

**Iowa Department of Natural Resources
Environmental Services Division
Air Quality Bureau**



**Prevention of Significant Deterioration (PSD) Permit Review
Technical Support Document for Issuance of PSD Permits for
Project Number 07-602, Plant Number 64-01-012**

**Interstate Power and Light (IPL) Company
Sutherland Generating Station
3001 East Main Street
Marshalltown, IA 50158**

Table of Contents

Purpose of this Document	5
Introduction to the Project	
Background on IPL and Sutherland Generating Station.....	5
Basic Power Plant Concepts.....	7
SGS Unit 4 Project Description.....	11
Analysis of the Application	
Prevention of Significant Deterioration (PSD)	16
New Source Performance Standards (NSPS).....	17
Subpart A.....	17
Subpart Da	17
Subpart Db	17
Subpart Y.....	17
Subpart OOO.....	18
Subpart IIII	18
National Emission Standards for Hazardous Air Pollutants (NESHAP)	18
Subpart A.....	18
Subpart B.....	18
Subpart ZZZZ	18
Acid Rain	18
Iowa Administrative Code (IAC).....	18
Introduction to New Source Review (NSR) and Prevention of Significant Deterioration (PSD)	
Regulatory Background	19
PSD Concepts.....	19
Best Available Control Technology (BACT).....	21
Air Quality Impact Analysis	21
Additional Impact Analysis	22
Public Participation	22
PSD Applicability	22
PM _{2.5}	
Background	24
Conclusion.....	27
CO ₂	
Background	27
Recent Court Cases and Related Activities.....	30
Conclusion.....	33
Best Available Control Technology (BACT).....	33
Boiler 4	
Appendix J.....	34
BACT decisions	34
Particulate Matter (PM).....	35
Particulate Matter with an aerodynamic diameter of 10 microns (PM ₁₀)	36
Opacity (visible emissions)	37
Sulfur dioxide (SO ₂).....	37
Nitrogen oxides (NO _x).....	37
Volatile Organic Compounds (VOC)	38
Carbon monoxide (CO)	38
Fluorides (F).....	38
Sulfuric Acid Mist (H ₂ SO ₄)	39

Table of Contents (Continued)

Total Reduced Sulfur (TRS)	39
Auxiliary Boiler.....	40
Particulate Matter (PM)	40
Particulate Matter with an aerodynamic diameter of 10 microns (PM ₁₀)	40
Opacity (visible emissions)	40
Sulfur dioxide (SO ₂)	41
Nitrogen oxides (NO _x)	41
Volatile Organic Compounds (VOC)	41
Carbon monoxide (CO).....	41
Sulfuric Acid Mist (H ₂ SO ₄).....	42
Total Reduced Sulfur (TRS).....	42
Emergency Generator, Fire Pump, and Booster Fire Pump.....	42
Particulate Matter (PM)	42
Particulate Matter with an aerodynamic diameter of 10 microns (PM ₁₀)	43
Opacity (visible emissions)	43
Sulfur dioxide (SO ₂)	43
Nitrogen oxides (NO _x)	44
Volatile Organic Compounds (VOC)	44
Carbon monoxide (CO).....	45
Sulfuric Acid Mist (H ₂ SO ₄).....	45
Fluorides (F)	46
Total Reduced Sulfur (TRS).....	46
Cooling Tower	47
Particulate Matter (PM)	47
Particulate Matter with an aerodynamic diameter of 10 microns (PM ₁₀)	47
Opacity (visible emissions)	47
Material Handling Systems (Point Sources).....	48
Particulate Matter (PM)	48
Particulate Matter with an aerodynamic diameter of 10 microns (PM ₁₀)	48
Opacity (visible emissions)	49
Material Handling Systems (Non-point Sources).....	49
Particulate Matter (PM)	49
Particulate Matter with an aerodynamic diameter of 10 microns (PM ₁₀)	49
Opacity (visible emissions)	50
Haul Roads.....	50
Particulate Matter (PM)	50
Particulate Matter with an aerodynamic diameter of 10 microns (PM ₁₀)	50
Opacity (visible emissions)	51
Gate Station Heater.....	51
Particulate Matter (PM)	51
Particulate Matter with an aerodynamic diameter of 10 microns (PM ₁₀)	51
Opacity (visible emissions)	51
Sulfur dioxide (SO ₂)	52
Nitrogen oxides (NO _x)	51
Volatile Organic Compounds (VOC)	52
Carbon monoxide (CO).....	52
Sulfuric Acid Mist (H ₂ SO ₄).....	52
Total Reduced Sulfur (TRS).....	52

Table of Contents (Continued)

PSD Ambient Air Quality Analysis	52
PSD Ambient Air Monitoring (Pre- and Post-Construction)	53
National Ambient Air Quality Standards (NAAQS)	54
PSD Increment	55
Class I Area Impact Analysis	57
Additional Impact Analysis	57
Growth.....	59
Soils	60
Vegetation	61
NO _x	62
SO ₂	67
PM.....	68
CO	69
Ozone	69
Fluorides.....	70
Department Soils & Vegetation Tool.....	70
Threatened and Endangered Species	70
Wildlife Species	71
Plant Species.....	73
Visibility	73
Case-by-Case Maximum Achievable Control Technology (MACT) Determinations	
Background	76
112(g).....	77
112(j).....	79
MACT Analysis.....	79
Boiler 4	
Uncontrolled Emissions	80
Organic Hazardous Air Pollutants (Organic HAP).....	81
Non-Mercury Metals	82
Acid Gases.....	83
Mercury (Hg)	84
Auxiliary Boiler.....	85
Organic Hazardous Air Pollutants (Organic HAP).....	85
Gate Station Heater	86
Compliance Demonstration	86
Boiler 4	86
Auxiliary Boiler.....	86
Emergency Generator, Fire Pump, and Booster Fire Pump.....	87
Cooling Tower	87
Material Handling Systems (Point Sources).....	87
Non-point source particulate sources.....	88
Gate Station Heater.....	88
Confidentiality	89
Requirements of PSD Public Notice	89
Reopening of Public Comment Period	90
Department Determination	90
Supporting References to the Administrative Record Not Footnoted in or	
Attached to the Technical Support Document	91

Purpose of this Document

This document has been prepared to fulfill the public participation requirements of 567 Iowa Administrative Code (IAC) 22.2(2), 567 IAC 33.17.

Introduction to the Project

Background on IPL and Sutherland Generating Station:

Interstate Power and Light (IPL) is proposing to construct and operate a new 649 megawatt (MW) (net)/733.5 MW (gross) supercritical pulverized coal (SCPC) fired boiler at its existing Sutherland Generating Station (SGS) located in Marshalltown, Marshall County, Iowa. IPL is the Iowa utility subsidiary of the Alliant Energy Corporation.

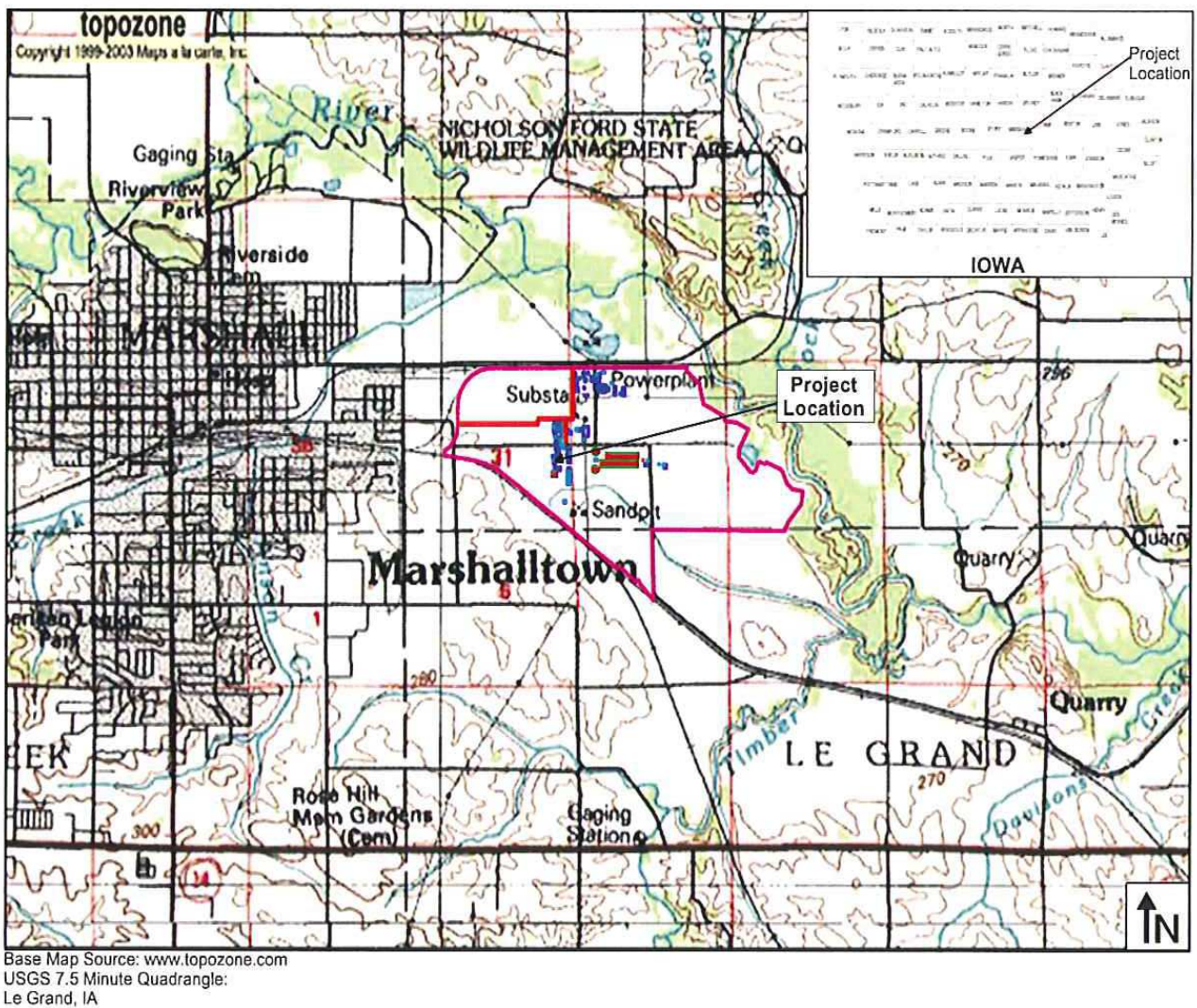


Figure 1 – Map of the Project Location¹

¹ Map is from Page 2-1 of original application which was submitted on November 1, 2007.

As can be seen by Figure 1, the existing Sutherland plant (and proposed Unit 4) is located on the east side of Marshalltown. The plant is situated along the southern side of an east-west reach of the Iowa River. The terrain of the proposed site is mostly agricultural flat land located within a floodplain with some gently rolling hills located to the north and east. The area surrounding the plant is generally used for farming and residential purposes.

The existing Sutherland plant has three (3) coal fired boilers (Units 1, 2, and 3) and six (6) oil fired combustion turbine generating units. It has the capability to provide approximately 308 MW of power. Units 1 & 2 are dry bottom pulverized coal fired boilers with low NO_x burners. Each unit has a rated capacity of 444 million British thermal units per hour (MMBTU/hr) of heat input and is designed to produce about 32 megawatts (MW) of electricity. Unit 1 has been in operation since 1954 and Unit 2 has been in operation since 1955. Each unit is permitted to combust coal, petroleum coke, and natural gas. Unit 3 is a cyclone furnace boiler with a rated capacity of 868 MMBTU/hr (heat input) and is designed to produce about 82 MW of electricity that was installed in 1961. Unit 3 is also permitted to burn coal, petroleum coke, and natural gas.

In addition, SGS has six (6) 1978 simple cycle combustion turbines. These units are permitted to burn fuel oil and are operated in pairs. Each turbine has a rated capacity of 402 MMBTU/hr (heat input) and a electrical output design of 54 MW. A picture of the existing SGS facility is below in Figure 1:



Figure 2 – Existing Sutherland plant²

² Picture from Alliant Energy website (<http://www.alliantenergy.com/docs/groups/public/documents/pub/p015726.hcsp>).

Basic Power Plant Concepts:

IPL is proposing to combust several fuels in SGS Unit 4. The main fuel will be coal. About 90% of the electricity generated in the United States is from three fuels: coal, nuclear, and natural gas.³ In fact, almost half of the electricity generated in the US in 2007 was from the combustion of coal. This is shown in Figure 3.

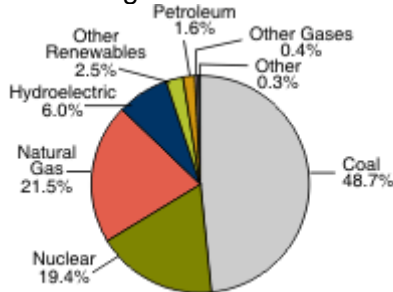


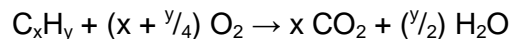
Figure 3 – Sources of Electricity Generation⁴

Most electricity is generated by rotating turbines that drive alternators. Turbines are typically driven by water, wind, hot gases, and most commonly steam. Steam is produced in several ways:

- From water that is boiled by burning fossil fuels (i.e. coal, natural gas, fuel oil, etc.), biomass materials (i.e. wood, wood waste, agricultural waste, etc.), municipal solid waste, or other combustible materials.
- From boiling water through nuclear fission.
- From geothermal resources.

In the case of a coal-fired power plant, the chemical energy stored in the coal is converted into thermal energy, mechanical energy, and finally electrical energy. This is done by burning the coal in a boiler to heat water to produce steam. The steam which is at a high pressure flows through a turbine which spins a generator to produce electricity. The steam is cooled, condensed back into water, and returned to the boiler to start the process over. Figure 4 shows the basic design of a coal-fired power plant.

Combustion of coal is a chemical reaction and complete combustion is summarized by the following chemical reaction:



The simple word equation for the above chemical reaction is:



³ Energy Information Administration (http://tonto.eia.doe.gov/energy_in_brief/electricity.cfm).

⁴ Source: Energy Information Administration, Form EIA-906, "Power Plant Report" and Form EIA-920, "Combined Heat and Power Plant Report".

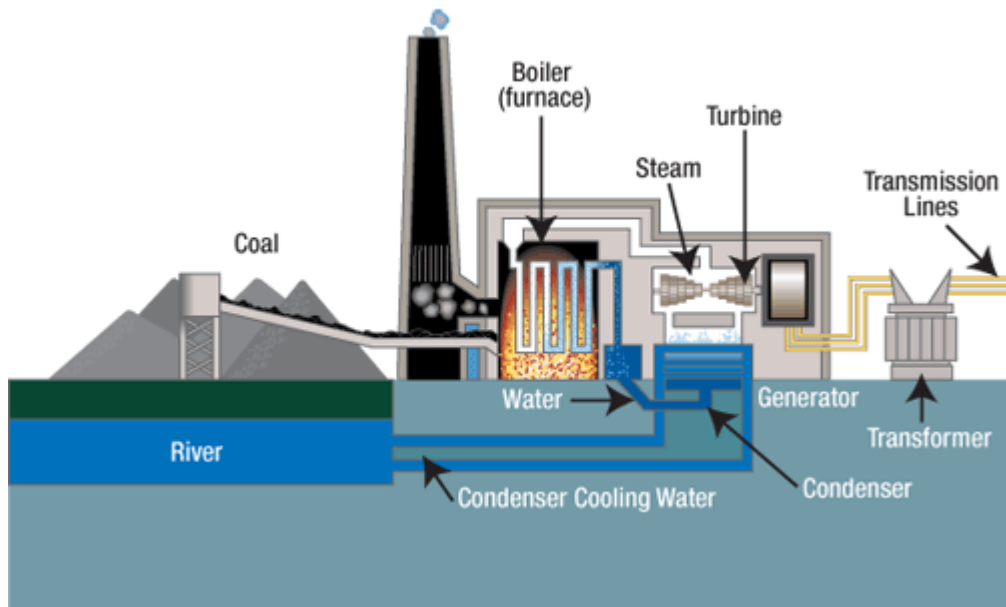


Figure 4 – Basic Design of a Coal-Fired Power Plant⁵

Coal, like all fossil fuels, generates carbon dioxide when it is burned. Since no fossil fuel plant is able to burn fuel perfectly as seen in complete combustion there are always products of incomplete combustion produced in varying quantities. A few of these products of incomplete combustion are sulfur dioxide (SO_2), oxides of nitrogen (NO_x), carbon monoxide (CO), and volatile organic compounds (VOC).

There are four main types (or ranks) of coal. The rank is dependent upon the amounts and types of carbon it contains along with the amount of heat energy it can produce. The rank of a deposit of coal depends on the pressure and heat acting on the plant debris as it sank deeper and deeper over millions of years. For the most part, the higher ranks of coal contain more heat-producing energy. The ranks of coal are:

- **Lignite:** This is the lowest rank of coal with the lowest energy content. Lignite coal tends to be relatively young coal deposits that were not subjected to extreme heat or pressure. Lignite is crumbly and has a high moisture content. There are 20 lignite mines in the US which produce about 7% of the US coal. Most lignite is mined in Texas and North Dakota. Lignite is burned mainly in power plants in order to generate electricity.
- **Sub-bituminous:** This coal has a higher heating value than lignite. Sub-bituminous coal typically contains 35 – 45% carbon, compared to 25 – 35% for lignite. Most sub-bituminous coal in the US is at least 100 million years old. About 44% of the coal produced in the US is sub-bituminous. Wyoming is the leading source of sub-bituminous coal.

⁵ Diagram is from Tennessee Valley Authority (TVA) website (www.tva.gov/power/images/coalart.gif).

- **Bituminous:** This coal contains 45 – 86% carbon and has two (2) to three (3) times the heating value of lignite. Bituminous coal was formed under high heat and pressure. Bituminous coal in the US is between 100 – 300 million years old. It is the most abundant rank of coal found in the US. It accounts for ½ of the US coal production. Bituminous coal is used to generate electricity and is an important fuel and raw material for the steel and iron industries. West Virginia, Kentucky, and Pennsylvania are the largest producers of bituminous coal.
- **Anthracite:** This coal contains 86 – 97% carbon and has a heating value slightly lower than bituminous coal. It is very rare in the US as it accounts for less than ½ of 1% of the coal mined in the US. All of the anthracite mines in the US are located in northeastern Pennsylvania.⁶

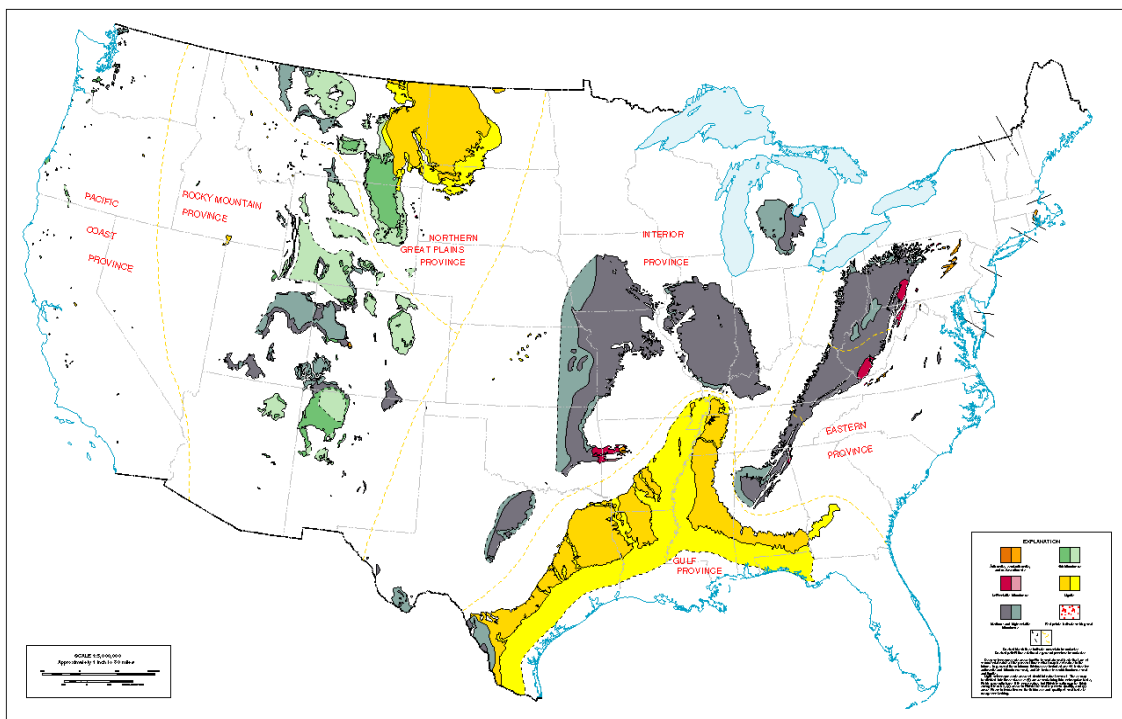


Figure 5 – Map of US coal deposits⁷

Figure 5 above is a map of the US showing the various coal deposits. Figure 6 is an enlarged view of the key.

⁶ The information on the types of coal is from the Energy Information Administration website (<http://www.eia.doe.gov/kids/energyfacts/sources/non-renewable/coal.html#types>).

⁷ Produced by the US Geological Survey. Map can be found at <http://pubs.usgs.gov/of/1996/of96-092/index.htm>.

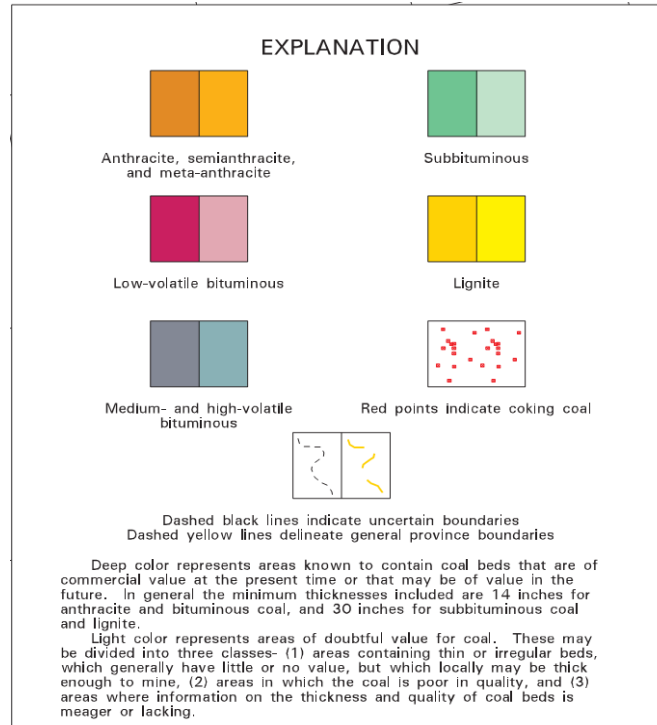


Figure 6 – Key to Figure 5

As stated earlier in this document, IPL is proposing to install a supercritical pulverized coal fired boiler. A boiler can be thought of as a large box that contains a burning fuel/air mixture with the walls of the box consisting of a large number of tubes through which water and steam flow. There are three (3) main coal boiler technologies. They are:

- Pulverized coal,
- Fluid bed combustion, and
- Integrated Gasification Combined Cycle.

Of these, pulverized coal is the dominant technology used. Pulverized coal combustion involves pulverizing the coal into a fine dust which is mixed with hot air and injected into a boiler to be burned. Water circulates through tubes lining the boiler and the heat given off from the combustion of the coal drives the water to steam. There are three (3) types of pulverized coal boilers:

- Subcritical,
- Supercritical, and
- Ultra-supercritical.

The above terms are derived from the definition of the temperature and pressure at which water vapor and liquid water are indistinguishable. This is known as the “critical point”. The critical point of water occurs at 705 degrees Fahrenheit (°F) or 374 degrees Celsius (°C) under a pressure of 3,208 pounds per square inch (psia) or 221 bar. At the critical point, the bubbling formation associated with boiling no longer occurs. Instead, with the addition of heat or an increase in pressure the fluid experiences a continuous transition from water-like to steam-like characteristics. Typical temperatures and pressures for the different types of plants using bituminous coal are presented in Table 1.

Table 1 – Operating Parameters for Pulverized Technologies⁸

Boiler Type	Temperature	Pressure
Subcritical	538 °C (1000 °F)	167 bar (2422 psi)
Supercritical	540 – 566 °C (1004 – 1050 °F)	250 bar (3625 psi)
Ultra-supercritical	580 – 620 °C (1076 – 1148 °F)	270 – 285 bar (3916 – 4133 psi)

The higher temperature and pressure allows a boiler to operate at a higher efficiency. In simplest terms, efficiency represents the difference between energy input and energy output. The higher the efficiency of a boiler the less fuel it needs in order to produce a given amount of electricity.

Most of the current electric generation in the US comes from subcritical pulverized coal fired boilers. However, its low efficiency (up to 37% for new plants) and its high emission rates for various pollutants has left it out of favor with utilities when they consider building new base-load plants.

Most new power plants being constructed are supercritical units. While the supercritical technology has been around for decades it is only recently that these units have been constructed in the US. The main benefits from a supercritical unit is that it operates at efficiencies of 40% or more which reduces the amount of coal that needs to be used and consequently the emission of harmful pollutants to generate each kilowatt-hour of energy.

There are no ultra-supercritical pulverized coal power plants currently in the US. Southwestern Electric Power Company (a unit of American Electric Power) has proposed to install an ultra-supercritical unit in Arkansas. Currently the majority of ultra-supercritical units in existence are in either Europe or Asia. Ultra-supercritical units can achieve efficiencies of 42 – 45% and with advancements in materials could potentially achieve efficiencies of 50 – 55%.

SGS Unit 4 Project Description:

IPL is proposing this project (Air Quality Bureau Project Number 07-602) in order to provide additional electrical generating capacity. The new unit will be installed in order to provide reliable base load energy. IPL has stated this project is necessary in order to meet the increasing energy requirements in the region. SGS Unit 4 is scheduled to begin commercial operation in 2013.

