fuel and good combustion practices for PM/PM_{10}. The emission limits proposed by SIE are also BACT, as follows: 0.074 lb/MMBtu for CO, 0.02 lb/MMBtu for NO_x, and 0.0052 lb/MMBtu/hr for PM/PM_{10}.

i. Selexol AGR CO_2 Vent (SRC17)

BACT is required for emissions of CO from this emission source. BACT is also considered for CO, NO_x, and PM/PM_{10} emissions associated with the selected control technology, a thermal oxidizer.

Proposed BACT Technology and Limit:

CO. The CO_2 vent stream is composed of CO_2, CO, H_2S, and COS. In response to public comments, SIE has worked with their vendor to confirm that the thermal oxidizer can reach destruction efficiencies for CO of 95% instead of the 90% originally proposed. The proposed CO emission limit is therefore 8.7 lb/hr instead of 17.3 lb/hr.

PM/PM_{10}. BACT not specifically proposed.

NO_x. NO_x from combustion of natural gas in the 9 MMBtu/hr burner associated with the thermal oxidizer will be limited to 0.098 lb/MMBtu (0.9 lb/hr).

BACT Technology and Limit:

CO. Thermal oxidation can achieve 90% to 95% destruction efficiency, as can catalytic oxidation,[14] so each of these oxidation technologies could be considered the "top control" for CO emissions from the AGR CO_2 vent. SIE evaluated and selected thermal oxidation and good operating practices for control of CO. SIE therefore selected one of the equivalent "top control" technologies, and no further evaluation of alternatives was required.

NO_x. The 9 MMBtu/hr burner associated with the thermal oxidizer will operate at maximum capacity only during startup. As demonstrated in the BACT analysis for the gasifier heaters, the use of natural gas as a fuel and good combustion practices constitute BACT for NO_x emissions from this combustion source.

[14] December 22, 2008, Homeland Energy Solutions, PSD Permit Fact Sheet, Project No. 08-555, Plant No. 19-04-002, Iowa Department of Natural Resources, Environmental Services Division, Air Quality Bureau.

PM/PM_{10}. Natural gas is the "top control" option for using clean fuels in fuel-burning equipment to reduce emissions of PM/PM_{10}. As demonstrated in the BACT analysis for the gasifier heaters, the use of natural gas as a fuel and good combustion practices constitute BACT for the small amount of PM/PM_{10} emissions from this combustion source.

No PM/PM_{10} is emitted as mists. Emission estimates associated with the Selexol AGR CO_2 vent were obtained from UOP and CSM technologies. UOP is the licensor of the Selexol technology, and CSM is a potential provider of the thermal oxidizer for CO, H_2S, and COS abatement. UOP previously confirmed for SIE that the gas leaving the Selexol unit is free of moisture and other mists, as the syngas entering the Selexol system is treated to remove moisture. The CO_2 vent stream is composed of CO_2, CO, H_2S, and COS. According to UOP, there are no discernable acid compounds in the vent gas. The thermal oxidizer reduces the amount of CO, H_2S, and COS to form more CO_2, water, and SO_2. The thermal oxidizer has a destruction efficiency of 95% for these compounds (see the response to Comment 91 in the Response to Comments document). Absent moisture or acid mist from the Selexol AGR process, it is reasonable to conclude that there are no quantifiable emissions of particulate matter (in the form of acid mist) from the Selexol system.

Based on DEQ's review of the applicant's submittal and other sources, DEQ determined that a thermal oxidizer and good combustion practices is BACT for CO, the use of natural gas and good combustion practices is BACT for NO_x, and natural gas fuel and good combustion practices for PM/PM_{10}. The BACT emission limit for CO is 8.7 lb/hr, and 0.9 lb/hr for NO_x emissions. Fuel selection (natural gas) and good combustion practices are BACT work practices for emissions of PM/PM_{10} from the oxidizer burner.

j. Nitric Acid Unit – Tailgas (SRC20)

BACT is required for emissions of NO_x from the nitric acid tailgas vent.

Proposed BACT Technology and Limit: SIE proposed SCR with a limit of 15.33 lb/hr (50 ppmv) for NO_x emissions.

BACT Technology and Limit:

NO_x. As shown in Table 4-12 of the application, SCR is the "top control" technology for controlling NO_x for this source. No further evaluation of alternatives was required.

As described in the application, SCR control efficiency for NO_x is about 98%, with controlled emission rates ranging from 50 ppmv to 200 ppmv. SIE selected the lowest value in this range, 50 ppmv. On a mass basis, this results in 15.33 lb/hr NO_x emissions (equivalent to 0.64 lb of NO_x per ton of acid produced) when producing 575 tons per day of nitric acid. The NO_x emissions rate was determined by scaling design information for a 525 ton per day Weatherly nitric acid plant using SCR as BACT (with 100 ppmv NO_x emissions) to the proposed production level of 575 tons per day, and dividing the resulting pound-per-hour rate by two to reflect a maximum 50 ppmv NO_x concentration.

DEQ's review of BACT limits in permits issued in 2004 or later for nitric acid plants shows BACT limits set at the NSPS "floor" of 3.0 lb/ton of acid produced (2005) and 0.524 lb/ton (2004, for Plant 7, for a Kennewick, Washington PSD facility.[15] In that 2004 permit, a limit of 0.3 lb/ton was imposed for emissions from the Plant 9 nitric acid plant located at the same facility. That limit was subsequently

[15] http://www.ecy.wa.gov/programs/air/psd/psd_pdfs/PSD0401_final.pdf, issued to Kennewick Fertilizer Operations on August 27, 2004.

increased to 0.6 lb/ton in the 2008 permit referenced by the commenter.[16] Each of these BACT limits for the Kennewick facility is *averaged over all operating hours during any consecutive 12-calendar month period.*

SIE's proposed BACT limit in the draft permit of 15.33 lb/hr for NO_x emissions from the nitric acid plant (nitric acid tailgas vent) is equivalent to 50 ppmv and to 0.64 lb/ton of acid at the maximum production rate of 575 tons of acid per day. This limit applies at all times during steady-state operations, and is hence more stringent than the "rolling 12-month average" limits imposed on the Kennewick facility's nitric acid plants.

Based on DEQ's review of the applicant's submittal and other sources, DEQ determined that the applicant proposed BACT for the nitric acid tailgas vent: SCR with a NOx emission limit of 50 ppmv.

k. Ammonium Nitrate Neutralizer Vent (SRC29)

BACT is required for emissions of PM/PM_{10} from the AN neutralizer vent.

<u>Proposed BACT Technology and Limit</u>: SIE proposed no add-on controls (a wet scrubber that captures and recycles 90% of the particulates is an integral part of the neutralizer process), and a PM/PM_{10} emission limit of 1.5 lb/hr.

<u>BACT Technology and Limit</u>:

DEQ reviewed permits for other facilities using an AN neutralizer (Dyno Nobel, Inc., in Laramie County, Wyoming [scrubber];Farmland Industries, Fort Dodge, Iowa [2 packed bed scrubbers in series]) and determined that wet scrubbers are typically used within these processes or as add-on controls.

DEQ reviewed emission factors contained in AP-42 Section 8.3, "Ammonium Nitrate," which were last updated in 1993. As shown in Table 8.3-2 of that section, the uncontrolled PM emission factor from a neutralizer ranges from 0.09 to 8.6 lb per ton of product, and the controlled PM emission factor ranges from 0.004 to 0.43 lb per ton of product. These emission factors were based on reference materials developed from 1979 – 1981, and 1991. While AP-42 emission factors can be helpful if no other information is available, preference is always given to vendor data (for preconstruction compliance reviews) and source test data from the facility (for demonstrating compliance after construction or for subsequent analyses for facility modifications).

The controlled PM/PM_{10} emission factor used by SIE for emissions from the AN neutralizer vent was 1.5 lb/hr, based on Stamicarbon vendor information. This represents an emission rate of about 0.05 lb/ton of product from the production of 715 tons per day of ammonium nitrate, which is in the mid-range of "controlled" emission factors listed in AP-42. The emission estimate was based on Stamicarbon technology using a wet scrubber with a minimum PM/PM_{10} capture and recycle efficiency of 90% (see the KBR report included in Appendix D of the application).

DEQ's review of technical literature identified that concentrations of particulates in AN neutralizer process exhaust is typically less than 30 mg/Nm^3.[17] A review of RBLC BACT determinations identified scrubber controls with 90% efficiency as BACT for an ammonium nitrate concentrator (Mississippi Chem. Nitrogen, LLC, RBLC ID No. MS-0070, 2004).

[16] http://www.ecy.wa.gov/programs/air/psd/psd_pdfs/PSD0401_final1stAmend.pdf, issued to Kennewick Fertilizer Operations on July 10, 2008.

