Appendix B

Air Quality

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Appendix B-1

BACT Analysis

APPENDIX B-1
BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

In Washington, Best Available Control Technology BACT is required for criteria and toxic air pollutant (TAP) emissions from new and modified industrial sources. This Appendix presents a BACT analysis for emission units associated with the PMEC. The basis for the emissions-related analyses is annual average operation at a design capacity of nominally 600 gross megawatts (MW). The proposed PMEC as currently configured will involve the following major processes and emission units:

- Two Syngas-Fired Combustion Turbines;
- Two Heat Recovery Steam Generators (HRSG) and two Steam Turbine-generator;
- Two 6-cell, Recirculating, Mechanical-draft Cooling Towers for the combined cycle plants;
- One 7-cell Recirculating, Mechanical-draft Cooling Tower for the Air Separation Unit;
- One Auxiliary Boiler
- Solid Feedstock Receiving and Handling (railcar and ship facilities, feeding two storage domes)
- Gasification Plant, including Enclosed Flare
- Slag Handling System
- Syngas Cleanup Processes
- Tank Vent Oxidizer System
- Emergency, Diesel Engine-Driven Generator and Fire Water Pump

B-1.1 BACT ANALYSIS OVERVIEW AND RESULTS SUMMARY

The proposed BACT controls and associated emission rates for each emission unit are summarized in Table B-1-1. Project sources addressed in this table include:

- Combustion turbines
- Railcar solid feedstock unloading to storage bins
- Ship solid feedstock unloading to storage bins
- Feedstock preparation plant (handling systems, rod mill)
- Sulfur recovery unit
- Gasification island flare
- Tank vent collection and boiler system
- Auxiliary boiler

- Cooling towers
- Emergency diesel engines

The IGCC process converts fossil fuel feedstock (petroleum coke, coal, or a combination) into a synthesis gas (syngas), which then can be used to fuel combustion turbines to generate electricity. Figure 2.3-1 of this Application provides an illustration of the proposed PMEC complex indicating the layout of the major plant components within the site.

In this application Energy Northwest is proposing the installation of Selective Catalytic Reduction (SCR) as an (Innovative Control Technology) ICT (defined in 40 CFR 52.21(b)(19)), which surpasses EPA established BACT NO_x control at IGCC facilities. This will be the first proposed installation in the western United States of post-combustion add-on emission controls on syngas-fired combustion turbines. While SCR is commonly used to limit NO_x emissions from natural gas-fired combustion turbines, no prior New Source Review (NSR) permits for IGCC facilities have specified this or any other post-combustion control technology as BACT for NO_x. The explanation for this history is the potential for adverse effects of syngas combustion products on the SCR catalyst and other technical barriers to SCR implementation at IGCC power plants. SCR may only be considered as technically feasible at a cost level much higher than is acceptable for BACT-based emission limits, and as noted above, its performance has never been demonstrated for turbines at an IGCC plant. Petroleum coke (petcoke) or coal-derived syngas is sufficiently different in composition compared to natural gas that SCR cannot be assumed to provide reliable NO_x emissions control without very high additional expenditures to remove sulfur and other contaminants from the syngas fuel. PMEC plans to accomplish this through the addition of a Selexol ® or equivalent system

TABLE B-1-1
PROPOSED BACT FOR THE PMEC

Pollutant	Control	Emissions Limits
IGCC Combustion Turbines (Emissions shown per combustion turbine excluding Start up / Shutdown conditions). All values in lb/MMBtu are based on fuel energy input of feedstock to the gasifiers.		
NO_x	Diluent Injection (BACT Limit)	15 ppm NOx @ 15% O_2 on syngas gas fuel, 3-hour average
		25 ppm NOx @ 15% O_2 on natural gas fuel, 3-hour average
	Selective Catalytic Reduction (ICT Limit)	3 ppm NOx @ 15% O_2 on syngas gas fuel, 3-hour average
		5 ppm NOx @ 15% O_2 on natural gas fuel, 3-hour average
CO	Good Combustion Practices (GCP)	15 ppm @ 15% O_2 (above 50% load) 3-hour average
PM/PM_{10}	GCP, gas cleanup, Gaseous Fuels only	0.009 lb/MMBtu heat input to gasifier

Table B-1-1 (Continued)
Proposed BACT for the PMEC

Pollutant	Control	Emissions Limits
SO_2	Gas cleanup (BACT Limit)	50 ppmvd H_2S in undiluted, unsaturated syngas, rolling 30-day average
	Selexol® Gas Cleanup (ICT limit)	10 ppmvd H_2S in undiluted, unsaturated syngas, rolling 30-day average,
VOC	GCP	0.003 lb/MMBtu heat input to gasifier
NH_3	Molar ratio control on Injection Sys.	5 ppmvd @ 15% O_2 (ammonia slip), 20 lb/hr (ICT-based Limit)
H_2SO_4	Gas cleanup/ Limit on reduced sulfur in syngas	3.2 lb/hr, 13.83 tpy (10 ppm S)
Mercury	Syngas Cleanup Process	0.0033 lb/hr
Railcar Unloading Building and Transfer to Storage Domes (3,186 tons feedstock per hour)		
PM/PM_{10}	Baghouse, 99% efficiency	0.171 lb/hr
Ship Unloading Facility and Transfer to Storage Domes (1,900 tons feedstock per hour)		
PM/PM_{10}	Baghouse, 99% efficiency	0.436 lb/hr
Storage Domes Ventilation (3,186 maximum tons feedstock per hour)		
PM/PM_{10}	Baghouse, 99% efficiency	0.085 lb/hr
Gasification Island Enclosed Flare (capacity of 3,730 MMBtu/hr as syngas) - Assumes worst-case upset (85% of max syngas capacity for gasifiers).		
NO_x	GCP	Exit velocity > 60 meters/second
CO	GCP	
PM/PM_{10}	GCP, gaseous fuel only	
SO_2	GCP, Gas cleanup/Limit on reduced sulfur in syngas	Natural gas purge Steam or air assisted flare design
VOC	GCP	
Tank Vent Collection System and Vapor Processing Unit		
NO_x	GCP, low-NOx burner	0.3 lb/MMBtu fired, 3-hr average
CO	GCP	0.09 lb/MMBtu fired, 3-hr average
PM/PM_{10}	GCP, gaseous material only	0.01 lb/MMBtu fired, 3-hr average
SO_2	Gas cleanup/Limit on reduced sulfur in syngas	5.8 lb/hr SO_2 (1-hour average) 4.2 llb/hour SO_2 (24-hour average)
VOC	GCP	0.004 lb/MMBtu fired, 3-hr average
Auxiliary Boiler (Natural Gas-Fired, 130 MMBtu/hr heat input)		
NO_x	GCP, low-NOx burner	0.036 lb/MMBtu fired, HHV, 3-hr average
CO	GCP	0.074 lb/MMBtu fired, HHV, 3-hr average
PM/PM_{10}	GCP, natural gas fuel only	0.005 lb/MMBtu fired, HHV, 3-hr average
SO_2	GCP, natural gas fuel only	0.00286 lb/MMBtu fired, HHV 3-hr average
VOC	GCP, natural gas fuel only	0.004 lb/MMBtu fired, HHV, 3-hr average

Table B-1-1 (Continued)
Proposed BACT for the PMEC

Pollutant	Control	Emissions Limits
Cooling Towers (2, 6-cell, Mechanical Draft Type)		
PM/PM_{10}	High Efficiency Mist Eliminators, TDS limit in circulating water	0.0010% draft as percent of circulating water
Emergency Diesel Engines (1, 300 hp firewater pump; 1, 2-MW, 2682 hp generator) - assumes 100 hours per year normal maintenance operation per engine.		
NO_x	Combustion controls, restricted operating hours	Operatons limited to < 100 hours/year Use of low-sulfur (0.05 weight percent) diesel fuel.
CO	Combustion controls, restricted operating hours	
PM/PM_{10}	Combustion controls, restricted operating hours, low-sulfur diesel fuel	
SO_2	Low-sulfur diesel fuel, restricted operating hours	
VOC	Combustion controls, low-sulfur diesel fuel, restricted operating hours	

The following sections describe the BACT demonstration process, the unique characteristics of IGCC and syngas that affect facility emissions, and the individual control technology evaluations for each emission unit and pollutant subject to BACT-based limits. Important information is provided comparing the BACT-based limits proposed for NO_x and the alternative limits that are based on adoption of an ICT for the PMEC.

This BACT analysis accounts for combustion turbine unit and syngas clean-up startup cycles, as well as normal operations of this equipment. There will be higher transient emission rates for NO_x, CO and VOC during each turbine start-up event than during normal turbine operations. This is explained by decreased fuel combustion efficiency during the early stages of a startup event and exhaust temperatures that will initially be below the lower end of the SCR operating range. Accordingly, the total annual emissions have been calculated throughout this Application with a conservative assumption of 50 hours of startup operating mode per turbine per year, with normal turbine operations at 100% of capacity for the remaining hours of the year. In practice, a more realistic capacity factor of 90% or less is more likely to occur.

To evaluate BACT for the emission units at an IGCC plant, it is important to understand the IGCC process. Detailed process descriptions for the proposed facilities are given in the main body of this Application. In addition, Section B-1.3 gives a general overview of the regulatory mechanism and requirements for adopting an ICT as part of a New Source Review permit. Sections B-1.4 and B-1.5 provide background on existing or proposed IGCC facilities in the United States, their expected emission levels, and the unique characteristics of this process that must be considered in a BACT evaluation.