SGS Unit 4 will be a 649 MW (net)/733.5 MW (gross) supercritical pulverized coal fired boiler with a maximum design heat input of 6,326 MMBTU/hr. The boiler will be designed to burn natural gas, coal, and biomass. A drawing of the proposed SGS Unit 4 and its associated control equipment is in Figure 7.

Natural gas is used in the boiler igniters to slowly increase boiler metal temperatures. The unit is designed to initially startup on natural gas until the load on the boiler reaches about 10%. At that point coal will be introduced into the boiler in combination with natural gas until the boiler reaches 25% load.

⁸ From World Coal Institute website (http://www.worldcoal.org/coal_technologies.asp).



Figure 7 – Drawing of the proposed SGS Unit 4 and its control equipment⁹

The primary fuel for SGS Unit 4 is coal. The unit is designed to combust Powder River Basin (PRB) coal. PRB coal gets its name from region of the country it comes from. The Powder River basin is a region in southeast Montana and northeast Wyoming about 120 miles (190 km) east to west and 200 miles (320 km) north to south known for its coal deposits. Figure 8 below shows a map of the region.



Figure 8 – Map of Powder River Basin Region¹⁰

⁹ Drawing is from 2007 Alliant Energy Environmental Progress Report (<http://www.alliantenergy.com/docs/groups/public/documents/pub/p015517.pdf>).

¹⁰ Image from Wikipedia (http://en.wikipedia.org/wiki/Powder_River_Basin).

In addition to PRB coal, SGS Unit 4 will be capable of using up to a 10% blend of bituminous coal (Eastern or Western). Finally, the unit will also be able to use biomass.

Coal will be delivered to the site by rail car where it will be unloaded, conveyed and stacked in a coal storage yard. The coal will be transferred by conveyors to coal storage silos. Coal mills will then crush the coal to reduce it to the required size for efficient combustion. Pressurized air will transport the crushed coal to the boiler's burners. The coal will then be mixed with additional air and the mixture will be ignited.

Before exiting to the atmosphere, the flue gas from the boiler will go through a series of air quality control devices which are designed to remove air contaminants from the exhaust gas. The proposed air quality control system is shown in Figure 9.

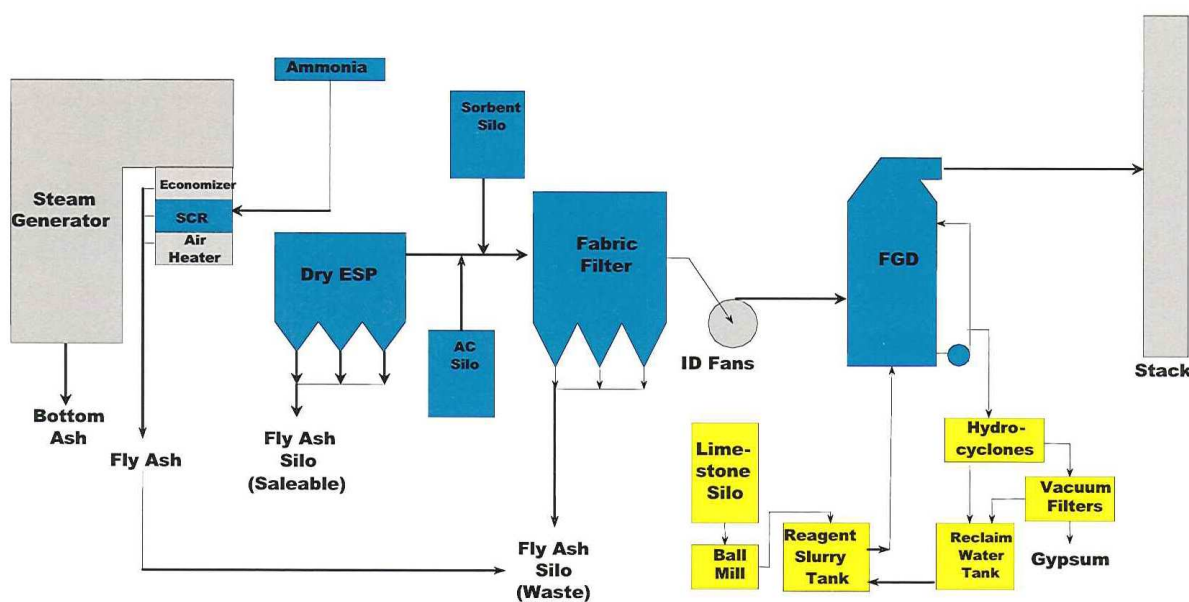


Figure 9 – SGS Unit 4 Proposed Air Quality Control System¹¹

The flue gas will first enter the selective catalytic reduction (SCR) system. SCR uses ammonia in the presence of a catalyst to reduce nitrogen oxides (NO_x). Either urea or aqueous ammonia is injected into the flue gas upstream of the catalyst. The ammonia and the NO_x in the flue gas combine in the presence of the catalyst to form inert nitrogen and water.

After the SCR, the flue gas will pass through a dry electrostatic precipitator (DESP). The DESP is being installed in order to collect fly ash for beneficial reuse as an ingredient in commercial concrete or other industries such as cement manufacturing. An ESP is basically a large box that contains a series of charged electrodes and parallel steel plates about 12 – 16 inches apart. The ESP negatively charges the electrodes and positively

¹¹ Drawing is taken from page 2-6 of the original application which was submitted on November 1, 2007.

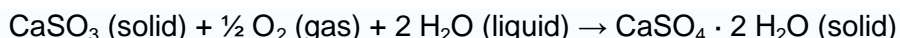
charges the plates to create a voltage differential. As the flue gas passes between the plates and electrodes, the ash particles in the gas become negatively charged. The particles then accumulate on the positively charged plate. At periodic intervals the plates are “rapped” to remove the ash from the plates where it drops into a hopper for either disposal or beneficial reuse.

After exiting the DESP, activated carbon is injected into the flue gas stream. This activated carbon injection (ACI) is used to remove mercury (Hg). Mercury adheres to the activated carbon which allows it to be captured and removed by the particulate removal system.

Next a Trona (sodium sesquicarbonate) will be injected into the flue gas in order to capture sulfur trioxide (SO₃). Removal of SO₃ is important as SO₃ will combine with water in the stack to form sulfuric acid mist (H₂SO₄). The Trona is also captured by the particulate removal system.

The flue gas next enters a fabric filter or baghouse. A baghouse uses fabric bags as filters to collect particulate. The particulate laden flue gas enters a baghouse compartment and passes through a layer of particulate and filter bags. The collected particulate forms a “cake” on the bag which enhances the bag’s filtering efficiency. The pressure drop across the bags increases as the thickness of the cake increases. Once the pressure drop reaches a specific set point, the filter bags are cleaned. This cleaning dislodges a large portion of the filter cake where it falls into a hopper for collection and disposal.

Before exiting out of the stack the flue gas goes through one final cleaning process. This process is a flue gas desulfurization (FGD) system. The FGD uses either lime or limestone as a reagent in a “shower-like” process to remove sulfur dioxide (SO₂), other sulfur compounds, and acid gases from the flue gas. The reagent contacts the contaminants in the flue gas and undergoes a chemical reaction that produces gypsum:



In addition to SGS Unit 4, the proposed project includes a new gas fired auxiliary boiler, an emergency diesel generator, a diesel fire pump, a diesel fuel fired booster pump engine, a gate station natural gas heater, a sixteen (16) cell linear mechanical draft cooling tower (LMDCT), and various material handling and storage systems associated with the fuels, combustion byproducts, and reagents. The new coal unloading, storage, and conveyance systems are being installed not only to serve SGS Unit 4, but to also replace the existing systems.

A complete list of the emission units and emission points associated with this project are presented in Table 2. It also lists the draft permit number for each emission point.

Table 2 – List of Equipment in Project Number 07-602

EP	Description	Permit Number
248	Boiler 4 (EU 248)	08-A-542-P
249	Auxiliary Boiler (EU 249)	08-A-543-P
250	Emergency Generator (EU 250)	08-A-544-P
251	Fire Pump (EU 251)	08-A-545-P
252	Booster Fire Pump (EU 252)	08-A-546-P
253	Cooling Tower (EU 253)	08-A-547-P
254a	Coal Transfer Points (EUs 254a, 254b, and 254c)	08-A-548-P
254b	Coal Transfer Points (EUs 254a, 254b, and 254c)	08-A-549-P
255	Coal Transfer Points (EUs 255a and 255b)	08-A-550-P
256	Stockout Conveyor to Emergency Stockout Coal Pile (EU 256)	08-A-551-P
257	Coal Conveyor Transfer Points (EUs 257a, 257b, and 257c)	08-A-552-P
258	Coal Transfer Point (EU 258)	08-A-553-P
259	Coal Transfer Points (EUs 259a – 259g)	08-A-554-P
260	Coal Transfer Point (EU 260)	08-A-555-P
261	Coal Transfer Points (EUs 261a & 261b)	08-A-556-P
262	Coal Conveying (EUs 262a & 262b)	08-A-557-P
263	Coal Transfer Point (EU 263)	08-A-558-P
264	Coal Transfer Points (EUs 264a, 264b, and 264c)	08-A-559-P
265	Coal Transfer Point (EU 265)	08-A-560-P
266	Coal Transfer Points (EUs 266a – 266d)	08-A-561-P
267	Coal Transfer Points EUs 267a – 267h)	08-A-562-P
268	Emergency Stockout Coal Pile (EU 268)	08-A-563-P
269	Coal Stacker Reclaimers (EUs 269a – 269d)	08-A-564-P
270	PRB Coal Inactive Pile (EU 270)	08-A-565-P
271	Eastern Coal Inactive Piles (EU 271)	08-A-566-P
272	North Gate Haul Road (EU 272)	08-A-567-P
273	West Gate Haul Road (EU 273)	08-A-568-P
274	Limestone Transfer Points (EUs 274a – 274e)	08-A-569-P
275	Limestone Transfer Points (EUs 275a – 275d)	08-A-570-P
276	Active Limestone Storage Pile (EU 276)	08-A-571-P
277	Inactive Limestone Storage Pile (EU 277)	08-A-572-P
278a	Saleable Flyash Transfer Point (EU 278)	08-A-573-P
278b	Saleable Flyash Transfer Point (EU 278)	08-A-574-P
279	Saleable Fly Ash Silo Loading and Unloading to Rail Car/Truck (EU 279)	08-A-575-P
280a	Saleable Fly Ash – Winter Storage (EU 280)	08-A-576-P
280b	Saleable Fly Ash – Winter Storage (EU 280)	08-A-577-P
281a	Waste Fly Ash Transfer Point (EU 281)	08-A-578-P
281b	Waste Fly Ash Transfer Point (EU 281)	08-A-579-P
282	Waste Fly Ash Silo and Loading & Unloading to Rail Car/Truck (EU 282)	08-A-580-P
283	PAC Storage – Transfer & Storage (EU 283)	08-A-581-P
284	Transfer of Sorbent to Day Silo & Silo Storage (EU 284)	08-A-582-P
285	Transfer of Sorbent to Long Term Storage Silo & Silo Storage (EU 285)	08-A-583-P
286	Lime Transfer to Lime Silo & Storage for Water Treatment Process (EU 286)	08-A-584-P
287	Biomass Material Handling Operations (EUs 287a – 287d)	08-A-585-P
288	Biomass Material Handling Operations (EUs 288a – 288d)	08-A-587-P
289	Gate Station Heater (EU 289)	08-A-588-P

The Department has completed its review of the air quality applications (Project Number 07-602) for the emission units listed in Table 2. This document contains the Department's decisions regarding the draft permits.

Contact information for both IPL and the Department concerning this project can be found in Table 3.

Table 3 – Contact Information

Responsible Party	Company Contact	Air Quality Contact
Dale Withers Vice President Construction 200 First Street SE Cedar Rapids, IA 52401 Ph: Fax:	Alan Arnold Senior Environmental Specialist 200 First Street SE Cedar Rapids, IA 52401 Ph: (319) 786-4476 Fax: (319) 786-4747 AlanArnold@alliantenergy.com	Christopher A. Roling, PE Senior Environmental Engineer 7900 Hickman Rd, Suite 1 Urbandale, IA 50322 Ph: (515) 242-6002 Fax: (515) 242-5094 chris.roling@dnr.iowa.gov

A list of important dates in regards to this application and the public comment period are found in Table 4.

Table 4 – Important Dates

Application Received Date:	November 1, 2007
Completed Application:	April 3, 2008
Beginning of Public Comment Period:	February 16, 2009
Public Hearing Date:	(See note below)
Ending of Public Comment Period:	March 20, 2009

NOTE: There will two (2) separate public hearings for the purpose of gathering oral comments. They will be held:

- March 16, 2009 at the Iowa Veterans Home (Whitehill Chapel, 1501 Summit Street, Marshalltown, Iowa). There will be two (2) separate sessions in which the public can make oral or written comments. The sessions will run from 2:30 pm – 5 pm and 6:30 pm to 9 pm.
- March 17, 2009 at the Meskwaki Tribal Center (346 Meskwaki Road, Tama, IA 52339). There will be two (2) separate sessions in which the public can make oral or written comments. The sessions will run from 3 pm – 5 pm and 7 pm to 9 pm.

Analysis of the Application

A. *PSD*: The source is classified as a "major stationary source" for PSD purposes. Therefore, the PSD process must be followed for all pollutants for which emissions will be increased equal to or greater than the PSD significance levels. Particulate matter (PM), particulate matter with an aerodynamic diameter less than 10 microns (PM₁₀), sulfur dioxide (SO₂), nitrogen oxides (NO_x), carbon monoxide (CO), volatile organic compounds (VOC), Fluorides (F), Total Reduced Sulfur (TRS), and sulfuric acid mist (H₂SO₄) all exceed their respective significance levels. No source subject to PSD review may be constructed without a PSD permit. To obtain a PSD permit the applicant must:

- 1) Conduct a BACT analysis, on a case-by-case basis, in which energy, environmental and economic impacts are considered in determining the maximum degree of reduction of emissions that are achievable for the proposed unit.
- 2) Perform an analysis of the ambient air quality prior to the major modification (i.e. preconstruction monitoring).
- 3) Demonstrate that the modified emissions from the proposed project and associated growth due to the project will not exceed the NAAQS or applicable PSD increments.
- 4) Perform additional analysis on the effects of the modified emissions on soils, vegetation, and visibility.
- 5) Address the air quality impacts of associated growth in the area of the source since the minor source baseline date and of major sources in the area since the major source baseline date.
- 6) Demonstrate that the modification will not adversely impact a Class I area.

In addition, the public must be notified of the proposed project, the degree of the increment consumption, and be given the opportunity for submitting written comments. The Department will hold a public opportunity for persons to comment on the project in person.

A more detailed analysis of the PSD program and all PSD analyses conducted for this project (Project Number 07-602) starts on page 19 of this document.

B. *New Source Performance Standards (NSPS)*: The following NSPS subparts are applicable to this project (copies of these regulations are attached in Appendix A):

1. Subpart A (40 CFR §60.1 - 40 CFR §60.19; General Provisions): This subpart affects any facility that is subject to any NSPS subpart.
2. Subpart Da (40 CFR §60.40a - 40 CFR §60.49a; Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978): This subpart affects any fossil-fuel-fired steam generating unit of more than 73 megawatts heat input rate (250 MMBTU/hr) that commences construction or modification after September 18, 1978.
3. Subpart Db (40 CFR §60.40b - 40 CFR §60.49b; Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units): This subpart affects each steam generating unit that commences construction, modification, or reconstruction after June 19, 1984 and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 29 MW (100 MMBTU/hr).
4. Subpart Y (40 CFR §60.250 - 40 CFR §60.254; Standards of Performance for Coal Preparation Plant): This subpart affects certain processes at a coal preparation plant which processes more than 181 Mg (200 tons) per day and commences construction or modification after October 24, 1974.

5. Subpart OOO (40 CFR §60.670 - 40 CFR §60.676; Standards of Performance for Nonmetallic Mineral Processing Plants): This subpart affects operations such as screening operations, storage bins, and handling operations that process nonmetallic minerals such as limestone.
 6. Subpart IIII (40 CFR § 60.4200 – 60.4219; Standards of Performance for Stationary Compression Ignition Internal Combustion Engines): This subpart affects manufacturers, owners, and operators of stationary compression ignition internal combustion engines.
- C. *National Emission Standards for Hazardous Air Pollutants (NESHAP)*: The following NESHAP subparts are applicable to this project (copies of these regulations are attached in Appendix B):
1. Subpart A (40 CFR §63.1 - 40 CFR §63.15; General Provisions): This subpart affects any facility that is subject to any NESHAP subpart.
 2. Subpart B [40 CFR §63.40 - 40 CFR §63.56; Requirements for Control Technology Determination for Major Sources in Accordance With Clean Air Act Sections, Sections 112(g) and 112(j)]: This subpart requires a Case-by-Case MACT determination for those source categories for which a NESHAP has not been promulgated.
 3. Subpart ZZZZ (40 CFR §63.1 - 6580 CFR §63.6675; National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines): This subpart establishes requirements for reciprocating internal combustion engines (RICE) that are located at major sources of HAP emissions.
- D. *Acid Rain*: The facility is considered an affected source under 40 CFR 72, 73, 75, 76, 77, and 78 definitions as emission units at the source are subject to the acid rain emission reduction requirements or the acid rain emission limitations, as adopted by the Department by reference (See 567 IAC 22.120 – 567 IAC 22.148). Boiler 4 will be subject to the SO₂ allowance allocation, NO_x emission limitations, and monitoring provisions of the federal acid rain program.
- E. *Iowa Administrative Code (IAC)*: The following sections of the IAC are applicable to the proposed project:
1. 567 IAC 21.5: *Evidence used in establishing that a violation has or is occurring.*
 2. 567 IAC 22.1(1): *Permit required.* Requirement for new or modified equipment to obtain a construction permit.
 3. 567 IAC 22.120 – 567 IAC 22.148: *Acid Rain program.* State references to the Acid Rain program.
 4. 567 IAC 23.1(2)"v": *Coal preparation plants.* State reference to NSPS Subpart Y.
 5. 567 IAC 23.1(2)"z": *Electric utility steam generating units.* State reference to NSPS Subpart Da.
 6. 567 IAC 23.1(2)"ccc": *Industrial-commercial-institutional steam generating units.* State reference to NSPS Subpart Db.
 7. 567 IAC 23.1(2)"yyy": *Emission standards for stationary compression ignition internal combustion engines.* State reference to NSPS Subpart IIII.

8. 567 IAC 23.1(4)"b"(1): *Section 112(g) requirements*. State reference to NESHAP Subpart B.
9. 567 IAC 23.1(4)"cz": *Emission standards for stationary reciprocating internal combustion engines*. State reference to NESHAP Subpart ZZZZ.
10. 567 IAC Chapter 33: *Special regulations and construction permit requirements for major stationary sources – Prevention of Significant Deterioration (PSD) of air quality*. State adoption of the PSD regulations.

Introduction to New Source Review (NSR) and Prevention of Significant Deterioration (PSD)

Regulatory Background:

On August 7, 1977 Congress substantially amended the Clean Air Act (CAA or the Act). These amendments added detailed PSD and nonattainment area (NAA) programs. On June 19, 1978 the United States Environmental Protection Agency (USEPA or EPA) revised the PSD regulations to comply with the 1977 amendments. The June 1978 regulations were challenged in court and as a result of the judicial review on August 7, 1980 EPA extensively revised both the PSD (for attainment areas) and NAA (for nonattainment areas) regulations. Five sets of regulations resulted from those revisions. These regulations, subsequent modifications, EPA guidance documents, interpretations, and policies represent the current NSR regulatory requirements.

The first set of regulations, 40 CFR §51.166, specifies the minimum requirements that a PSD air quality permit program under Part C of the Act must contain in order to obtain approval by EPA as a revision to a State Implementation Plan (SIP). The second set, 40 CFR §52.21, delineates the federal PSD permit program which currently applies as part of the SIP for States that have not submitted a PSD program meeting the requirements of 40 CFR §51.166. Roughly two thirds of the States are implementing their own PSD programs which have been approved by EPA under 40 CFR §51.166. Iowa is implementing its own PSD program [see 567 Iowa Administrative Code (IAC) Chapter 33]. 40 CFR §52.21 applies in the remaining States. The remainder of the five (5) regulations applies to the NAA program.

PSD Concepts:

The PSD permitting program is for new and modified major sources of air pollution that emit a pollutant subject to regulation under the CAA. PSD applies to all pollutants that do not exceed the National Ambient Air Quality Standards (NAAQS) in an area. The NAAQS establish the maximum pollution concentration levels to protect public health and welfare from harmful levels of pollutants. Pollutants covered by the NAAQS are nitrogen oxides (NO_x), volatile organic compounds (VOC) which are precursors to ground-level ozone, sulfur dioxide (SO₂), fine particulate (PM₁₀ and PM_{2.5}), carbon monoxide (CO), and lead (Pb). These pollutants are called criteria pollutants.

PSD also applies to other pollutants that do not have a NAAQS. These non-criteria pollutants are listed in the regulations and include fluorides, sulfuric acid mist, total reduced sulfur, and certain contaminants from municipal solid waste plants.

PSD does **not** prevent sources of air pollution from increasing emissions. Instead, the PSD regulations are designed to achieve the following:

- 1) to ensure that economic growth will occur in harmony with the preservation of existing clean air resources
- 2) to protect the public health and welfare from any adverse effects which might occur even though air pollution concentrations are below the National Ambient Air Quality Standards (NAAQS)
- 3) to preserve, protect, and enhance the air quality in areas of special natural recreational, scenic, or historic value, such as national parks and wilderness areas
- 4) to provide the opportunity for public comment on proposed applications

The PSD program applies to a new stationary source that will have a “major” and “significant” amount of any air pollutant subject to regulation under the CAA. It also applies to an existing major stationary source that plans to modify its operations in such a way that would lead to an increase of air pollution that would be “major” or “significant”.

All PSD thresholds are based upon "potential-to-emit (PTE)." For PSD applicability purposes only, this is the maximum design capacity of a stationary source to emit a pollutant under its physical and operational design after the application of air pollution control equipment and after considering all "federally enforceable" limitations restricting the potential-to-emit of the source.

Therefore, a "major stationary source" is defined in Section 169 of the CAA as:

“Any one of 28 types of sources with the potential-to-emit 100 tons per year or more of any pollutant regulated in the CAA or any other type of source with the potential to emit regulated pollutants in amounts equal to or greater than 250 tons per year.”

Per 567 IAC 33.3(1), a regulated pollutant is defined as:

1. *Any pollutant for which a national ambient air quality standard has been promulgated and any constituents or precursors for such pollutants identified by the Administrator (e.g., volatile organic compounds and NO_x are precursors for ozone);*
2. *Any pollutant that is subject to any standard promulgated under Section 111 of the Act;*
3. *Any Class I or Class II substance subject to a standard promulgated under or established by Title VI of the Act; or*
4. *Any pollutant that otherwise is subject to regulation under the Act; except that any or all hazardous air pollutants either listed in Section 112 of the Act or added to the list pursuant to Section 112(b)(2) of the Act, which have not been delisted pursuant to Section 112(b)(3) of the Act, are not regulated NSR pollutants unless the listed hazardous air pollutant is also regulated as a constituent or precursor of a general pollutant listed under Section 108 of the Act.*

The term “significant” refers to the thresholds assigned to each criteria pollutant and certain non-criteria pollutants. For example, the significant threshold is 40 tpy for NO_x and 15 tpy for PM₁₀.

Before a new major stationary source constructs or an existing major stationary source makes a significant modification, the source is required to obtain a PSD permit. A PSD permit is a legal document that limits the amount of air pollution that may be released by the source. The permit will also specify things such as the construction that is allowed, all emission limits (both state and federal), compliance testing requirements, operating monitoring, recordkeeping, and the type of pollution controls.

In order to obtain a PSD permit the source must meet the following requirements of the PSD program:

- *Best Available Control Technology (BACT)*

BACT is defined as an emission limit (including a visible emissions standard) based on the maximum degree of reduction for each regulated NSR pollutant which would be emitted from any proposed major stationary source or major modification. BACT is determined on a case-by-case analysis that takes into account energy, environmental, and economic impacts. BACT can be add-on control equipment or it can be modification to the production processes/methods.

- *Air Quality Impact Analysis*

The main purpose of the air quality analysis is to demonstrate that new air pollution from the proposed major stationary source or major modification in conjunction with other applicable emissions increases and decreases from existing sources will not cause or contribute to a violation of any applicable NAAQS or PSD increment.

PSD increment is the amount of pollution an area is allowed to increase. PSD increments prevent the air quality in clean areas from deteriorating to the level set by the NAAQS. PSD regions are defined as Class I through Class III. Area classifications affect the maximum allowable increase in the PSD ambient air increments with Class I areas allowed the least increase and Class III areas allowed the most.

- Class I areas are international parks, national wilderness areas and national memorial parks greater than 5,000 acres in size and national parks which exceed 6,000 acres in size.
- Class II areas include all areas not designated as Class I or Class III.
- Class III areas are planning areas set aside for industrial growth.

All of the State of Iowa is classified as a Class II area. All planning areas were initially designated either Class I or Class II. States must request and receive approval from the Environmental Protection Agency (EPA) for Class III areas. No Class III areas have been approved in the United States and therefore none exist at this time.

Generally, the air quality analysis will involve

- (1) An assessment of existing air quality, which may include ambient monitoring data and air quality dispersion modeling results, and

(2) Prediction, using dispersion modeling, of the ambient concentrations that will result from the applicant's proposed project and future growth associated with the project.

- *Additional Impact Analysis*

The additional impacts analysis assesses the impacts of air, ground, and water pollution on soils, vegetation, and visibility caused by any increase in emissions of any regulated pollutant from the source or modification under review and from associated growth. Associated growth is industrial, commercial, and residential growth that will occur in the area due to the new source or modification.

- *Public Participation*

Public participation is citizens being involved in the permitting process. Any person may comment on the permit(s) or request a public hearing if one has not been scheduled during the public comment period.

PSD Applicability

The existing SGS plant is classified under the two (2) digit Standard Industrial Classification (SIC) of 49. Since the plant combusts coal and oil to produce steam in order to make electricity it is considered a fossil fuel-fired steam electric generator. In addition, the capacity of the existing units is greater than 250 MMBTU/hr. Therefore, the existing SGS plant is considered one of the 28 listed source categories.