[17] Hodge, Charles A., and Neculai N. Popovici, Eds, Pollution Control in Fertilizer Production, CRC Press 1994, ISBN 0824791886, 9780824791889, accessible at http://books.google.com

Because of the expense of conducting a source test to measure emissions from such a small emission source, work practices have been imposed instead of an emission limit. Although the AN neutralizer scrubber is process equipment, it has been added to the list of equipment for which O&M manual provisions must be developed and implemented.

Based on DEQ's review of the applicant's submittal and other sources, DEQ determined that the wet scrubber (process equipment) designed to capture and recycle 90% of the particulates in the neutralizer process. Work practices (O&M manual provisions for the AN neutralizer scrubber) are BACT for the AN neutralizer vent.

l. Urea Melt Plant Vent (SRC23)

The urea melt plant vent comes off the process water recovery system. The emissions from this vent are limited to ammonia (see the KBR report in Appendix D and Addendum No. 4 of the application). At an exhaust stack temperature of about 113^{o}F, the ammonia will be emitted as a lighter-than-air gas,[18] not as a mist that should be evaluated as an emission of PM_{10}. BACT is therefore not required for this emission source.

m. Urea Granulation Vent (SRC19)

BACT is required for emissions of PM/PM_{10} from the urea granulation vent.

<u>Proposed BACT Technology and Limit</u>: SIE proposed a wet scrubber with a minimum control efficiency of 98% for PM/PM_{10}, and a PM emission limit of 20.5 lb/hr and PM_{10} emission limit of 9.0 lb/hr.

<u>BACT Technology and Limit</u>:

DEQ reviewed RBLC BACT determinations for process type 61.012, Fertilizer Porduction. BACT for a granulation drum at an Ohio facility (RBLC ID No. OH-0267) was shown as a 98% efficiency pulse jet baghouse with an emission limit of 0.005 gr/dscf.

Like SIE, DEQ reviewed best available techniques for urea granulation published by the European Fertilizer Manufacturers Association,[19] which says that dust removal efficiencies of 98% can be achieved using standard wet scrubbers. Urea dust concentrations from an existing plant were reported as a being in the range of 30 to 75 mg/Nm^3.

As described in the application, wet scrubbers are typically used to control emissions from urea granulation. DEQ reviewed emission factors contained in AP-42 Section 8.2, "Urea," which were last updated in 1993. As shown in Table 8.2-1 of that section, the uncontrolled PM emission factor from drum granulation is listed as 241 lb/ton of product, and the controlled PM emission factor is listed as 0.234 lb per ton of product. At the maximum granulated urea production of 1,800 tons per day, the emission limits proposed by SIE are equivalent to 0.011 lb PM/ton of product and 0.005 lb PM_{10}/ton of product. SIE's proposed PM emission rate is less than 5% of the AP-42 emission rate. The proposed emission rates can reasonably be presumed to represent BACT.

Based on DEQ's review of the applicant's submittal and other sources, DEQ determined that a wet scrubber with a minimum 98% efficiency for PM/PM_{10} is the "top control" technology for

---

[18] April 22, 2008, Mallinckrodt Baker, Inc., MSDS Number A5472, Ammonia Solution, Strong, accessible at http://www.jtbaker.com/msds/englishhtml/a5472.htm

[19] Best Available Techniques, 2000, European Fertilizer Manufacturers Association, accessible at http://cms.efma.org/EPUB/easnet.dll/ExecReq/Page?eas:template_im=000BC2&eas:dat_im=000EAE

urea granulation. BACT emission limits are 0.011 lb PM/ton of product and 0.005 lb PM_{10}/ton of product.

PROCESS FLARES

n. Process Flare (SRC21)

The process flare is used to control emissions of ammonia and hazardous gases from the ammonia and urea processes. See the BACT discussion for the gasifier flare.

DEQ determined that a smokeless flare designed and operated in accordance with 40 CFR 60.18 with a natural gas pilot is the "top control" technology, and combined with work practices specified in 40 CFR 60.18 are BACT for CO, NO_x, PM, and PM_{10} for the process flare.

o. Ammonia Storage Flare (SRC27)

The ammonia storage flare is used to control emissions from the ammonia storage tanks. See the BACT discussion for the gasifier flare.

DEQ determined that a smokeless flare designed and operated in accordance with 40 CFR 60.18 with a natural gas pilot is the "top control" technology, and combined with work practices specified in 40 CFR 60.18 are BACT for CO, NO_x, PM, and PM_{10} for the process flare.

COOLING TOWERS

p. Cooling Tower (SRC22)

BACT is required for emissions of PM/PM_{10} from the cooling tower.

<u>Proposed BACT Technology and Limit</u>: SIE proposed drift/mist eliminators to control PM/PM_{10}, with an emission limit of 1.51 lb/hr based on an elimination efficiency of 0.0005% of the circulating water flow rate. SIE's vendor, SPX Cooling Technologies asserted that this was LAER for cooling tower emissions.

<u>BACT Technology and Limit</u>:

DEQ reviewed RBLC BACT determinations for process type 99.009, Industrial Process Cooling Towers. The dominant BACT technology is clearly drift/mist eliminators. Drift/mist eliminator efficiencies reported ranged from 75% (RBLC AR-0051) to 99.95% (RBLC AR-0047), and limits not to exceed 0.0005% (AZ-0047) and 0.0010% (RBLC AR-0070) drift loss.

Based on DEQ's review of the applicant's submittal and other sources, DEQ determined that a high efficiency drift/mist eliminators are the "top control" technology. BACT emission limits for PM/PM_{10} are 0.0005% of the total circulating water flow rate.

q. Zero Liquid Discharge System (ZLDS, SRC30)

BACT is required for emissions of PM/PM_{10} from the cooling tower.

<u>Proposed BACT Technology and Limit</u>: SIE proposed drift/mist eliminators to control PM/PM_{10}, with an emission limit of 0.3 lb/hr based on an elimination efficiency of 0.001% of the circulating water rate.

<u>BACT Technology and Limit</u>:

DEQ reviewed RBLC BACT determinations for process type 99.009, Industrial Process Cooling Towers. The dominant BACT technology is clearly drift/mist eliminators. Drift/mist eliminator efficiencies reported ranged from 75% (RBLC AR-0051) to 99.95% (RBLC AR-0047), and limits not to exceed 0.0005% (AZ-0047) and 0.0010% (RBLC AR-0070) drift loss.

The ZLDS will operate at a considerably smaller circulating flow rate than the cooling tower (about 985 gpm compared to 121,000 gpm), but with a much higher concentration of total dissolved solids (50,000 mg/L compared to 5,000 mg/L). Based on this, it is unlikely that the ZLDS drift/mist eliminators could meet the 0.0005% BACT limit proposed for the cooling tower. Given the ten-fold increase in solids concentration for the ZLDS compared to the cooling tower, SIE is proposing that the elimination efficiency of the ZLDS will be reduced by only half compared to the cooling tower.

Based on DEQ's review of the applicant's submittal and other sources, DEQ determined that a high efficiency drift/mist eliminators are the "top control" technology. BACT emission limits for PM/PM_{10} are 0.001% of the total circulating water flow rate.

EMERGENCY GENERATORS

r. 2 MW Diesel Emergency Engine Generator (SRC25)

BACT is required for emissions of CO, NOx, PM, and PM_{10} from the engine generator.

Proposed BACT Technology and Limit: SIE proposed installing modern, typical engine controls coupled with frequent maintenance in accordance with manufacturer's specifications.

BACT Technology and Limit:

The new engine generator will be subject to NSPS Subpart IIII. Installation and operation of a new engine meeting Subpart IIII requirements is the "top control" for this type of emission source.

Based on DEQ's review of the applicant's submittal and other sources, DEQ determined that installation of a new engine generator meeting the requirements of NSPS Subpart IIII is BACT.

s. 500 kW Diesel Emergency Engine Generator (Fire Pump)(SRC26)

BACT is required for emissions of CO, NOx, PM, and PM_{10} from the engine generator.

Proposed BACT Technology and Limit: SIE proposed installing modern, typical engine controls coupled with frequent maintenance in accordance with manufacturer's specifications.

BACT Technology and Limit:

The new engine generator will be subject to NSPS Subpart IIII. Installation and operation of a new engine meeting Subpart IIII requirements is the "top control" for this type of emission source.

Based on DEQ's review of the applicant's submittal and other sources, DEQ determined that installation of a new engine generator meeting the requirements of NSPS Subpart IIII is BACT.

The control technologies and emission limits or work practices that were determined to be BACT for CO, NO_x, PM, and PM_{10} emission sources are summarized in Table 4.12. Process information, selection of fuel types, or other information considered in determining BACT is also noted in the table.