B-1.2 BACT REVIEW PROCESS

BACT is defined in the PSD regulations as:

> *"... an emission limitation based on the maximum degree of reduction for each pollutant subject to regulation under the Act which would be emitted from any proposed major stationary source ... which [is determined to be achievable], on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs" [40 CFR 52.21(b)(12)]*

In a December 1, 1987 memorandum from the EPA Assistant Administrator for Air and Radiation, the agency provided guidance on the "top-down" methodology for determining BACT. The "top-down" process involves the identification of all applicable control technologies according to control effectiveness. Evaluation begins with the "top," or most stringent, control alternative. If the most stringent option is shown to be technically or economically infeasible, or if environmental impacts are severe enough to preclude its use, then it is eliminated from consideration and then the next most stringent control technology is similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by technical or economic considerations, energy impacts, or environmental impacts. The top control alternative that is not eliminated in this process becomes the proposed BACT basis.

This top-down BACT analysis process can be considered to contain five basic steps described below (from the EPA's Draft New Source Review Workshop Manual, 1990)[1]:

Step 1. Identify all available control technologies with practical potential for application to the specific emission unit for the regulated pollutant under evaluation;

Step 2. Eliminate all technically infeasible control technologies;

Step 3. Rank remaining control technologies by control effectiveness and tabulate a control hierarchy;

Step 4. Evaluate most effective controls and document results; and

Step 5. Select BACT, which will be the most effective practical option not rejected, based on economic, environmental, and/or energy impacts.

Formal use of these steps is not always necessary. However, EPA has consistently interpreted the statutory and regulatory BACT definitions as containing two core requirements, which EPA believes must be met by any BACT determination, irrespective of whether it is conducted in a "top-down" manner. First, the BACT analysis must include consideration of the most stringent available technologies: i.e., those that provide the "maximum degree of emissions reduction."

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[1] "New Source Review Workshop Manual", DRAFT October 1990, EPA Office of Air Quality Planning and Standards

Second, any decision to require a lesser degree of emissions reduction must be justified by an objective analysis of “energy, environmental, and economic impacts” contained in the record of the permit decisions.

Additionally, the minimum control efficiency to be considered in a BACT analysis must result in an emission rate no less stringent than the applicable New Source Performance Standard (NSPS) emission rate, if any NSPS standard for that pollutant is applicable to the source.

This BACT analysis was conducted in a manner consistent with this stepwise approach. Control options for potential reductions in criteria pollution emissions were identified for each source. These options were identified by researching the EPA database known as the RACT/BACT/LAER Clearinghouse (RBLC), drawing upon previous environmental permitting experience for similar units and surveying available literature. Available controls that are judged to be technically feasible are further evaluated based on an analysis of economic, environmental, and energy impacts.

Assessing the technical feasibility of emission control alternatives is discussed in EPA's draft "New Source Review Workshop Manual." Using terminology from this manual, if a control technology has been "demonstrated" successfully for the type of emission unit under review, then it would normally be considered technically feasible. For an undemonstrated technology, “availability” and “applicability” determine technical feasibility. An available technology is one that is commercially available; meaning that it has advanced through the following steps:

- Concept stage;
- Research and patenting;
- Bench scale or laboratory testing;
- Pilot scale testing;
- Licensing and commercial demonstration; and
- Commercial sales.

Suitability for consideration as a BACT measure involves not only commercial availability (as evidenced by past or expected near-term deployment on the same or similar type of emission unit), but also involves consideration of the physical and chemical characteristics of the gas stream to be controlled. A control method applicable to one emission unit may not be applicable to a similar unit, depending on differences in the gas streams’ physical and chemical characteristics.

For this BACT analysis, the available control options were identified by querying the EPA RBLC and by consulting available literature on control options for IGCC. The analysis also involves review of currently permitted and operating IGCC facilities.

B-1.3 INNOVATIVE CONTROL TECHNOLOGY PROVISIONS

The Washington Department of Ecology (Ecology) air quality regulations have incorporated by reference the federal definition of ICT, as it relates to emission controls adopted as part of a PSD

permit. EFSEC, in turn, has adopted by reference virtually all the provisions of WAC 173-400, including the section related to ICT. To utilize these provisions, a new major source may request that EFSEC approve the implementation of an air pollution control system as an ICT, including special conditions regarding a demonstration phase to achieve effective control. The definition of ICT, as referenced by Washington Administrative Code (WAC) 173-400-720 (4)(a)(v), is provided in Title 40, Part 52 of the Code of Federal Regulations:

> *"...any system of air pollution control that has not been adequately demonstrated in practice but would have a substantial likelihood of achieving greater continuous emissions reduction than any control system in current practice, or of achieving at least comparable reductions at lower cost in terms of energy, economics, or non-air quality environmental impacts." [40 CFR 52.21(b)(19)]*

Adoption of an ICT as part of a project includes conditional permit limits that are typically more stringent than BACT-based limits. However, the ICT limits do not completely replace the role of BACT in the new source's permit. The BACT-based limits for the source are still included in the new source's permit in the event that the more stringent levels anticipated for the ICT are not achieved in practice. The ICT-based limits also do not, by their inclusion in the permit, represent a more stringent BACT determination for the affected source category.

In a practical sense, several conditions must be met before the Department can approve the installation of an ICT in conjunction with issuing or revising an air quality permit. These conditions are:

1. The source demonstrates that the proposed control system would not cause or contribute to an unreasonable risk to public health, welfare, or safety in its operation or function.

2. fThe source agrees to a level of continuous emissions reduction equivalent to that which would have been required as a BACT limit by a date specified in the permit or permit revision.

3. Before the date specified in the permit or permit revision, the new source must be able to demonstrate that the achieved emissions (with or without ICT) would not:

    a. Cause or contribute to any violation of an applicable state ambient air quality standard; or

    b. Impact any area where an applicable increment is known to be violated.

4. All other applicable requirements for adoption of the PSD permit conditions, including those for public participation and regional EPA approval, have been met.

A recent precedent in which Ecology included ICT-based limits and related provisions is the PSD permit issued on August 2004, Permit Number PSD-04-01, to the Kennewick Fertilizer Operations (KFO) of Agrium U.S. Inc. for modification of emissions controls on nitric acid plants at their facility in Kennewick, Washington. This permit included a schedule of ICT-based emission rate milestones to be demonstrated for KFO Plant 9. In effect, a sequence of decreasing

daily NO_x emission rate milestones (in units of lb/day) was established for the initial 48 months of source operation after the modification.

The PMEC proposes to implement SCR in concert with enhanced syngas cleanup with the Selexol® or equivalent® process as ICT. In the case of other proposed and permitted IGCC plants, SCR has not been deemed feasible as BACT. Only by making a sizeable investment in more complete syngas desulfurization, beyond that normally deemed BACT for SO2 emission limits, can the PMEC reasonably attempt to utilize SCR for NO_x control, thus potentially reducing NOx emissions of that pollutant by a further 80%.

There is no commercial operating experience with SCR on ICGC plants utilizing coal-derived syngas. However, there is a "substantial likelihood" that the proposed control technology package can achieve reduced NO_x emissions from combustion of syngas. The primary uncertainties, which are substantial, relate to several factors, including system reliability, performance at all operating conditions, reduced catalyst service life, and elevated operating costs. The proposed final ICT NO_x emission limits are shown in Table B-1-1 for the IGCC combustion turbines. Further, as shown below, the proposed PMEC using Selexol® or equivalent with SCR meets each of the previously stated criteria for treatment as an ICT:

1) Both the Selexol® systems and SCR processes are well-established at refineries, utility generating plants, and for larger gas preparation / combustion sources in other industries. Handling and bulk storage of an ammonia solution is necessary to provide a reagent to facilitate the SCR reactions that convert NO_x to elemental nitrogen, but this can be accomplished safely with suitable equipment and work practice safeguards, as evidenced by the routine use of this technology on combustion turbines utilizing natural gas. When properly designed, installed and operated the Selexol®/SCR processes do not "cause or contribute to an unreasonable risk to public health, welfare, or safety."

2) Energy Northwest will agree to include in the requested permit a requirement to achieve by a date-certain a continuous level of NO_x emission control that is at least as stringent as that corresponding to BACT limits for the IGCC combustion turbines.

3) Energy Northwest has supplied with this Application a suitable ambient air impact analysis that demonstrates, based on accepted dispersion models, that the new PMEC combustion turbine emissions, based on ICT limits or the alternative BACT-based limits, will not cause or contribute to violations of an ambient air standard or PSD increment.

4) Lastly, all of the prescribed PSD permit processing requirements for adoption of the ICT and BACT based limits will be met, including public participation and EPA Region 10 review.

The analysis to establish the alternate NO_x emission limits from the PMEC combustion turbines has been included in Section B-1.7.1, in order to support the BACT-based limits that must also be included in the requested PSD permit. In developing the requested permit, Energy Northwest

intends to work with EFSEC to establish a reasonable set of demonstration milestones and a timetable for ICT implementation. It is anticipated that the ICT criteria in the permit could also be based on observed system reliability. To illustrate, if there is evidence after a sufficient test period that the use of Selexol® or equivalent and SCR will not be capable of reliably achieving the ICT limits described above, then some relaxation of these limits will be warranted. Dispersion modeling presented in this application demonstrates that compliance with applicable Washington and National Ambient Air Quality Standards and PSD increments would continue to be achieved, even in the extremely unlikely event that the proposed ICT NO_x control package provided no emission reduction beyond BACT-level controls.