As can be seen in Table 5 below, the potential emissions of PM, PM₁₀, SO₂, NO_x, CO, and H₂SO₄ are all over 100 tons per year (tons/yr) based on the data submitted by IPL on its Title V operating permit application. Therefore, the existing SGS plant is considered a “major stationary source” for PSD purposes. In addition, fugitive emissions, to the extent quantifiable, are considered in any subsequent PSD analysis since it is one of the 28 listed source categories.

Table 5 – Existing SGS Potential Emissions

Pollutant	Potential Emissions (tpy)	Baseline Emissions (tpy)
PM	8,544	614
PM ₁₀	1,341	572
SO ₂	23,824	9,128
NO _x	14,892	3,423
CO	9,344	7,123
VOC	57	25
Pb	0.35	0.14
H ₂ SO ₄	555	265
TRS	5	4
F (as HF)	72	11

Table 5 also shows the baseline emissions for the existing SGS facility. In simple terms, baseline emissions are actual emissions based on the average of two (2) years worth of operating data. The two (2) years used by IPL were 2006 and 2007.

Table 6 shows the net emissions increase for the SGS Unit 4 project calculated by IPL (with some corrections made by the Department) along with the PSD significance level for each pollutant. Since PM, PM₁₀, SO₂, NO_x, CO, VOC, H₂SO₄, TRS, and F emissions are all over their respective PSD significant increase level they are subject to PSD review. This means the proposed addition of a new coal-fired boiler and its ancillary equipment is considered a “major modification” to a “major stationary source”. As stated earlier, part of that review is to determine BACT. A complete discussion on the BACT analysis is found later in this document on page 33.

Table 6 – Net Emission Increases for Project Number 07-602

Pollutant	Net Emissions Increase (tpy)	PSD Significant Increase Level (tpy)
PM	2,770	25
PM ₁₀	2,770	15
SO ₂	4,498	40
NO _x	3,213	40
CO	3,346	100
VOC	95.7	40
Pb	0.51	0.6
H ₂ SO ₄	111	10
TRS	27.7	10
F	4.80	3

Table 7 below provides a summary of the potential emissions for the main boiler and the project with BACT emission rates.

Table 7 – Potential Emissions with BACT

Pollutant	Main Boiler (tpy)	Overall Project (tpy)
PM	465.5	506.9
PM ₁₀	465.5	501.0
SO ₂	858.9	859.3
NO _x	969.8	981.9
CO	2,770.8	2,774.3
VOC	94.2	94.6
Pb	0.50	0.51
H ₂ SO ₄	58.2	58.5
TRS	19.7	19.8
F (as HF)	2.52	2.52

Recently there has been much discussion about two (2) additional pollutants and the requirements for those pollutants to be reviewed under the PSD program. Those pollutants are particulate matter with an aerodynamic diameter less than 2.5 microns ($PM_{2.5}$ or fine particulate) and carbon dioxide (CO_2). At this time, the draft construction permits do not contain any requirements for $PM_{2.5}$ and CO_2 . However, the Department is still evaluating the requirements to regulate these pollutants under the PSD program and is therefore accepting comments from the public on the necessity and the requirements to regulate these pollutants under the PSD program. Below is a detailed discussion on each of these pollutants.

➤ *PM_{2.5}*:

Background¹²:

The Clean Air Act requires EPA to set National Ambient Air Quality Standards (NAAQS) for six criteria pollutant. Particle pollution (also known as particulate matter) is one of these. The Clean Air Act established two types of national air quality standards for particle pollution. **Primary standards** set limits to protect public health, including the health of "sensitive" populations such as asthmatics, children, and the elderly. **Secondary standards** set limits to protect public welfare, including protection against visibility impairment, damage to animals, crops, vegetation, and buildings.

The CAA requires EPA to review the latest scientific information and standards every five (5) years. Before new standards are established, policy decisions undergo a review by the scientific community, industry, public interest groups, the general public, and the Clean Air Scientific Advisory Committee (CASAC).

The nation's air quality standards for particulate matter were first established in 1971 and were not significantly revised until 1987 when EPA changed the indicator of the standards to regulate inhalable particles smaller than or equal to 10 micrometers in diameter (approximately $\frac{1}{4}$ the size of a single grain of table salt).

Ten years later (1997) after a lengthy review, the particulate standards were revised by EPA. Standards were set for fine particulates ($PM_{2.5}$) based on their link to serious health problems ranging from increased symptoms, hospital admissions, and emergency room visits for people with heart and lung disease to premature death in people with heart or lung disease.

The 1997 standards also retained but slightly revised the standards for PM_{10} which were intended to regulate inhalable coarse particles ranging from 2.5 – 10 micrometers in diameter. PM_{10} measurements include both fine and coarse particles. A comparison of particle size can be found in Figure 10.

¹² Information in the "Background" section is from EPA's website on particulate matter. See <http://www.epa.gov/air/particlepollution/index.html> for the homepage.

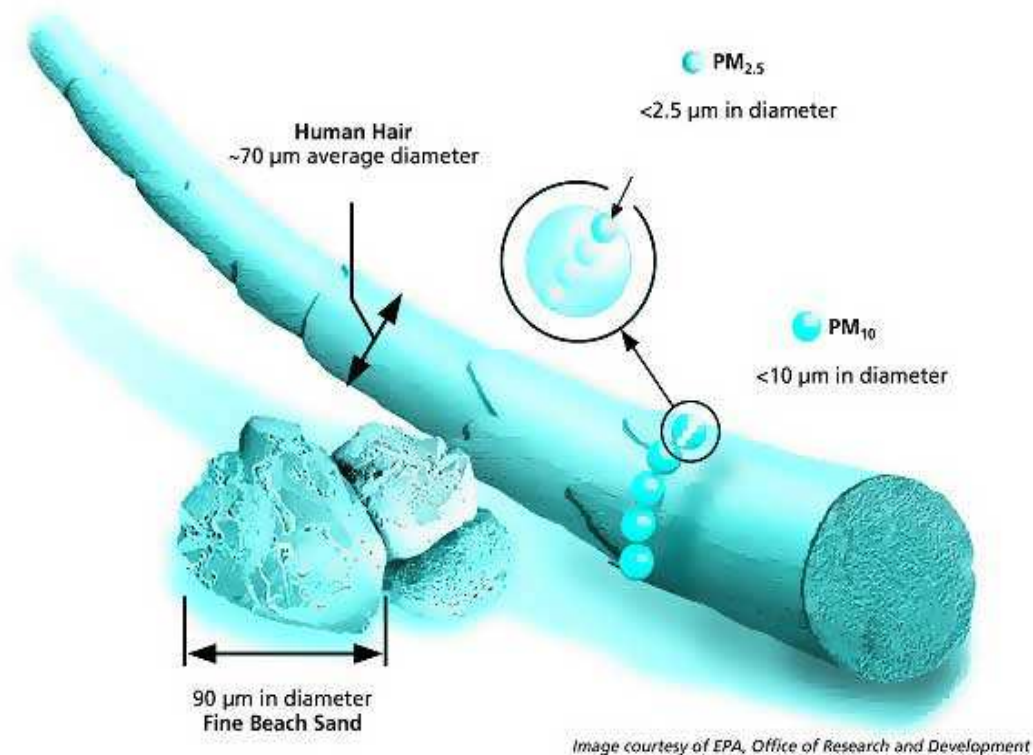


Figure 10 – Comparison of Size of Particulate Pollution¹³

EPA revised the air quality standards for particle pollution in 2006. The 2006 standards tightened the twenty-four hour (24-hr) fine particulate standard from the 1997 level of 65 micrograms per cubic meter ($\mu\text{g}/\text{m}^3$) to 35 $\mu\text{g}/\text{m}^3$. The annual standard of 15 $\mu\text{g}/\text{m}^3$ was retained. EPA retained the 24-hr PM₁₀ standard of 150 $\mu\text{g}/\text{m}^3$, but revoked the annual PM₁₀ standard.

After EPA promulgated the PM_{2.5} NAAQS in 1997 it issued a guidance document entitled “Interim Implementation for the New Source Review Requirements for PM_{2.5}” (John S. Seitz, EPA; October 23, 1997). A copy of this guidance document is attached in Appendix C. This guidance stated sources would be allowed to use implementation of a PM₁₀ program as a surrogate program for meeting PM_{2.5} requirements.

On April 5, 2005 EPA issued a guidance document titled “Implementation of New Source Review Requirements in PM_{2.5} Nonattainment Areas” (Stephen D. Page, EPA). This memo provided guidance on the implementation of the nonattainment major NSR provisions of PM_{2.5} nonattainment areas in the interim period between the effective date of the PM_{2.5} NAAQS designations and the promulgation date of the final NSR regulations for PM_{2.5}. Besides affirming the continuation of the Seitz guidance memo the April 5, 2005 memo recommends that until EPA promulgates the PM_{2.5} major NSR regulations states should use a PM₁₀ nonattainment major NSR program as the surrogate to address the requirements of nonattainment major NSR for PM_{2.5}. A copy of this memo can also be found in Appendix C.

¹³ Diagram is taken from EPA’s website on basic information on particulate pollution (<http://www.epa.gov/air/particlepollution/basic.html>).

On April 25, 2007 EPA promulgated the Clean Air Fine Particle Implementation Rule which provided rules and guidance on the CAA requirements for State and Tribal plans to implement the 1997 PM_{2.5} NAAQS. The rule did not include final PM_{2.5} requirements for the NSR program. A copy of this final rule is also in Appendix C.

On May 16, 2008 EPA promulgated the first of two (2) NSR rules regarding PM_{2.5} [Implementation of the New Source Review (NSR) Program for Particulate Matter Less Than 2.5 Micrometers (PM_{2.5})]. The rule covered:

- Pollutants that contribute to PM_{2.5} subject to NSR regulations
- Major source thresholds
- Significant emission rates
- Interpollutant offset trading
- Revised SIP submittal deadlines
- Timing of implementation of the rule

The second rule was proposed on September 21, 2007 and dealt with PM_{2.5} increments, significant impact levels (SILs), and significant monitoring concentrations (SMCs). A copy of the May 16, 2008 rule and the September 21, 2007 Federal Register notice is attached in Appendix C. Since the second PM_{2.5} PSD rule has not been promulgated the Department has not adopted either of the two (2) PSD rules and is currently following EPA's guidance (i.e. the October 23, 1997 Seitz memo).

According to EPA, once these two (2) rules are implemented and in effect, the PM_{2.5} PSD program will no longer use a PM₁₀ surrogate as has been its practice under the existing guidance.

A brief summary of the history of particulate matter standards is presented below:

- 1971 – EPA issued the first National Ambient Air Quality Standards for Total Suspended Particles (TSP).
- 1987 – EPA revised the standards and replaced TSP with PM₁₀ (targeting particles smaller than 10 micrometers).
- 1997 – EPA revised the standards and included PM_{2.5} (targeting particles smaller than 2.5 micrometers).
- 1997 – Several industry and other organizations, some state governments challenged EPA's standards in the U.S. Court of Appeals for the D.C. Circuit.
- 2001 – The U.S. Supreme Court upheld EPA's authority under the Clean Air Act to set standards, clarified that EPA cannot consider cost in setting standards. Remanded several issues to the appellate court.
- 2002 – The DC Circuit Court rejected all remaining legal challenges to EPA's 1997 standards for PM_{2.5}.
- 2006 – EPA revises particulate matter standards.

- 2007 – EPA promulgates the Clean Air Fine Particle Implementation Rule.
- 2007 – EPA proposes PSD rule for PM_{2.5} for increments, significant impact levels (SILs), and significant monitoring concentrations (SMCs).
- 2008 – EPA promulgates Implementation of the New Source Review (NSR) Program for Particulate Matter Less Than 2.5 Micrometers (PM_{2.5}).

Conclusion:

As stated above, the Department has been following EPA's guidance concerning PM_{2.5} and therefore has not been requiring PM_{2.5} to be reviewed under the PSD program. The Department is evaluating whether or not it should continue to follow EPA's guidance concerning PM_{2.5}.

Since the Department is still evaluating this issue it is accepting comments from the public concerning the regulation of PM_{2.5} under the PSD program.

➤ CO₂:

Background¹⁴:

Climate change refers to any significant change in measures of climate (i.e. temperature, precipitation, or wind) lasting for an extended period (i.e. decades or longer). The Earth's climate has changed numerous times in its history. These events range from ice ages to long periods of warmth. Currently it is getting warmer.

Historically, natural factors such as volcanic eruptions, changes in the Earth's orbit, and the amount of energy released from the Sun have affected the Earth's climate. Beginning in the late 18th century, human activities associated with the Industrial Revolution have also had an effect on the composition of the atmosphere and thereby affecting the Earth's climate.

For the past 200 years, the burning of fossil fuels, such as coal and oil, and deforestation has caused the concentration of heat-trapping "greenhouse gases" to increase in our atmosphere. These gases prevent heat from escaping to space similar to glass panels of a greenhouse. This is called the "greenhouse effect" (See Figure 11 for a visual description).

¹⁴ Information in the "Background" section is from EPA's website on greenhouse gas emissions and climate change. See <http://www.epa.gov/climatechange/emissions/index.html> for the greenhouse gas homepage and <http://www.epa.gov/climatechange/index.html> for the climate change homepage.

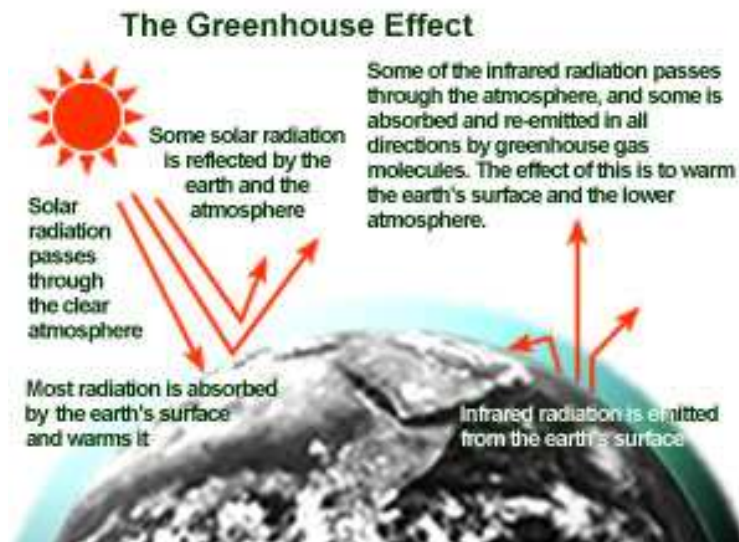


Figure 11 – Visual of the Greenhouse Effect¹⁵

Some greenhouse gases such as carbon dioxide (CO₂) occur naturally and are emitted to the atmosphere through natural processes and human activities. Other greenhouse gases (i.e. fluorinated gases) are created and emitted solely through human activities. The principal greenhouse gases from human activities are:

- Carbon dioxide (CO₂): CO₂ is the result of combustion. This could be combustion of fossil fuels (i.e. oil, natural gas, and coal), solid waste, and trees and other wood products. CO₂ is also the result of some chemical reactions such as the manufacturing of cement or fermentation from the making of ethanol. CO₂ is also removed from the atmosphere by plants as part of the biological carbon cycle.
- Methane (CH₄): Methane comes from the production and transport of coal, natural gas, and oil. It is also produced from livestock and other agricultural practices and by the decay of organic wastes in municipal solid waste landfills.
- Nitrous oxide (N₂O): Nitrous oxide is the result of agricultural and industrial activities as well as the combustion of fossil fuels and solid waste.
- Fluorinated gases: Hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride are synthetic, powerful greenhouse gases that are emitted from a variety of industrial processes. These gases are sometimes used as substitutes for ozone depleting substances (i.e. CFCs, HCFCs, and halons).

¹⁵ Diagram is from EPA's website (See <http://www.epa.gov/climatechange/science/index.html>).

Energy related activities account for three quarters of our human generated greenhouse gas emissions in the US. Most of those emissions are in the form of CO₂ from the combustion of fossil fuels. More than half of the energy related emissions come from large stationary sources such as power plants. About one third comes from transportation. Industrial processes such as the production of cement, steel & aluminum, agriculture, forestry, other land use, and waste management are also sources of greenhouse gas emissions in the US.

Greenhouse gases are required for life as we know it as they do keep the planet's surface warmer than it would otherwise be, but as the concentrations of these gases continue to increase in the atmosphere the Earth's temperature is climbing above past levels.

According to the National Oceanic and Atmospheric Administration (NOAA) and the National Aeronautics and Space Administration (NASA), the Earth's average surface temperature has increased about 1.2 – 1.4 °F in the last 100 years. Most of the warming in recent decades is likely the result of human activities. Other aspects of the climate are also changing such as rainfall patterns, snow and ice cover, and sea level.

Climate models predict that the average temperature at the Earth's surface could increase from 3.2 to 7.2 °F above 1990 levels by the end of this century if greenhouse gases continue to increase. Scientists are certain that human activities are changing the composition of the atmosphere and that increasing the concentration of greenhouse gases will change the planet's climate, but they are not sure by how much it will change, at what rate it will change, or what the exact effects will be.

It should be pointed out that the terms “climate change” and “global warming” are often used interchangeably. However, according to the National Academy of Sciences, the phrase “climate change” is growing in preferred use because it helps convey there are other changes in addition to rising temperatures. These terms are defined as:

- Climate change refers to any significant change in measure of climate such as temperature, precipitation, or wind that lasts for an extended period of time (i.e. decades or longer). Climate change can result from:
 - Natural factors such as changes in the sun's intensity or slow changes in the Earth's orbit around the sun,
 - Natural processes within the climate system (i.e. changes in ocean circulation),

- Human activities that change the atmosphere's composition and the land surface. These changes range from the combustion of fossil fuels to deforestation, reforestation, urbanization, desertification, etc.
- Global warming refers to an average increase in the temperature of the atmosphere near the Earth's surface and in the troposphere which can contribute to changes in global climate patterns. It can occur from both natural causes and humans. In general the term "global warming" often refers to the warming that can occur as a result of increased emissions of greenhouse gases from human activities.

Recent Court Cases and Related Activities:

Recently, global warming and climate change have come to the forefront of air related environmental discussions. A group of private organizations and local and state governments petitioned the EPA to regulate greenhouse gas (GHG) emissions. The EPA denied the petition and the organizations and governments asked the courts to review the denial. The DC Circuit Court of Appeals denied the petition for review, at which time the case was taken by the Supreme Court.

In April 2007, the United States Supreme Court issued its decision in *Massachusetts v. Environmental Protection Agency* (A copy of this decision can be found in Appendix D). The Court considered the issue of the EPA's authority to regulate GHG emissions from new motor vehicles. *Massachusetts v. Environmental Protection Agency*, 127 S.Ct. 1438, 1449 (2007). §202(a)(1) of the Clean Air Act (CAA) authorizes EPA to regulate any air pollutant from new motor vehicles if EPA determines the emissions would cause or contribute to air pollution that may endanger public health or welfare. *Id.* at 1459, 1460. Section 302 (g) of the CAA defines air pollutant as:

"any air pollution agent or combination of such agents, including any physical, chemical, biological, radioactive (including source material, special nuclear material, and byproduct material) substance or matter which is emitted into or otherwise enters the ambient air." 42 U.S.C. 7602.

The Court concluded:

"Because greenhouse gases fit well within the Clean Air Act's capacious definition of "air pollutant," we hold that EPA has the statutory authority to regulate the emission of such gases from new motor vehicles."
Massachusetts at 1462.

and that:

“Under the clear terms of the Clean Air Act, EPA can avoid taking further action only if it determines that greenhouse gases do not contribute to climate change or if it provides some reasonable explanation as to why it cannot or will not exercise its discretion.” *Id.* at 1462.

If EPA makes the endangerment finding, then the CAA requires EPA to regulate the greenhouse gas emissions from new motor vehicles. *Id.*

The Court reversed the Appeal Court's decision and remanded the case, requiring EPA to make the greenhouse gas endangerment determination. The Court stopped short of telling EPA what the determination must be in that it stated:

“We need not and do not reach the question whether on remand EPA must make an endangerment finding.... We hold only that EPA must ground its reasons for action or inaction in the statute.” *Id.* at 1463.

The impact of *Massachusetts v. Environmental Protection Agency* has been far reaching with PSD permits being challenged in various states because the permits did not include a BACT analysis for GHG emissions.

In July 2008, EPA issued an Advanced Notice of Proposed Rulemaking (ANPR) for GHG emissions. The notice seeks comments on numerous issues concerning possible rulemaking for GHG emissions.

Also, in July 2008 the county court in Fulton County, Georgia ruled on *Friends of Chattahoochee vs. Georgia Department of Natural Resources*. One of the issues before the court was whether the state should have required BACT for CO₂ for a new coal-fired power plant for Longleaf Energy Associates. The court ruled that the PSD permit cannot be issued without CO₂ emission limitations based on a BACT analysis. This case will be heard by the Georgia Supreme Court.

More recently (November 2008), the Environmental Appeals Board (EAB) remanded an EPA Region VIII issued PSD permit for Deseret Power Electric Cooperative (Bonanza Power Plant) because EPA did not address CO₂.

The EAB is the final agency decision maker on administrative appeals under all major environmental statutes that the Agency administers. It is an impartial body independent of all Agency components outside the immediate Office of the Administrator. The EAB typically sits in panels of three (3) judges and makes decisions by majority vote. Currently, nine (9) experienced attorneys serve as counsel to the EAB.

A copy of the EAB decision on Deseret (PSD Appeal No. 07-03) is attached to this document in Appendix D. As stated on page 6 of the decision, the EAB could not

sustain EPA's CO₂ decision on the administrative record and therefore remanded the permit back to EPA. On page 9 of the decision the EAB states:

“By our holding today, we do not conclude that the CAA (or an historical Agency interpretation) requires the Region to impose a CO₂ BACT limit. Instead, we conclude that the record does not support the Region's proffered reason for not imposing a CO₂ BACT limit – that although EPA initially could have interpreted the CAA to require a CO₂ BACT limit, the Region no longer can do so because of an historical Agency interpretation. Accordingly, we remand the Permit to the Region for it to reconsider whether or not to impose a CO₂ BACT limit and to develop an adequate record for its decision.”

The EAB further states on page 19:

“The regulations specifically provide that “[t]he record shall be complete on the date the final permit is issued. *Id.* § 124.18(c). Questions regarding completeness of the administrative record have arisen in situations where the permit issuer either failed to issue its responses to comments until after issuing its permitting decision or where the permit issuer has sought to introduce on appeal a new or additional rationale for its permitting decision or additional information supporting its permitting decision. In rare cases, the Board has allowed a rationale to be supplemented on appeal where the missing explanation was fairly deducible from the record. *See In re Steel Dynamics, Inc.*, 9 E.A.D. 165, 191 (EAB 2000). More typically, the Board has remanded the permit.”

On December 18, 2008 EPA Administrator Stephen L. Johnson issued an interpretation of the term “subject to regulation” in light of the EAB decision on Deseret Power. A copy of that memorandum is also attached in Appendix D. The main conclusion from the memo is summed up in the following statement from the memo:

“EPA interprets the definition of “regulated NSR pollutant” in 40 C.F.R. §52.21(b)(50) to exclude pollutants for which EPA regulations only require monitoring or reporting but to include each pollutant subject to either a provision in the Clean Air Act or regulation promulgated by EPA under the Clean Air Act that requires actual control of emissions of that pollutant.” (Quote is from page 6 of the memo. Similar language can also be found on page 2 of the memo)

This memo was published in the Federal Register (FR) on December 31, 2008 (See copy of the FR notice in Appendix D. Also on December 31, 2008, environmental groups filed a petition with EPA asking that EPA withdraw the memo. EPA did not withdraw the memo and on January 15, 2009, the Sierra Club, the National

Resources Defense Council (NRDC), and the Environmental Defense Fund (EDF) filed a lawsuit in the D.C. Court of Appeals challenging Administrator Johnson's December memo on GHG regulation.

Like EPA, the Department has not applied the PSD program to pollutants that are subject to only monitoring and reporting requirements.

Conclusion:

The Department is still reviewing whether or not CO₂ is a regulated NSR pollutant. Since the Department is still evaluating this issue it is accepting public comments concerning whether or not CO₂ is required to be regulated under the PSD program.

Best Available Control Technology (BACT)

BACT is defined as:

“an emissions limitation, including a visible emissions standard, based on the maximum degree of reduction for each regulated NSR pollutant which would be emitted from any proposed major stationary source or major modification which the reviewing authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combination techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 567—subrules 23.1(2) through 23.1(5) (standards for new stationary sources, federal standards for hazardous air pollutants, and federal emissions guidelines), or federal regulations as set forth in 40 CFR Parts 60, 61 and 63 but not yet adopted by the state. If the department determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard or combination thereof may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation and shall provide for compliance by means which achieve equivalent results.” [567 IAC 33.3(1)]

To fulfill the PSD requirements, the applicant has performed a BACT analysis for the new & modified equipment for each pollutant emitted above the PSD "significance level." Following is a summary of the BACT determinations for each pollutant and each piece of equipment with the control options considered. A complete description of all of the control technologies reviewed for each pollutant are included in Appendix E.

- **Boiler 4:**

Appendix J:

It needs to be pointed out that IPL supplied an evaluation on various types of coal generation technologies (See IPL's November 2007 application, Appendix J: Site Evaluation Study – Coal Technology Assessment). This draft report was conducted by Black & Veatch and was an assessment of the cost estimates (with an accuracy range of +/- 25%) and the performance of the various technologies. The technologies reviewed in this assessment were pulverized coal boilers (both supercritical & ultra-supercritical), circulating fluidized bed (CFB) boilers, and IGCC.