Table 4.12 SUMMARY OF BACT DETERMINATIONS FOR EACH EMISSION POINT

Source ID No.	Description	Pollutant-Specific BACT Emission Limits	Best Available Control Technology/ Basis or Consideration
 SRC01 SRC02 SRC03 SRC04 SRC05 SRC06 SRC07	Coal/Petcoke Railcar Unloading Railcar Hopper to Railcar Conveyor Railcar Conveyor to Silo Conveyors Silo Conveyor to Stacker Conveyors Silo 3 Vent Silo 1 Vent Silo 2 Vent	Each Source: PM: 0.09 lb/hr PM10: 0.04 lb/hr 5% opacity	BACT for Each Source: Enclosure(s) as described in Table 3.1 of this permit. Baghouse, minimum 99% control for PM/ PM_{10}
 SRC08 SRC09 SRC10 SRC11 SRC12	Coal/Petcoke Silo 1 Reclaimer to Reclaim Conveyor Silo 2 Reclaimer to Reclaim Conveyor Silo 3 Reclaimer to Reclaim Conveyor Reclaim Conveyor to Rod Mill Hopper 1 Reclaim Conveyor to Rod Mill Hopper 2	Each Source: PM: 0.002 lb/hr PM_{10}: 0.001 lb/hr 5% opacity	BACT for Each Source: Enclosure(s) as described in Table 3.1 of this permit. Baghouse, minimum 99% control for PM/PM_{10}
SRCxx	Fluxant Silo Filling	PM: 0.002 lb/hr PM_{10}: 0.002 lb/hr	BACT: Baghouse/cartridge filter, minimum 99% control for PM/PM_{10}
FUG	Fluxant unloading and conveying	None. Work practices in lieu of emission limits.	BACT for Each Source: Enclosure(s) as described in Table 3.1 of this permit. Water sprays. BMPs for fugitive controls.
SRC28	Slag handling and storage	None. Work practices in lieu of emission limits.	BACT: Slag storage in 3-sided bunker. BMPs for fugitive controls.
FUG	Process equipment leaks - CO	None. Work practices in lieu of emission limits.	BACT: None CO Fugitive BMP Plan
SRC13	ASU Regen Heater	None. Work practices in lieu of emission limits.	BACT: Good combustion practices. Natural gas fuel exclusively. Consideration(s): Natural gas fuel Small source (100,000 Btu/hr) Intermittent operation.
SRC14 SRC15	Gasifier Heater #1 Vent Gasifier Heater #2 Vent	None. Work practices in lieu of emission limits.	BACT: Good combustion practices. Natural gas fuel exclusively. Consideration(s): Natural gas fuel. Small source (~9 to 25 MMBtu/hr) Only one heater operated after routine startup during normal operations.
SRC16	Gasifier Flare	None. Work practices in lieu of emission limits.	BACT: Good combustion practices. Steam- or air-assist required only if unassisted flare produces smoke. Meet 40 CFR 60.18 Consideration(s): Natural gas pilot fuel. Flare only during startup, shutdowns Syngas cleanup: quench, sour water scrubber, carbon beds prior to flaring.

Table 4.12 SUMMARY OF BACT DETERMINATIONS FOR EACH EMISSION POINT

Source ID No.	Description	Pollutant-Specific BACT Emission Limits	Best Available Control Technology/ Basis or Consideration
SRC17	Selexol AGR CO_2 vent (AGR Stream 2)	SO_2: 3.6 lb/hr NOx: 0.9 lb/hr CO: 17.3 lb/hr	BACT: Thermal Oxidizer with minimum 90% control for CO and H2S, COS (as SO2) Oxidizer NOx control: Good combustion practices. Consideration(s): Syngas cleanup upstream of AGR, AGR removes most sulfur compounds and hydrogen from this CO_2-rich stream.
SRC18	Wet Sulfuric Acid Plant vent (DELETED)	---	---
SRC19	Urea Granulation Vent	PM: 0.011 lb/ton of product PM_{10}: 0.005 lb/ton of product	BACT: Wet scrubber, minimum 98% control for PM/PM_{10} Consideration(s): Granulation results in less PM_{10} than prilling.
SRC20	Nitric Acid Unit – Tailgas	NOx: 50 ppmv	BACT: SCR with minimum 98% control for NO_x
SRC21	Process Flare	None. Work practices in lieu of emission limits.	BACT: Good combustion practices. Steam- or air-assist required only if unassisted flare produces smoke. Meet 40 CFR 60.18 Consideration(s): Natural gas pilot fuel. Intermittent Flare Syngas cleanup train upstream of ammonia and urea plants.
SRC22	Cooling Tower	PM/ PM_{10}: 0.0005% of total circulating flow rate	BACT: Drift/mist eliminators
SRC23	Urea Melt Plant Vent	None.	Not subject to BACT. No emissions of CO, NO_x, PM/PM_{10}
SRC24	Package Boiler	PM/ PM10: 0.0052 lb/MMBtu NOx: 0.02 lb/MMBtu CO: 0.074 lb/MMBtu	BACT: Good combustion practices for all pollutants except NOx. NOx: Low-NOx burner. Flue gas recirculation, minimum 95 % control. Consideration(s): Operated only during startup and shutdown Fired exclusively on natural gas

Table 4.12 SUMMARY OF BACT DETERMINATIONS FOR EACH EMISSION POINT

Source ID No.	Description	Pollutant-Specific BACT Emission Limits	Best Available Control Technology/ Basis or Consideration
SRC31	Steam Superheater Boiler	PM/ PM10: 0.0052 lb/MMBtu NOx: 0.02 lb/MMBtu CO: 0.074 lb/MMBtu	BACT: Good combustion practices for all pollutants except NOx. NOx: Low-NOx burner SCR, minimum 97% control for NOx Fuels limited to PSA tailgas and natural gas. Consideration(s): Syngas cleanup upstream of AGR, AGR removes most CO, CO_2, COS, and H2S, from the syngas stream before passing through the PSA. Maximum 100% of PSA tailgas produced may be burned in the Steam Superheater boiler. PSA tailgas contains more H_2 than natural gas.
SRC25	2 MW Diesel Emergency Engine Generator	PM: 0.15 lb/hr PM10: 0.15 lb/hr NOx: 31.89 lb/hr CO: 1.7 lb/hr	BACT: New engine generator certified to be in compliance with 40 CFR 60, Subpart IIII.
SRC26	500 kW Diesel Emergency Engine Generator (Fire Pump)	PM: 0.03 lb/hr PM10: 0.03 lb/hr NOx: 8.5 lb/hr CO: 0.6 lb/hr	BACT: New engine generator or NFPA 20-certified fire pump certified to be in compliance with 40 CFR 60, Subpart IIII.
SRC27	Ammonia Storage Flare	None. Work practices in lieu of emission limits.	BACT: Good combustion practices. Steam- or air-assist required only if unassisted flare produces smoke. Meet 40 CFR 60.18 Consideration(s): Natural gas pilot fuel. Intermittent Flare Syngas cleanup train upstream of ammonia plant.
SRC29	Ammonium Nitrate Neutralizer Vent	None. Work practices in lieu of emission limits.	BACT: 90% efficient wet scrubber is integral to the process.
SRC30	Zero Liquid Discharge System (ZLDS)	PM/ PM_{10}: 0.001% of total circulating flow rate	BACT: Drift/Mist Eliminators
TNK03 TNK04	Ammonia Storage Tank Ammonia Storage Tank	None.	Not subject to BACT. No emissions of CO, NO_x, PM/PM_{10}
TNKxx TNKxx	Elemental Sulfur Storage Tank(s)	None.	Not subject to BACT. No emissions of CO, NO_x, PM/PM_{10}
TNK07 TNK08 TNK09 TNK10	UAN Storage Tank UAN Storage Tank UAN Storage Tank UAN Storage Tank	None.	Not subject to BACT. No emissions of CO, NO_x, PM/PM_{10}
TNK11	Nitric Acid Storage Tank	None.	Not subject to BACT. No emissions of CO, NO_x, PM/PM_{10}
TNK18	500 kW Diesel Emergency Engine Generator (Fire Pump) Fuel Tank	None.	Not subject to BACT. No emissions of CO, NO_x, PM/PM_{10}
TNK19	2 MW Diesel Emergency Engine Generator	None.	Not subject to BACT. No emissions of CO, NO_x, PM/PM_{10}

4.12 Permit Conditions Review

Facility-Wide Conditions

PC 2.1, Definitions. Facility comments on the draft permit identified the need to explicitly define some of the regulatory terms used in the permit. Malfunction, initial startup, and startup are defined in NSPS general provisions and in the Rules. Commencement of operations is not explicitly defined in either the federal or Idaho rules. Because startup means the setting in *operation* of a source for any purpose, a *source* is any building, structure, etc. that emits or may emit an air pollutant, and to *commence* means to begin[20], *commencement of operations* is defined as the initial startup of any emissions source at the facility.