B-1.4 PROJECT SOURCES SUBJECT TO BACT ANALYSIS

To evaluate possible emission control technologies, it is first important to understand the unique IGCC process and the supporting ancillary plant processes. The process descriptions for the various processes that make up the PMEC are included in Chapter 2 of this Application. The PMEC will consist of several facilities/systems representing sources of regulated air pollutants that are addressed in this BACT analysis:

- Combined Cycle Combustion Turbine Generators (Two Units)
- Railcar Solid Feed Stock Unloading and Transfer Points
- Ship Solid Feed Stock Unloading and Transfer Points
- Solid Feed Stock Storage Dome Vents
- Gasification Island Flare
- Tank Vent Collection and Boiler System
- Auxiliary Boiler (One Unit)
- Cooling Towers (two 6 and one 7 cell units)
- Emergency Diesel Engines (Generator and Fire Water Pump)

B-1.5 CONSIDERATION OF ALTERNATIVE GENERATING TECHNOLOGIES

This section addresses recent guidance relating to the need for consideration of alternative electrical generating technologies for the proposed project, as part of the BACT analysis. Compared to Pulverized Coal (PC)-fired Boilers and Circulating Fluidized Bed (CFB) Boilers, the proposed IGCC process is indeed the very lowest emitting solid fuel-based electricity generating technology available, and selection of a completely different solid fuel-based generating technology would not result in lower emissions. Later portions of this BACT analysis address the specific controls that are proposed to minimize the emissions from the proposed IGCC process.

As introduced in Section B-1.2, the first step in a BACT determination process is to identify all available control technologies that could potentially be used to minimize the emissions of the source and pollutant under evaluation. The most common control technologies considered in a BACT analysis are add-on control measures and inherent process characteristics that minimize generation of pollutants. Additionally, it is sometimes possible to modify the production process

or work practices to improve the emissions performance of a proposed project. These types of process modifications/measures, when applicable, are properly considered in a BACT analysis. In contrast, consideration of alternatives that would involve completely "redefining the design" of the proposed process are not required to be considered (1990 Draft New Source Review Workshop Manual, Section IV.A.3). Alternative generating processes, such as natural gas-fired combined-cycle plants, represent a completely different family of power generation plant designs from IGCC. While there are certain types of components in common, such as cooling towers and steam-driven turbine generators, the technical basis for a gas-fired plant differs markedly from that of the IGCC facility.

Since CFB or PC boilers or a natural gas-fired electrical generating plant would be completely different processes, and represent "redefining the design" compared to IGCC, it is reasonable to conclude that EPA would not require that the BACT analysis for PMEC compare these different technologies. This point was recently reinforced in a December 13, 2005 letter from Stephen Page, Director of EPA's OAQPS, to E3 Consulting, LLC regarding BACT requirements for proposed coal-fired power plant projects. In that letter, EPA clarified that a BACT analysis need not consider an alternative "which would wholly replace the proposed facility with a different type of facility."

The remainder of this BACT analysis describes the various emission control options for specific IGCC facility processes, and demonstrates that the proposed PMEC would achieve the lowest emissions rate technically and economically feasible for such a facility.

B-1.6 EXISTING AND PERMITTED IGCC FACILITIES

For this BACT analysis, the available control options were identified by querying the RBLC database and by consulting available literature on control options for IGCC. Applications and/or permits from a number of other IGCC facilities that have completed the New Source Review process were also reviewed to provide additional reference material for this BACT analysis. A brief summary of the other permitted IGCC plants in the United States and their emissions limits is presented in this section.

Other existing or permitted IGCC facilities include the following examples:

- SG Solutions, Wabash River Generating Station, West Terre Haute, Indiana (operating);
- Tampa Electric Company, Polk Power Station, Mulberry, Florida (operating);
- Global Energy, Inc.'s Kentucky Pioneer Energy LLC, Trapp, Kentucky (permitted/not constructed);
- We Energies, Elm Road Generating Station, Wisconsin (permitted/not constructed);
- Global Energy, Inc.'s Lima Energy Company, Lima, Ohio (permitted/not constructed);
- Steelhead Energy Center, Southern Illinois Clean Energy Center
- ERORA Group, Taylorville Energy Center

The air permits, BACT analyses and additional literature for each of these existing or proposed facilities and several other proposed IGCC plants that have yet to complete permitting were reviewed. Each facility is discussed briefly below and Table B-1-3 summarizes the criteria pollutant emission levels permitted for the combustion turbines units at each facility. The facilities that were subject to BACT determinations are listed as such.

Wabash River Generating Station and PSI Combined Cycle Power Station: The DOE and a Joint Venture formed in 1990 between Destec Energy Inc. and Public Service of Indiana (PSI) initiated the Wabash River Coal Gasification Repowering Project. The gasification island includes an E-Gas (originally developed by Dow Chemical and known earlier as Destec Technology, and now operated by SG Solutions) two-stage, oxygen blown gasifier with full heat recovery that is integrated with the power block. This facility has been operated since 1995.

Tampa Electric Company - Polk Power Station: The DOE partly funded the Polk Power Station IGCC project. The facility includes a Texaco (now GE Energy) oxygen blown gasifier with full heat recovery using both radiant and convective syngas coolers. The GE STAG-107FA power block integrates process syngas, steam, and nitrogen. This IGCC facility has been operating since 1996.

Global Energy - Kentucky Pioneer Power Station: Global Energy USA (Global), owner of Kentucky Pioneer Energy, LLC, negotiated with the DOE and Clean Energy Partners, LP to acquire a conditionally approved IGCC Demonstration Project. The British Gas/Lurgi (BG/L) slagging fixed-bed gasification technology has been proposed in a new 540 MW (net) IGCC facility using both coal and refuse derived fuel as a feedstock. The gasification system would be coupled with Fuel Cell Energy, Inc.'s molten carbonate fuel cell. The air permit for this facility was originally issued in June 2001, and has been extended conditioned on revision of the BACT Analysis; this project is not expected to go forward.

Global Energy - Lima Energy Power Station: Lima Energy Company, a Global Energy company, obtained a final Ohio EPA Permit to Install an IGCC facility in Lima, Ohio. The 540 MW (net) IGCC is expected to use ConocoPhillip's E-Gas entrained flow gasification technology to convert high sulfur coal or petroleum coke into syngas. The air permit was issued in 2002. Construction of the feedstock storage building has begun in order to keep the PSD permit in place while Global decides on whether or not to continue the project.

We Energies - Elm Road Generating Station: We Energies recently proposed a new 600 MW net nominal base-load IGCC generating unit at the Elm Road Generating Station. The facility includes a gasification plant, sulfuric acid plant, two combustion turbine generators and HRSGs, and a steam turbine generator. The permit for this facility was received in January 2004. However, commencement of construction was linked to a determination of need and further acceptance by the Public Utility Commission, which ultimately rejected We Energies' proposal to advance the project.

ERORA Group - Taylorville Energy Center: The ERORA Group is developing the Taylorville Energy Center, a 630 MW (net) IGCC facility to be located in Southern Illinois, and the similar Cash Creek Generation IGCC facility, to be located near Owensboro, Kentucky. They are proposing to use GE Energy gasification technology at both facilities, using local coals

(Kentucky coal for Cash Creek and Illinois coal for Taylorville) as the feedstocks. Both will use Selexol AGR systems, as well as SCR. Neither site is in an ozone non-attainment area, so SCR is not required for BACT purposes. ERORA is using SCR to minimize NO_x emissions from the plant, but not as BACT. This will allow them to minimize the cost to acquire NO_x allowances from the market. ERORA notes that in order to increase the chance that the SCR system will work in this unproven application on coal-derived syngas, higher sulfur removal, by using Selexol instead of MDEA, will be required. Both the Taylorville and Cash Creek applications are under agency review.

Steelhead Energy: Southern Illinois Clean Energy Center This proposed facility will incorporate IGCC with co-production of synthetic natural gas (SNG). The 544 MW (net) facility is proposed to consist of an IGCC plant that will provide syngas to two combustion turbines, with additional syngas being processed in a methanation facility to produce SNG. The primary feedstock for the facility will be Illinois #6 bituminous coal from an adjacent mine. The IGCC facility will consist of two ConocoPhillips gasifiers with syngas cleanup, sulfur or sulfuric acid plant and mercury removal systems. The primary fuel for the combustion turbines will be syngas from the IGCC unit. Natural gas from the SNG unit will be available for startups and as a backup fuel. According to discussions with State of Illinois EPA staff, this project may be re-located to another site, and may only include SNG production, without IGCC power production.

TABLEB-1-3
PERMITTED EMISSION RATES FOR IGCC UNITS

In lbs/MMBtu gasifier fuel energy input (approximate) Location	MMBtu/hr as coal to gasifier or Plant MW (estimated)	CO	NOx	SO_2	PM	VOC
Wabash River (operating)	2,356	0.036	0.087	0.126	0.005	0.001
Polk Power Station (operating)	2,191	0.045	0.101	0.170	0.008	0.001
Kentucky Pioneer	4,413	0.026	0.059	0.026	0.009	0.004
Lima Energy	4,413	0.035	0.067	0.022	0.008	0.007
We Energies	5,424	0.024	0.059	0.023	0.008	0.003
Steelhead Energy Center	544 MW	0.04	0.059	0.033	0.0092	0.0029
Taylorville Energy Center	677 MW	0.036	0.058	0.045	0.007	0.008
PMEC Proposed IGCC	600	0.036	0.012 (3- hr, ICT)	0.016 (3-hr, ICT)	0.0010	0.003

The emission rates listed in Table B-1-3 have been estimated based on permit documents or other published information on the respective facilities and converted to the units of lbs per million Btu of gasifier feedstock, for the purposes of general comparison. The actual permitted levels and/or BACT determination in many cases are expressed in units different than lbs/MMBtu, and may be expressed on the basis of MMBtu input of syngas fuel to the combustion turbines rather than MMBtu to the gasifier (the correct basis). The conclusion to be drawn from this comparative review is that proposed BACT limits for the PMEC are similar to, or more stringent than, those that have been accepted in other recent IGCC permits throughout the United States.

In addition to the units listed in the table above, OUC and Southern Power Company have proposed a nominal 285 Megawatt (net) IGCC Unit (Stanton Unit B) and auxiliary equipment. Unit B will consist of: an air-blown coal gasification system that produces syntesis gas (syngas); one syngas and natural gas-fired General Electric 7FA+e combustion turbine-electrical generator (CT); a duct burner within a supplementary-fired heat recovery steam generator (HRSG); a steam turbine electrical generator (STG); an exhaust stack and a multi-point ground flare. The project was selected by the Department of Energy for funding under Round 2 of the Clean Coal Power Initiative. A Preliminary Determination and draft construction permit for this project were issued by the Florida Department of Environmental Protection Division of Air Resource Management in the summer of 2006.