The Department did not review this assessment as it was not a BACT analysis and the Department followed EPA guidance regarding the review of changing the emission unit for BACT purposes. Per page B.13 of EPA's draft New Source Review Workshop Manual (NSR Manual):

“Historically, EPA has not considered the BACT requirement as a means to redefine the design of the source when considering available control alternatives. For example, applicants proposing to construct a coal-fired electric generator, have not been required by EPA as part of the BACT analysis to consider building a natural gas-fired electric turbine although the turbine may be inherently less polluting per unit product (in this case electricity). However, this is an aspect of the PSD permitting process in which states have the discretion to engage in a broader analysis if they so desire. Thus, a gas turbine normally would not be included in the list of control alternatives for a coal-fired boiler.”

This guidance is based on several decisions made by the EAB. In Pennsauken County, New Jersey Resource Recovery Facility (PSD Appeal No. 88-8) the EAB stated:

“These objections are beyond the scope of this proceeding and therefore are not reviewable under 40 CFR 124.19, which restricts review to “conditions” in the permit. Permit conditions are imposed for the purpose of ensuring that the proposed source of pollutant emissions – here, a municipal waste combustor – uses emission control systems that represent BACT, thereby reducing emissions to the maximum degree possible. ... The permit conditions that define these systems are imposed on the source as the applicant has defined it. Although imposition of the conditions may, among other things, have a profound effect on the viability of the proposed facility as conceived by the applicant, the conditions themselves are not intended to redefine the source ...” (pages 10 – 11).

In addition, in Hawaiian Commercial & Sugar Company (PSD Appeal No. 92-1) the EAB held that:

“EPA's PSD permit conditions regulations do not mandate that the permitting authority redefine the source in order to reduce emissions.” (page 5)

Other EAB decisions that have been made regarding “redefining” a source include:

- Old Dominion Electric Cooperative (PSD Appeal No. 91-39)
- SEI Birchwood Inc (PSD Appeal Nos. 93-11 & 93-12)
- Knauf Fiber Glass, GMBH (PSD Appeal Nos. 98-3 through 98-20).

Copies of all of the above mentioned EAB decisions can be found in Appendix F.

Output based standards:

Historically, emission limits on electric generating units (EGU’s) and other types of boilers have been “input based”. These limits are in the form of pounds of emissions per million British thermal unit (lb/MMBTU). However, this form of emission limit does not account for the pollution prevention benefits of increased efficiency in the generation of electricity. By using an input based standard one is eliminating energy efficiency as a control option.

Output based emission limits which are expressed as emissions per unit of useful energy output {i.e. pounds of emissions per gross megawatt hour [lb/MWh(gross)]} promote clean energy by accounting for the air pollution effects of energy efficiency. Output based emission standards allow and encourages efficiency to be used as a control option (i.e. combustion efficiency, reduced parasitic loads, generator efficiency) and links emissions to productive output. Therefore, energy efficiency is being used as part of the BACT assessment and as a control option.

Ideally the BACT limits would have been based on output based measurements to allow for uniform and direct comparisons. However, that data was not available. Therefore, the limits in the permit are based on the input based limits and converted to output based format. The calculation used to convert from an input based emission rate to an output based emission limit was:

$$\frac{\text{Heat Input Rate} \left(\frac{\text{lb}}{\text{MMBTU}} \right) \times 6326 \frac{\text{MMBTU}}{\text{hr}}}{733.5 \text{ MW (gross)}}$$

The BACT emission limits discussed below also show the equivalent input based emission rate for comparison.

BACT decisions:

- Particulate Matter (PM):

IPL proposed to use the top available method for controlling total particulate (both filterable and condensable) emissions which is a baghouse. Therefore, no further review of the type of control equipment to be used was necessary.

The emission rate was based on reviewing stack testing data from other similar facilities. This was done in three (3) steps:

- 1) A statistical analysis was done on the filterable data from the various stack tests
- 2) A statistical analysis was done on the condensable data from the stack tests of similar types of boilers.
- 3) The results from steps 1 and 2 were added together.

The statistical analysis used in this case and for other pollutants and other emission units was the upper bound 95% confidence interval. The formula used was:

$$95\% = \text{avg} + t \frac{S}{\sqrt{n}}$$

where: avg = average of the test runs

S = standard deviation of the test runs

t = percentage point of the *t* distribution with n-1 degrees of freedom

n = number of test runs

A copy of the above analysis and all other BACT calculations are in Appendix G.

Control technology: Baghouse
It should be noted that there is also a Dry Electrostatic Precipitator (DESP) that will be used to collect saleable fly ash prior to injecting activated carbon.

BACT emission limit: 465.5 tons/yr (rolling-12-month total)
0.145 lb/MWh (gross) [avg. of 3 test runs]
(heat input equivalent = 0.0168 lb/MMBTU)

- o Particulate Matter with an aerodynamic diameter of 10 microns (PM₁₀):

IPL assumed the PM₁₀ emissions are equivalent to the total particulate emissions. Since PM₁₀ is a subset of total PM this is a conservative estimate, but close to being accurate as almost all of the emissions will be PM₁₀. Therefore, the BACT analysis will be the same as the PM BACT analysis.

Control technology: Baghouse
It should be noted that there is also a Dry Electrostatic Precipitator (DESP) that will be used to collect saleable fly ash prior to injecting activated carbon.

BACT emission limit: 465.5 tons/yr (rolling-12-month total)
0.145 lb/MWh (gross) [avg. of 3 test runs]
(heat input equivalent = 0.0168 lb/MMBTU)

o Opacity (visible emissions):

Per the definition of BACT an emission limit is required on visible emissions or opacity. For the most part, visible emissions from a stack are the result of particulate matter. Therefore, the control of opacity is the same as the control for particulate emissions.

The emission limit was established based on data from other coal fired boilers and the expected opacity from a coal fired combustion stack with a grain loading of 0.0059 gr/dscf.

Control technology: Baghouse
BACT emission limit: 5% (6-minute avg.)

Sulfur Dioxide (SO₂):

IPL proposed to use wet flue gas desulfurization (WFGD) to control SO₂ emissions. Since this is the top available control technology no further review of the type of control equipment to be used was necessary.

Information gathered by the Department concerning wet scrubbers showed that the Chiyoda Jet Bubbling Reactor (CT-121) can meet removal efficiencies of over 99%. In addition, according to CEM data for Pleasant Prairie Units 1 & 2 they were consistently below 0.03 lb/MMBTU.

Presented with this information IPL proposed a BACT emission rate of 0.031 lb/MMBTU which was accepted by the Department and converted to an output based emission limit.

Control technology: Wet Scrubber (WFGD)
BACT emission limit: 858.9 tons/yr (rolling-12-month total)
 0.267 lb/MWh (gross) [30-day rolling avg.]
 (heat input equivalent = 0.031 lb/MMBTU)

o Nitrogen Oxides (NO_x):

IPL proposed Selective Catalytic Reduction (SCR) with low NO_x burners (LNB) and overfire air (OFA) as its control option for NO_x emissions. This combination is also the top available control technology so no further review of the type of control equipment to be used was necessary.

An upper bound 95% confidence interval analysis was done on the on test data for Unit 4 for MidAmerican's Walter Scott Jr. Energy Center. The results of that data showed a rate of 0.035 lb/MMBTU. After being presented with this information IPL accepted the emission rate.

Control technology: LNB, OFA, and SCR
BACT emission limit: 969.8 tons/yr (rolling-12-month total)
 0.302 lb/MWh (gross) [30-day rolling avg.]
 (heat input equivalent = 0.035 lb/MMBTU)

o Volatile Organic Compounds (VOC):

The top-down BACT analysis was followed and it was determined that Good Combustion Controls was BACT.

Originally the Department had considered using the upper bound 95% confidence interval analysis from similar units such as Unit 4 at MidAmerican's Walter Scott Jr. Energy Center.

However, IPL pointed out that in order to lower the VOC emission rate would require increases in excess air and flame temperatures in the combustion zone which decreases boiler efficiency and increases uncontrolled NO_x emissions. Therefore the Department accepted IPL's proposed VOC emission rate.

Control technology:	Good Combustion Controls
BACT emission limit:	94.2 tons/yr (rolling-12-month total) 0.029 lb/MWh (gross) [avg. of 3 test runs] (heat input equivalent = 0.0034 lb/MMBTU)

o Carbon Monoxide (CO):

Like VOC, the top-down BACT analysis was followed and it was determined that Good Combustion Controls was BACT.

Again, the Department originally considered using the upper bound 95% confidence interval analysis from similar units such as Unit 4 at MidAmerican's Walter Scott Jr. Energy Center.

However, IPL pointed out that in order to lower the CO emission rate would require increases in excess air and flame temperatures in the combustion zone which decreases boiler efficiency and increases uncontrolled NO_x emissions. Therefore the Department accepted IPL's proposed CO emission rate.

Control technology:	Good Combustion Controls
BACT emission limit:	2770.8 tons/yr (rolling-12-month total) 0.862 lb/MWh (gross) [24-hr rolling avg.] (heat input equivalent = 0.10 lb/MMBTU)

o Fluorides (F):

The best method of controlling fluorides is the same method used to control SO₂ emissions. Since IPL proposed a WFGD no further analysis of the control technologies was required.

Based on the fuel and fuel blends being proposed by IPL and the fluorine (F) contents of those fuels, IPL proposed to remove 99% of the fluorides from the gas stream with the control technology. This percent reduction resulted in a

proposed emission rate of 0.000091 lb/MMBTU which was accepted by the Department and converted to an output based standard.

Control technology: Wet Scrubber (WFGD)
BACT emission limit: 2.52 tons/yr (rolling-12-month total)
0.00078 lb/MWh (gross) [avg. of 3 test runs]
(heat input equivalent = 0.000091 lb/MMBTU)

o Sulfuric Acid Mist (H₂SO₄):

IPL proposed to use sorbent injection (SI) along with the proposed baghouse to control sulfuric acid mist emissions. Since this is considered the top control alternative no further analysis of the control technologies was required.

The emission rate was based on the upper bound 95% confidence level of other coal-fired boilers. IPL has concerns about the test method being reproducible at such low levels and does not believe the limit should be set below 0.004 lb/MMBTU.

The Department did not agree with IPL for the following reasons:

- Other states have set SAM emission limits at values less than 0.004 lb/MMBTU.
- The Department was not convinced by IPL's reasoning that the limit should be set at 0.004 lb/MMBTU because the test method may not be accurate below that level. All but one (1) test run from the three (3) stack tests were below the level of 0.004 lb/MMBTU and each was on a different boiler. In addition, the accuracy of the method can be increased by extending the run times as is common practice.
- Finally, the emission limit established in the permit was based on data at other sites with a statistical analysis. To set a limit other than the 95% confidence level is contrary to data currently available.

Control technology: Sorbent Injection (SI) with Baghouse
BACT emission limit: 58.2 tons/yr (rolling-12-month total)
0.0181 lb/MWh (gross) [avg. of 3 test runs]
(heat input equivalent = 0.0021 lb/MMBTU)

o Total Reduced Sulfur (TRS):

TRS is reduced using the same control technologies as SO₂. Like SO₂ IPL proposed using the top control technology which is WFGD therefore, no further analysis of the control technologies was required.

The only data available on TRS for a similar type emission unit was the data from Unit 4 at MidAmerican's Walter Scott Jr. Energy Center. An upper bound 95% confidence level analysis was conducted on the data and it yielded a result of 0.00071 lb/MMBTU which was then converted to an output based emission limit.

Control technology: Wet Scrubber (WFGD)
BACT emission limit: 19.7 tons/yr (rolling-12-month total)
 0.0061 lb/MWh (gross) [avg. of 3 test runs]
 (heat input equivalent = 0.00071 lb/MMBTU)

- **Auxiliary Boiler:**

The auxiliary boiler is used during startup of the main boilers, during periods when the boilers are offline, and to supply steam for onsite building heat and services.

In all cases except opacity and CO, the BACT emission rate was based on the upper bound 95% confidence level from the stack test results for the auxiliary boiler at MidAmerican's Walter Scott Jr. Energy Center in Council Bluffs. The reason for not using the CO data was that MidAmerican's unit does not have CO control where IPL proposed control for its unit. Opacity data was not used since this unit is natural gas fired. The Department set the BACT opacity limit based on its past experience with these types of units.

Also, it should be noted that IPL is limiting the operation of the auxiliary boiler to 527 million cubic feet (MMCF or MMft³) per twelve (12) month rolling period. This is equivalent to two thousand (2,000) hours of operation at the maximum rated capacity.

- Particulate Matter (PM):

The top-down BACT analysis was followed and it was determined that firing on natural gas was BACT.

Control technology: Limitation to Firing on Natural Gas
BACT emission limit: 0.54 tons/yr (rolling-12-month total)
 0.002 lb/MMBTU (avg. of 3 test runs)

- Particulate Matter with an aerodynamic diameter of 10 microns (PM₁₀):

The top-down BACT analysis was followed and it was determined that firing on natural gas was BACT.

Control technology: Limitation to Firing on Natural Gas
BACT emission limit: 0.54 tons/yr (rolling-12-month total)
 0.002 lb/MMBTU (avg. of 3 test runs)

- Opacity (visible emissions):

As stated earlier in this document for the most part visible emissions from a stack are the result of particulate matter emissions. Since the BACT control technology is firing on natural gas this is also BACT for opacity.

BACT opacity was determined to be "no visible emissions". This is based on past Department experience with natural gas fired units and with units with such low particulate emission rates (0.0025 gr/dscf). IPL also proposed the BACT emission rate of "no visible emissions".

Control technology: Limitation to Firing on Natural Gas
BACT emission limit: No Visible Emissions

o Sulfur Dioxide (SO₂):

The top-down BACT analysis was followed and it was determined that firing on natural gas was BACT.

Control technology: Limitation to Firing on Natural Gas
BACT emission limit: 0.27 tons/yr (rolling-12-month total)
 0.001 lb/MMBTU (avg. of 3 test runs)

o Nitrogen Oxides (NO_x):

The top-down BACT analysis was followed and it was determined that Good Combustion Controls with a Low NO_x Burner (LNB) and Flue Gas Recirculation (FGR) was BACT.

Control technology: LNB, FGR, and Good Combustion Controls
BACT emission limit: 9.93 tons/yr (rolling-12-month total)
 0.001 lb/MMBTU (30-day rolling avg.)

o Volatile Organic Compounds (VOC):

The top-down BACT analysis was followed and it was determined that Good Combustion Controls was BACT.

Control technology: Good Combustion Controls
BACT emission limit: 0.27 tons/yr (rolling-12-month total)
 0.001 lb/MMBTU (avg. of 3 test runs)

o Carbon Monoxide (CO):

In the case of Carbon monoxide, IPL proposed to use an oxidation catalyst for maximum available control technology (MACT) purposes. This was also determined to be the top control option for BACT. Therefore, no further review of other control technologies was required.

Since the Department did not have any data on emission rates from units with oxidation catalyst other than the data supplied by IPL the Department accepted IPL's proposed CO BACT emission limit.

Control technology: CO Oxidation Catalyst
BACT emission limit: 1.88 tons/yr (rolling-12-month total)
 0.007 lb/MMBTU (30-day rolling avg.)

- Sulfuric Acid Mist (H₂SO₄):

The top-down BACT analysis was followed and it was determined that firing on natural gas was BACT.

Control technology:	Limitation to Firing on Natural Gas
BACT emission limit:	0.24 tons/yr (rolling-12-month total) 0.0009 lb/MMBTU (avg. of 3 test runs)

- Total Reduced Sulfur (TRS):

The top-down BACT analysis was followed and it was determined that firing on natural gas was BACT.

Control technology:	Limitation to Firing on Natural Gas
BACT emission limit:	0.08 tons/yr (rolling-12-month total) 0.0003 lb/MMBTU (avg. of 3 test runs)

- **Emergency Generator, Fire Pump, and Booster Fire Pump:**

Within the last year new federal standards were established for new nonroad diesel engines. These standards are being phased in over time for specific horsepower ratings, representing major emissions reductions for new nonroad diesel engines. Since these emission levels are being phased in over time, the emission limits for available engines is decreasing over time based on what technologies are available for control on the engines. The federal standards do not specify specific control technologies to be used, but instead set numerical emission limits in terms of grams per brake-horsepower hour. Therefore, many different technologies could be used to meet the emission standards. In addition, all of these engines are emergency use engines that are limited to operating for no more than 100 hours per year. Therefore, the ton per year emissions allowed for each pollutant from each engine is very small. Accordingly BACT is being established as an emission limit to meet the Tier 3 nonroad diesel standards for the fire pumps and the Tier 2 nonroad diesel standards for the generator. The different tiers selected are due to the different sizes of the engines being installed.

- Particulate Matter (PM):

Available particulate controls for internal combustion engines include engine design and combustion optimization, low sulfur diesel fuel specification, diesel oxidation catalysts (DOC) and diesel particulate filters (DPF) or catalyzed diesel particulate filters (CDPF). Each of these control options are considered technically feasible and can be used separately or in combination to achieve an emission reduction.

Emergency Generator:	
Control Technology:	Control to Meet Tier 2 Nonroad Diesel Standards
BACT emission limit:	0.15 g/bhp-hr (average of 3 stack test runs) 0.05 tons/yr (rolling-12-month total)

Fire Pumps:

Control Technology: Control to Meet Tier 3 Nonroad Diesel Standards
BACT emission limit: 0.15 g/bhp-hr (average of 3 stack test runs)
 0.009 tons/yr (rolling-12-month total) for Fire Pump
 0.002 tons/yr (rolling-12-month total) for Booster
 Fire Pump

- o Particulate Matter with an aerodynamic diameter of 10 microns (PM₁₀):

Available particulate controls for internal combustion engines include engine design and combustion optimization, low sulfur diesel fuel specification, diesel oxidation catalysts (DOC) and diesel particulate filters (DPF) or catalyzed diesel particulate filters (CDPF). Each of these control options are considered technically feasible and can be used separately or in combination to achieve an emission reduction.

Emergency Generator:

Control Technology: Control to Meet Tier 2 Nonroad Diesel Standards
BACT emission limit: 0.15 g/bhp-hr (average of 3 stack test runs)
 0.05 tons/yr (rolling-12-month total)

Fire Pumps:

Control Technology: Control to Meet Tier 3 Nonroad Diesel Standards
BACT emission limit: 0.15 g/bhp-hr (average of 3 stack test runs)
 0.009 tons/yr (rolling-12-month total) for Fire Pump
 0.002 tons/yr (rolling-12-month total) for Booster
 Fire Pump

- o Opacity (visible emissions):

The following emission rate was considered BACT for the emergency generator and the fire pumps:

BACT emission limit: 5% (6-minute avg.)
 20% applies during periods of startup, shutdown,
 and malfunction

- o Sulfur Dioxide (SO₂):

The only available SO₂ control for internal combustion engines is the use of low-sulfur (S) diesel fuel.

Emergency Generator:

Control Technology: Use of low sulfur (S) diesel fuel (maximum of
 0.05% S by weight)
BACT emission limit: 0.17 g/bhp-hr (average of 3 stack test runs)
 0.06 tons/yr (rolling-12-month total)

Fire Pumps:

Control Technology: Use of low sulfur (S) diesel fuel (maximum of 0.05% S by weight)

BACT emission limit: 0.17 g/bhp-hr (average of 3 stack test runs)
0.011 tons/yr (rolling-12-month total) for Fire Pump
0.003 tons/yr (rolling-12-month total) for Booster Fire Pump

o Nitrogen Oxides (NO_x):

Available NO_x controls for internal combustion engines include fuel injection rate shaping and multiple fuel injections, charge air cooling, injection timing retard, exhaust gas recirculation, and lean-NO_x catalyst technology. These technologies are considered feasible and can be used separately or in combination to achieve an emission reduction.

Emergency Generator:

The Tier 2 Nonroad Diesel standard for NO_x specifies an emission limit of NO_x plus Non-Methane Hydrocarbons (NMHC). Based on background documentation in the rule development, the Department separated the limits for NO_x and VOC.

Control Technology: Control to Meet Tier 2 Nonroad Diesel Standards

BACT emission limit: 4.5 g/bhp-hr (average of 3 stack test runs)
1.46 tons/yr (rolling-12-month total)

Fire Pumps:

The Tier 3 Nonroad Diesel standard for NO_x specifies an emission limit of NO_x plus Non-Methane Hydrocarbons (NMHC). Based on background documentation in the rule development, the Department separated the limits for NO_x and VOC.

Control Technology: Control to Meet Tier 3 Nonroad Diesel Standards

BACT emission limit: 2.8 g/bhp-hr (average of 3 stack test runs)
0.285 tons/yr (rolling-12-month total) for Fire Pump
0.074 tons/yr (rolling-12-month total) for Booster Fire Pump

o Volatile Organic Compounds (VOC):

Available VOC controls for internal combustion engines include engine design and combustion optimization and oxidation catalysts. Each of these control options are considered technically feasible and can be used separately or in combination to achieve an emission reduction.

Emergency Generator:

The Tier 2 Nonroad Diesel standard for VOC specifies an emission limit of NO_x plus Non-Methane Hydrocarbons (NMHC). Based on background documentation in the rule development, the Department separated the limits for NO_x and VOC.

Control Technology: Control to Meet Tier 2 Nonroad Diesel Standards
BACT emission limit: 0.3 g/bhp-hr (average of 3 stack test runs)
 0.10 tons/yr (rolling-12-month total)

Fire Pumps:

The Tier 3 Nonroad Diesel standard for VOC specifies an emission limit of NO_x plus Non-Methane Hydrocarbons (NMHC). Based on background documentation in the rule development, the Department separated the limits for NO_x and VOC.

Control Technology: Control to Meet Tier 3 Nonroad Diesel Standards
BACT emission limit: 0.2 g/bhp-hr (average of 3 stack test runs)
 0.019 tons/yr (rolling-12-month total) for Fire Pump
 0.005 tons/yr (rolling-12-month total) for Booster Fire Pump

o Carbon Monoxide (CO):

Available CO controls for internal combustion engines include engine design and combustion optimization, combustion modification, and catalytic oxidation. Each of these control options are considered technically feasible and can be used separately or in combination to achieve an emission reduction.

Emergency Generator:

Control Technology: Control to Meet Tier 2 Nonroad Diesel Standards
BACT emission limit: 2.6 g/bhp-hr (average of 3 stack test runs)
 0.84 tons/yr (rolling-12-month total)

Fire Pumps:

Control Technology: Control to Meet Tier 3 Nonroad Diesel Standards
BACT emission limit: 2.6 g/bhp-hr (average of 3 stack test runs)
 0.164 tons/yr (rolling-12-month total) for Fire Pump
 0.043 tons/yr (rolling-12-month total) for Booster Fire Pump

o Sulfuric Acid Mist (H₂SO₄):

The only available H₂SO₄ control for internal combustion engines is the use of low-sulfur (S) diesel fuel.

Emergency Generator:

Control Technology: Use of low sulfur (S) diesel fuel (maximum of 0.05% S by weight)
BACT emission limit: 0.24 g/bhp-hr (average of 3 stack test runs)
 0.08 tons/yr (rolling-12-month total)

Fire Pumps:

Control Technology: Use of low sulfur (S) diesel fuel (maximum of 0.05% S by weight)
BACT emission limit: 0.24 g/bhp-hr (average of 3 stack test runs) for Fire Pump
 0.015 tons/yr (rolling-12-month total) for Fire Pump
 0.30 g/bhp-hr (average of 3 stack test runs) for Booster Fire Pump
 0.004 tons/yr (rolling-12-month total) for Booster Fire Pump

o Fluorides (F):

The only available F control for internal combustion engines is the use of low-sulfur (S) diesel fuel.

Emergency Generator:

Control Technology: Use of low sulfur (S) diesel fuel (maximum of 0.05% S by weight)
BACT emission limit: 0.008 g/bhp-hr (average of 3 stack test runs)
 0.003 tons/yr (rolling-12-month total)

Fire Pumps:

Control Technology: Use of low sulfur (S) diesel fuel (maximum of 0.05% S by weight)
BACT emission limit: 0.009 g/bhp-hr (average of 3 stack test runs) for Fire Pump
 0.0005 tons/yr (rolling-12-month total) for Fire Pump
 0.0012 g/bhp-hr (average of 3 stack test runs) for Booster Fire Pump
 0.0000001 tons/yr (rolling-12-month total) for Booster Fire Pump

o Total Reduced Sulfur (TRS):

The only available TRS control for internal combustion engines is the use of low-sulfur (S) diesel fuel.

Emergency Generator:

Control Technology: Use of low sulfur (S) diesel fuel (maximum of 0.05% S by weight)
BACT emission limit: 0.08 g/bhp-hr (average of 3 stack test runs)
 0.03 tons/yr (rolling-12-month total)

Fire Pumps:

Control Technology:	Use of low sulfur (S) diesel fuel (maximum of 0.05% S by weight)
BACT emission limit:	0.09 g/bhp-hr (average of 3 stack test runs) for Fire Pump 0.005 tons/yr (rolling-12-month total) for Fire Pump 0.11 g/bhp-hr (average of 3 stack test runs) for Booster Fire Pump 0.0018 tons/yr (rolling-12-month total) for Booster Fire Pump

- **Cooling Tower:**

The cooling tower is a source of particulate emissions due to the drift of cooling water from the tower containing dissolved solids. Materials are usually added to the water to prevent the growth of biological matter; however any VOC or Chromium based materials are prohibited from being used in the tower. Emissions from the cooling tower are PM, PM₁₀, and opacity.

- Particulate Matter (PM):

The top-down BACT analysis was followed and it was determined that high efficiency drift eliminators are considered to be the appropriate BACT technology.

Control technology:	High Efficiency Drift Eliminator
BACT emission limit:	0.0005% control efficiency in gallons of drift per gallon of cooling water flow

- Particulate Matter with an aerodynamic diameter of 10 microns (PM₁₀):

The top-down BACT analysis was followed and it was determined that high efficiency drift eliminators are considered to be the appropriate BACT technology.

Control technology:	High Efficiency Drift Eliminator
BACT emission limit:	0.0005% control efficiency in gallons of drift per gallon of cooling water flow

- Opacity (visible emissions):

Since opacity would be directly related to the particulate emissions in this case the high efficiency drift eliminator is considered to be the appropriate BACT technology. Based on the Department's past experience with these types of emission units and the low grain loading being emitted from the cooling tower no visible emissions are expected.