Deleted Draft PC 2.2, HAP Emission Limits. HAP emission limits were set at 8 tons per year for any HAP and 20 tons per year for all HAPs to provide a federally-enforceable limit to keep the facility as a minor or synthetic minor source for HAPs. This permit condition was deleted. The uncontrolled emissions of all HAPs are less than 25 tons per year, but at 16.3 tons per year the COS emissions exceed 10 tons per year. Federally-enforceable conditions are in place to limit the emissions of COS to 0.8 tons per year (95% efficient thermal oxidizer on the AGR CO_2 vent).

PC 2.2, Requirement to Modify PTC. Because the detailed engineering has not yet been done for this proposed project, specific operating parameter ranges are not yet available for pollution control devices and process equipment that serves a secondary purpose reducing pollutant loads in the process stream. The permit requires that the applicant develop and submit to DEQ for review and comment an O&M manual, CO Fugitive BMP Plan, and SSM Plan. The operating parameters contained in these documents are incorporated by reference into the permit as enforceable conditions.

This requirement to modify the PTC serves two functions: it will eliminate the need for inspectors to determine which provisions in those plans are enforceable, and it will provide an opportunity for public review and comment on these provisions.

The timing for the PTC modification was set at 180 days after initial startup, although the plans must be submitted to DEQ at least 60 days prior to startup. It is typical for minor adjustments to be made to operating parameter ranges based on accumulated experience operating the processes. Deferring the permit modification until 180 days after initial startup is meant to take advantage of lessons learned during the initial shakedown period for this facility.

PC 2.3 and 2.4. O & M Manual and Baghouse/Filter System Procedures. Rather than including a separate requirement in each applicable permit section, operating and maintenance documentation requirements for all pollution control devices are included in these two facility-wide conditions. The conditions use the most recent standard language developed by DEQ.

In the final permit, control equipment associated with the sulfuric acid plant has been deleted from the O&M manual list of equipment. The ammonium nitrate neutralizer scrubber, which is an integral part of the ammonium nitrate process, has been added to the list of equipment that must be addressed in the operations and maintenance (O&M) manual.

PC 2.5, Fugitive Dust Emissions. This permit condition requires that reasonable precautions be taken to control fugitive dust emissions, in accordance with IDAPA 58.01.01.650-651. Periodic monitoring is limited to quarterly inspections because of the level of fugitives control required in other permit conditions. Monitoring and recordkeeping to demonstrate compliance with the Rule is included in this

[20] Merriam-Webster dictionary, accessed at www.merriam-webster.com/dictionary/commence

permit condition. In addition to the reasonable precautions listed in this permit condition (which reflect the language in the Rules), the permittee may also consider implementing the following actions to ensure that fugitive dust is well-controlled:

- Develop plans or procedures for controlling fugitive dust. It's recommended that these plans or procedures identify potential sources of fugitive dust, establish good operating practices for limiting the formation and dispersion of dust from those sources, establish criteria to determine when dust control is needed, and provide for training or orientation for employees or contractors about recommended ways to control fugitive dust.
- For construction activities:
  - Minimize the disturbed surface area by reducing the excavation size and/or number of excavations.
  - Limit dusty work on windy days.
  - Pave haul roads and storage areas. If paving all of the site roads is not practical, pave just the entrance and exit to minimize carryout and gravel the remainder.
  - Water and/or sweep roadways often to ensure that vehicle traffic is not picking up dust.
  - Slow down. The amount of dust produced by vehicle traffic increases with the speed of the vehicle.
  - Prevent transport of dusty material off-site by rinsing vehicles and equipment before they leave the property. Tightly cover loaded trucks.
  - Enclose storage and handling areas if dusty materials are frequently loaded and unloaded at these sites. Use storage silos, three sided bunkers, or open-ended buildings. If handling is less frequent, try wind fencing.
  - Keep storage piles covered when not in use. Apply a dust suppressant spray or cover with a tarp. Limit the working face of the pile to the downwind side. Most dust emissions come from loading and unloading the pile and from truck and loader traffic in the immediate area. Keep the drop height low to reduce dust and the ground at the base of the pile clear of spills.
  - Use dust suppression measures when needed.
  - Clean up dusty spills immediately. Waiting will increase the mess and prolong cleanup.
  - Cover open areas with vegetative ground cover to hold soil in place. Growing grasses or other native plants is an effective control because these plants provide a dense, complete cover. Even when the vegetation dries up, the roots will help hold the soil in place.
  - Use wind erosion controls. Plant bushes or trees, construct wood or rock walls or earthen banks as permanent windbreaks or install porous wind or snow fences as temporary measures. Reduced wind velocity allows the larger particles to settle to the ground.
- Apply water or suitable dust suppressant chemicals (e.g., magnesium chloride) on a regular schedule to dirt roads.
- Pave roadways and maintain them in a clean condition.
- Use water sprays, wet or dry sweeping or vacuuming, wheel wash stations, and wheel shaker/wheel spreading devices (rumble grates) to prevent trackout of dirt or mud onto public roadways.

- Use enclosures, covering or tarping, water sprays, or dust suppressant chemicals to prevent wind erosion from disturbed areas or material stockpiles.

PC 2.6 and 2.7, Visible Emissions (Opacity). In accordance with IDAPA 58.01.01.625, visible emissions from all point sources at this facility are subject to a maximum 20% opacity limit. This is in addition to any specific opacity limit imposed elsewhere in this permit. Where IDAPA and federal opacity limits (e.g., contained in NSPS requirements) differ, the facility shall meet the most stringent of the applicable limits. Monthly monitoring inspections are required to ensure continuous compliance unless bag leak detection systems are used to monitor the baghouse conditions. Monitoring and recordkeeping to demonstrate compliance with the Rule is included in these permit conditions.

PC 2.8 and 2.9, Odors. The definition for air pollutant/air contaminant in IDAPA 58.01.01.006 includes odors. In accordance with IDAPA 58.01.01.775-776, the PCAEC facility is prohibited from emitting odors in such quantities as to cause air pollution. *Air pollution* is defined in IDAPA 58.01.01.006 as the presence in the outdoor atmosphere of any air pollutant or combination thereof in such quantity of such nature and duration and under such conditions as would be injurious to human health or welfare, to animal or plant life, or to property, or to interfere unreasonably with the enjoyment of life or property. Monitoring and recordkeeping to demonstrate compliance with the Rules is included in these permit conditions.

PC 2.10, Open Burning. In accordance with IDAPA 58.01.01.600-616, any open burning at the PCAEC facility is subject to the applicable sections of the Rules.

PC 2.11, Emission Limits (Grain Loading) for Fuel-Burning Equipment. *Fuel-burning equipment* is defined in IDAPA 58.01.01.006 as any furnace, boiler, apparatus, stack and all appurtenances thereto, used in the process of burning fuel for the primary purpose of producing heat or power by indirect heat transfer. The 2 MW and 500 kW emergency engine generators proposed for the PCAEC are not subject to this rule, because the energy from burning fuel in these engines is converted directly into mechanical energy or power. The package boiler and steam superheater boiler are subject to this requirement because natural gas or PSA tailgas are burned to heat a liquid (water), which is used to transfer heat to various processes. Compliance with this requirement is demonstrated by performance testing specified in Permit Condition 6.17.

PC 2.12 through 2.15, Fuel Specifications. In order to prevent excessive ground level concentrations of SO_2, fuel to be used in any fuel-burning source at the PCAEC is subject to the sulfur limitations for fuel oil and coal specified in Permit Conditions 2.12, in accordance with IDAPA 58.01.01.725-729. Note that a *fuel-burning source* is not specifically defined in the Rules. Fuel-burning sources include but are not limited to, fuel-burning equipment. The 2 MW and 500 kW emergency diesel engine generators are subject to these limits.

In addition, because the 2 MW and 500 kW emergency diesel engine generators will be subject to 40 CFR 60, Subpart IIII, diesel fuel to be used in these engines must also meet the more stringent fuel specification for non-road engines listed in Permit Condition 2.13.

As discussed in pages 5-157 and 5-158 of the application, SIE has asserted the gasifiers are not “fuel-burning sources,” i.e., that *gasification* of coal is a chemical process designed to produce CO and H_2 carried out under reduced oxygen conditions, while the *burning* of coal is intended to maximize the thermal output by completely oxidizing the carbon to CO_2 with large quantities of excess air. DEQ concurs that the gasifiers are not fuel-burning sources. The coal fed to the gasifiers is therefore not subject to the IDAPA 58.01.01.729 maximum sulfur concentration limit of 1 percent by weight.

Based on the assumptions used in the application, the sulfur content of the coal and petcoke is limited to 6.0% on an as-received basis.

Monitoring and recordkeeping to demonstrate compliance with these requirements is included in Permit Condition 2.15.