The IGCC process represents a unique generating technology with promises of increased efficiency, fuel flexibility, low emissions, and opportunities for carbon sequestration. However, it is relevant to note that while there has been significant interest in IGCC facilities, few projects permitted in the past several years have moved substantially forward. The lack of progress toward widespread commercialization of this promising technology is due largely to the fact that the first generation of IGCC plants has incurred significant financial and operational risks. This burden is significant and should be considered in the determination of required emissions controls, particularly if the use of higher levels of controls or unproven methods might add significantly to the costs, reliability or other operational risks of the PMEC.

B-1.7 COMBUSTION TURBINE BACT ANALYSIS

The following BACT analysis evaluates control technologies applicable to each of the criteria pollutants that would be emitted from the combustion turbines of the proposed PMEC to determine appropriate BACT emission limits. This BACT analysis is based on the current state of IGCC technology, energy and environmental factors, current expected economics, energy, and technical feasibility.

B-1.7.1 NITROGEN OXIDES BACT ANALYSIS

The criteria pollutant nitrogen oxides (NO_x) is primarily formed in combustion processes in two ways: 1) the reaction of elemental nitrogen and oxygen in the combustion air within the high temperature environment of the combustor (thermal NO_x), and 2) the oxidation of nitrogen contained in the fuel (fuel NO_x). Syngas contains negligible amounts of fuel-bound nitrogen, although some molecular nitrogen is present. Therefore, it is expected that essentially all NO_x emissions from the PMEC combustion turbines will originate as thermal NO_x.

As noted in Section B-1.4 of this Appendix, an IGCC combustion turbine is an inherently low-emitting process. The proposed PMEC combustion turbines can nominally achieve 0.06 lb/MMBtu using diluent injection (i.e., without SCR). The remainder of this analysis considers the use of this lower-emitting IGCC process in conjunction with add-on controls that eliminate emissions after they are produced by fuel combustion in the turbines.

The rate of formation of thermal NO_x in a combustion turbine is a function of residence time, oxygen radicals, and peak flame temperature. Front-end NO_x control techniques are aimed at controlling one or more of these variables during combustion. Examples include diluent

injection (steam, water, or nitrogen) and dry low-NO_x burners. These technologies are considered to be commercially available pollution prevention techniques. It is necessary to recognize the fundamental differences between natural-gas fired and syngas-fired combustion turbines in evaluating these techniques. Compared to natural gas, syngas has a much higher hydrogen content (natural gas is often over 90% methane), and a much lower heating value (about 250 Btu/scf for syngas vs. 1,000 Btu/scf for natural gas). Also, the pretreatment of the syngas includes a moisturization step which increases the content of water vapor in the gas. Taken together, these differences alter the combustion kinetics of the burner flame in a manner that prevents the use of lean-premix combustion techniques, which are the defining feature of effective Low-NO_x burner design [2].

B-1.7.1.1 Identify Control Technologies

Possible control technologies for the proposed turbines were identified by examination of previous IGCC permits and through RBLC queries for natural gas-fired combined cycle (NGCC) combustion turbines. All previous BACT and LAER determinations for IGCC facilities have resulted in the finding that diluent injection represents the best available control for NO_x. However, for this top-down analysis, all of the following technologies were considered to be potentially available for the PMEC combustion turbines:

<u>Combustion Process Controls</u>

- Dry Low NO_x burners
- Diluent injection (nitrogen or steam)

<u>Post-Combustion Controls</u>

- $SCONO_x$™
- SCR
- Selective non-catalytic reduction (SNCR)

B-1.7.1.2 Evaluate Technical Feasibility

Each identified technology is first examined to determine if it is technically feasible for IGCC combustion turbines burning coal-derived syngas. First, controls potentially achieved by modifications to the combustion process itself are considered. Next, potential control methods utilizing add-on control equipment, such as SCR, to remove NO_x from the exhaust gas stream after its formation during combustion are examined.

Dry Low NO_x Burners

Dry Low-NO_x (DLN) burners control NO_x formation in conventional Natural Gas Combined Cycle (NGCC) combustion turbines by staged combustion of the natural gas. This is done by

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[2] "Major Environmental Aspects of Gasification-Based Power Generation Technologies", U.S. DOE, Office of Fossil Energy, National Energy Technology Laboratory, December 2002.

designing the burners to control both the stoichiometry and temperature of combustion by tuning the fuel and air locally within each individual burner's flame envelope. Burner design includes features that regulate the aerodynamic distribution and mixing of the fuel and air. A lean, pre-mixed burner design mixes the fuel and air prior to combustion. This results in a homogeneous air/fuel mixture, which minimizes localized fuel-rich pockets that produce elevated combustion temperatures and higher NO_x emissions. A lean fuel-to-air ratio approaching the lean flammability limit is maintained, and the excess air serves as a heat sink to lower the combustion temperature, which in turn lowers thermal NO_x formation. A pilot flame is used to maintain combustion stability in this fuel-lean environment.

Syngas differs from natural gas in heating value, gas composition, and flammability characteristics. Existing DLN burner technologies available for combustion turbines were designed for natural gas (methane-based) fuels and will not operate on the syngas (H_2/CO-based) fuels utilized by IGCC combustion turbines. DLN combustors are not technically feasible for this application due to the potential for explosive mixtures in the combustion section due primarily to the high hydrogen content of the syngas. No manufacturer currently makes DLN burners that can be used for a combustion turbine burning petroleum coke or coal-derived syngas. Combustion turbine vendors are currently researching DLN for syngas-fueled combustion turbines, but such combustors are not yet commercially available. Therefore, DLN burners are not a technically feasible control option for this unit.

Diluent Injection

The addition of an inert diluent such as atomized water or nitrogen into the syngas before combustion, and/or steam or nitrogen injection into the high temperature region of a combustor flame serves to inhibit NO_x formation by reducing the peak flame temperature. For the PMEC, the syngas will be diluted with nitrogen and moisturized to condition it for use in the combustion turbine. This effectively lowers the fuel heat content and, consequently, the combustion temperature, and therefore reduces NO_x emissions. Another level of this control option is steam injection directly into the combustion zone to cool temperatures and reduce NO formation. Diluent injection can achieve emission levels of 15 ppmvd NO_x (at 15 % oxygen) when firing 100% syngas. A secondary benefit of diluent injection is that it will increase the mass flow of the exhaust and, thus, the power output per unit of fuel input also increases. It is important to note that the best performance achievable for combustion turbines that are optimized for syngas is 25 ppm NOx when they are firing natural gas.

Diluent injection represents an inherently lower-emitting process for IGCC units, and is a technically feasible control technology. Diluent injection (water vapor and nitrogen) during the conditioning of the syngas is proposed as the BACT limit basis for the PMEC combustion turbines. This option will achieve NO_x levels of 15 ppmvd (at 15% O_2) over a 3-hour average (excluding start up, shutdown and upset periods), and is proposed as the baseline case for the IGCC combustion turbine NO_x BACT analysis. This NO_x control technology and emission level have also been determined as BACT for all other recent IGCC permits.

SCR

SCR is a technology that achieves post-combustion reduction of NO_x from flue gas within a catalytic reactor. The SCR process involves the injection of ammonia (NH_3) into the exhaust gas stream upstream of a specialized catalyst module, promoting conversion of NO_x to molecular nitrogen. The hardware of an SCR system is composed of an ammonia storage tank, an injection grid (system of nozzles that spray NH_3 into the exhaust gas ductwork), the structured, fixed-bed catalyst module, and electronic controls. This is an increasingly common control technology for use on NGCC combustion turbines. However, the design conditions and performance concerns are different for each technology, and a single SCR design is not generally transferable from one generating technology to another.

In the SCR process, NH_3, usually diluted with air or steam, is injected through a grid system into the exhaust gas upstream of the catalyst bed. On the catalyst surface, the NH_3 reacts with NO_x to form molecular nitrogen and water. The basic reactions are:

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

A fixed-bed catalytic reactor is typically used for SCR systems. The function of the catalyst is to lower the activation energy required for NO_x decomposition to occur. In natural gas turbine, NO_x removal of 90 percent or higher is theoretically achievable at optimum conditions. Key SCR performance issues focus on flue gas characteristics (temperature and composition), catalyst design, and ammonia distribution. Certain compounds such as sulfur and certain metals, if present in the exhaust gas stream, can "poison" the catalyst, reducing its performance and useful life, impact catalyst activity, or inhibit conversion efficiency.

The typical effective temperature range for base-metal SCR catalysts is 600 to 800˚F. If the exhaust gas temperature drops below 600˚F, the reaction efficiency becomes too low and increased amounts of NO_x and NH_3 will be released out the stack to the atmosphere. The exhaust temperature after the heat recovery steam generator (HRSG) in a combined cycle unit will be only about 250˚F. Since this temperature is too low for the SCR reactions to occur, SCR catalyst would need to be located upstream of the HRSG where the exhaust gas temperature conditions are favorable.

The most significant SCR feasibility issue for this project is the fact that the syngas contains reduced sulfur compounds, even after the high-efficiency sulfur recovery proposed for the PMEC plant. These drawbacks are reduced, but not eliminated, by the utilization of Selexol® technology for additional sulfur removal to the extent practical. After combustion, some of the oxidized sulfur will form ammonium-sulfur salts in the presence of the ammonia reagent that can impact the SCR catalyst and equipment downstream.