Control technology:	High Efficiency Drift Eliminator
BACT emission limit:	No Visible Emissions

- **Material Handling Systems (Point Sources):**

IPL will have numerous pieces of equipment to handle materials. The materials include coal, limestone, biomass, FGD solids, and fly ash. The material handling operations can be split into two (2) categories: Point sources & Non-point sources.

This section will discuss the BACT determinations for point sources. The BACT determinations for all of the point sources are the same. The only differences are the ton/yr emission limits on the various stacks as those limits are based on the individual flowrates of the various stacks.

- Particulate Matter (PM):

IPL proposed to use a baghouse which is considered to be the top control technology and therefore no further review of the available control technologies was required.

Based on information (i.e. stack tests) from similar types of equipment the Department was prepared to set the BACT emission limits at 0.0032 gr/dscf for the handling equipment. However, in the most recent dispersion modeling IPL modeled all of the handling equipment with an equivalent grain loading of 0.001 gr/dscf. Since IPL apparently believes it can meet this emission rate for the purposes of dispersion modeling the Department used it for BACT purposes.

Control technology:	Baghouse
BACT emission limit:	0.001 gr/dscf (avg. of 3 stack tests) The ton/yr limits are rolling-12-month totals and are dependent upon the flowrate of the individual stack

- Particulate Matter with an aerodynamic diameter of 10 microns (PM₁₀):

IPL proposed to use a baghouse which is considered to be the top control technology and therefore no further review of the available control technologies was required.

Based on information (i.e. stack tests) from similar types of equipment the Department was prepared to set the BACT emission limits at 0.0032 gr/dscf for the handling equipment. However, in the most recent dispersion modeling IPL modeled all of the handling equipment with an equivalent grain loading of 0.001 gr/dscf. Since IPL apparently believes it can meet this emission rate for the purposes of dispersion modeling the Department used it for BACT purposes.

Control technology:	Baghouse
BACT emission limit:	0.001 gr/dscf (avg. of 3 stack tests) The ton/yr limits are rolling-12-month totals and are dependent upon the flowrate of the individual stack

- Opacity (visible emissions):

All of the visible emissions from the material handling stacks would be the result of particulate matter emissions. Since the BACT control technology is a baghouse this is also BACT for opacity.

BACT opacity was determined to be “no visible emissions”. This is based on past Department experience with particulate emission units with such low particulate emission rate (0.001 gr/dscf).

Control technology:	Baghouse
BACT emission limit:	No visible emissions

- **Material Handling Systems (Non-point Sources):**

IPL also proposes to have numerous material handling operations that do not vent through stacks. These material handling operations include storage piles (coal, saleable fly ash, and limestone), FGD waste handling, bottom ash handling, and conveyor belts.

- Particulate Matter (PM):

Depending on the process IPL has requested controls ranging from total enclosure of belt conveyors, the use of telescopic chutes, and the use of chemical dust suppressants. The individual permits have required these controls dependent upon the source of emissions.

Control technology:	Total enclosure, telescopic chute, and/or chemical dust suppressant.
BACT emission limit:	No BACT emission rate was established in the permit. A work practice standard was established instead. The work practice requires that the facility uses its proposed control method to meet an overall control efficiency of 95%.

- Particulate Matter with an aerodynamic diameter of 10 microns (PM₁₀):

Depending on the process IPL has requested controls ranging from total enclosure of belt conveyors, the use of telescopic chutes, and the use of chemical dust suppressants. The individual permits have required these controls dependent upon the source of emissions.

Control technology:	Total enclosure, telescopic chute, and/or chemical dust suppressant.
BACT emission limit:	No BACT emission rate was established in the permit. A work practice standard was established instead. The work practice requires that the facility uses its proposed control method to meet an overall control efficiency of 95%.

- Opacity (visible emissions):

Since all of the visible emissions will be due to particulate emissions IPL proposed the same control strategies for opacity that it did for particulate.

BACT opacity was determined to be “no visible emissions”.

Control technology:	Total enclosure, telescopic chute, and/or chemical dust suppressant.
BACT emission limit:	No Visible Emissions

- **Haul Roads:**

Haul roads at the facility are used for both the delivery and disposal of materials. These materials include but are not limited to limestone, ash, FGD solids, and biomass. IPL proposed to have all of the roads paved. The resulting emissions include PM, PM₁₀, and opacity.

- Particulate Matter (PM):

IPL proposed to pave all of the haul roads in the facility. In addition, IPL proposed to sweep the roads and use wet dust suppression on the roads.

Control technology:	Daily Water Flushing followed by Vacuum Sweeping
BACT emission limit:	No BACT emission rate was established in the permit. A work practice standard was established instead. The work practice requires that the facility complete daily water flushing followed by vacuum sweeping at least once per day. As an option, the facility may use a high efficiency vacuum sweeper than can meet an overall control efficiency of 80%.

- Particulate Matter with an aerodynamic diameter of 10 microns (PM₁₀):

IPL proposed to pave all of the haul roads in the facility. In addition, IPL proposed to sweep the roads and use wet dust suppression on the roads.

Control technology:	Daily Water Flushing followed by Vacuum Sweeping
BACT emission limit:	No BACT emission rate was established in the permit. A work practice standard was established instead. The work practice requires that the facility complete daily water flushing followed by vacuum sweeping at least once per day. As an option, the facility may use a high efficiency vacuum sweeper than can meet an overall control efficiency of 80%.

- Opacity (visible emissions):

All of the visible emissions from the haul roads would be the result of particulate matter emissions. Since the BACT control technology is a daily water flushing followed by vacuum sweeping this is also BACT for opacity.

BACT opacity was determined to be “no visible emissions”.

Control technology:	Daily Water Flushing followed by Vacuum Sweeping
BACT emission limit:	No Visible Emissions

- **Gate Station Heater:**

Natural gas is to be used during startup for both the new boiler and the existing boilers at the Sutherland facility. Natural gas is also the primary fuel for the proposed auxiliary boiler. The natural gas is delivered via a high pressure pipeline. As this gas is taken from the pipeline there is a reduction in pressure which naturally cools the gas to a temperature too low to be combusted by the boilers. The gate station heater will be used to reheat the natural gas to a usable temperature. Since this emission unit is so small (only 3 MMBTU/hr) the controls for the BACT analysis were assumed to be the same as those of the auxiliary boiler at MidAmerican’s Walter Scott Jr. Energy Center for all pollutants except for NO_x.

- Particulate Matter (PM):

Control technology:	Limitation to Firing on Natural Gas
BACT emission limit:	0.03 tons/yr (rolling-12-month total) 0.002 lb/MMBTU (avg. of 3 test runs)

- Particulate Matter with an aerodynamic diameter of 10 microns (PM₁₀):

Control technology:	Limitation to Firing on Natural Gas
BACT emission limit:	0.03 tons/yr (rolling-12-month total) 0.002 lb/MMBTU (avg. of 3 test runs)

- Opacity (visible emissions):

Control technology:	Limitation to Firing on Natural Gas
BACT emission limit:	No Visible Emissions

- Sulfur Dioxide (SO₂):

Control technology:	Limitation to Firing on Natural Gas
BACT emission limit:	0.01 tons/yr (rolling-12-month total) 0.001 lb/MMBTU (avg. of 3 test runs)

- Nitrogen Oxides (NO_x):

Since this unit is so small it was determined that no add on controls would be required for BACT and that the BACT technology was good combustion controls. This decision was based on the Department's experience with previous BACT decisions.

Control technology: Good Combustion Controls
BACT emission limit: 0.49 tons/yr (rolling-12-month total)
 0.037 lb/MMBTU (30-day rolling avg.)

- Volatile Organic Compounds (VOC):

Control technology: Good Combustion Controls
BACT emission limit: 0.01 tons/yr (rolling-12-month total)
 0.001 lb/MMBTU (avg. of 3 test runs)

- Carbon Monoxide (CO):

Control technology: CO Oxidation Catalyst
BACT emission limit: 0.045 tons/yr (rolling-12-month total)
 0.59 lb/MMBTU (30-day rolling avg.)

- Sulfuric Acid Mist (H₂SO₄):

Control technology: Limitation to Firing on Natural Gas
BACT emission limit: 0.01 tons/yr (rolling-12-month total)
 0.0009 lb/MMBTU (avg. of 3 test runs)

- Total Reduced Sulfur (TRS):

The top-down BACT analysis was followed and it was determined that firing on natural gas was BACT.

Control technology: Limitation to Firing on Natural Gas
BACT emission limit: 0.04 tons/yr (rolling-12-month total)
 0.0003 lb/MMBTU (avg. of 3 test runs)

PSD Ambient Air Quality Analysis

Applicants for a PSD permit are required to conduct an air quality analysis of the ambient impacts associated with the construction and operation of the proposed new source or modification. The main purpose of the air quality analysis is to demonstrate that the new emissions emitted from a proposed project in conjunction with other applicable emissions from existing sources (including secondary emissions from growth associated with the new project) will not cause or contribute to a violation of any applicable NAAQS or PSD increment. This review is required for both criteria and non-criteria pollutants.

A separate air quality analysis is required for each regulated pollutant that will be emitted in a net significant amount. Each air quality analysis is unique due to the variety of sources and meteorological and topographical conditions that may be involved. Nevertheless, the air quality analysis must be accomplished in a manner consistent with the requirements in 567 IAC 33.3(11) through 567 IAC 33.3(16) which adopted 40 CFR §51.21(k) through 40 CFR §51.21(o) by reference. Generally, the analysis involves

- An assessment of existing air quality, which may include ambient monitoring data and air quality dispersion modeling results.
- Predictions, using air dispersion modeling, of ambient concentrations that will result from the applicant's proposed project and future growth associated with the project.

There are two (2) distinct phases for the ambient air assessment:

- 1) *Preliminary analysis*: This analysis models only the significant increase in potential emissions of a pollutant from the proposed project. The results of this preliminary analysis determine whether the applicant must perform a full impact analysis involving the estimation of background pollutant concentrations resulting from existing sources and growth associated with the proposed project. Specifically it:
 - Determines whether the applicant can forgo further air quality analysis for a particular pollutant;
 - May allow the applicant to be exempted from the ambient monitoring data requirements; and
 - Is used to define the impact area within which a full impact analysis must be carried out.

Historically, the Department has not required a full impact analysis for a particular pollutant when the emissions of that pollutant from a proposed project would not increase ambient concentrations by more than the prescribed significant ambient impact levels.

- 2) *Full impact analysis*: This analysis is required for any pollutant for which the proposed project's estimated ambient pollutant concentrations exceed prescribed significant ambient impact levels. This analysis expands the preliminary analysis in that it considers emissions from the proposed project, existing sources, and residential, commercial, and industrial growth associated with the new project.

A copy of the Department's modeling memo which details the Department's review of the ambient air quality analysis is attached as Appendix H.

PSD Ambient Air Monitoring (Pre- and Post-Construction)

567 IAC 33.3(13) adopted 40 CFR §52.21(m) by reference. 40 CFR §52.21(m) requires preconstruction ambient air monitoring for any pollutant in which the applicant proposes to emit in significant amounts. If, however, either the predicted ambient impact caused by the emissions increase or the existing ambient air concentrations are less than the prescribed significant monitoring value [See 40 CFR §52.21(i)(8)], the permitting agency has discretionary authority to exempt an applicant from this data requirement.

As can be seen from Table 8, all of the modeled impacts are below the applicable significant monitoring concentrations. Historically the Department has exempted applicants from the requirement to do preconstruction monitoring if the modeled concentrations are below the significant monitoring concentrations. Therefore, no preconstruction monitoring has been required for this project.

Table 8 – Monitoring Significance Levels

Pollutant	Averaging Period	Maximum Modeled Concentration ($\mu\text{g}/\text{m}^3$)	Monitoring de minimis Level ($\mu\text{g}/\text{m}^3$)
PM ₁₀	24-hr	4.91	10
	Annual	0.87	---
SO ₂	3-hr	11.32	---
	24-hr	3.52	13
	Annual	0.29	---
NO _x	Annual	0.64	14
CO	1-hr	48.09	---
	Annual	18.63	575
Fluorides	24-hr	0.01	0.25
TRS	1-hr	0.54	---

NAAQS:

The NAAQS are maximum concentration “ceilings” measured in terms of the total concentration of a pollutant in the atmosphere. They are health and welfare based standards established by EPA. For a new project, compliance with any NAAQS is based upon the total estimated air quality. This is the sum of the ambient estimates resulting from existing sources of air pollution (modeled source impacts plus measured background concentrations) and the modeled ambient impact caused by the proposed project and its associated growth.

As stated earlier, a separate air quality analysis is required for each regulated pollutant if the applicant proposes to emit the pollutant in a significant amount from a new major stationary source, or proposes to cause a significant net emissions increase from a major modification. A new or modified source is determined to contribute to a violation of NAAQS if it is expected to increase the ambient concentration by the PSD "significant amount" at the location of a violation of an ambient standard. Any contribution to a violation is considered "significant" according to PSD if it exceeds the values listed in Table 9.

Table 9 – PSD Significant Impact Concentrations

Pollutant	Annual	24-hr	8-hr	3-hr	1-hr
PM ₁₀	1 $\mu\text{g}/\text{m}^3$	5 $\mu\text{g}/\text{m}^3$	--	--	--
NO _x	1 $\mu\text{g}/\text{m}^3$	--	--	--	--
SO ₂	1 $\mu\text{g}/\text{m}^3$	5 $\mu\text{g}/\text{m}^3$	--	25 $\mu\text{g}/\text{m}^3$	--
CO	--	--	500 $\mu\text{g}/\text{m}^3$	--	2,000 $\mu\text{g}/\text{m}^3$
Ozone	--	--	See Note 1	--	--

- NOTES:** 1) There is no significant ambient impact concentration established. Instead, any net emissions increase of 100 tons per year of VOC subject to PSD would be required to perform an ambient impact analysis. The 1-hour standard for ozone has been rescinded, and there is currently no accepted method to evaluate the 8-hour standard.
- 2) There is no significant impact level for Pb.

Comparing the maximum modeled concentrations listed in Table 8 to the values in Table 9 shows all of the modeled impacts are below the applicable PSD significant impact concentrations. Therefore, full impact modeling analyses are not required.

PSD Increment.

The PSD increment is the maximum allowable increase in ambient concentrations that is allowed to occur above a baseline concentration for a given pollutant. The baseline concentration is defined for each pollutant and its related averaging period(s). In general, the baseline concentration is the ambient concentration existing at the time the first complete PSD permit application affecting the area is submitted.

Therefore, the submittal date of the first complete PSD application in an area is the “baseline date.” On or before this date most emissions are considered to be part of the baseline concentration and emission changes which occur after that date affect the amount of available increment. However, to fully understand how and when increment is consumed or expanded one must understand three (3) different dates related to baseline:

- *Major source baseline date:* This is the date after which actual emissions associated with construction at a major stationary source affect the available increment. Other changes in actual emissions occurring at any source after the major source baseline date do not affect the increment, but instead contribute to the baseline concentration until after the minor source baseline date is established.
- *Trigger date:* This is the date after which the minor source baseline date may be established. Both the major source baseline date and the trigger date are fixed dates although different dates apply to SO₂ & particulate and NO_x as shown in Table 10:

Table 10 – Major Source Baseline and Trigger Dates for PM, SO₂, and NO_x

Pollutant	Major Source Baseline Date	Trigger Date
PM & SO ₂	January 6, 1975	August 7, 1977
NO _x	February 8, 1988	February 8, 1988

- *Minor source baseline date:* This is the earliest date after the trigger date on which a complete PSD application is received by the permit agency. If the application that established the minor source baseline date is ultimately denied or is voluntarily withdrawn by the applicant the minor source baseline date remains in effect because the date marks the point in time after which actual emissions changes from all sources affect the available increment. This is often referred to as the “baseline date”. The minor source baseline date for a particular pollutant

is triggered by a PSD applicant only if the proposed increase in emissions of that pollutant is significant. So the minor source baseline date for different pollutants could be different in the same area.

The area where the minor source baseline date is established by a PSD permit application is known as the baseline area. It is limited to intrastate areas and may include one or more areas designated as attainment or unclassified under Section 107 of the CAA.

The baseline area is to include all portions of the attainment or unclassifiable area in which the PSD applicant would propose to locate and any attainment or unclassifiable area in which the proposed emissions would have a significant impact. In this case significant impact is defined as at least a $1 \mu\text{g}/\text{m}^3$ annual increase in the average annual concentration of the applicable pollutant.

The amount of PSD increment consumed in an area is determined from the emission increases and decreases that have occurred from sources since the applicable baseline date. It should be noted that increment consumption calculations reflect only the ambient pollutant concentration change attributable to increment affecting emissions.

Emission increases that consume a portion of the applicable increment are usually all those not accounted for in the baseline concentration and specifically include:

- actual emissions increases occurring after the major source baseline date which are associated with physical changes or changes in the method of operation at a major stationary source and
- actual emissions increases at any stationary source, area source, or mobile source occurring after the minor source baseline date.

The amount of available increment may be expanded in two ways. The main way is through the reduction of actual emissions from any source after the minor source baseline date. Any such emissions reduction would increase the amount of available increment to the extent that the ambient concentrations would be reduced.

Increment expansion can also result from the reduction of actual emissions after the major source baseline date, but before the minor source baseline date if the reduction results from a physical change or a change in the method of operation at a major stationary source. The reduction will only add to the increment if the reduction is made enforceable through a permit or State Implementation Plan (SIP) provision.

Significant deterioration is considered to have occurred when the amount of new air pollution would exceed the applicable PSD increment. It should be noted that even if not all of the increment is consumed in an area the air quality cannot deteriorate to the point where it exceeds the applicable NAAQS.

Finally, only those pollutants that exceed the PSD significant impact levels are reviewed for increment consumption. Since all of the worst case modeled impacts from this project were below the applicable PSD significant impact levels a PSD increment analysis was not required.

Class I Area Impact Analysis

Class I areas are places of special national or regional value from a natural, scenic, recreational, or historic perspective. The PSD regulations provide special protection for these areas. There are three (3) types of Class I areas:

- *Mandatory Federal Class I areas:* These are specified as Class I by the CAA on August 7, 1977 and include:
 - International parks,
 - National wilderness areas including certain national wildlife refuges, national monuments, and national seashores which exceed 5,000 acres in size, and
 - National parks which exceed 6,000 acres in sizeThese Class I areas cannot be reclassified to Class II or Class III. They are managed by the Forest Service, National Park Service, or the Fish and Wildlife Service.
- *Federal Class I areas:* These are Federal lands in which a State has redesignated as a Class I area. They are managed by the Forest Service, National Park Service, or the Fish and Wildlife Service.
- *Non-Federal Class I areas:* These are State or Indian lands reclassified as Class I.

PSD projects that propose to locate within 100 kilometers (km) of a Class I area and PSD projects that propose to locate at a distance greater than 100 km that have an impact on a Class I area are required to conduct a Class I area impact analysis. There is currently no Class I area located within 100 km of Iowa's borders (see map in Appendix I). The closest Class I areas to the proposed project are the Rainbow Lake Wilderness Area in Wisconsin (~510 km away) and the Hercules-Glades Wilderness Area in Missouri (~590 km away).

In a letter dated November 5, 2007, IPL notified the Region 9 USDA Forest Service, the US Fish and Wildlife Service, and the National Parks Service about the proposed project. In a November 5, 2007 email to IPL, the Forest Service stated that it had reviewed the proposed project and that:

“Due to the emissions from the facility, in relation to its distance from the Forest Service Class I area, we are not requesting that any Class I modeling be done for this project.”

The federal land managers listed above will also be notified by the Department during the public comment period for this project.

Additional Impact Analysis

All PSD permit applicants are required to prepare an additional impact analysis for each pollutant subject to regulation under the CAA which will be emitted by the proposed project. This analysis assesses the impacts on air, ground, and water pollution to soils, vegetation, and visibility caused by any increase in emissions of any regulated pollutant from the project and its associated growth.

Other impact analysis requirements can also be imposed on the applicant under local, State, or Federal laws which are outside of the PSD permitting process. For example, two (2) Federal laws which may apply on occasion are the Endangered Species Act and the National Historic Preservation Act. Even though not required as part of the PSD permit, such legislation may require additional analysis if any federally listed rare or endangered species or any sites that are included (or are eligible to be included) in the National Register of Historic Sites are identified in the source's impact area.

The depth of the additional impact analysis will generally depend on the existing air quality, the quantity of emissions, and the sensitivity of the local soils, vegetation, and visibility in the source's impact area. It is important that the analysis fully document all sources of information, assumptions made, and any agreements reached with any government agencies (i.e. EPA, State, US Forest Service, etc.).

The additional impact analysis usually has four parts:

- *Growth*: The purpose of the growth analysis is to predict how much new growth is likely to occur to support the new project and then estimate the emissions that will result from that growth. This analysis includes:
 - A projection of associated industrial, commercial, and residential growth that will occur in the area due to the project, and
 - An estimate of the air emissions generated by the above associated industrial, commercial, and residential growth.

First the applicant needs to assess the amount of residential growth that the proposed project will bring to the area. This will depend on the size of the available work force, the number of new employees, and the availability of housing in the area.

Associated commercial and industrial growth consists of new businesses providing goods and services to the new employees and to the proposed project. Other growth is all growth that is not covered by the preceding, including construction related activities and mobile sources (permanent and temporary).

Next the applicant is required to develop an estimate of the air pollution which would likely result from this associated growth.

- *Ambient air quality impact analysis*: This analysis projects the air quality which will exist in the area of the proposed project during construction and after the project begins operation.

The applicant combines the air pollutant emissions estimates for the associated growth with the estimates of emissions from the proposed project. Next, the projected emissions from other sources in the area which have been permitted, but are not yet in operation are included in the modeling analysis.

The applicant then models the combined emissions estimate and adds the modeling analysis results to the background air quality to arrive at an estimate of the total ground level concentration of pollutants which can be anticipated as a result of the construction and operation of the proposed project.

- *Soils & vegetation impacts:*

The analysis of soils & vegetation air pollution impacts are based on an inventory of the soils & vegetation types found in the impact area. This inventory includes all vegetation with any commercial or recreational value. The inventory may be available from conservation groups, State agencies, and universities.

In most cases, ambient concentrations of criteria pollutants below the secondary NAAQS will not result in harmful effects to soils & vegetation. However, there are sensitive vegetation species such as soybeans and alfalfa which may be harmed by long term exposure to low ambient air concentrations of regulated pollutants for which there are no NAAQS.

- *Visibility impairment:* This analysis is different than the Class I visibility analysis requirement. In this analysis the applicant is to review the impacts that occur within the impact area of the proposed project. EPA's suggested components of a good visibility analysis are:

- A determination of the visual quality in the area,
- An initial screening of emission sources to assess the possibility of visibility impairment, and
- If warranted, a more in-depth analysis involving computer models.

EPA's "Workbook for Plume Visual Impact Screening and Analysis (Revised)", October 1992 (EPA-450/4-88-015) is used to conduct a visibility impairments analysis. The workbook outlines a screening procedure designed to expedite the analysis of emissions impacts on the visual quality of an area. Although it is designed for Class I area impacts, the procedures are also generally applicable to other areas. See Appendix J for a copy of the workbook.

Growth:

According to IPL's application, IPL's electric generating load and capability indicates a capacity deficiency for regulated load starting in 2010. The load and capability takes into account all owned generation added to date as well as all purchased power contracts with accredited capacity that are currently performing. IPL's firm demand continues to grow about 40 megawatts (MW) per year on average from the current projected load of 2,916 MW in 2007. It is expected to increase to a net system peak load of 3,256 MW in 2016.

The addition of SGS Unit 4 is intended to meet this demand growth from IPL's service area and provide reliability and flexibility in fleet-wide operation, especially in regards to IPL's older, smaller coal-fired units that may have to be operated differently, fuel switched, or possibly shutdown.

Since the proposed project is being installed to meet the existing and current projected electrical demands of the surrounding area and not to attract local business, IPL anticipates little growth will be associated with its operation. There will be an increase in the local labor force during the construction phase of the project, but that increase will be temporary, short lived, and is not expected to result in any significant, permanent

commercial or residential growth in the Marshalltown area. It is expected that any temporary labor that may come from outside the commuting area will be absorbed by the surrounding hotel network.

Once completed, the project will result in approximately 85 full-time jobs. This will result in minor amounts of secondary employment created by the economic activity of the plant. Due to the small number of staff that will be required to operate and maintain the units within the project, IPL expects the ambient air impacts from the growth due to this project will be insignificant. Therefore, IPL did not conduct an air quality analysis for the effects of the growth from this project nor did the Department require such an analysis.

Soils

IPL completed a soil inventory by obtaining a soil survey within a three (3) kilometer radius study area surrounding the facility. The soil survey was obtained from the Natural Resource Conservation Service. The different soil types that were found to be in excess of 1% of the total land area of the three (3) kilometer study area are listed in Table 11.

Table 11 – Main Soil Types Near the SGS Facility¹⁶

Soil Type	Acres	Percent
<i>Tama silty clay loam</i>	1,670.8	18.751
<i>Colo-Hanlon-Lawson complex</i>	1,018.2	11.427
<i>Downs silt loam</i>	931.8	10.457
<i>Zook silty clay loam</i>	667.8	7.495
<i>Lawson silty clay loam</i>	592.2	6.646
<i>Tama-Urban land complex</i>	481.8	5.407
<i>Colo silty clay loam</i>	419.8	4.711
<i>Water</i>	304.7	3.420
<i>Colo-Urban land complex</i>	234.5	2.632
<i>Lawler loam</i>	218.6	2.453
<i>Nevin silty clay loam</i>	205	2.301
<i>Bremer silty clay loam</i>	188.5	2.115
<i>Colo-Ely complex</i>	172	1.930
<i>Dinsdale silty clay loam</i>	153	1.717
<i>Fayette silt loam</i>	150.3	1.687
<i>Lindley loam</i>	141.4	1.587
<i>Ackmore-Colo complex</i>	121.5	1.364
<i>Tama silty clay loam, benches</i>	107.9	1.211
<i>Nodaway silt loam, channeled</i>	107	1.201
<i>Muscatine-Urban land complex</i>	105.5	1.184
<i>Pits</i>	94.2	1.057
<i>Ackmore silt loam</i>	92.1	1.034
<i>Nodaway silt loam</i>	90.7	1.018

¹⁶ Data was taken from the Natural Resources Conservation Service's web soil survey (<http://websoilsurvey.nrcs.usda.gov/app/>) for the 6 x 6 km domain in Marshall County, Iowa. The complete table can be found Attachment 3 of IPL's November 1, 2007 application.