PC 2.16, Source Testing Outside Permit Requirements. Conditions in this permit allow setting new maximum process parameters based on source testing. This permit condition clarifies the requirements for conducting such source tests in accordance with DEQ's Source Test Guidance Manual.[21]

PC 2.17, Tier I Application Requirement. This initial PTC is just the first step in air quality permitting for this major Title V facility. A new Title V source such as the PCAEC must apply for a Title V operating permit (called a Tier I permit in Idaho) within 12 months of commencing operations.

PC 2.18, Reports and Certifications. Reports that are required by this permit must include a certification statement and be certified by the facility's responsible official in accordance with IDAPA 58.01.01.123.

PC 2.19, NSPS General Provisions. For equipment that is subject to NSPS requirements, Table 2.2 in this permit condition provides a summary of the general provisions that may apply, and lists the addresses where notifications should be sent. Specific parts of these General Provisions that are applicable to the PCAEC are noted in each permit section.

PC 2.20, NESHAP Reporting and Notifications. None of the processes described in the PTC application for the PCAEC are subject to a current NESHAP because the facility is not a major source for HAPs, and is not included in any of the currently effective area source MACTs. Should the PCAEC be subject to a new area source MACT that has not yet been promulgated, notifications and reports must be sent to the addresses listed in Table 2.2.

Feedstock Storage and Handling

PC 3.1 and 3.2. This permit has been granted on the basis of design information presented with its application, which is reflected in the process narrative and table. Changes in design, equipment or operations may be considered a modification. Modifications are subject to DEQ review in accordance with IDAPA 58.01.01.200 through 228 of the Rules for the Control of Air Pollution in Idaho.

PC 3.3 BACT Emission Limits. The proposed enclosures and control equipment (listed in Table 3.1) were determined to be BACT for these sources. The BACT emission limits for PM and PM_{10} were set equal to the values proposed in the application. The EPA has proposed specific emission limits for facilities subject to NSPS Subpart Y (73 FR 22901, April 28, 2008). The proposed grain loading limit of 0.011 g/dscm (0.005 gr/dscf) will apply only to facilities handling coals *other than bituminous coals*. The emission limits proposed by the applicant are considerably less than 0.005 gr/dscf (lb/hr limits in the permit convert to a range between 0.00001 and 0.0009 gr/dscf) (see the response to Comment 102 in the Response to Comments document for additional discussion).

The draft permit required that fluxant be stored in a silo or equivalent enclosure provided with a high efficiency baghouse (minimum 99%). Table 3.3 has been revised to include pound-per-hour PM/PM_{10} limits for this emission point that are equivalent to the requirement contained in the draft permit, but which may be more easily verified should DEQ determine that performance testing is warranted for this emission source. The 0.0025 lb/hr emission estimate shown in the emission inventory (Table 3.5) was rounded down to 0.002 lb/hr, which should reasonably be achievable using a high-efficiency baghouse.

PC 3.4, BACT Opacity Limits. The EPA has proposed more stringent emission limits for facilities subject to NSPS Subpart Y (73 FR 22901, April 28, 2008). Clean Air Act Section 111 requires that NSPS reflect the degree of emission limitation achievable through application of the best system of

[21] July 2008, Idaho Department of Environmental Quality, Source Test Guidance Manual, Section 9.8.

emissions reductions which (taking into consideration the cost of achieving such emissions reductions, any non-air quality health and environmental impact and energy requirements) the EPA determines has been adequately demonstrated (i.e., best demonstrated technology). As noted in the preamble to this proposed rule, BACT for these facilities was determined to be enclosures in conjunction with either wet or chemical suppression or venting to a [baghouse]. For new coal processing and conveying equipment, coal storage systems, and transfer and loading systems, best demonstrated technologies can meet an opacity limit of five (5) percent. This has been applied to coal and petcoke feedstock handling emission points as a BACT limit.

PC 3.5, Opacity Limit (NSPS Subpart Y). The facility is subject to the 20% opacity limit currently listed Subpart Y for affected *coal* handling facilities (this limit does not apply to emissions from petcoke handling). The 20% opacity limit contained in IDAPA 58.01.01.625, however, applies to all of the point source emissions from feedstock handling (see Facility-Wide Permit Condition 2.6).

Throughput Limits. Modeling for PM_{10} emissions from the unloading and processing of coal, petcoke, and fluxant was based on handling these materials at the maximum capacity for each step in the process for 24 hours per day and 8,760 hours per year. Daily and annual limits on the amount of these feedstocks that can be unloaded or processed were therefore not needed.

PC 3.6, BACT Controls. Enclosures and baghouses were determined to be BACT for PM/PM_{10} for these emission point sources. BACT for PM/PM_{10} fugitive emissions was determined to be BMPs for controlling fugitives. These BMPs are prescribed in PC 2.5 and must also be addressed in the O&M manual per PC 2.3.

PC 3.7, Feedstock Analysis. Pre-construction emission estimates of toxic air pollutants for facility emissions were based on typical feedstock constituents for coal and petcoke. Because the level of these toxics can vary widely depending on the source of the feedstock, this permit condition requires that the feedstocks be analyzed prior to first use, whenever the feedstock source changes, and periodically to determine representative amounts of these toxics present in the feedstocks. Because the specific fluxant has not been identified, but will likely be limestone, iron ore, or silica sand, analysis for the fluxant is limited to just the potential metal constituents. This provision is included as a reasonable permit condition in accordance with IDAPA 58.01.01.211.01.

PC 3.8, Initial Performance Tests. An initial performance test is required for the baghouses serving any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal that is subject to Subpart Y, in accordance with 40 CFR 60.8. An initial performance test is required for the baghouses serving the coal/petcoke unloading, storage systems, conveyors, and processing equipment. Performance testing is not required for the fluxant silo because this is a relatively small source, silo filling emissions must be controlled by a baghouse or cartridge filter, and the emission point is subject to monthly visible emission inspections unless a baghouse leak detection system is installed. This provision is included as a reasonable permit condition in accordance with IDAPA 58.01.01.211.01, to demonstrate compliance with the applicable BACT emission limits.

PC 3.9, Periodic Performance Tests. Periodic performance tests are required at least every five years for the baghouses serving the coal/petcoke unloading, storage systems, conveyors, and processing equipment. This provision is included as a reasonable permit condition in accordance with IDAPA 58.01.01.211.01, to demonstrate compliance with the applicable BACT emission limits. The five (5)-year period was determined to be adequate based on the stringent 5% opacity limit and monthly visible emissions inspections (or installation of a baghouse leak detection system) for these emission points. Performance testing is not required for the fluxant silo because this is a relatively small source, silo filling emissions must be controlled by a baghouse or cartridge filter, and the emission point is subject to monthly visible emission inspections unless a baghouse leak detection system is installed.

PC 3.10, Notification (NSPS). Notification of the date that construction begins and the date of initial startup of the coal handling equipment subject to Subpart Y is required in accordance with part 60.7 of the NSPS general provisions. Addresses where the notifications should be sent are included in the table contained in Table 2.2 of the permit. Equipment that will be used to handle only petcoke or fluxant is not subject to this requirement.

Natural Gas Fired Heaters

PC 4.1 and 4.2 This permit has been granted on the basis of design information presented with its application, which is reflected in the process narrative and table. Changes in design, equipment or operations may be considered a modification. Modifications are subject to DEQ review in accordance with IDAPA 58.01.01.200 through 228 of the Rules for the Control of Air Pollution in Idaho.

PC 4.3, the fuel for these heaters is restricted to natural gas, and each heater is required to be operated using good combustion practices at all times. This constitutes BACT for these sources.

Natural Gas Combustion Limits. Natural gas combustion in these heaters contributes an estimated 0.135 pounds per hour to the total of 15.69 pounds per hour of PM_{10} from all of the facility point sources, or about 0.86% of the total. These emission rates were based on operating the ASU regen heater at 0.1 MMBtu/hr and both gasifier heaters at 9 MMBtu/hr, and the emissions were modeled based on operating at these levels for 24 hours per day. During normal startup, however, the heater serving the gasifier that will be used for production will be operating at 25.5 MMBtu/hr. Modeling for short-term emission impacts was based on both gasifier heaters operating at 9 MMBtu/hr and all other emission sources being operating at normal production rates (even though the processes downstream of the gasifier cannot be placed in production mode until the gasifier stabilizes. These assumptions conservatively overestimate the ambient impact from these sources during startup. Hourly or daily monitoring of natural gas combustion emissions from these sources is therefore not needed to demonstrate continued compliance with short-term NAAQS.

Likewise, modeling for annual ambient impacts was based on operating both gasifier heaters at 9 MMBt/hr, and all other emission sources being operated at normal or maximum rates. During normal operations, however, only the heater being operated in standby mode will be running on natural gas. The heater serving the active gasifier will be turned off. These assumptions conservatively overestimate the annual ambient impact from these sources. Annual monitoring of natural gas combustion emissions from these three heaters is therefore not needed to demonstrate continued compliance with annual NAAQS.