This path of fuel sulfur through the process starts with oxidation of syngas sulfur during combustion, primarily to SO_2 and also a small fraction to SO_3. If SCR were installed, the vanadium in the SCR catalyst would oxidize additional amounts of the SO_2 in the flue gas to SO_3. Adsorption of these sulfur oxides can deactivate the catalyst reaction sites, tending to shorten the effective catalyst service life. In addition, some of the NH_3 reagent injected upstream

of the catalyst will react with the available vapor phase SO_3 to form ammonium sulfate and ammonium bisulfate salts. These salts will largely remain in the vapor phase at the elevated temperature of the SCR system. However, as the exhaust gas cools in the HRSG and further downstream, the gas will drop below the sublimation temperature of these compounds and they will begin to precipitate out, forming corrosive, sticky particles. Accumulation of these salts can cause serious corrosion and plugging/fouling problems in a conventional HRSG, as well as a loss of heat transfer efficiency, even at the relatively low levels of sulfur present in the syngas.

As deposits of ammonium salts increase, they would need to be cleaned periodically from the surface of the HRSG heat transfer fins in order to restore heat transfer efficiency and pressure within the HRSG. The PMEC is incorporating specific design features in the HRSG to facilitate such cleaning, as necessary, downstream of the SCR module. Absent costly design features, adequate cleaning of the heat transfer fins is difficult in a conventional HRSG because of the following:

- Access to interior tube banks is restricted in a compact HRSG module;
- Excessive capital cost and potential for leakage would be encountered if the HRSG heat exchange elements were designed for removal/replacement; and
- The HRSG is in close proximity to upstream catalyst modules; power washing of the HRSG would increase the possibility of inadvertently flooding the fixed-bed catalyst, which would damage it.

The other main feasibility issue with SCR on IGCC units is the potential presence of trace metals and other trace compounds in syngas, which are known to deactivate the sensitive SCR catalyst. For example, arsenic is known to deactivate certain types of catalyst, and the deactivation rate can vary in the presence of other compounds, such as calcium. Research is ongoing to understand how individual and various combinations of flue gas constituents may impact catalyst deactivation rates and performance. Because no full-scale IGCC unit has been tested or operated with SCR in a coal-derived syngas environment, many unknowns remain regarding the potential impacts of trace constituents such as arsenic, nickel, lead, and cadmium. Consequently it is difficult to predict SCR system performance, control efficiency, or catalyst life for this unique application. These uncertainties reinforce the need for SCR to be considered an ICT, as described previously.

There is a growing experience base of SCR use on conventional PC units that seem to suggest that SCR should work in the seemingly less extreme exhaust conditions of an IGCC combustion turbine. However, many key process parameters are different in an IGCC versus a PC unit, and these differences may significantly impact SCR's feasibility, cost, design, and performance in this unique service environment. Key differences for an IGCC compared to a PC plant SCR system application include the following:

- SCR performance expectation in conventional PC unit service is significantly lower (i.e., higher outlet NO_x) than would be needed in this case. PC-based SCR systems typically achieve about 0.07-0.10 lb NO_x/MMBtu with SCR, which is greater than the PMEC proposed level (nominally 0.06 lb/MMBtu for a 3-hour average) without any add-on controls.

- Ammonium bisulfate salts may form in a PC unit air preheater, which is of a very different design from a HRSG. Air preheaters can be designed to accommodate more frequent cleaning, and are thus better-suited to handling precipitation/deposits/corrosion. Air preheater heat transfer baskets are not impacted as much by corrosion as the heat transfer fins in a HRSG.
- Ammonia preferentially adsorbs onto the fly ash produced from a PC unit, so that sulfates and bisulfate can be captured in downstream particulate matter control equipment.

Recent papers by EPA[3] and DOE[4] recognize the challenges associated with the application of SCR to IGCC. These concerns are well-known and validated in the technical literature, and raise legitimate questions regarding the practicality of SCR for this (or any other) IGCC project. However, Energy Northwest proposes to adopt this aggressive control technique along with additional syngas sulfur cleaning as an ICT. This option must be viewed as an enhanced level of emission control that is more stringent than BACT. As explained at the end of Section B-1.2 of this Appendix, EPA does not consider a technology "available" until it has reached commercial availability for the intended service. While SCR is clearly an "available" technology that is commercially demonstrated for many applications, SCR is only at the "concept stage" for IGCC. EPA's New Source Review Workshop Manual[5] specifically states that "Technologies which have not been applied to (or permitted for) full scale operations need not be considered available; an applicant should be able to purchase or construct a process or control device that has already been demonstrated in practice."

The question of SCR feasibility in IGCC service has been addressed recently by several other proposed projects and their state and regional environmental agencies. Polk Power Station in Florida, Kentucky Pioneer LLC in Kentucky, Lima Energy LLC in Ohio, and We Energies in Wisconsin have all finalized or updated BACT determinations for their IGCC projects. The state environmental agencies in Florida, Kentucky, Ohio, and Wisconsin, along with US EPA Regions IV and V, have determined BACT for those IGCC projects to be 15 ppm NO_x @15% O_2 using diluent injection (when firing syngas). In each case, SCR was rejected as BACT. This finding is consistent with recent previous BACT determinations for IGCC units using solid feedstocks such as petroleum coke and/or coal.

In summary, SCR has never been employed at an IGCC facility using a solid feedstock such as coal or petroleum coke. No previous BACT determination has found SCR to be technically feasible and economically feasible on an IGCC. On this basis, PMEC is requesting that the adoption of SCR in conjunction with an enhanced level of Selexol® or equivalent-based syngas sulfur removal, be treated as an ICT for purposes of incorporating permit conditions that allow a sufficient incremental timeframe for technology demonstration and final determination of NO_x

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[3] "Environmental Impact Comparisons IGCC vs. PC Plants", Kahn, Wayland, and Schmidt of US EPA, presented at Pittsburgh Coal Conference, September 2005.

[4] "Major Environmental Aspects of Gasification-Based Power Generation Technologies", U.S. DOE/NETL, December 2002

[5] Pg. B-12, "New Source Review Workshop Manual" Draft 1990, EPA Office of Air Quality Planning and Standards.

emissions. Generally accepted BACT for IGCC combustion turbines is diluent injection, and this should be identified as the basis for BACT emission limits in the PMEC permit as well.

SCONOx

The $SCONO_x$™ system is an add-on control device that reduces emissions of multiple pollutants. $SCONO_x$™ control technology is provided by Emerachem, LLC (formerly Goal Line Environmental Technologies). $SCONO_x$™ utilizes a single catalyst for the reduction of CO, VOC and NO_x, which are converted to CO_2, H_2O and N_2. The system does not use NH_3 and operates most effectively at temperatures ranging from 300°F to 700°F. Operation of $SCONO_x$™ requires natural gas, water, steam, electricity and ambient air, and no special reagent chemicals or processes are necessary. Steam is used periodically to regenerate the catalyst bed and is an integral part of the process.

There are currently several $SCONO_x$™ units in commercial installations worldwide, although all are on much smaller facilities than the proposed PMEC. The original installation is at the Federal Plant in Vernon, California owned by Sunlaw Cogeneration. This installation is on a GE LM2500, an approximately 25 MW combined cycle system, which has had an operating $SCONO_x$™ system since December 1996. That system has undergone many changes over the years. The second commissioning of a $SCONO_x$™ system was at the Genetics Institute in Massachusetts on a 5 MW Solar Turbine Taurus 50 Model. This facility has reported problems with meeting permitted NO_x levels of 2.5 ppm, and subsequently received a permit modification extending the $SCONO_x$™ demonstration period. Three other units were installed in recent years, two on 13 MW Solar Titan CTs at the University of California, San Diego, and one on an 8 MW Allison combustion turbine at Los Angeles International airport.

There is no current working experience of $SCONO_x$™ on large combustion turbine units such as those proposed for the PMEC. Similarly, there are no applications of this technology with the fuel sulfur levels associated with IGCC combustion turbines. $SCONO_x$™ was considered at some larger applications including a 250 MW unit at the La Paloma plant near Bakersfield, and a 510 MW plant in Otay Mesa. However, the La Paloma and Otay Mesa projects were given the alternative to install SCR and now plan to do so. In evaluating technical feasibility for large IGCC power stations, the additional concerns are:

- $SCONO_x$™ uses a series of dampers to re-route air streams to regenerate the catalyst. The proposed PMEC is significantly larger than the much smaller facilities where $SCONO_x$ has been used. This would require a significant redesign of the damper system, which raises feasibility concerns regarding reliable mechanical operation of the larger and more numerous dampers that would be required for application to the PMEC combustion turbines.
- The catalyst is very susceptible to poisoning by sulfur compounds. Because of the sulfur content of the syngas, a separate catalyst to absorb SO_2 would be required. The vendor offers a $SCOSO_x$™ catalyst; however, its operation is not proven, and upon regeneration this process would create an H_2S stream that would require treatment.

- SCONOx™ would not be expected to achieve lower guaranteed NO_x levels than SCR, and, for reasons described above, it has even greater feasibility concerns with respect to application on IGCC turbines than those for SCR

For the above reasons, SCONOx™ is considered technically infeasible for application to the PMEC combustion turbines.

SNCR

Selective Non-Catalytic Reduction (SNCR) is a post-combustion NO_x control technology in which a reagent (NH_3 or urea) is injected into the exhaust gases to react chemically with NO_x, forming elemental nitrogen and water without the use of a catalyst. The success of this process in reducing NO_x emissions is highly dependent on the ability to achieve uniform mixing of the reagent into the flue gas. This must occur within a zone of the exhaust stream where the flue gas temperature is within a narrow range, typically from 1,700°F to 2,000°F. In order to achieve the necessary mixing and reaction, the residence time of the flue gas within this temperature window should be at least 0.5 to 1.0 second. The consequences of operating outside the optimum temperature range are severe. Above the upper end of the temperature range, the reagent will be converted to NO_x. Below the lower end of the temperature range, the reagent will not react with the NO_x and the NH_3 slip concentrations (NH_3 discharge from the stack) will be very high.