According to the US Department of Agriculture Soil Conservation Service, the Tama silty clay loam series consists of very deep well drained soils formed in loess. The surface runoff potential is negligible to high. Tama silty clay loam soils that are nearly level to gently sloping are cultivated with the principal crops being corn, soybeans, small grains, and legume hays. Tama silty clay loam soils that are on steeper slopes are commonly used as pasture lands. The native vegetation found within Tama silty clay loam soils are big bluestem, little bluestem, switchgrass, and other grasses of the tall grass prairie.

Sulfates and nitrates caused by SO₂ and NO_x deposition onto the soil can be either beneficial or detrimental to soil depending on its composition. Since the proposed SO₂ and NO_x emission rates are below the secondary NAAQS this project is not expected to have an adverse impact upon the soils in the immediate vicinity.

Vegetation:

Many factors play a role in determining whether or not vegetation will be impacted by certain levels of pollution. These factors include the type of exposure (acute or chronic), influences of stress from other biotic (insects and disease) or abiotic factors (edaphic or climatic), the type of response measured, and the species or population.

The NSR Manual states an analysis of air pollution impacts on vegetation should be based on an inventory of the species found in the impact area (i.e. significant impact area or SIA). Since the emissions from the project are not projected to have concentrations greater than the significant impact levels, no SIA exists. Therefore, IPL used an area of three (3) kilometers centered on the SGS facility for its analysis.

IPL determined from topographic maps and aerial photography that there are no state parks or designated sensitive areas within the three (3) kilometer area reviewed. IPL conducted a field survey of the three (3) kilometer (a 6 x 6 km area) in April of 2007 for plant species mainly sensitive to SO₂ and NO_x. IPL used the US Department of Agriculture's Natural Resources Conservation Service (NRCS) for a vegetation inventory for all other applicable PSD pollutants. According to the NRCS there are a total of thirty-five (35) different plant species located within Marshall County (See Appendix K for a complete list. This list is a copy of a table provided by IPL in Appendix I, Attachment 3 of the November 1, 2007 application).

The results from IPL's modeling analysis are listed in Table 12. These results were used by IPL to determine the effects on nearby vegetation. Following Table 12 is a summary of IPL's vegetation analysis for each pollutant.

Table 12 – Summary of Vegetation Impacts

Pollutant	Averaging Period	Modeled Concentration ($\mu\text{g}/\text{m}^3$)	Min. Concentration Resulting in Foliar Injury for Sensitive Species ($\mu\text{g}/\text{m}^3$)
SO ₂	1-hr	22.77	1,310 – 2,620
	3-hrs	11.32	790 – 1,570
NO _x	1-hr	20.28	1,200
	4-hrs	10.28	3,760
	24-hrs	4.98	500
	1 month	1.44	564
	Annual	0.64	94
CO	1-hr	48.09	1,800,000 [†]
Ozone	1-hr	19.6	139.7 ^{††}
HF	1-hr	0.08	2 [‡] , 0.17 ^{‡‡} , 0.27 ^{‡‡‡}

[†] The averaging period is one (1) week.

^{††} The exposure period is two (2) weeks.

[‡] The exposure period is two hundred seventy-six (276) hours.

^{‡‡} The exposure period is ninety-nine (99) days.

^{‡‡‡} The exposure period is eighty-three (83) days.

➤ NO_x:

All nitrous gases turn the edges of leaves brown or brownish black and cause blotches. Plant cells start to shrink and protoplasts detach from the cell wall. This process ultimately results in the damaged parts of the cell drying out. Poisoning by nitrous gases is mainly due to nitrogen dioxide (NO₂). However, IPL examined vegetation in the area surrounding the SGS facility with regard to the presence of plants sensitive to all NO_x species that may be emitted.

The sensitivity of the plant communities identified to NO_x is determined on the basis of the plant species sensitivity listing provided in EPA's *Air Quality Criteria for Oxides of Nitrogen*¹⁷. A copy of the referenced table can also be found in "*Air Quality Criteria for Oxides of Nitrogen - Vegetation Impacts*" on the Department's website at http://www.iowadnr.gov/air/prof/progdev/files/nox_veg_impacts.pdf. A copy of this document is attached in Appendix L.

IPL identified four (4) species that were not on the list that are dominant species found in the study area. Those species are silver maple (trees & shrubs), Eastern cottonwood (trees & shrubs), tall fescue (field crops & grasses), and smooth brome (field crops & grasses). Since these species are not in the table IPL identified closely related species in the table and assumed the NO_x tolerance level was the same. Therefore, the four (4) additional species were listed as having the following tolerance levels:

- Silver maple – intermediate
- Eastern cottonwood – tolerant
- Tall fescue – tolerant

¹⁷ US EPA, "Air Quality Criteria for Oxides of Nitrogen, Volume II of III", EPA/600/8-91/049bF, August 1993. The complete document can be found at <http://browser.grik.net/cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=40179>.

- Smooth brome – tolerant

IPL's study identified nine (9) categories based on tolerance and composition as potentially occurring in the project study area. Those categories are:

- **Tolerant**
 - Woodland (upland deciduous)
 - Pasture
 - Emergent wetland
 - Native prairie
 - Urban/residential
 - Commercial/industrial
- **Intermediate**
 - Woodland (riparian)
 - Cropland (corn, soybeans)
- **Sensitive**
 - Cropland (alfalfa, clover)

IPL used aerial photography to divide the study area into a grid-work of twelve (12) acre parcels. Figure 12 is an aerial photograph of the three (3) kilometer radius surrounding the SGS facility and the twelve (12) acre parcel grid-work. IPL assessed each twelve (12) acre parcel and placed it in one of the categories in the table from EPA's *Air Quality Criteria for Oxides of Nitrogen*". The categories were color coded and mapped to illustrate the distribution of NO_x sensitivity and plant communities in the area of the SGS facility. A copy of this color coded illustration is in Figure 13.

Of the nine (9) categories identified, IPL discovered seven (7) to be present. The alfalfa/clover cropland and the native prairie categories were not found to be present in the study area.

According to the Department's "*Air Quality Criteria for Oxides of Nitrogen - Vegetation Impacts*", a 1-hr NO₂ concentration of 7,520 µg/m³ results in 5% foliar injury for the most susceptible plant species.

According to EPA's screening document, the minimum NO₂ concentrations at which adverse growth effects or tissue injury occurred for the most sensitive vegetation are listed in Table 12.

Finally, Figure 15 on page 84 in the US Fish and Wildlife Service document "*A Biologist's Manual for the Evaluation of Impacts of Coal-fired Power Plants on Fish, Wildlife, and their Habitats*" (copy of the document can be found in Appendix M) shows metabolic and growth effects occurring for NO₂ levels of 1,200 µg/m³ (1-hr averaging period) and 500 µg/m³ (24-hr averaging period).

As can be seen in Table 12, the maximum predicted impacts are significantly lower than the screening concentrations that cause foliar injury. Therefore, no adverse impacts on vegetation in the area surrounding the proposed project are anticipated due to the new project.

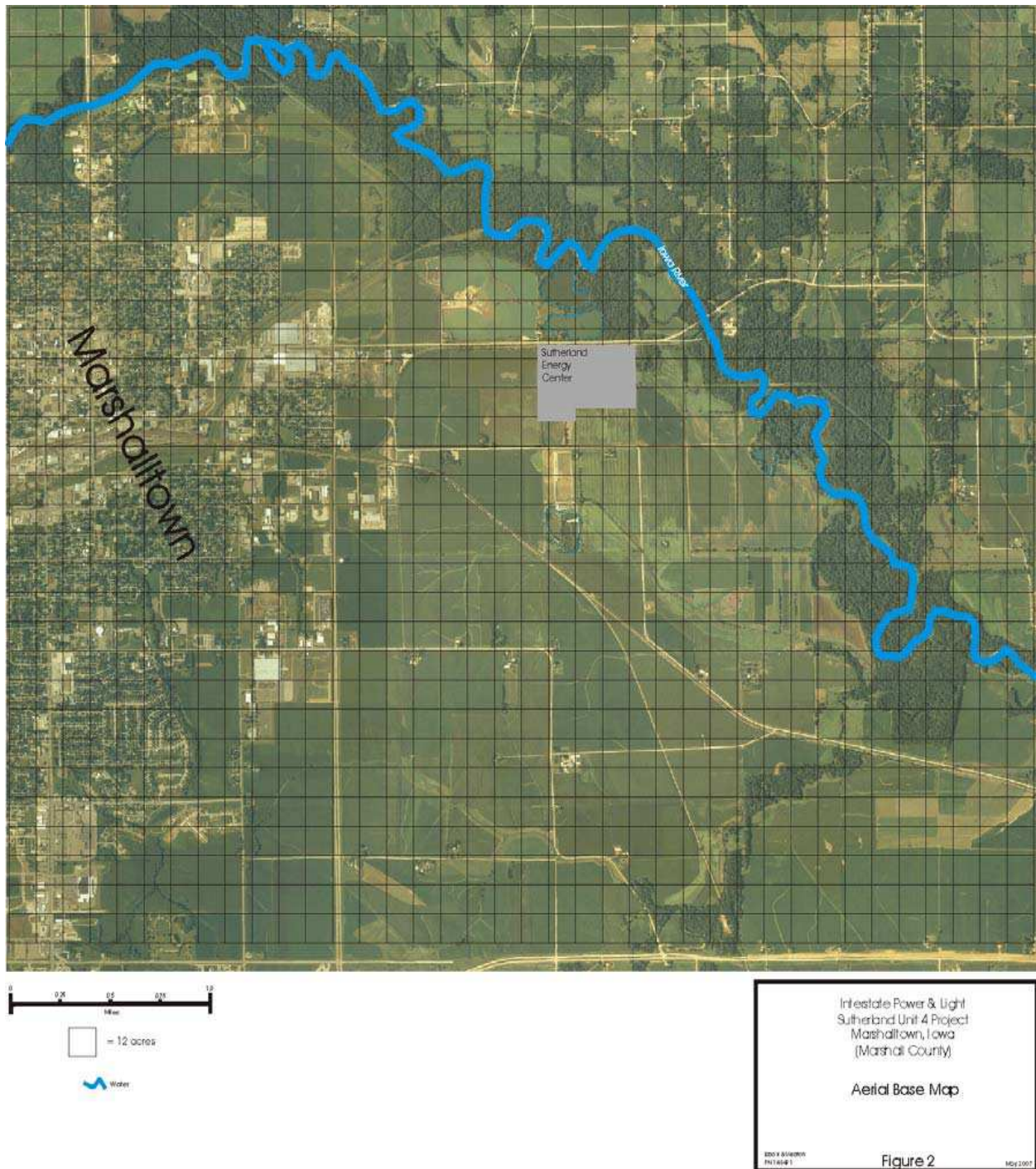


Figure 12 – Aerial Photo of the Parcelled Area¹⁸

¹⁸ Figure is taken from Appendix I of IPL's November 2007 permit application. Figure was also included in IPL's April 2008 additional information.

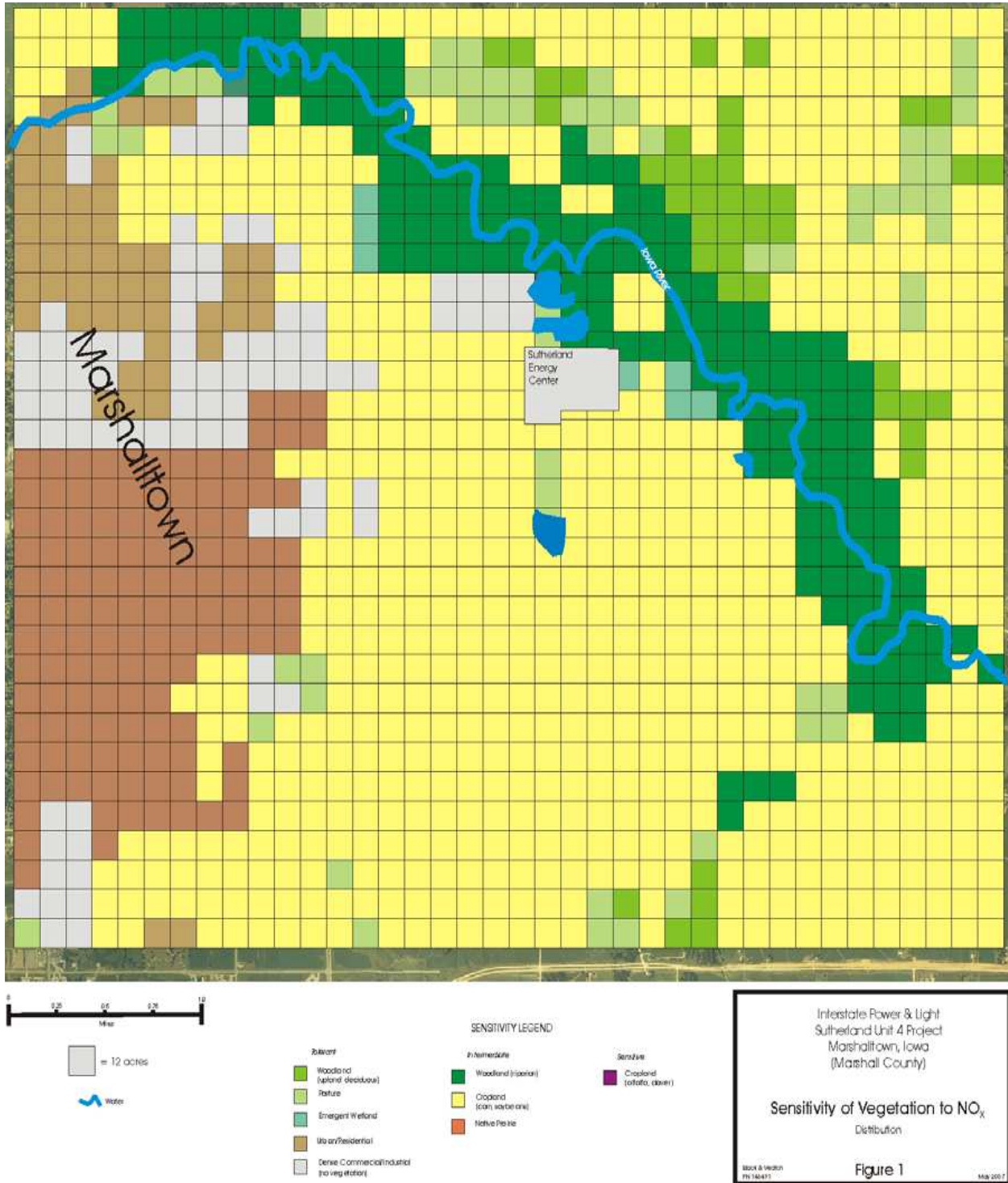


Figure 13 – Distribution of Study Categories¹⁹

¹⁹ Figure is taken from Appendix I of IPL’s November 2007 permit application. Figure was also included in IPL’s April 2008 additional information.

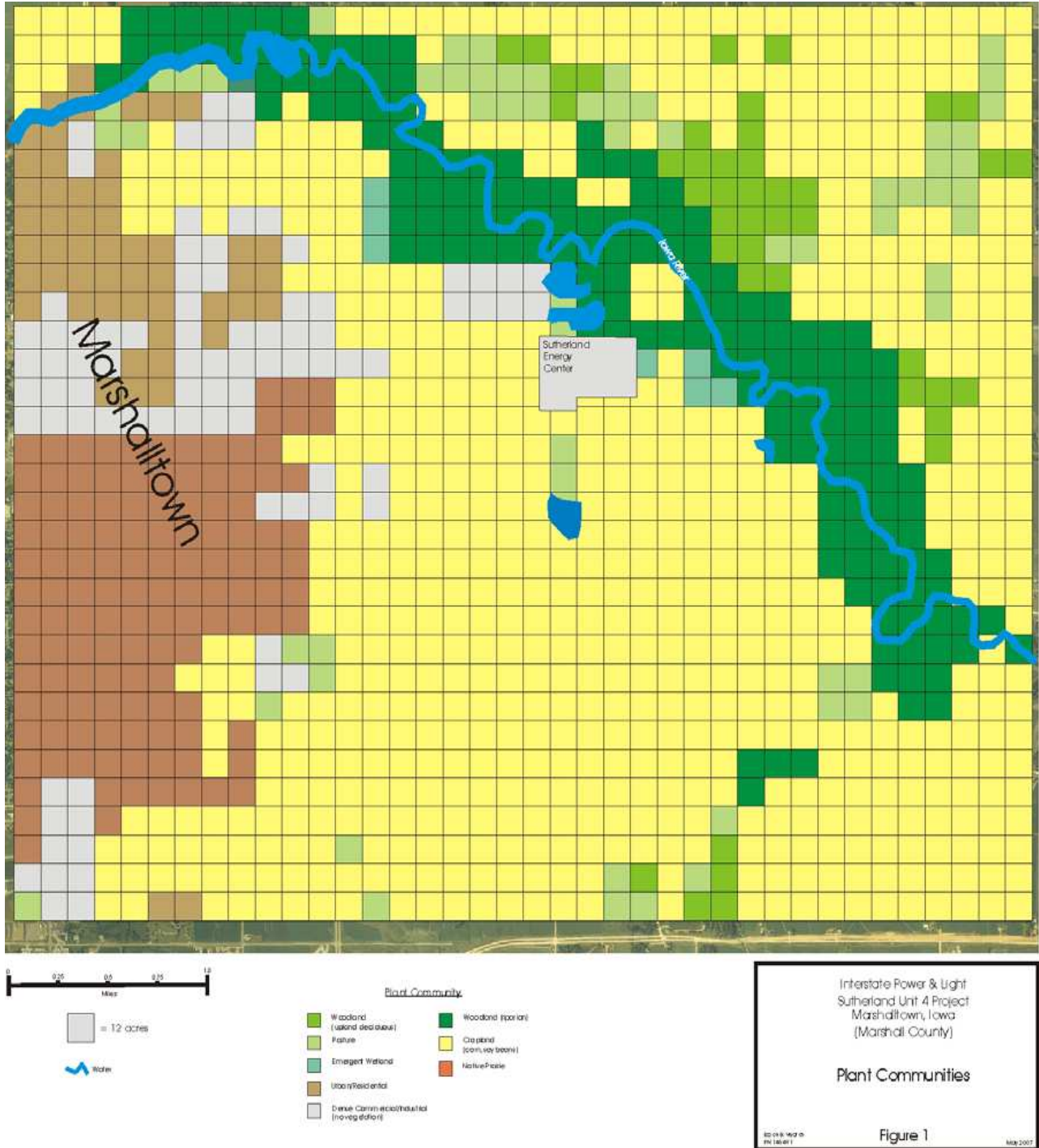


Figure 14 – Distribution of Study Categories²⁰

²⁰ Figure is taken from Appendix I of IPL's November 2007 permit application. Figure was also included in IPL's April 2008 additional information.

➤ SO₂:

The effects of SO₂ exposure on plants is not only dependent upon the pollutant concentration and duration of exposure, but also the genetic makeup of the plant and the environmental factors under which the exposure occurred. In general, regardless of the condition of exposure for a given plant species or variety there is a critical SO₂ concentration and duration of exposure above which the plant will be injured. Such injury is the result of exceeding the plant's capability to transform toxic SO₂ and sulfite into much less toxic sulfate and ultimately to transfer or break down the sulfate.

Possible plant responses to sulfur compounds such as SO₂ include:

- Increased growth and yield due to fertilization effects,
- No detectable response,
- Injury manifested as growth and yield reductions without visible symptoms on the plant,
- Injury exhibited as chronic or acute symptoms on the plant with or without associated reduction in growth and yield, and
- Death of plants.

Several plant species are sensitive to low concentrations of SO₂ and can be used as bio indicators. However, even sensitive species can be asymptomatic depending on the environmental conditions before, during, and after the SO₂ exposure. Due to the absence of empirical data quantifying the losses in growth or yield in relation to SO₂ exposure sensitive species are generally identified on the basis of visible symptoms.

Visible damage to above ground plant parts is due to the direct action of SO₂ entering the leaves via the stomata. It physiologically and biochemically impairs the photosynthesis, the respiration, and the transpiration due to its detrimental effect on the pore aperture mechanism. Indirect damage is due to soil acidification and results in stunted growth. The conversion of SO₂ to acid rain can take several days to occur.

IPL's study on SO₂ impacts on vegetation incorporated published information gathered from topographic maps, aerial photography, and soil surveys. The data was coupled with field surveys of a three (3) kilometer radius around the SGS facility conducted in April 2007. The plant communities were identified on the basis of the structure (i.e. grassland & forest), position in landscape (i.e. upland & wetland), and the dominant plant species.

IPL identified seven (7) plant species/land use categories following the *Flora of the Great Plains* (Great Plains Flora Association, 1986, University Press of Kansas, Lawrence, KS). The plant communities/land use categories identified are:

- Woodland (upland deciduous)
- Woodland (riparian)
- Pasture
- Emergent wetland
- Native prairie
- Urban/residential
- Commercial/industrial
- Cropland (corn, soybeans)

Similar to the NO_x analysis, the study area was divided into a grid of twelve (12) acre parcels using aerial photography (See Figure 12). Each twelve (12) acre parcel was assessed based on a field assessment and aerial photography and the dominant plant community in each twelve (12) acre parcel was mapped. The distribution of plant communities in surrounding area of the SGS facility are illustrated in Figure 14.

None of the plant communities in the area appear to be composed of a dominant species that has been identified as very sensitive to SO₂. The riparian and upland woodlands are considered sensitive or intermediate tolerance due to the dominance of maple and oak. The cropland is considered sensitive if soybeans are planted, but tolerant if corn is planted. The remaining species are not sensitive to SO₂. By reviewing Figure 14 it is apparent that most of the region surrounding the SGS facility is to some degree sensitive to SO₂.

Table 12 lists the SO₂ exposure levels that cause foliar damage for the most sensitive vegetations. The levels listed in Table 12 are from EPA's "Air Quality for Particulate Matter and Sulfur Oxides"²¹. As can be seen from Table 12 the SO₂ impacts are significantly lower than the sensitivity levels. Therefore, no adverse impacts to the vegetation in area surrounding the SGS facility are anticipated due this project.

➤ PM:

The effects of particulate matter will vary greatly depending upon the particular mix of particles. Any particulate deposited on above ground plant parts can potentially exert physical or chemical effects. The effects of inert particulate are mainly physical where the effects of toxic particles are both chemical and physical.

Deposition of inert particulate on above ground plant organs sufficient to coat them with a layer of dust may result in changes in radiation received, a rise in leaf temperature, and the blockage of stomata. The main factor leading to plant injury is normally the chemical composition and more specifically the alkalinity of the applied dust.

²¹ US EPA, "Air Quality Criteria for Particulate Matter and Sulfur Oxides (Vol. 3)". EPA/600/8-82/029cF, 1982. The complete document can be found at <http://cfpub.epa.gov/ncea/CFM/recordisplay.cfm?deid=46205>.

Uptake of available metals in the ground can also result in metabolic effects in above ground tissues. Trace metals with a density greater than 6 g/cm^3 are referred to as “heavy metals” and are of particular interest because of their potential toxicity to both plants and animals. Some trace metals are essential for vegetative and animal health, but they are all toxic in large quantities. However, according to the information in IPL’s application only copper (Cu), nickel (Ni), and zinc (Zn) have been documented as frequently being toxic.

Generally, only the heavy metals cadmium (Cd), Chromium (Cr), Nickel (Ni), and mercury (Hg) are released from a coal-fired boiler stack in the vapor phase. Due to good combustion practices and the utilization of the air pollution control train that is highly effective at removing trace elements the proposed boiler will not emit very large quantities of these compounds. Therefore, no adverse impacts to vegetation around the SGS facility are anticipated from the particulate emissions due to this project.

➤ CO:

Carbon monoxide does not poison vegetation since it is rapidly oxidized to carbon dioxide which is used for photosynthesis. However, extremely high concentrations can reduce the photosynthetic rate. According to EPA’s “*A Screening Procedure for the Impacts of Air Pollution Sources on Plant, Soils, and Animals*” (copy attached in Appendix N), a CO concentration of $1,800,000 \text{ } \mu\text{g/m}^3$ (1 week averaging period) could potentially reduce the photosynthetic rate for the most sensitive vegetation.

As is listed in Table 12, the predicted maximum CO impact is $48.09 \text{ } \mu\text{g/m}^3$ (1-hr average) which is significantly lower than the screening level. Therefore, no adverse impacts to vegetation are expected from CO emissions due to this project.

➤ Ozone:

Ozone (O_3) impacts plants by destroying chlorophyll and in particular chlorophyll b. Acute symptoms of ozone damage are necrosis, chlorosis, and water marks. Ozone causes noticeable leaf damage in many crop and tree species. Certain varieties of soybeans, clover, onions, spinach, muskmelon, and alfalfa are especially susceptible. Trees such as lilac, aspen, and ash are also sensitive to ozone.

Ozone is not directly emitted from the processes in this project. It is formed in a reaction between carbon dioxide (CO_2), nitrogen oxides (NO_x), volatile organic compounds (VOC), and ultra violet (UV) light from the sun.

The increase in ozone formation due to the NO_x and VOC emissions from the project was estimated using the “*VOC/ NO_x Point Source Screening Tables*” developed by Scheffe. A copy of this document is attached in Appendix O. The estimated impact from this project was less than 0.010 ppm ($19.6 \text{ } \mu\text{g/m}^3$) on an hourly basis as can be seen in Table 12.

According to “The Response of Native, Herbaceous Species to Ozone: Growth and Fluorescence Screening²²” a reduction in the growth rate was found in certain plants after being fumigated with 139.7 $\mu\text{g}/\text{m}^3$ of ozone for two (2) weeks. A copy of this article is also in Appendix O.

➤ Fluorides:

Signs of fluoride phytotoxicity such as chlorosis, necrosis, and decreased growth rates are most likely to occur in young expanding tissues of broadleaf plants and elongating needles of conifers. Toxicity is specific not only to plant species, but also to ionic species of fluoride (i.e. aluminum fluoride and hydrogen fluoride). Most of the studies performed have involved the fumigation of plants with hydrogen fluoride.