Diesel-Fired Emergency Engine Generators

PC 5.1 and 5.2. This permit has been granted on the basis of design information presented with its application, which is reflected in the process narrative and table. Changes in design, equipment or operations may be considered a modification. Modifications are subject to DEQ review in accordance with IDAPA 58.01.01.200 through 228 of the Rules for the Control of Air Pollution in Idaho.

PC 5.3, Emission Limits. This permit condition requires that the nominal 2 MW emergency engine generator comply with the applicable EPA Tier 2 emission limits specified in Subpart IIII (which for an emergency generator of this size, requires compliance with the non-road engine emission standards contained in 40 CFR 89.112) for the type of engine and model year.

The nominal 500 kW engine generator must comply with the requirements applicable to an NFPA 20-certified fire pump that meets the emission standards in Subpart IIII, or (for an emergency engine generator that is not a certified fire pump engine) meets the EPA Tier 3 emission standards specified in

Subpart IIII (which for an emergency generator of this size, requires compliance with the non-road engine emission standards contained in 40 CFR 89.112).

PC 5.4 and 5.5, Opacity. In accordance with 40 CFR 60.4205(b), only emergency engine generators that are not fire pump engines are subject to the opacity limits specified in 40 CFR 89.113. Note that the 50% opacity allowed by Subpart IIII during peaks in acceleration mode may exceed the 20% opacity limit (for more than 3 minutes in any 60-minute period) specified in IDAPA 58.01.01.625. Subpart IIII does not impose an opacity limit for fire pump engines. If an NFPA 20-certified fire pump engine is used, the emissions are subject only to the IDAPA 58.01.01.625 20% opacity limit included in the facility-wide conditions.

PC 5.6, Allowable Fuels. Because the emergency engine generators (including any fire pump engine) are subject to Subpart IIII, the diesel fuel must meet more stringent requirements for fuel sulfur content than required in the Rules, in accordance with 40 CFR 60.4207(a) and (b). Monitoring and recordkeeping to demonstrate compliance with these limits is included in Permit Conditions 5.11 and facility-wide Permit Condition 2.15.

PC 5.7, Maximum Hours of Operation. Modeling used to demonstrate compliance with applicable air quality standards was based on operating the 2 MW and 500 kW engine generators for 24 hours per day, for a maximum of 100 hours per year for non-emergency testing and maintenance. An hourly or daily limit on non-emergency operations is therefore not needed, but an annual limit of 100 hours per year for non-emergency use is required.

PC 5.8, Engine Generator Operations. Under Subpart IIII, continuous compliance with the applicable emission standards is presumed as long as the owner operates and maintains the engine generators in accordance with the manufacturer's instructions or procedures, and if the owner changes only those settings as permitted by the manufacturer.

PC 5.9, Other Requirements. Under Subpart IIII, if the permittee installs new generator engines (not used or refurbished existing engines), the engines must comply with the applicable requirements in Subpart IIII.

PC 5.10, Generator Replacement. Under Subpart IIII, if the permittee installs generator engines (2007 model year or newer) or a fire pump engine (2009 model year or newer), any replacement for those engines must meet the same Subpart IIII emission standards as the engine generator being replaced.

PC 5.12 and 5.13, Operating Hours Monitoring. Under Subpart IIII, a non-resettable hour meter is required to be installed on each of the emergency engine generators. Monitoring and recordkeeping of the operating hours to demonstrate compliance with the 100 hour per year limit is included in Permit Condition 5.13, based on a rolling monthly average.

PC 5.14, Testing. As noted in the regulatory analysis in Section 4.5 of this statement of basis, performance testing under 40 CFR 60.8 is not required for these emergency engine generators. If the owner decides to conduct a performance test, however, the test must be conducted in accordance with the provisions of 40 CFR 60.4212(a) through (d).

PC 5.15, Notification (NSPS). Notification of the date that construction begins is not applicable (the engine generators are constructed before being shipped to the facility). Notification of the date of initial startup is required in accordance with part 60.7 of the NSPS general provisions. Addresses where the notifications should be sent are included in the table contained in Table 2.2 of the permit.

Package Boiler and Steam Superheater

PC 6.1 and 6.2. This permit has been granted on the basis of design information presented with its application, which is reflected in the process narrative and table. Changes in design, equipment or operations may be considered a modification. Modifications are subject to DEQ review in accordance with IDAPA 58.01.01.200 through 228 of the Rules for the Control of Air Pollution in Idaho.

PC 6.3 Package Boiler and Steam Superheater Emission Limits. The option to install a sulfuric acid plant and a package boiler has been deleted. As described in the draft permit, when using a Claus sulfur recovery unit, the package boiler will be operated only on natural gas and only during startup and shutdown. Emissions from the package boiler and steam superheater used in the modeling analysis were based on operating the two boilers for a combined total of 24 hours per day and 8,760 hours per year. The pound per day limits in Table 6.2 of the draft permit have been converted to equivalent limits in pounds per MMBtu for PM, PM_{10}, NOx, and CO, to allow easier comparison with published BACT limits for similar sources. The pound per hour limits remain in the permit as secondary limits. The ton per year limits on emission from these two boilers inherently limit the total amount of natural gas and PSA tailgas that can be combusted in the boilers. A pound per hour ammonia limit for the steam superheater boiler was not included because the slip is limited to 10 ppmv in PC 6.10.1, and the facility-wide ammonia emissions were predicted to be a maximum of 4.5% of the applicable 24-hour AAC.

PC 6.4 NSPS Subpart Db, PM Emissions and Opacity Limit. This condition imposes the Subpart Db (60.43b) emission and opacity limits on the boiler(s) when burning PSA tailgas. See the regulatory review in Section 4.4 of this statement of basis.

PC 6.5 IDAPA Opacity Limit. This permit condition was included as a reminder that allowing the opacity from the boiler stacks to reach 27% for a six-minute period per hour (as allowed in Subpart Db) will violate the 20% opacity limit (an aggregate of 3 minutes in any 60 minute period) contained in the Rules.

PC 6.6 IDAPA Grain Loading Emission Limit. The boilers are subject to the IDAPA 58.01.01.676 emission limit of 0.015 gr/dscf of effluent gas corrected to 3% oxygen when burning natural gas, PSA tailgas, or a mixture of these two fuels. The emissions estimates used by the applicant to demonstrate compliance with air quality standards presumed that the emissions would be unchanged when burning PSA tailgas compared to burning only natural gas. Accordingly, this permit condition imposes the grain loading limit applicable to gases when burning natural gas, PSA tailgas, or a mixture of these two fuels.

PC 6.7 NSPS Subpart Db, NO_x Emission Limit . This condition imposes the applicable Subpart Db (60.44b) NO_x emission limits on the boiler(s) when burning natural gas, PSA tailgas, or a mix of these fuels in the boilers. Because the heat release rate for the boilers is not yet known, Permit Condition 6.18 requires the permittee to notify DEQ of the boiler heat release rates in conjunction with the required initial startup notification for these boilers. See the regulatory review in Section 4.4 of this statement of basis.

The boilers are subject to the IDAPA 58.01.01.676 emission limit of 0.015 gr/dscf of effluent gas corrected to 3% oxygen when burning natural gas, PSA tailgas, or a mixture of these two fuels. The emissions estimates used by the applicant to demonstrate compliance with air quality standards presumed that the emissions would be unchanged when burning PSA tailgas compared to burning only natural gas. Accordingly, this permit condition imposes the grain loading limit applicable to gases when burning natural gas, PSA tailgas, or a mixture of these two fuels.

PC 6.8 Boiler Fuels. Boiler operations for the case in which a Claus sulfur recovery unit would be used were described in the applicable section in the draft permit. For clarity, however, PC 6.8 was revised highlight that the package boiler can be operated only during startup and shutdown, may burn only natural gas, and that when both the package boiler and steam superheater boiler are operating the combined heat input to the boilers cannot exceed 250 MMBtu per hour.

The boilers are limited to burning only natural gas, PSA tailgas, or a mixture of these two fuels. No restrictions are included with regard to the maximum amount of PSA tailgas that can be burned. Performance testing in accordance with IDAPA 58.01.01.157 requires testing at “worst case normal” conditions, so the permittee will be required to conduct performance tests on these boilers using the maximum amount of PSA tailgas expected to be used in normal operations.

PC 6.9 NSPS Subpart Db, Fuel SO_2 Limit. The boilers are exempt from Subpart Db SO_2 emission limits only if the potential SO_2 emission rate of the fuel does not exceed 140 ng/J (0.32 lb/MMBtu). In addition, the boilers were determined to be exempt from Subpart Db requirements to install a COMS based on burning only fuel with a potential SO_2 emission rate that does not exceed 26 ng/J (0.060 lb/MMBtu). This permit condition requires that the fuel burned in the boilers comply with these limits, or, if the potential SO_2 emission rate of the fuel is more than 26 ng/J (0.060 lb/MMBtu), but less than or equal to 140 ng/J (0.32 lb/MMBtu), requires the permittee to install a COMS. Monitoring and recordkeeping to demonstrate compliance with these provisions is included in Permit Condition 6.15. See the regulatory review for 40 CFR 60.42b(k)(2), 60.45b(k), and 60.49b(r) in Section 4.4 of this statement of basis.