This technology is occasionally used in conventional fired heaters or boilers upstream of any HRSG or heat recovery unit. SNCR has never been applied in IGCC service, primarily because there are no flue gas locations within the combustion turbine or upstream of the HRSG with the requisite temperature and residence time characteristics to facilitate the SNCR flue gas reactions. Because of the incompatibility of the exhaust temperature with the SNCR operating regime, this technology is considered to be technically infeasible.

B-1.7.1.3 Rank Control Technologies

Among the control technologies considered in the previous subsection, only one was determined to be both technically feasible and commercially demonstrated at a cost level acceptable as a BACT option. Specifically, the feasible option is diluent injection upstream of the combustion zone to achieve a controlled level of 15 ppmvd NO_x at 15% O_2 while firing syngas, and 25 ppmvd NO_x at 15% O_2 while firing natural gas. Table B-1-4 shows the typical NO_x control levels for the different options, in comparison with the NSPS Subpart Da limit of approximately 100 ppmv for stationary gas turbines burning syngas that are considered the BACT "floor" for this source category. In addition, a comparison with the proposed installation of SCR as an ICT is included in Table B-1-4.

During periods of firing natural gas as the start-up or back-up fuel, the combustion turbine will achieve 25 ppmvd NO_x, without the benefit of proposed ICT add-on control. This is due to the higher heating value and difference in diffusion flame speed for natural gas versus syngas. The applicant proposes to use natural gas for less than 50 hours/year for turbine startups plus up to 440 hours per year of full-load operation during transition to syngas firing. The annual emissions estimates for the combustion turbine assume this higher NO_x emissions rate for 490 hours per year (total of start up periods and full-load natural gas firing).

TABLE B-1-4
RANKING OF NO_X BACT EMISSION LIMIT OPTIONS FOR COMBUSTION TURBINES

Control Technology Option	Emissions per IGCC CT without Option1 (Tons/yr)	Emissions Reduction per IGCC CT1 (Tons/yr)	Emission Performance	Emissions per IGCC CT1 (Tons/yr)
Selective Catalytic Reduction (SCR) – ICT	725	580	3 ppmv @ 15% O2, 3-hour average (Syngas) 5 ppmv @ 15% O2, 3-hour average (Nat Gas)	145
Diluent (Nitrogen/Moisture) Injection – Proposed BACT	~ 1,520	795	15 ppmv @ 15% O2, 3-hour average (Syngas) 25 ppmv @ 15% O2, 3-hour average (Nat Gas)	725
NSPS BACT [2,]	Baseline Option	N/A	100 ppm @ 15% O_2 (Syngas)[3]	~4,800 tons

Notes:
1. Annual emissions are based on one combustion turbine firing ~490 hours per year on natural gas, and the balance on syngas at full load. (PMEC includes 2 combustion turbines)
2. Most stringent potentially applicable emission limit for the IGCC combustion turbines, from NSPS Subparts Da Syngas units without duct burners

B-1.7.1.4 Evaluate Control Options

The next step in a BACT analysis is to conduct an analysis of the energy, environmental and economic impacts associated with each feasible control technology. Based on the evaluation in the previous step, the only technically feasible and commercially proven technology suitable for establishment of BACT limits is diluent injection. The most notable environmental impact associated with this NO_x control technology is water usage. Depending on the diluent selected, this option could entail additional water usage. Approximately 25,000 gallons per hour would be used in the moisturization process for NO_x control and power augmentation. Moisturization of the syngas is expected to comprise of approximately 8-9% of total PMEC make-up water usage. The emission rate shown for this option in Table B-1-4 is based on the PMEC combustion turbines operating with nitrogen and water vapor injection into the syngas stream. Since SCR with enhanced syngas desulfurization is proposed as an ICT measure, this evaluation also addresses the energy and environmental effects of SCR.

The principal environmental consideration with respect to implementation of SCR is that, while it will reduce NO_x emissions, it will add NH_3 emissions associated with use of ammonia (NH_3) as the reagent chemical. A portion of the unreacted NH_3 passes through the catalyst and is emitted from the stack. This is called ammonia slip and the magnitude of these emissions depends on the catalyst activity and the degree of NO_x control desired. While reduction in NO_x emissions offers benefits with respect to NO_2 PSD increment consumption and conformance with the NO_2 ambient air quality standard, ammonia is listed as a Class B toxic air pollutant in Ecology regulations (WAC 173-460-160). Also, ammonia emissions contribute to the generation of aerosol species that are regional haze precursors.

As described in Section B-1.7.1.2, there are potential technical barriers to cost-effective implementation of SCR. Injection of ammonia results in formation of ammonium sulfate salts that deposit on the SCR catalyst module, and on duct and heat transfer surfaces downstream of the SCR module. Accumulation of these precipitated ammonium sulfate salts can cause corrosion and plugging/fouling problems in a conventional HRSG, as well as a loss of heat transfer, even at the relatively low levels of sulfur present in the PMEC syngas (see the discussion on the nature of these problems in Section B-1.7.1.2).

The accumulation of a layer of ammonium salts on the heat transfer fins located inside the HRSG gradually decreases the heat transfer efficiency as they become increasingly fouled with deposits. Power output from the combustion turbine can also be significantly affected due to an increase in pressure drop within the HRSG resulting from the partial blockage of gas flow by these deposits. This pressure rise can also impact HRSG casing design requirements. In addition, ammonium bisulfate is corrosive and corrodes the heat transfer fins or tubes, potentially impacting the reliability of the HRSG.

B-1.7.1.5 Select Control Technologies

The final step in the top-down BACT analysis process is to select BACT based on the results of the previous steps. As has been explained, for this application of syngas-fired combustion turbines within an IGCC facility, diluent injection in the combustion turbine is the appropriate control technique for setting BACT-based emission limits. The proposed BACT limits based on this technology are 15 ppmvd NOx at 15% O_2 for syngas firing, and 25 ppmvd NOx at 15% O_2 for natural gas firing.

The BACT selection of diluent injection to the NO_x levels described above is strongly supported by recent precedents for similar IGCC projects. Diluent injection was designated as LAER for an IGCC combustion turbine project in Delaware (Motiva/Star Enterprises), as BACT for three new IGCC projects in Wisconsin (We Energies), Kentucky and Ohio (Global Energy) and as BACT in a BACT re-evaluation of an existing IGCC facility in Florida (Tampa Electric).

Implementation of add-on controls such as SCR and SCONOx™ is subject to significant technical feasibility issues with regard to their application to IGCC units, and are not commercially demonstrated for such an application. The PMEC facility has proposed installation of SCR as an ICT, and will accept alternate NO_x emission limits based on this technology target of 3 ppmv NO_x at 15% O_2 for syngas firing, and 5 ppmv NO_x at 15% O_2 for natural gas firing. The demonstration period for these alternate ICT limits should be tied to a schedule for achieving specific emission rate performance and reliability milestones, starting from the initial date of SCR system operation (first day exhaust is treated). If there is evidence after a sufficient test period that the use of Selexol® or equivalent and SCR will not be capable of reliably achieving the ICT limits described above, then some relaxation of these limits will be warranted. Energy Northwest will work closely with EFSEC to establish the ICT timetable and interim target emission rates.

B-1.7.2 SULFUR DIOXIDE AND SULFURIC ACID MIST BACT ANALYSIS

B-1.7.2.1 Identify Control Technologies

Sulfur dioxide emissions from any combustion process are largely defined by the sulfur content of the fuel being combusted and the rate of the fuel usage. The combustion of syngas in the combustion turbines creates primarily SO_2 and small amounts of sulfite (SO_3) by the oxidation of the fuel sulfur. The SO_3 can react with the moisture in the exhaust to form sulfuric acid mist, or H_2SO_4. Emissions of these sulfur species can be controlled, either by limiting the sulfur content of the fuel (pre-combustion control) or by scrubbing the SO_2 from the exhaust gas (post-combustion control). Potentially available control technologies include:

<u>Pre-Combustion Process Controls</u>

- Chemical Absorption Acid Gas Removal (AGR), e.g., MDEA
- Physical Absorption, e.g., Selexol®, Rectisol®

<u>Post-Combustion Controls</u>

- Flue Gas Desulfurization (FGD)

Acid Gas Removal (AGR)

In the gasification process sulfur in the petroleum coke or coal feedstock converts primarily to hydrogen sulfide (H_2S) and, to a lesser extent, to other sulfur species such as carbonyl sulfide (COS). A COS hydrolysis unit is provided in IGCC plants to achieve a higher level of sulfur removal. In the hydrolysis unit, the COS is converted to H_2S, which is more efficiently removed in an AGR system. Solvent-based acid gas cleanup is commonly used for "gas sweetening" processes in refinery fuel gas or tail gas treatment units, where H_2S in the process gas is removed before use as a fuel or release to the atmosphere. The removed H_2S is recovered either as elemental sulfur in a Sulfur Recovery Unit (e.g., using a Claus process) or converted to H_2SO_4 in a sulfuric acid plant.

Chemical absorption occurs in amine-based systems that use solvents such as methyldiethanolamine (MDEA). Amine solvents chemically bond with the H_2S. The H_2S can be easily liberated with low-level heat in a stripper to regenerate the solvent. This is the technology that has been used in all existing and recently-permitted IGCC facilities, and is considered the baseline BACT level of control for this application.

The operating IGCC facilities at Polk Power Station and Wabash River (SG Solutions) both use amine systems to treat the syngas to total sulfur levels of 100 to 400 ppm. A few IGCC permits were issued between 2001 and 2004 with amine systems designed to treat syngas down to 40 ppm sulfur – however, none of these projects has yet been constructed. While some recent IGCC permit applications (permits pending) have proposed as BACT MDEA systems scrubbing to syngas sulfur levels of 50-75 ppm levels, others (including PMEC) have proposed more aggressive controls such as Selexol®.