According to GreenFacts²³, leaf necrosis has been known to occur at concentrations of 0.17 $\mu\text{g}/\text{m}^3$ (99 day exposure) and 0.27 $\mu\text{g}/\text{m}^3$ (83 day exposure) in the case of grapevines. The German Federal Ministry for Economic Cooperation and Development²⁴ also references that for the highly sensitive Crocus an exposure to a hydrogen fluoride (HF) concentration of 2 $\mu\text{g}/\text{m}^3$ over 276 hours can cause extremely severe leaf necrosis.

As can be seen in Table 12 the maximum modeled impact is well below all of these values. Therefore, no adverse impacts on vegetation are anticipated due to fluoride emissions from this project.

Department Soils & Vegetation Tool:

In addition to the soils and vegetation analysis conducted by IPL as already discussed, IPL used the Department’s Soils and Vegetation Screening Tool. Although the results from the screening tool indicates a value over the screening level for the ten (10) day averaging period for fluoride, the tool conservatively estimates impacts based on the ton per year of fluoride being emitted. The Department modeled impact of the twenty-four (24) hour averaging period indicates that the ten (10) day screening level for fluoride will not be exceeded. For all other pollutants, the results of the screening tool indicate no adverse impacts to soils and vegetation in the area around the SGS facility are anticipated. A copy of the screening tool results can be found in Appendix P.

Threatened and Endangered Species:

The Endangered Species Act (ESA) of 1973²⁵ was signed on December 28, 1973 and provides for the conservation of species that are endangered or threatened throughout all or a significant portion of their range, and the conservation of the

²² “The Response of Native, Herbaceous, Species to Ozone: Growth and Fluorescence Screening,” *New Phytologist*, Volume 120, Issue 1, 1992, pages 29 – 37.

²³ GreenFacts is a Belgian non-profit organization, created in December 2001 by individuals from different backgrounds, with the aim to bring complex scientific consensus reports on health and the environment to the reach of non-specialists. The website address is <http://www.greenfacts.org/en/index.htm>.

²⁴ German Federal Ministry for Economic Cooperation and Development. Environment Handbook – Document on Monitoring and Evaluating Environmental Impacts, Volume III: Compendium of Environmental Standards. See <http://144.16.93.203/energy/HC270799/HDL/ENV/enven/begin3.htm#Contents>.

²⁵ A copy of the ESA can be found on the web at <http://www.nmfs.noaa.gov/pr/pdfs/laws/esa.pdf>.

ecosystems on which they depend. The ESA replaced the Endangered Species Conservation Act of 1969. The ESA has been amended several times²⁶.

A species is considered endangered if it is in danger of extinction throughout all or a significant portion of its range. A species is considered threatened if it is likely to become an endangered species within the foreseeable future.

There are approximately 1,930 total species listed under the ESA. Of these, approximately 1,355 are found in part or entirely in the US and its waters. The rest are foreign species.

The National Oceanic and Atmospheric Administration's (NOAA) National Marine Fisheries Service (NMFS) and the US Fish and Wildlife Service (USFWS)²⁷ share responsibility for implementing the ESA. Generally, USFWS manages land and freshwater species while NMFS manages marine and anadromous²⁸ species. NMFS has jurisdiction over sixty-seven (67) species²⁹.

On April 11, 2007 IPL sent a letter to the US Fish and Wildlife Service requesting information on the potential impacts on endangered species from the proposed SGS Unit 4 project. The USFWS responded on May 17, 2007 that there are four (4) species found the area of the SGS facility which includes the distribution line upgrade project. Those four (4) species are:

- The bald eagle
- The prairie bush clover
- The northern monkshood
- The western prairie fringed orchid

According to the USFWS and the Natural Resources Conservation Service's³⁰ websites there is larger list. Therefore, IPL used those sources for its analysis.

➤ Wildlife Species:

According to USFWS there are fifteen (15) animal species that are listed as being threatened or endangered in the state of Iowa. Table 13 summarizes those species and their status (i.e. threatened or endangered) and whether or not they occur in Iowa.

To be conservative for its analysis IPL assumed that all of the animal species occur in the state. Information on the affects of the pollutants emitted by this project on the species listed in Table 13 is minimal. Therefore, IPL assumed that a comparison to information provided in laboratory experiments on test species would be sufficient.

²⁶ A copy of the ESA as amended through the 108th Congress can be found at <http://www.fws.gov/endangered/pdfs/ESAall.pdf>.

²⁷ Website for USFWS Endangered Species Program is <http://www.fws.gov/endangered/>.

²⁸ Anadromous species are those that live their adult lives in the ocean but move into freshwater streams to reproduce or spawn (e.g., salmon).

²⁹ See National Oceanic and Atmospheric Administration website at <http://www.nmfs.noaa.gov/pr/laws/esa/>.

³⁰ Website for Natural Resources Conservation Service is <http://www.nrcs.usda.gov/>.

Lethal concentrations are usually reported as several different values with the most common being LC₅₀. This is the concentration of a chemical in the air that kills 50% of the test animals in a given time and the lethal concentration low (LC_{Lo}) which is the lowest concentration of a chemical in air reported to have caused death in humans or animals. Table 14 is a reproduction of a table from Appendix I of IPL's application which is a summary of the laboratory findings for the PSD pollutants of concern for the proposed project.

Comparing the impacts from the dispersion modeling to the concentrations listed in Table 14 it is concluded the emissions from the proposed project will not have adverse impacts on the animal species.

Table 13 – USFWS Threatened and Endangered Animal Species in the State of Iowa³¹

Species Name	Listing Name	Status	Occur
Bat, Indiana	Myotis sodalis	Endangered	Yes
Higgins eye (pearlymussel)	Lampsilis higginsii	Endangered	Yes
Plover, piping except Great Lakes watershed	Charadrius melodus	Threatened	Yes
Shiner, Topeka	Notropis topeka (=tristis)	Endangered	Yes
Snail, Iowa Pleistocene	Discus macclintocki	Endangered	Yes
Sturgeon, pallid	Scaphirhynchus albus	Endangered	Yes
Tern, least interior pop.	Sterna antillarum	Endangered	Yes
Wolf, gray Lower 48 States, except where delisted and where EXPN. Mexico.	Canis lupus	Endangered	Yes
Wolf, gray Western Great Lakes DPS	Canis lupus	Endangered	Yes
Beetle, American burying	Nicrophorus americanus	Endangered	No
Curlew, Eskimo	Numenius borealis	Endangered	No
Mapleleaf, winged Entire; except where listed as experimental populations	Quadrula fragosa	Endangered	No
Mussel, scaleshell	Leptodea leptodon	Endangered	No
Pimpleback, orangefoot (pearlymussel)	Plethobasus cooperianus	Endangered	No
Pocketbook, fat	Potamilus capax	Endangered	No

Table 14 – Summary of Lethal Concentrations of Select Pollutants on Laboratory Animals

Chemical	Lethal Concentration Value	Test Animal
CO	LC ₅₀ – 2,103 mg/m ³ (4 hours)	Rat
NO ₂	LC ₅₀ – 57.3 mg/m ³ (1 hour)	Guinea Pig
	LC ₅₀ – 16.8 mg/m ³ (4 hours)	Rat
	LC _{Lo} – 123 mg/m ³	Dog
SO ₂	LC ₅₀ – 346 mg/m ³ (24 hours)	Mouse
Ozone	LC ₅₀ – 41.9 mg/m ³	Mouse
HF	LC ₅₀ – 1,062 mg/m ³ (1 hour)	Rat

³¹ Information can be found on USFWS website at http://ecos.fws.gov/tess_public/pub/stateListingAndOccurrence.jsp?state=all or http://ecos.fws.gov/tess_public/pub/stateListingAndOccurrence.jsp?state=IA.

➤ Plant Species:

According to USFWS there are five (5) plant species that are listed as being threatened or endangered in the state of Iowa. Those species are listed in Table 15 and are from the same site as the threatened and endangered animal species.

The Natural Resources Conservation Service lists a total of 154 plant species in Iowa that are listed on either the federal or state level as being threatened or endangered³². However, none of the 154 plant species are found in Marshall County.

Table 14 – USFWS Threatened and Endangered Plant Species in the State of Iowa³³

Species Name	Listing Name	Status	Occur
Bush-clover, prairie	<i>Lespedeza leptostachya</i>	Threatened	Yes
Milkweed, Mead's	<i>Asclepias meadii</i>	Threatened	Yes
Monkshood, northern wild	<i>Aconitum noveboracense</i>	Threatened	Yes
Orchid, eastern prairie fringed	<i>Platanthera leucophaea</i>	Threatened	Yes
Orchid, western prairie fringed	<i>Platanthera praeclara</i>	Threatened	No

There are several species (i.e. violets and trout lilies) which are within the three (3) kilometer radius of the SGS facility that are similar (same genus) to some of those found on the threatened or endangered list.

Based on the impacts from the dispersion modeling, the emissions from this project are not expected to adversely impact the most sensitive vegetation.

Visibility:

A visibility analysis was performed to determine the impact that the proposed project would have on Class II sensitive areas such as state parks, wilderness areas, and scenic sites and overlooks. IPL chose to analyze the visibility impacts on the nearest state park since the modeling results indicated the proposed project will not have a significant impact for any pollutant. The nearest state park is Union Grove which is located about fourteen (14) kilometers northeast of the SGS facility. Figure 15 illustrates the location of Union Grove State Park in comparison to the SGS facility.

³² A complete list can be found on the Natural Resource Conservation Service's United States Department of Agriculture (USDA) website at <http://plants.usda.gov/java/threat?txtparm=&category=sciname&familycategory=all&duration=all&growthhabit=all&wetland=all&statefed=all&stateSelect=US19&sort=sciname&submit.x=42&submit.y=14>.

³³ Information can be found on USFWS website at http://ecos.fws.gov/tess_public/pub/stateListingAndOccurrence.jsp?state=all or http://ecos.fws.gov/tess_public/pub/stateListingAndOccurrence.jsp?state=IA.

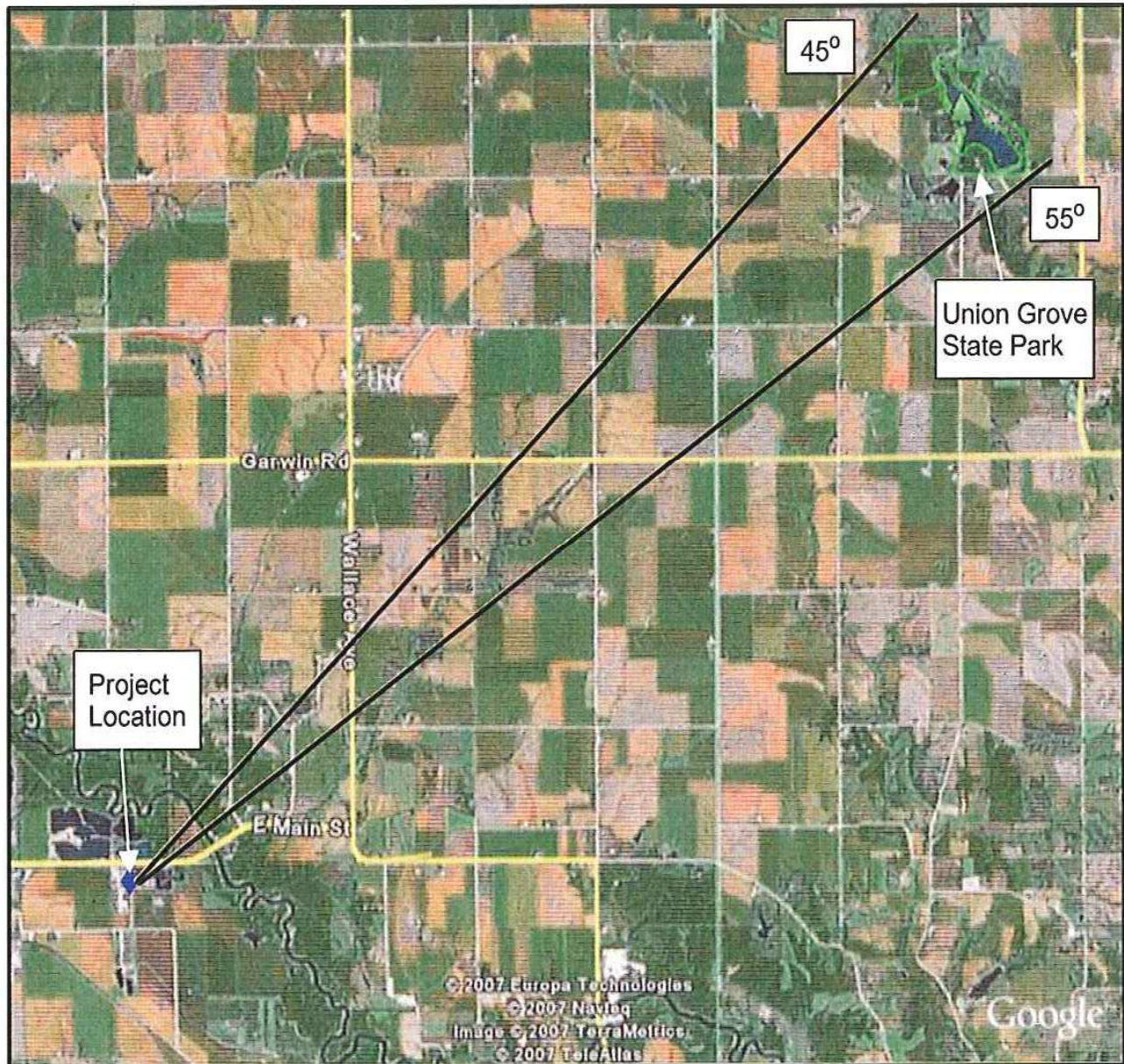


Figure 15 – Location of Union Grove State Park in Relation to the Project³⁴

In addition, the Department requested IPL to perform a visibility analysis on the Rock Creek State Park which is the nearest state park considering the predominant wind flows in that area of the state. Rock Creek State Park is located twenty-nine (29) kilometers south of the SGS facility. Figure 16 illustrates the location of Rock Creek State Park in comparison to the SGS facility.

Since there is no significant terrain within either park, only results for inside the state parks against a sky background were reviewed. The submitted Level 2 screening

³⁴ Figure is taken from Appendix I of IPL's November 2007 permit application. Figure was also included in IPL's April 2008 additional information.

analyses of the incremental increase in emissions associated with the SGS Unit 4 project indicated that the visibility screening criteria for inside the state parks and against a sky background would be exceeded during meteorological conditions that are likely to occur less than one (1) percent of the time or about four (4) days per year. These results can be found in Appendix I of the November 2007 permit application and Appendix I of the additional information submitted in April 2008.

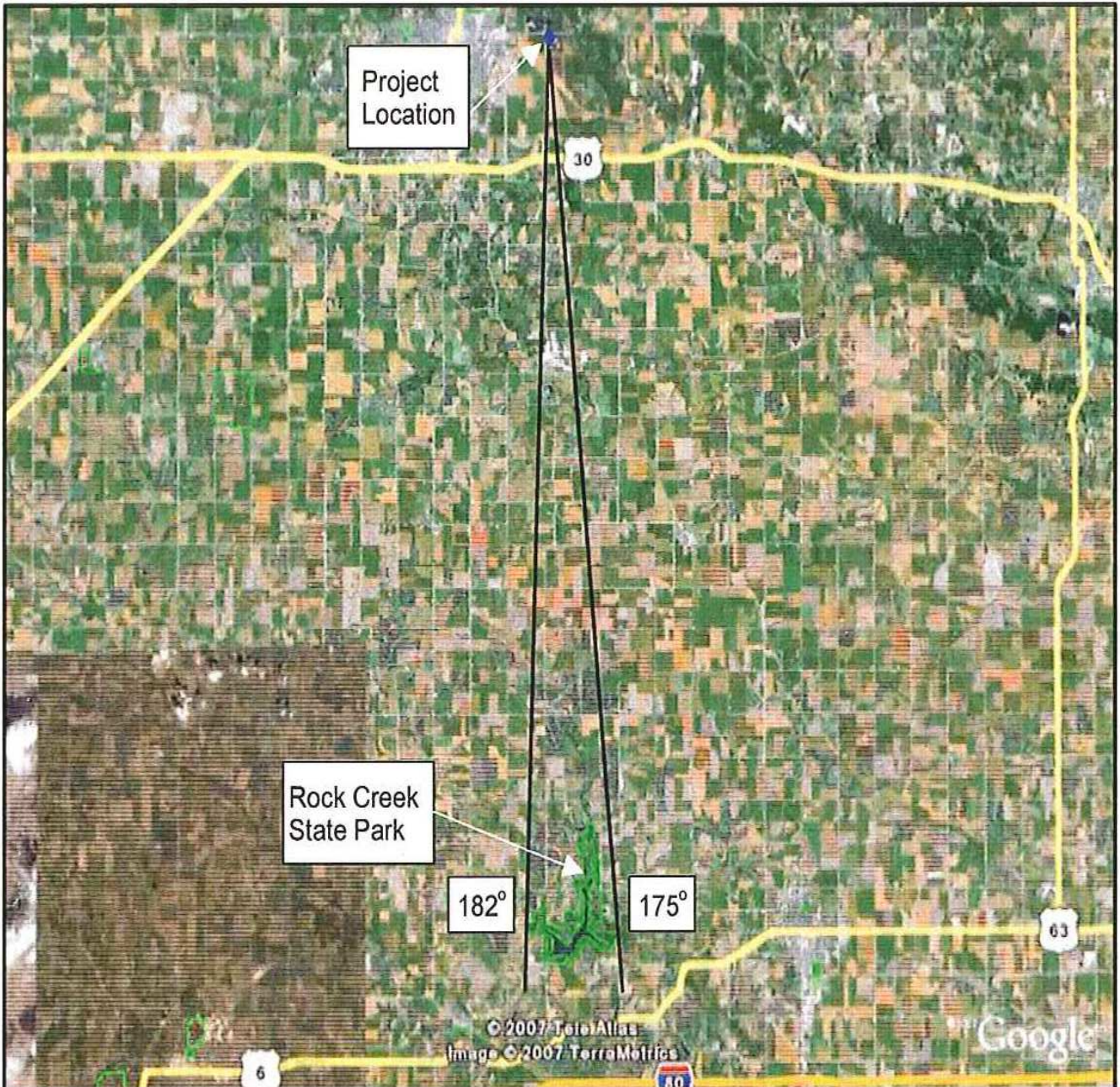


Figure 16 – Location of Rock Creek State Park in Relation to the Project³⁵

³⁵ Figure is taken from Appendix I of IPL's November 2007 permit application. Figure was also included in IPL's April 2008 additional information.

The Department conducted an additional evaluation to determine the net increase in the number of days with a visible plume at the state parks that are likely to occur as a result of the SGS Unit 4 project. This was done by using the visibility analysis once with existing facility-wide emission and then again with the proposed facility-wide emissions after the project. The net increase in days with a visible plume is calculated as the difference between the numbers of days with a visible plume for each scenario. Again, only results for inside the state parks against a sky background were reviewed because there is no significant terrain within either park.

The Department's visibility analysis indicated that the emissions from the SGS facility both before and after the project have the potential to cause a visible plume at the Union Grove State Park under all of the meteorological conditions recommended to be evaluated in EPA's "Workbook for Plume Visual Impact Screening and Analysis (Revised)", October 1992 (EPA-450/4-88-015). As stated earlier this document is in Appendix J.

Since the plume is visible during all of the meteorological conditions reviewed, this methodology is not useful in determining increased plume visibility. Any increase in the number of days with a visible plume at the Union Grove State Park due to this project is likely to be negligible.

The revised visibility analysis for the Rock Creek State Park indicated that the emissions from the SGS Unit 4 project have the potential to cause a visible plume at the Rock Creek State Park no more than an additional 0.3% of the time. This is equivalent to one (1) additional day per year. Again, any increased plume visibility due to the proposed modification is likely to be negligible.

Case-by-Case Maximum Achievable Control Technology (MACT) Determinations

Background:

The 1990 amendments to the CAA mandated significant new air quality programs and substantially enhanced some of the existing programs. Among the existing programs that were amended was the NESHAP program which is under Title I of the CAA. It should be noted that while the new NESHAP provisions were found in Title III of the 1990 amendments, the provisions amended Title I of the CAA.

The provisions of Title I that address the control of HAP emissions (or toxics) are found in Section 112 of the CAA. Section 112 includes provisions for the promulgation of NESHAP, or maximum achievable control technology (MACT) standards, as well as several related programs designed to enhance and support the NESHAP program. For more information on air toxics please see EPA's Air Toxics Website (<http://www.epa.gov/ttn/atw/index.html>).

There are nineteen (19) subsections to Section 112. There are two (2) subsections that directly affect this project. Those subsections are:

- **112(g):** *Modifications, Construction and Reconstruction.* Also referred to as the Case-by-Case MACT. Requires owners or operators of newly constructed, reconstructed, and modified major sources of HAP to apply MACT if emission increases are above certain levels. For purposes of Section 112(g) sources must

submit a pre-construction permit application proposing source-specific MACT. At this time the rulemaking implements these requirements for construction and reconstruction only.

- **112(j): *Equivalent Emission Limitation by Permit.*** Also referred to as the MACT Hammer. It ensures control of HAP emissions even if the EPA should miss a scheduled NESHAP promulgation date. If the EPA misses a scheduled promulgation date by eighteen (18) months, major sources in that category must submit to their respective State or local agencies a permit application proposing source-specific MACT. Conditions of the MACT determination must be incorporated into the Title V operating permit.

Subsection 112(g) affects utility boilers such as the proposed SGS Unit 4 and subsection 112(j) affects industrial, commercial, and institutional boilers and process heaters such as the auxiliary boiler and the gate station heater. Each of these subsections and the affected source category is discussed below.

Subsection 112(g):

Section 112(g) of the CAA requires that any constructed or reconstructed major source of Hazardous Air Pollutants (HAP) go through a case-by-case determination of the Maximum Achievable Control Technology (MACT) if no standard has been promulgated under Section 112(d) for the source category. The specific regulations implementing this requirement are promulgated at 40 CFR §63.40 through 40 CFR §63.44 (40 CFR 63 Subpart B). These regulations are adopted by reference into Iowa's State Implementation Plan (SIP) at 567 Iowa Administrative Code (IAC) 23.1(4)"b". 40 CFR §63.41 defines the phrase *Construct a Major Source* as

“(2) To fabricate, erect or install at any developed site a new process or production unit which in and of itself emits or has the potential to emit 10 tons per year of any HAP or 25 tons per year of any combination of HAP, unless the process or production unit satisfies criteria in paragraphs (2)(i) through (vi) of this definition.”

Paragraphs 2(i) through (vi) address the control of a new process or production unit with existing control equipment at a facility.

40 CFR §63.40(c) excluded electric utility generating units from the requirements of 40 CFR 63 Subpart B until such time as they are added to the source category list pursuant to Section 112(c)(5) of the Act. On December 20, 2000 EPA published in the Federal Register a "Regulatory Finding on the Emissions of Hazardous Air Pollutants From Electric Steam Generating Units" which added coal- and oil-fired electric steam generating units to the list of source categories under 112(c) of the Act (65 FR 79825).

On January 30, 2004, EPA proposed a rule with two (2) basic approaches for controlling mercury (Hg) from power plants. One approach would require power plants to meet emission standards reflecting the application of MACT determined according the procedure set forth in Section 112(d) of the CAA. The second approach was to create a market based “cap and trade” program. EPA proposed to pursue the “cap and trade” program under either Section 111 or Section 112 of the CAA.

On March 15, 2005, EPA issued the final Clean Air Mercury Rule (CAMR). EPA stated this was proposed to build on EPA's Clean Air Interstate Rule (CAIR) by reducing Hg emissions at coal-fired power plants. CAMR established "standards of performance" limiting mercury emissions from new and existing utilities by creating a market based "cap and trade" program. This rule was proposed as a New Source Performance Standard (NSPS) under Section 111 of the CAA.

Also on March 15, 2005, in a separate but related action, EPA revised and reversed its December 2000 finding that it was "appropriate and necessary" to regulate coal and oil fired power plants under Section 112 of the CAA. EPA stated this decision was made because it believed the December 2000 finding lacked foundation and because information in 2005 demonstrated that it was not appropriate or necessary to regulate coal and oil fired utilities under Section 112.

In effect EPA removed the regulating of all HAP emissions from electric utilities from Section 112 of the CAA which is the section of the CAA that is specifically for hazardous air pollutants. Instead EPA decided to regulate only one (1) hazardous air pollutant (Hg) through Section 111 of the CAA which was designed to establish performance standards for new sources.

EPA was sued on CAMR by New Jersey along with numerous other states, Native American tribes, public health groups, environmental groups, and other organizations. On February 8, 2008, The US Court of Appeals for the District of Columbia decided on *State of New Jersey v. EPA*. In its decision the three (3) judge panel unanimously vacated CAMR and EPA's delisting of electric generation units (EGU's) from Section 112.

EPA and the Utility Air Regulatory Group (UARG) petitioned the full DC Circuit to overturn the three (3) judge panel's vacatur of CAMR. In late May 2008, the full US Court of Appeals for the DC Circuit denied EPA and UARG requests to rehear the original court panel's unanimous decision.

On October 17, 2008 the US Department of Justice filed an appeal with the US Supreme Court asking that the court overturn the US Court of Appeals for the DC Circuit's vacatur of CAMR. Prior to this UARG had already filed an appeal to the Supreme Court.

On February 6, 2009 acting Solicitor General Edwin Kneedler asked the Supreme Court to dismiss the Bush Administration's request for review of its controversial mercury rule for power plants (CAMR). In a two-page motion, Kneedler noted that

"Since the petition for a writ of certiorari was filed, EPA has decided, consistent with the court of appeals' ruling, to develop appropriate standards to regulate power plant emissions under Section 7412."

This decision negates the need to review the DC Circuit's decision. However, UARG's request to hear this case is still pending before the Supreme Court.