PC 6.10, NO_x Pollution Control Equipment for the Boilers. This permit condition requires that the NO_x pollution control technology determined to be BACT be installed and used on each of the boilers.

PC 6.11, Reporting Period. The reporting period for reports required under Subpart Db is every 6 months, in accordance with 40 CFR 60.49b(v) and (w). See the regulatory review in Section 4.4 of this statement of basis.

PC 6.12, Fuel Combustion Monitoring. This permit condition contains the requirement to monitor and record the amount and type of fuel combusted in the boilers, in accordance with 60.49b(d), defines how to calculate the annual capacity factor in accordance with the definition in 60.41b, requires calculating the 30-day heat input, and requires that the permittee determine which NOx emission limit specified in Table 6.3 applies to the most recent 30-day period.

PC 6.13, PM Emissions Monitoring (NSPS Opacity). This condition requires the installation of a COMS and related recordkeeping if the potential SO_2 emission limit of the fuel is more than 26 ng/J (0.060 lb/MMBtu), and the boiler is burning PSA tailgas or a combination of natural gas and PSA tailgas.

PC 6.14, NO_x Emissions Monitoring (NSPS COMS). This condition requires using either a CEMS or a PEMS to continuously monitor NO_x emissions from the boilers on a 30-day rolling average. See the regulatory review in Section 4.4 of this statement of basis.

PC 6.15, Fuel Potential SO2 Emissions Monitoring. See the discussion for Permit Condition 6.9.

PC 6.16, PM and NO_x Initial Performance Test (NSPS). This condition requires that the permittee conduct the required initial PM and NO_x performance tests for the boilers in accordance with 40 CFR 60.8 and 60.46b. See the regulatory review in Section 4.4 of this statement of basis. As a reasonable permit condition, the permittee is required to conduct these PM and NO_x tests at least once every 5 years, with the source test results submitted to DEQ.

PC 6.17, PM Initial Performance Test (BACT). This condition requires that the permittee conduct performance testing to demonstrate compliance with the BACT emission limits for PM, PM_{10} (including condensables or “back half”), and NO_x. As a reasonable permit condition, the permittee is required to conduct these performance tests at least once every 5 years, with the source test results submitted to DEQ.

PC 6.18, Reporting. Initial startup notification is required for each of the boilers because they are subject to NSPS Subpart Db. See the regulatory review in Section 4.4 of this statement of basis. As a reasonable permit condition, the permittee is required to include information regarding the boiler heat release rates (which have not been determined at this time) with the initial startup notification.

PC 6.19, Initial Performance Test and CEMS Reports The permittee must submit initial performance test reports and CEMS reports as required by 60.49b. See the regulatory review in Section 4.4 of this statement of basis.

PC 6.20, NO_x CEMS/PEMS Reports. Section 60.49b(i) of Subpart Db includes a specific requirement to submit a report (for each reporting period) describing the NOx emission rates, any NO_x excess emissions, and CEMS operating parameters. See the regulatory review in Section 4.4 of this statement of basis.

PC 6.21, Excess Emissions. Section 60.49b(h) of Subpart Db includes specific requirements for excess emissions reporting that are not otherwise required in the Rules. See the regulatory review in Section 4.4 of this statement of basis.

Gasification Island

PC 7.1 and 7.2. This permit has been granted on the basis of design information presented with its application, which is reflected in the process narrative and table. Changes in design, equipment or operations may be considered a modification. Modifications are subject to DEQ review in accordance with IDAPA 58.01.01.200 through 228 of the Rules for the Control of Air Pollution in Idaho.

PC 7.3, Emission Limits. Emission limits associated with the sulfuric acid plant have been deleted. SIE determined in consultation with their technology provider that 95% destruction removal efficiency (DRE) was technically feasible for treating CO, COS, and H_2S in the AGR CO_2 vent emissions (see Addendum No. 4 to the application). As a result of this change, the lb/hr emission rates in Table 7.2 were revised. The SO_2 limits were increased slightly from 3.6 lb/hr to 3.8 lb/hr and from 15.6 T/yr to 16.5 T/yr. The CO limits were reduced from 17.3 lb/hr to 8.7 lb/hr and from 75.9 T/yr to 38.0 T/yr.

Compliance was demonstrated by modeling using the rates listed in the draft permit. A pound per hour ammonia limit was not included because the slip is limited to 10 ppmv in PC 7.6, and the facility-wide ammonia emissions were predicted to be a maximum of 4.5% of the applicable 24-hour AAC.

PC 7.4, Gasifier Feedstocks Emission estimates for processes downstream of the gasifier, and for the gasifier flare, were based on feeding 5,000 tons per day of solid feedstocks to the gasifier, at a blended maximum sulfur content of 6%. In addition, this permit condition requires that the amount of feedstock fed to the gasifier does not exceed the working capacity of the syngas cleanup train.

PC 7.5, Syngas Cleanup Train and T.O. DRE. Requirements applicable to the sulfuric acid plant have been deleted. This permit condition requires the installation, maintenance, and use of the syngas cleanup train as described in the application for startups and for normal production operations. Requirements for the gasifier flare are included in this permit condition.

SIE determined in consultation with their technology provider that 95% DRE was technically feasible for treating CO, COS, and H_2S in the AGR CO_2 vent emissions (see Addendum No. 4 to the application). PC 7.5 has been revised to increase the minimum required design DRE for the thermal oxidizer from 90% to 95%.

PC 7.6, SSM Plan. This permit condition requires that the permittee develop and submit a set of procedures to minimize the emissions associated with startups, shutdowns, malfunctions, and scheduled maintenance, in accordance with IDAPA 58.01.01.133.02.

PC 7.7, Throughput Monitoring – Gasifier Feedstocks. This permit condition requires that the permittee monitor and record the amount of solid feedstock fed to the gasifier and sulfur content of the feedstock each day. Monitoring the daily amounts of feedstocks, coupled with representative analyses for the metals present in the feedstocks, provides a means for ensuring that the actual TAPs metals emissions rates are consistent with the values used in the modeling compliance demonstration.

PC 7.8, Gasifier Flare Testing and Monitoring. This permit condition requires that the permittee conduct and record an initial test of the gasifier flare to confirm that the flare is operating properly and meets the applicable requirements of 40 CFR 60.18.

PC 7.9, Option #2, SCR Ammonia Slip Monitoring. This permit condition required that the permittee monitor and record the ammonia slip for the Haldor-Topsoe WSA (if installed). This permit condition was deleted in response to Addendum No. 3 to the application, which removed the sulfuric acid plant from the project scope.

PC 7.9, BMPs for fugitive CO. A BMP Plan for fugitive CO emissions is now specifically required in Permit Condition 7.9 for the part of the gasifier island where CO concentrations in the process stream will be relatively high (i.e., from the gasifier to the last sour shift reactor).

PC 7.10, Syngas Monitoring. This permit condition requires that the permittee conduct initial and periodic sampling and analysis of the syngas that is being vented to the gasifier flare during startup conditions. In the final permit, Permit Condition 7.10 has been revised to clarify that the analyses must include determination of the concentration of sulfur compounds (to ensure that the amine scrubber is functioning as designed) and the concentration of the toxic metal compounds listed in Permit Condition 3.7.1.

Ammonia and Urea Plants

PC 8.1 and 8.2. This permit has been granted on the basis of design information presented with its application, which is reflected in the process narrative and table. Changes in design, equipment or operations may be considered a modification. Modifications are subject to DEQ review in accordance with IDAPA 58.01.01.200 through 228 of the Rules for the Control of Air Pollution in Idaho.

PC 8.3, Emission Limits. The pound per hour limits in Table 8.2 of the draft permit have been converted to equivalent limits in pounds per ton of product for PM and PM_{10} to allow easier comparison with published BACT limits for similar sources. The pound per hour limits and the ton per year limit for PM_{10} remain in the permit as secondary limits.

PC 8.4, Production Limits. Production limits were not imposed on the production of ammonia or liquid urea because the production of these products is not directly tied to any emissions point, except for the process flare. A production limit on the amount of granular urea was included, however, because the estimated emissions from the granular urea vent stack are proportional to the granular urea production level. The production level was set at the 1,800 tons per day used to develop the emissions estimate for this source. This limit may be increased, however, to any level used in a performance test that demonstrated compliance with the PM/PM_{10} emission limits specified for the granular urea vent stack. Monitoring and recordkeeping requirements to demonstrate compliance with this production limit are contained in Permit Condition 8.7 (renumbered from draft PC 8.6).