Similar or lower levels of sulfur removal are possible using physical absorption AGR systems. The AGR system proposed for the PMEC is an enhanced level of physical absorption employing the Selexol® or equivalent technology that uses mixtures of dimethyl ethers of polyethylene glycol. This process, which will achieve a long-term average of 10 ppmv reduced sulfur in the syngas, is an integral part of the ICT options proposed for inclusion in the PMEC permit. As described in the previous turbine NO_x BACT section, low sulfur levels in the syngas fuel are essential to the viability of SCR for control of reduced turbine NO_x emissions.

Another comparable AGR technology, Rectisol®, utilizes refrigerated methanol as the physical solvent. In these types of AGR processes the H_2S is dissolved under pressure into the solvent. Dissolved acid gases are removed by depressurization to regenerate the solvent for reuse. Physical absorption methods have been used for many years to purify gas streams in the chemical processing and natural gas industries. For example, Selexol® was used with high-sulfur coals in the Cool Water IGCC Project, which was a demonstration facility operated from 1984 – 1988.

The various physical and chemical absorption systems for acid gas removal can be operated at varying levels of efficiency, with capital and operating costs increasing for increasing sulfur removal. In general, the Selexol® and Rectisol® systems can achieve lower sulfur levels than conventional MDEA absorption, or other amine-based chemical absorption systems. There are also operating conditions where the removal efficiencies overlap. For example, MDEA systems are generally the most cost-effective for lower levels of sulfur removal, but the costs increase significantly if deeper sulfur removal is required. In contrast, a Selexol® system would have higher initial capital costs, but would be able to achieve deeper removal levels at a lower incremental cost.

Flue Gas Desulfurization

Typical FGD processes operate by contacting the exhaust gas downstream of the combustion zone with an alkaline slurry or solution that absorbs and subsequently reacts with the acidic SO_2. FGD technologies may be wet, semi-dry, or dry based on the state of the reagent as it is injected or pumped into the absorber vessel. Also, the reagent may be regenerable (where it is treated and reused) or non-regenerable (all waste streams are de-watered and either discarded or sold). Wet, calcium-based processes, which use lime (CaO) or limestone ($CaCO_3$) as the alkaline reagent, are the most common FGD systems in PC unit applications. After the exhaust gas has been scrubbed, it is passed through a mist eliminator and exhausted to the atmosphere through a stack

FGD systems are commonly employed in conventional PC plants, where the concentration of oxidized sulfur species in the exhaust is relatively high. If properly designed and operated, FGD technology can reliably achieve more than 95% sulfur removal.

B-1.7.2.2 Evaluate Technical Feasibility

Both chemical and physical absorption methods for AGR are considered feasible for an IGCC, and can achieve control of the sulfur in syngas up to 99% or better. Both of these systems are further considered in this analysis.

FGD cannot provide as high a level of control as the pre-combustion AGR systems. In addition, FGD has the environmental drawbacks of substantial water usage and the need to dispose of a solid byproduct (the scrubber sludge). Given these disadvantages, even though FGD is not technically infeasible, it is not considered to be a reasonable technical option for IGCC. The sulfur would be removed more efficiently and economically from syngas prior to combustion in the combustion turbines; therefore FGD will not be considered further in this BACT analysis.

B-1.7.2.3 Rank Control Technologies

The technically feasible technologies for controlling syngas sulfur levels, and thus turbine SO_x emissions, are summarized in Table B-1-5 in descending order of control efficiency. Emissions in pounds per million Btu of coal feedstock and annual emissions for two combustion turbines are also shown along with uncontrolled and NSPS emissions limits for comparison.

TABLE B-1-5
RANKING OF SO_2 BACT EMISSION LIMIT OPTIONS

Control Technology Option	Sulfur in Syngas (ppm)	Control Efficiency	SO2 Emission Limit (lb/MMBtu input as coal) 2	Annual SO2 Emissions – Per Turbine (tons/yr) 3	Emissions Reduction (tons/yr)
AGR to 1 ppm (requires Rectisol)	1	99.99%	0.0005	6.5	318.5
AGR to 10 ppm (using Selexol®)	10	99.90 %	0.0050	65	260
AGR to 50 ppm[1] BACT Baseline Control Option	50	99.50%	0.0251	325	325
AGR to 100 ppm[1]	100	99.25%	0.05	650	-

1 -- Treatment of syngas to 50-100 ppm sulfur levels could be achieved with either an MDEA or Selexol® AGR system.
2 – Each emission limit must be combined with an averaging time that is suitable for the technology, and the reasonable expectations of process variability. For AGR, the presumed rolling average time is 30 days.
3 – Annual emissions for purposes of this BACT comparison does not include gasifier or turbine startup emissions.

B-1.7.2.4 Evaluate Technical Feasibility

Depending on the feedstock used, the syngas initially produced could contain more than 10,000 ppm sulfur for the worst-case feedstock, primarily in the form of H_2S. In an IGCC process, chemical absorption processes such as AGR with MDEA have been used for existing and permitted IGCC facilities. The normal level of removal for this type of technology is therefore considered the baseline level of control for purposes of this BACT assessment.

The most effective SO_2 control system that is considered to be technically feasible is the physical absorption AGR system using Rectisol to 1 ppm sulfur in syngas, as shown in the table above. The next levels of control can be achieved with either a Selexol®/equivalent or an MDEA system. Table B-1-6 shows incremental emissions reduction that can be achieved and the associated costs for a range of sulfur removal efficiencies compared to the IGCC baseline syngas sulfur level of 50 ppm.

B-17.2.5 Environmental and Economic Impacts

Table B-1-6 shows the average and incremental costs for varying levels of sulfur removal at the proposed PMEC. For this analysis, removal to 50 ppm was chosen as the base, or minimum BACT level of control for IGCC syngas. Significant sulfur removal (versus "uncontrolled" levels) is required at an IGCC facility. It would not be feasible to combust uncontrolled "raw" syngas in the combustion turbines.

TABLE B-1-6
ANNUALIZED COST EVALUATION FOR CANDIDATE BACT SO_2 CONTROL TECHNOLOGIES

Control Technology	Capital Investment (10^6 \$)	Annual Operating Costs (10^6 \$/yr)	Total Annualized Costs (10^6 \$/yr)	Baseline Emissions or Reduction (tons/yr)[1]	Cost Effectiveness (\$/ton)
AGR to 1 ppm (Rectisol)	39.961	4.106	8.494	319	\$26,662
AGR to 10 ppm (Selexol®)	20.980	2.891	5.195	260	\$19,975
AGR to 50 ppm[1] **BACT Baseline Control Option**	-	-	-	**325**	-

1 - Treatment of syngas to 50-100 ppm sulfur levels could be achieved with either an MDEA or Selexol® AGR system. Tons of SO_2 reduced are based on comparison with MDEA system at 50 ppm level.
2 – Each emission limit must be combined with an averaging time that is suitable for the technology, and the reasonable expectations of process variability. For AGR, the presumed rolling average time is 30 days.
3 – Annual emissions for purposes of this BACT comparison does not include gasifier or turbine startup emissions.
Note: *Basis for these cost estimates is provided in Attachment B-1-2.*

Although all the AGR systems require chemical handling and will generate a sour water stream, there are no unique collateral environmental issues that would preclude any of the systems from consideration as BACT. Both physical and chemical absorption-based AGR systems involve chemical processing systems that use solvents to remove H_2S from the syngas. The solvent in each system can be regenerated and reused. Acid gases removed from the syngas in each type of process will be processed to generate elemental sulfur in a separate sulfur recovery system. Each acid gas removal system will generate a sour water stream that must be processed prior to discharge. The potential for fugitive emissions of reduced sulfur compounds from these processes increases as the processes become more complex. Consequently, the capital costs of the AGR systems must assume that fittings and valves are specified to meet low-emission criteria.

B-1.7.2.6 Select Control Technology

The applicant proposes that BACT for control of SO_2 combustion turbine emissions from the IGCC facility (and concurrently for acid mist emissions) be defined as treatment of the syngas by acid gas removal to achieve a syngas sulfur concentration of 50 ppm.

However, the applicant intends to install the Selexol® or equivalent physical absorption system, which will remove more than 99% of the sulfur contained in the syngas used to fuel the combustion turbines and/or achieve a long-term average syngas reduced sulfur species content equal to or less than 10 ppmvd. Syngas at this reduced level of sulfur will result in annual average turbine SO_2 emissions of 0.0053 lb/MMBtu, based on gasifier heat input. Typical BACT determinations for prior IGCC projects utilizing physical absorption processes have operated with approximately 50 ppmv of sulfur remaining in the undiluted, unsaturated syngas (i.e., upstream of final conditioning). The enhanced level of sulfur treatment proposed by PMEC is a necessary prerequisite for effective SCR operation, and is therefore an integral component of the ICT proposed for the combustion turbines.

Use of Selexol® or equivalent to a 10 ppm sulfur level compared to chemical absorption at a 50 ppm level has an incremental cost effectiveness of almost $20,000 per ton of avoided SO_x emissions. Treatment to an even lower level of sulfur, while technically feasible, would be prohibitively more expensive. Achieving a level of 1 ppm sulfur in the syngas fuel using Rectisol® is estimated to require approximately $19 million additional capital investment for the AGR system and $1.2 million dollars per year of additional operating costs. Based on the total emission reduction from the MDEA baseline option, the cost-effectiveness to achieve this most-stringent level of emission equates to approximately $26,660 per ton of SO_2 controlled. Consequently, the annualized cost for an additional reduction of 58 tons per year is economically prohibitive. Therefore, PMEC proposes to implement a Selexol® system or equivalent to remove sulfur (H_2S + COS) down to 10 ppmvd (30-day rolling average) in the undiluted, unsaturated syngas prior to combustion in the combustion turbines.