Since the court vacated CAMR and the delisting of EGUs instead of remanding the regulations it is as if the rules never existed. Therefore, until a final decision is made by the Supreme Court, SGS Unit 4 is subject to NESHAP Subpart B (Case-by-Case MACT) as EGU's are considered a listed source under Section 112 of the CAA and EPA has not yet

promulgated a standard for HAP emissions from EGU's. Copies of the court decisions to date along with analysis of the decision can be found in Appendix Q.

Subsection 112(j):

Section 112(j) of the CAA requires that any new or existing emissions unit at a major source of HAP emissions go through a case-by-case MACT determination if EPA has failed to promulgate a standard by the required date. The specific regulations implementing this requirement are promulgated at 40 CFR §63.50 through 40 CFR §63.56 (40 CFR 63 Subpart B). These regulations are adopted by reference into Iowa's State Implementation Plan (SIP) at 567 Iowa Administrative Code (IAC) 23.1(4)"b".

On September 13, 2004 EPA promulgated NESHAP Subpart DDDDD (40 CFR §63.7480 – 40 CFR §63.7575; National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters). This rule was also referred to as being the Boiler MACT and it was amended on December 28, 2005. The Department has adopted this standard by reference [567 IAC 23.1(4)"dd"].

EPA was sued by the National Resource Defense Council (NRDC) on NESHAP Subpart DDDDD. On June 8, 2007 the US Court of Appeals for the District of Columbia vacated the Boiler MACT (*Natural Resources Defense Council v. EPA*, No. 04-1385; copy of the decision is attached as Appendix R). Since the court vacated the standard rather than remanding it, the standard is essentially wiped off of the books and lacks any legal significance.

Therefore, EPA is considered to have failed to meet the deadline for establishing limits under section 112 of the CAA for Industrial, Commercial, and Institutional Boilers and Process Heaters. This means the State is required under section 112 (j) – the “hammer provisions” – to set the limits for the affected facilities on a case-by-case basis. The Department is also in the process of removing the reference of NESHAP Subpart DDDDD from its rules.

Since the auxiliary boiler and the gate station heater fall under the classification of Industrial, Commercial, and Institutional Boilers and Process Heaters they are subject to Subpart B (Case-by-Case MACT).

MACT Analysis:

40 CFR §63.43(d) outlines the following principles of a MACT determination:

- “(1) The MACT emission limitation or MACT requirements recommended by the applicant and approved by the permitting authority shall not be less stringent than the emission control which is achieved in practice by the best controlled similar source, as determined by the permitting authority.
- (2) Based upon available information, as defined in this subpart, the MACT emission limitation and control technology (including any requirements under paragraph (d)(3) of this section) recommended by the applicant and approved by the permitting authority shall achieve the maximum degree of reduction in emissions of HAP which can be achieved by utilizing those control technologies that can be identified from the available information, taking into consideration the costs of achieving such

emission reduction and any non-air quality health and environmental impacts and energy requirements associated with the emission reduction.”

Item (1) is generally referred to as a MACT floor determination while item (2) is referred to as a beyond-the-floor determination. These principles are the same for 112(g) review as for a 112(j) review for a new source. EPA's guidance document entitled "Guidelines for MACT Determinations Under 112(j) Requirements" provides a thorough explanation of the methodology to be undertaken. This document is attached in Appendix S.

- **Boiler 4:**

Uncontrolled Emissions:

Table 15 below outlines the estimated uncontrolled emissions from SGS Unit 4:

Table 15 – Uncontrolled HAP Emissions

Pollutant	Uncontrolled Emissions (tons/yr)
Antimony (Sb)	3.00
Arsenic (As)	68.44
Beryllium (Be)	3.51
Cadmium (Cd)	8.51
Chromium (Cr)	43.40
Chromium VI (Cr ⁺⁶)	13.19
Cobalt (Co)	16.69
Hydrofluoric Acid (HF)	251.53
Hydrochloric Acid (HCl)	1,567.53
Lead (Pb)	19.95
Manganese (Mn)	81.79
Mercury (Hg)	0.6455 (1,291 lbs/yr)
Nickel (Ni)	46.74
Polychlorinated dibenzo-p-dioxins & polychlorinated dibenzofurans (PCDD/PCDF)	0.0004
Polycyclic organic matter (POM) & polynuclear aromatic hydrocarbons (PAH)	0.035
Other Organic Compounds such as benzene, toluene, xylene, etc.	15.33
Selenium (Se)	216.99
Total	2,357.3

Organic Hazardous Air Pollutants (Organic HAP):

The organic HAP emissions are the result of incomplete combustion. In the past no units of this type were identified as having add-on controls for organic HAP emissions. However, there were several units that had requirements to maintain good combustion practices to minimize the organic HAP emissions. CO emissions were monitored in order to demonstrate good combustion practices were being observed.

As the Department reviewed the available information including the types of pollutants that are listed as organic HAP emissions it was not apparent that the suite of controls being used by IPL could not reduce some of the organic HAP emissions. For example, the organic HAP pollutants are compounds that contain sulfur (S), fluorine (F), mercury (Hg), and chlorine (Cl). These are all compounds that will be controlled through the various pieces of control equipment so it is only logical to assume there may be some level of reduction of the organic HAP emissions.

In addition, there is no data available demonstrating CO is an appropriate surrogate for organic HAP emissions. The only reference to this being the case is the Federal Register (68 FR 1671) where EPA states:

“For organic HAP, EPA chose to use CO as a surrogate to represent the variety of organic compounds, including dioxins, emitted from the various fuels burned in boilers and process heaters. Because CO is a good indicator of incomplete combustion, there is a direct correlation between CO emissions and the formation of organic HAP emissions. Monitoring equipment for CO is readily available, which is not the case for organic HAP. Also, it is significantly easier and less expensive to measure and monitor CO emissions than to measure and monitor emissions of each individual organic HAP. Therefore, using CO as a surrogate for organic HAP is a reasonable approach because minimizing CO emissions will result in minimizing organic HAP emissions.”

Due to these uncertainties the Department has set limits on four (4) of the organic HAP (acetaldehyde, benzene, isophorone, and toluene). There is little data so the limits being set are temporary limits based on the AP-42 emission factors. IPL is required to do quarterly testing of these four (4) pollutants for the first year. After the first year IPL is required to submit the test data with a statistical analysis in order to set the permanent MACT emission limit.

In addition, IPL is required to submit the CO CEM data along with an analysis showing whether or not there is a correlation between CO and the previously listed organic HAP emissions. If there is a correlation, IPL can use CO as a surrogate for organic HAP.

Control technology:	Good Combustion Controls & Suite of Controls for Criteria Pollutants
MACT emission limits:	Acetaldehyde: 0.000310 lb/MWh (gross) 0.95 tons/yr
	Benzene: 0.000707 lb/MWh (gross) 2.17 tons/yr
	Isophorone: 0.000315 lb/MWh (gross) 0.97 tons/yr
	Toluene: 0.000131 lb/MWh (gross) 0.40 tons/yr
	CO (possible surrogate): 0.9031 lb/MWh (gross) 2770.8 tons/yr

Non-Mercury Metals:

The metals of interest are arsenic (As), beryllium (Be), cadmium (Cd), chromium (Cr), lead (Pb), manganese (Mn), nickel (Ni), and selenium (Se). This group of metals was referred to as total selected metals (TSM) in the vacated Industrial/Commercial/Institutional Boiler and Process Heater standard. This nomenclature was used in the Department's analysis. Like mercury (Hg), these metals are natural constituents of coal. The content of each of these metals in coal will vary with the source of the coal.

The control of these metals is predominately achieved by the control devices employed for particulate matter. The most common and effective control devices for particulate matter from electric utility boilers are fabric filters (or baghouses) and electrostatic precipitators (ESP). Baghouses are considered more effective at controlling particulate matter from electric utility boilers burning low-sulfur western coal. Therefore, the use of a fabric filter has been determined to be the MACT floor for non-mercury metals. No other technologies have been identified to be included as a beyond-the-floor option.

Generally, fabric filters achieve emission reductions of 99% or greater for particulate matter. However, some of the metals that are found in coal such as Se have low boiling points and therefore, these metals tend to be vaporized during the combustion of the coal. As the exhaust gas travels through the heat transfer sections of the boiler, the exhaust gases cool and some of the metals will condense to a liquid or solid state. However, it should be noted that since selenium (Se) will tend to stay in the vapor phase. This may cause a reduced ability to remove selenium (Se) from the exhaust gas stream.

In addition, the system-wide particulate collection efficiency is enhanced by the FGD system which reduces flue gas temperatures via the addition of moisture in the form of lime or a limestone slurry thereby increasing particulate control efficiency.

IPL requested an emission rate of 0.000153 lb/MMBTU for TSM and this limit was based on 99% removal of the maximum fuel bound metals across all of the proposed coals. In addition, IPL requested that filterable particulate matter (Federal PM) be used as a surrogate for TSM as a way to demonstrate continual compliance since

the particulate emission rate is dependent upon the overall efficiency of the baghouse and FGD just like TSM.

The Department accepted IPL's proposed emission rate for TSM and converted it to an output based standard. In addition, the Department agrees with setting filterable particulate as a surrogate and based the filterable emission limit on test data submitted by IPL. The 95% upper bound confidence level yielded an emission rate of 0.0088 lb/MMBTU which was converted to an output based emission limit. Continual compliance will be demonstrated through the use of a PM CEMS after an initial compliance test is conducted.

Control technology:	Baghouse & WFGD
MACT emission limits:	TSM: 0.00138 lb/MWh (gross) 4.24 tons/yr
	Federal PM (surrogate): 0.070 lb/MWh (gross) 216.1 tons/yr

Acid Gases:

The combustion of coal results in two HAP emissions that are often referred to as acid gases. These are hydrogen chloride (HCl) and hydrogen fluoride (HF). The amount of these pollutants that are produced will depend on the chlorine (Cl) and fluorine (F) content of the coal consumed.

The emissions of acid gas HAP are controlled by the same equipment used to control SO₂ emissions from electric generating units (EGUs). There are two (2) types of scrubbers that are used to remove SO₂: wet and dry scrubbers. These two (2) technologies are able to achieve similar levels of control for acid gases.

The Department has determined that either a wet or dry scrubber can be used for the MACT floor. There are no other control technologies that have been identified for consideration in a beyond-the-floor MACT determination.

IPL proposes to use a WFGD to meet MACT on acid gas HAP. IPL has proposed an emission rate of 0.000047 lb/MMBTU for HCl and 0.00091 lb/MMBTU for HF. Both of these proposed limits were based on the worst case concentrations of Cl and F in the coal with 99% removal by the control device.

Since it is not appropriate to base the emission rate on the worst case coal contents if there is variability in the concentrations the Department has set a two (2) tiered limit for both HCl and HF. The Department has accepted the proposed emission rates and converted them to output based emission limits. However these limits are only applicable when the coal concentration (as-fired) is less than or equal to 136 ppm for Cl and less than or equal to 45 ppm for F. When the coal concentrations of Cl and F are greater than those listed then IPL must achieve 99% reduction.

Control technology: WFGD
MACT emission limits: HCl: 0.000423 lb/MWh (gross) when Cl \leq 136 ppm
99% reduction when Cl > 136 ppm
1.30 tons/yr
HF: 0.00082 lb/MWh (gross) when F \leq 45 ppm
99% reduction when F > 45 ppm
2.52 tons/yr

Mercury (Hg):

Mercury is a natural trace constituent of coal. Depending on the source of the coal the Hg content of the coal may vary. This can be seen by the coal data submitted by IPL as part of the application and additional information.

Unit 4 at MidAmerican's Walter Scott Jr. Energy Center uses activated carbon injection (ACI) which is the same control proposed by IPL. The Department considers activated carbon injection along with the co-benefits from the SO₂ and particulate controls to be the MACT floor.

Based on the information in the application and information obtained by the Department from the internet and at conferences it has been determined that MACT is a halogenated powder activated carbon (PAC) injection system.

The emission rate was determined by using data from the stack test at Unit 4 at MidAmerican's Walter Scott Jr. Energy Center. Based on this data IPL proposed an emission rate of one pound per trillion British thermal units (1 lb/TBTU) or 90% reduction (whichever comes first).

The Department has accepted the 1 lb/TBTU and converted it into an output based emission limit. However, this emission limit is only applicable when the mercury content of the coal (as-fired) is less than or equal to 0.09 ppm. When the mercury content of the coal (as-fired) is greater than 0.09 ppm then IPL is required to achieve at least 95% reduction of mercury.

The requirement for 95% reduction of mercury is based on data from several reports including one (1) report from a test done at an Alliant Energy facility in Wisconsin. The information in the documents shows that the percent removal is dependent upon the amount of activated carbon injected into the gas stream. Therefore, the higher the concentration of mercury in the gas stream and the more activated carbon injected into the gas stream the more likely it is to be controlled. These documents are attached in Appendix T.

Control technology: PAC, SCR, Baghouse, and WFGD
MACT emission limits: 0.000009 lb/MWh (gross) when Hg \leq 0.09 ppm
99% reduction when Hg > 0.09 ppm
0.028 tons/yr (56 lbs/yr)

- **Auxiliary Boiler:**

The auxiliary boiler is used during startup of the main boilers, during periods when the boilers are offline, and to supply steam for onsite building heat and services. Since the steam generated is not used to generate electricity for sale the auxiliary boiler is not considered an electric utility steam generating unit. Instead it is classified as an industrial/commercial/institutional boiler or process heater.

Since the auxiliary boiler is fired on only natural gas the only category of hazardous air pollutants that was reviewed was organic HAP emissions. The reason for this is there is very little mercury (Hg), metals, chlorine (Cl), and fluorine (F) in natural gas. The Department is not aware of any natural gas fired units that have additional controls for mercury (Hg), total selected metals (TSM), or acid gases. Therefore, by limiting the unit to natural gas these three HAP categories are limited.

Organic Hazardous Air Pollutants (Organic HAP):

Like the coal fired boiler, the organic HAP emissions are the result of incomplete combustion. No units of this type were identified as having add-on controls for organic HAP emissions. However, there were several units that had requirements to maintain good combustion practices to minimize the organic HAP emissions. CO emissions were monitored in order to demonstrate good combustion practices were being observed.

The Department did not find data demonstrating CO is an appropriate surrogate for organic HAP emissions. Like the coal fired boiler, the only reference to this being the case is the Federal Register (68 FR 1671) previously mentioned in the main boiler MACT section.

Since IPL is installing an oxidation catalyst to control CO emissions it is doubtful CO is an appropriate surrogate since the emission rate for CO is after control and the emissions for organic HAP is due solely to combustion.

Due to these uncertainties the Department has set limits on two (2) of the organic HAP (formaldehyde and hexane). There is little data so the limits being set are temporary limits based on the AP-42 emission factors. IPL is required to do quarterly testing of these two (2) pollutants for the first year. After the first year IPL is required to submit the test data with a statistical analysis in order to set the permanent MACT emission limit.

In addition, IPL is required to submit the CO CEM data along with an analysis showing whether or not there is a correlation between CO and the previously listed organic HAP emissions. If there is a correlation, IPL can use CO as a surrogate for organic HAP.

Control technology: Good Combustion Controls
MACT emission limits: Formaldehyde: 0.000074 lb/MWh (gross)
0.02 tons/yr
Hexane: 0.0018 lb/MWh (gross)
0.48 tons/yr
CO (possible surrogate): 0.007 lb/MWh (gross)
1.88 tons/yr

- **Gate Station Heater:**

There is no de minimus level for 112(j). However, this is a very small (3 MMBTU/hr) natural gas fired unit. Therefore, the Department looked at the same pollutants and the same temporary limits as it did for the auxiliary boiler. Instead of requiring testing on the gate station heater the Department is using the results of the auxiliary boiler to set the final MACT limits.

Control technology: Good Combustion Controls
MACT emission limits: Formaldehyde: 0.000074 lb/MWh (gross)
0.001 tons/yr
Hexane: 0.0018 lb/MWh (gross)
0.023 tons/yr
CO (possible surrogate): 0.045 lb/MWh (gross)
0.09 tons/yr

Compliance Demonstration

In order to make an emission limit enforceable as a practical matter a compliance demonstration is necessary (See “Limiting Potential to Emit in New Source Permitting” which can be found in Appendix U). This compliance demonstration usually is for both initial compliance and continuous or periodic compliance.

Compliance can be demonstrated several ways. It can be done through emission stack testing, continuous emission monitoring systems (CEMS), or monitoring & recordkeeping. The following discussion describes the compliance demonstrations required for the various units in this project:

- **Boiler 4:**
Multiple compliance methods are required in the permit for Boiler 4. An initial compliance test is required for each pollutant in the permit. In addition, CEMS are required for PM (filterable), opacity, NO_x, SO₂, CO, and Hg. The company is required to conduct coal sampling on its coals. Finally, monitoring & recordkeeping is required for the control equipment.
- **Auxiliary Boiler:**
This unit is limited to firing on natural gas. It is also required to conduct initial compliance testing for several pollutants (PM, PM₁₀, opacity, SO₂, NO_x, VOC, CO, Formaldehyde, and Hexane). Also, CEMS are required for NO_x and CO.

- **Emergency Generator, Fire Pump, and Booster Fire Pump:**

These units are all limited to 100 hours of operation per year so their continuous compliance demonstration is recordkeeping to show the units do not exceed that limit. In addition, the company is required to purchase an engine certified to meet emission standards within the NSPS subpart.
- **Cooling Tower:**

The compliance demonstration for this emission unit is testing of the total dissolved solids (TDS) in the water used and recordkeeping. In addition, chromium (Cr) and VOC containing water treatment chemicals are prohibited from use in this unit.
- **Material Handling (point sources):**

An initial compliance test is required on all of the point source material handling operations. There are a few cases where the facility is allowed to do representative testing to demonstrate compliance and there are a few cases where stacks are required to be tested simultaneously. The testing is summarized below:

 - EPs 254a & 254b: Emission units 254a, 254b, and 254c vent to two (2) baghouses which have separate stacks (EPs 254a & 254b). In order to ensure compliance of both stacks, particulate testing is required to be conducted on EPs 254a & 254b simultaneously.
 - EP 259: Testing is required and no representative testing is allowed.
 - EPs 260 & 263: The facility has the option of testing both emission points or testing one (1) emission point and considering the results representative of both emission points. Both emission points have similar emission units (conveyors), the same type of control (baghouse), and similar flowrates (6,000 scfm for EP 260 and 4,500 scfm for EP 263). Therefore, it is reasonable to allow representative testing.
 - EPs 261 & 264: The facility has the option of testing both emission points or testing one (1) emission point and considering the results representative of both emission points. Both emission points have similar emission units (conveyors), the same type of control (baghouse), and the same flowrate (8,000 scfm). Therefore, it is reasonable to allow representative testing.
 - EP 265: Testing is required and no representative testing is allowed.
 - EP 266: Testing is required and no representative testing is allowed.
 - EP 267: Testing is required and no representative testing is allowed.
 - EP 275: Testing is required and no representative testing is allowed.
 - EPs 278a & 278b: The facility has the option of testing both emission points or testing one (1) emission point and considering the results representative of both emission points. Both emission points have the same emission unit (EU 278), the same type of control (baghouse), and the same flowrate (2,700 scfm). Also, the

facility is not allowed to vent the emissions of EU 278 through EP 278a and EP 278b simultaneously. Therefore, it is reasonable to allow representative testing.

- EP 279: Testing is required and no representative testing is allowed.
- EPs 280a & 280b: Emission unit 280a vents to two (2) baghouses which have separate stacks (EPs 280a & 280b). In order to ensure compliance of both stacks, particulate testing is required to be conducted on EPs 280a & 280b simultaneously.
- EPs 281a & 281b: The facility has the option of testing both emission points or testing one (1) emission point and considering the results representative of both emission points. Both emission points have the same emission unit (EU 281), the same type of control (baghouse), and the same flowrate (2,700 scfm). Also, the facility is not allowed to vent the emissions of EU 281 through EP 281a and EP 281b simultaneously. Therefore, it is reasonable to allow representative testing.
- EP 282: Testing is required and no representative testing is allowed.
- EPs 284 & 285: The facility has the option of testing both emission points or testing one (1) emission point and considering the results representative of both emission points. Both emission points have similar emission units (sor bent transfer), the same type of control (baghouse), and the same flowrate (5,000 scfm). Therefore, it is reasonable to allow representative testing.
- EP 286: Testing is required and no representative testing is allowed.
- EPs 284 & 285: The facility has the option of testing both emission points or testing one (1) emission point and considering the results representative of both emission points. Both emission points have the type of emission units, the same type of control (baghouse), and the same flowrate (28,500 scfm). Therefore, it is reasonable to allow representative testing.
- **Non-point source particulate sources:**

Recordkeeping is required for all of the non-point source particulate sources. This recordkeeping is necessary to demonstrate the facility is applying the proper dust suppressant.

In addition to recordkeeping the facility is required to conduct testing on the silt loading for the haul roads.
- **Gate Station Heater:**

No testing was required for this unit since it is such a small unit (3.0 MMBTU/hr). Instead the unit is limited to firing on natural gas. It is assumed that if the auxiliary boiler is meeting its emission limits this unit is also be meeting its emission limits since they are both natural gas fired units.

Confidentiality

IPL did not request confidentiality on any part of this project.

Requirements of PSD Public Notice

All PSD permits must be put on public notice. The Department will make available:

- The draft PSD permits,
- The Department's Technical Support Document (i.e. Fact Sheet),
- The applications,
- All materials submitted by the applicant, and
- All correspondence

These materials will be available at the following locations:

- Air Quality Bureau website (<http://aq48.dnraq.state.ia.us:8080/airpermit/eecomment.jsp>)
- Marshalltown Library (105 West Boone Street, Marshalltown, IA 50158)
- Meskwaki Natural Resource Department (1826 340th St, Tama, IA 52339)
- EPA Region VII (901 N. 5th St., Kansas City, KS 66101)
- Iowa Department of Natural Resources (Air Quality Bureau, 7900 Hickman Road, Suite #1, Urbandale, IA 50322)

The Department will publish a public notice in the Des Moines Register and the Marshalltown Times-Republican. The notification will include notice of the PSD application, the determination, the degree of increment consumption that is expected from construction of the project, the opportunity for verbal public comment, and the opportunity for written comment.

Two (2) public comment meetings will be held for the purpose of receiving written and oral comments. They will be held on:

- March 16, 2009 at the Iowa Veterans Home (Whitehill Chapel, 1501 Summit Street, Marshalltown, Iowa). There will be two (2) separate sessions in which the public can make oral or written comments. The sessions will run from 2:30 pm – 5 pm and 6:30 pm to 9 pm.
- March 17, 2009 at the Meskwaki Tribal Center (346 Meskwaki Road, Tama, IA 52339). There will be two (2) separate sessions in which the public can make oral or written comments. The sessions will run from 3 pm – 5 pm and 7 pm to 9 pm.

Comments at the public meetings will be limited to five (5) minutes in order to provide ample opportunity for all interested parties to comment. Any presentations given shall also include a hard copy in order to be included in the public record.

All persons who have comments regarding the issuance of the attached draft permits are encouraged to submit their comments.

All comments not received at one of the public meetings shall be submitted in writing and must be submitted before 4:30 PM on the last day of the public comment period which will run from February 16, 2009 to March 20, 2009. Written and signed comments shall be directed to:

Christopher A. Roling, PE
Environmental Engineer Senior
Air Quality Bureau
Iowa Department of Natural Resources
7900 Hickman Road
Suite #1
Urbandale, Iowa 50322

Or emailed to: chris.roling@dnr.iowa.gov.

Any materials related to comments submitted by the public shall be included in full and not be incorporated by reference unless the material is already part of the administrative record or consists of State or Federal statutes and regulations, EPA documents of general applicability, or other available reference materials.

Upon a final decision on the project, all comments, Department responses, and the final documents will be available for public inspection at the Department address listed above and on the Air Quality Bureau website (<http://aq48.dnraq.state.ia.us:8080/airpermit/eeepsd.jsp>). In addition, all comments, Department responses, and the final documents will be available at EPA Region VII, the Marshalltown Library, and the Meskwaki Tribe for a minimum of thirty (30) days after the final decision.

Reopening of Public Comment Period

If information or comments submitted to the Department during the public comment period appear to raise substantial questions concerning the draft permits, then the Department may prepare revised draft permits, a revised or supplemental technical support document, and reopen or extend the public comment period. Any reopening or extension of the public comment period would be limited to those changes.

Department Determination

The Department determines that the applicant has met all of the requirements for issuance of Prevention of Significant Deterioration (PSD) construction permits for the proposed project under 567 IAC 22.3 and is proposing to issue the construction permits listed in Table 2 of this document.

**Supporting References to the Administrative Record Not
Footnoted in or Attached to the Technical Support Document**

The references below are additional documents used by the Department in its decision making process. They are the basis for the Iowa PSD program and may not be cited directly in either the permits or the technical support document.

1. The Clean Air Act as Amended through 1990.
2. US EPA Federal Register; <http://www.epa.gov/fedrgstr/index.html>.
3. New Source Performance Standards (NSPS); 40 CFR 60.
4. National Emission Standards for Hazardous Air Pollutants (NESHAP); 40 CFR 61 & 40 CFR 63.
5. Prevention of Significant Air Quality Deterioration (PSD) Regulations; 40 CFR 51.166, 40 CFR 52.21 & 567 IAC 33.
6. Iowa Code; Chapter 455B.
7. The Iowa Administrative Code; 567 IAC 20-34.
8. Compilation of Air Pollutant Emission Factors; 5th Edition and Revisions, AP-42; U.S. EPA.
9. New Source Review Workshop Manual; EPA-450/2-80-081, October 1990.
10. RACT/BACT/LAER Clearinghouse: A Compilation of Control Technology Determinations; <http://cfpub1.epa.gov/rblc/htm/bl02.cfm>.
11. OAQPS Control Cost Manual; Fourth Edition; USEPA, Office of Air Quality Planning and Standards; Research Triangle Park, NC; EPA 450/3-90-006; January 1990 and subsequent additions; <http://www.epa.gov/ttn/catc/products.html>.
12. 40 CFR Part 51, Appendix W.
13. Aermod Modeling System; http://www.epa.gov/scram001/dispersion_prefrec.htm#aermod.