PC 8.5, Process Flare. Requirements for the process flare are included in this permit condition.

PC 8.6, Urea Granulation Process Scrubber. The emission inventory and compliance modeling demonstration for the urea granulation process was based on the use of a wet scrubber that is an integral part of the urea granulation process (i.e., process equipment). Permit Condition 8.6 has been added to specifically require that this process equipment be designed to capture and recycle 98% of the PM/PM_{10} dust from the air in the granulator and coolers.

PC 8.7, Production Monitoring. Daily production monitoring and recording of granular urea production is required.

PC 8.8 through 8.11, Subpart VVa Monitoring, Performance Testing, and Reporting. Equipment in VOC service in the urea plant is subject to NSPS Subpart VVa, which requires specific monitoring and recordkeeping, as well as an initial performance test for fugitive emissions of volatile organic compounds from the urea process unit. Initial notifications and semiannual submittal of reports are also required for affected facilities under this subpart. See the regulatory review in Section 4.4 of this statement of basis. Based on the regulatory analysis, however, it appears that the only equipment used to handle formaldehyde (in the urea granulation process) is subject to the provisions of Subpart VVa.

Nitric Acid and Ammonium Nitrate/UAN Plants

PC 9.1 and 9.2. This permit has been granted on the basis of design information presented with its application, which is reflected in the process narrative and table. Changes in design, equipment or operations may be considered a modification. Modifications are subject to DEQ review in accordance with IDAPA 58.01.01.200 through 228 of the Rules for the Control of Air Pollution in Idaho.

PC 9.3, Emission Limits. The pound per hour nitric acid tailgas vent NO_x limit in Table 9.2 of the draft permit has been converted to an equivalent limit in parts per million by volume (ppmv) to allow easier comparison with published BACT limits for similar sources. The pound per hour limits and the ton per year limit for NOx remain in the permit as secondary limits. The lb/hr emission limit included in Table 9.2 for the AN neutralizer vent is BACT for this source.

PC 9.4, Emission Limits (NSPS). The nitric acid tailgas emission point is subject to a NOx limt and opacity limit in accordance with NSPS, Subpart G.

Note: Production limits were not imposed on the production of nitric acid, ammonium nitrate, or urea ammonium nitrate in the draft permit. Upstream limits on the feedstock to the gasifier provide an inherent limit to the production rates for these products. Pound per hour and ton per year limits on NO_x emissions from the nitric acid plant tailgas vent also serve to limit the amount of nitric acid that can be produced and fed to the AN neutralizer and UAN process, and NOx emissions from the nitric acid plant tailgas vent are continuously monitored using a NO_x CEMS.

PC 9.5, Nitric Acid Plant Pollution Control Equipment. The nitric acid tailgas stream must be controlled by an SCR unit with an ammonia slip no greater than 10 ppmv (dry) corrected to 15% oxygen. This was determined to be BACT for this emission source.

Emission Limit, Ammonia Slip. A pound per hour ammonia limit the slip is limited to 10 ppmv in PC 9.5.3, and the facility-wide ammonia emissions were predicted to be a maximum of 4.5% of the applicable 24-hour AAC.

PC 9.5.4, Ammonium Nitrate Neutralizer Process Scrubber requirements have been clarified. The emission inventory and compliance modeling demonstration for the ammonium nitrate neutralizer vent was based on the use of a 90% efficient wet scrubber that is an integral part of the neutralizer process (i.e., process equipment). General Provision 2 in the draft permit required that the permittee "maintain in good working order and operate as efficiently as practicable, all treatment or control facilities or systems installed and used to achieve compliance with the terms and conditions of this permit…" Permit Condition 9.5.4 has been added to specifically require that this process equipment be designed to capture and recycle 90% of the PM/PM_{10} within the process.

PC 9.6, Nitric Acid Plant Production Rate Monitoring. Although there is no production limit for the nitric acid plant, the production rate must be monitored and recorded as required by Subpart G.

PC 9.7 through 9.10, Nitric Acid Plant Emissions Monitoring, Testing, and Reporting. Subpart G requires that a NO_x CEMS be used to continuously monitor NO_x emissions in the nitric acid tailgas, and requires an initial performance test. Initial notification is required for construction and startup, and excess emissions must be determined and reported in accordance with specific criteria contained in Subpart G.

Diesel, Ammonia, Acid, and UAN Tank Storage

PC 10.1 and 10.2. This permit has been granted on the basis of design information presented with its application, which is reflected in the process narrative and table. Changes in design, equipment or operations may be considered a modification. Modifications are subject to DEQ review in accordance with IDAPA 58.01.01.200 through 228 of the Rules for the Control of Air Pollution in Idaho.

PC 10.3, Ammonia Storage Flare. Requirements for the ammonia storage flare are included in this permit condition.

Zero Liquid Discharge System (ZLDS) and Cooling Tower

PC 11.1 and 11.2. This permit has been granted on the basis of design information presented with its application, which is reflected in the process narrative and table. Changes in design, equipment or operations may be considered a modification. Modifications are subject to DEQ review in accordance with IDAPA 58.01.01.200 through 228 of the Rules for the Control of Air Pollution in Idaho.

PC 11.3, Emission Limits. The pound per hour BACT PM/PM_{10} emission limits for these two sources have been replaced by the equivalent percentage of total circulating water flow to allow easier comparison with published BACT limits for similar sources. These percent values were used to develop the pound per hour emission limits listed in the draft permit. The pound per hour and ton per year limits remain in the permit as secondary limits.

BACT pound per hour emission limits were set based on the hourly emission rates shown in the application. Process weight rate limits were included based on Idaho experience that cooling tower emissions may exceed process weight rate limits.

PC 11.4 – 11.6, Operating Requirements and Monitoring. The cooling tower and ZLDS may not be operated unless the drift/mist eliminators are installed and functioning as designed. The operational limits on water solids content and flow rate provides assurance of continuing compliance with the applicable emission rate limits.

PC 11.7 – 11.8, Initial and Periodic Performance Testing. Performance testing is required to demonstrate compliance with the applicable emission rate limits.

Slag and Solid Product and Byproduct Handling

PC 12.1 and 12.2. This permit has been granted on the basis of design information presented with its application, which is reflected in the process narrative and table. Changes in design, equipment or operations may be considered a modification. Modifications are subject to DEQ review in accordance with IDAPA 58.01.01.200 through 228 of the Rules for the Control of Air Pollution in Idaho.

PC 12.3 and 12.4. Fugitive emissions from these sources must be monitored and controlled in accordance with BMPs listed in Permit Condition 2.5.

5. PERMIT FEES

Table 5.1 lists the processing fee associated with this permitting action. The facility is subject to a processing fee of $10,000 because the facility is a new major PSD facility. The emissions in Table 5.1 were based on the PTE allowed in the final permit. HAPs emissions are shown as zero to avoid double-counting (i.e., metallic HAPs are included in PM_{10}, and organic HAPs tend to be included in the VOC total). These totals include steady state point source emissions and fugitive emissions. Refer to the chronology for fee receipt dates.

Table 5.1 PTC PROCESSING FEE TABLE

Emissions Inventory			
Pollutant	**Annual Emissions Increase (T/yr)**	**Annual Emissions Reduction (T/yr)**	**Annual Emissions Change (T/yr)**
NO_X	109	0	109
SO_2	23.4	0	23.4
CO	166	0	166
PM_{10}	60.2	0	60.2
VOC	5.1	0	5.1
HAPS	0.0	0	0.0
Total:	**363.7**	0	**363.7**
Fee Due	**$10,000.00**		

6. PUBLIC COMMENT

Because of the complexity of the proposed project and the level of public interest, DEQ added a page on the DEQ website specifically for this project. Application materials, major milestones, the projected schedule for permitting this project, the draft permit and statement of basis, and graphics developed for the informational meetings were posted and updated on this page as soon as the information became available. For example, the application materials received on Tuesday, April 29, 2008 were available on the DEQ website by the end of that week. The web page also included the permit engineer’s contact information, and a link for interested parties to sign up to receive automatic email notifications whenever the web page was updated.

In accordance with IDAPA 58.01.01.209.01.c, a public comment period was scheduled from September 24, 2008 through October 24, 2008. In response to a request from the Sierra Club, a notice was published on October 22, 2008 that extended the comment period for an additional 30 days, through November 24, 2008.

DEQ provided informational meetings regarding air quality permitting for this project in Pocatello, American Falls, and Fort Hall on September 22, 23, and 24, 2008 respectively. A Spanish-speaking DEQ staff member was available at the American Falls meeting to answer questions. A public hearing was held in American Falls on October 9, 2008. An additional informational meeting and public hearing were provided in Pocatello on October 20, 2008.

DEQ’s response to the comments submitted during the public comment period are included in the response to public comments document issued with the final permit.

.