The proposed turbine SO_2 emission rate of 0.0053 lb/MMBtu (as coal input to the gasifiers) compares very favorably with the new NSPS for Electric Utility Steam Generators (including IGCC) in 40 CFR 60 Subpart Da, which sets a standard of 2.0 lb/MWh, or approximately 0.2 lb/MMBtu. The desulfurization of the combusted fuel that is achieved with IGCC, and the resultant reduction in SO_2 emissions is one of the major environmental advantages of IGCC technology compared with other coal-based power generation systems.

B-1.7.3 VOLATILE ORGANIC COMPOUND BACT ANALYSIS

VOCs are a product of incomplete combustion of the organic syngas fuel. Reduction of VOC emissions is accomplished by providing adequate fuel residence time and high temperature in the combustion zone to ensure complete combustion. The primary technologies identified for reducing VOC emissions from the IGCC combustion turbines are oxidation catalysts and good combustion practices (GCP). A survey of the RBLC database indicated that good combustion control and burning clean gas fuel are the VOC control technologies primarily determined to be BACT. An inherent advantage of IGCC technology is the fact that the combustion turbines use

syngas, a fuel which contains a very low organic content and, when burned, yields very low levels of uncombusted VOC emissions.

B-1.7.3.1 Identify Control Technologies

Three technologies were identified as potentially applicable to the IGCC combustion turbines for control of VOC emissions:

Combustion Process Controls

- IGCC technology (use of low VOC syngas)
- Good Combustion Practices (GCP)

Post Combustion Controls

- Oxidation Catalysts

B-1.7.3.2 Evaluate Technical Feasibility

Low-VOC Syngas Fuel

Combustion of any hydrocarbon material can produce trace levels of uncombusted VOCs. However, combustion of fuels with very low hydrocarbon content can obviously further lower these VOC emissions. The very nature of the IGCC process leads to unusually low levels of any organic emissions from syngas combustion.

The gasification process involves feeding a slurry of carbon-containing materials into a heated and pressurized chamber (the gasifier) along with a controlled and limited amount of oxygen. At the extremely high operating temperature and pressure created by conditions in the gasifier, chemical bonds are broken by oxidation and steam reforming at temperatures sufficiently high to promote very rapid reactions. The various constituents in the feedstock are largely broken down into their fundamental elements in the gasifier, and are reformed in the syngas primarily in the form of diatomic hydrogen (H_2) and CO gas.

Good Combustion Practices (GCP)

GCPs applied to the proposed sources can achieve VOC emission levels below 3 ppmvd (at 15 percent O_2) based on data provided by Fluor. GCPs include operational and design elements to control the amount and distribution of excess air in the flue gas in order to ensure that enough oxygen is present for complete combustion. This is the technology used as BACT for all other recent IGCC permits.

Oxidation Catalyst

The option that has greatest uncertainty with respect to cost, long-term performance and reliability for application to IGCC turbines is the use of oxidation catalysts. Catalytic oxidation is a post-combustion technology wherein the products of combustion are introduced to a catalytic bed at the appropriate temperature point in the HRSG. The catalyst promotes the oxidation of VOC. The catalyst beds that reduce CO can also be effective in reducing VOC emissions. Such

systems typically achieve a maximum VOC removal efficiency of up to 50 percent, while providing upwards of 90% control for CO.

It is also worth noting that a typical additional incentive to using an oxidation catalyst, when feasible, is the incidental control of organic hazardous air pollutants (HAPs). For example, uncontrolled formaldehyde (CHOH) emissions can be fairly significant from conventional combustion of natural gas. However, since syngas contains primarily elemental hydrogen (H_2) and CO, uncontrolled turbine emissions of formaldehyde and other organic HAP emissions, are significantly less. The reaction path to create formaldehyde is not present for hydrogen and CO fuel constituents. For this reason, oxidation catalyst, even if feasible, would provide less benefit for a syngas-fired combustion turbine versus a natural gas-fired combustion turbine.

Oxidation catalysts are anticipated to experience performance problems due to the presence of low-levels of sulfur and trace metals in the syngas combustion exhaust, as further described in the CO BACT evaluation. The presence of sulfur compounds in the combustion turbine exhaust gases, even with the proposed BACT limit of 10 ppmv in the syngas, will cause poisoning of the metal-catalyst active sites in the catalyst pores. This will result in a more rapid decay in catalytic oxidizer module performance, and increased cost for more frequent catalyst replacement. Further, oxidation catalysts have seldom been applied, and are not viewed as commercially proven on coal-based combustion systems. For all these reasons, catalytic oxidation is not considered a practical or feasible technology for VOC removal for this IGCC application.

B-1.7.2.3 Select Control Technology

The recommended control of VOC emissions from each of the proposed combustion turbines is use of the low VOC fuel and GCPs at the IGCC combustion turbine. These practices will meet a VOC emission limit of 0.003 lb/MMBtu input to the gasifier, or 10 lb/hr/combustion turbine while operating under steady state conditions. This equates to approximately 2.4 ppmv at 15% O_2 in the stack gases. During start up cycles, the proposed BACT limitation on VOC emission is 263 lb/hr, which represents the worst case emission rate during syngas system start up.

B-1.7.4 CARBON MONOXIDE BACT ANALYSIS

CO is a product resulting from incomplete combustion. Control of CO is typically accomplished by providing adequate fuel residence time and high temperature in the combustion zone to ensure complete combustion. These control factors, however, can also tend to result in increased emissions of NO_x. Conversely, a lower NO_x emission rate achieved through flame temperature control (by diluent injection or dry lean pre-mix) may result in higher levels of CO emissions. Thus, a compromise must be established, whereby the flame temperature reduction is set to achieve the lowest NO_x emission rate possible while keeping CO emissions to an acceptable level.

CO emissions from combustion turbines are a function of oxygen availability (excess air), flame temperature, residence time at flame temperature, combustion zone design, and turbulence. Possible post-combustion control involves the use of catalytic oxidation, while front-end control involves controlling the combustion process to suppress CO formation.

B-1.7.4.1 Identify Control Technologies

Three technologies were identified as potentially applicable to the PMEC combustion turbines for control of CO emissions:

Combustion Process Controls

- Good Combustion Practices (GCPs)

Post Combustion Controls

- SCONOx™
- Oxidation Catalyst

B-1.7.4.2 Evaluate Technical Feasibility

Each identified technology was evaluated in terms of its technical feasibility for application to IGCC combustion turbines burning syngas. In general, post-combustion controls either had substantial feasibility issues, or did not offer a level of control that was practically better than GCP.

SCONOx™

The $SCONO_x$™ system was described in the BACT analysis for control of turbine NO_x emissions. It is commercially available for small-frame combustion turbines for controlling CO and can reduce emissions by up to 95 percent. However, it is not commercially available for large frame combustion turbines (like those to be used for PMEC) as discussed in the NO_x BACT discussion. Therefore, SCONOx™ is considered to be technically infeasible for PMEC.

Oxidation Catalysts

Catalytic oxidation is a post-combustion technology, which does not rely on the introduction of additional chemical reagents to promote the desired reactions. They have been permitted as required CO control equipment for a fairly large number of natural gas combustion turbine applications. The oxidation of CO to CO_2 utilizes excess air present in the combustion turbine exhaust, and the activation energy required for the reaction to proceed is lowered in the presence of a catalyst. Products of combustion are introduced into a catalytic bed, with the optimum temperature range for these systems being between 700°F and 1,100°F. The introduction of a catalyst bed in the combustion turbine exhaust stream will create a pressure drop, resulting in back pressure to the combustion turbine. This has the effect of reducing the efficiency of the combustion turbine and the power generating capabilities.

As previously mentioned, a common incentive to use a CO oxidation catalyst, if feasible, would be the incidental control of VOC and organic HAPs that would be realized in conjunction with reduced CO emissions. However, as discussed in the VOC BACT section, such benefits are less significant for gas turbines using syngas fuel, which has a very low VOC content, than for units burning natural gas.

A CO catalyst oxidizes CO to CO_2 and VOC and unburned hydrocarbons to CO_2 and H_2O, but also can promote other oxidation reactions such as NH_3 to NO_x and SO_2 to SO_3. Consequently, the presence of a CO catalyst can cause emissions of other pollutants to increase, and therefore its design needs to be carefully considered.

CO catalyst typically operate at temperatures between 750 to 1100ºF (400 to 600ºC), and typically the catalyst is more effective at promoting the oxidation reactions as the operating temperature increases. Typical CO to CO_2 conversion efficiencies from a CO oxidation catalyst are 80 to 90%, and typical VOC conversion efficiencies are 40 to 50%.[[6]]

At 750ºF (400ºC), a CO oxidation catalyst will also promote conversion of up to 35% of the SO_2 to SO_3, according to the Electric Power Research Institute (EPRI). At 1000 to 1100ºF (538 to 600ºC), the catalyst will promote an even higher rate of conversion of SO_2 to SO_3. Significant concentrations of SO_3 can promote the formation of visible sulfuric acid mist (also known as a "blue plume") when the exhaust gas cools below the sulfuric acid dewpoint.

If a high temperature (>1000ºF or 538ºC) CO catalyst is used, in order to avoid producing excessive SO_3, the sulfur content of the syngas must be low enough to yield no more than 2 ppmv SOx in the combustion turbine exhaust in order to avoid the blue plume. However, even if a lower temperature CO catalyst is used, the resulting SO_3 concentration would cause unacceptably high rates of ammonium bisulfide formation if an SCR is also present in the HRSG. Therefore, a CO catalyst is <u>not</u> recommended by EPRI for use in IGCC systems which incorporate an SCR. [[7]]

By placing the catalyst at the correct position within the HRSG, the temperature can fall within the range appropriate for CO catalytic oxidation. However, the same catalyst fouling issues mentioned in regard to SCR catalysts for NO_x control will be of concern with CO oxidation catalysts. Compounds in the syngas exhaust, such as sulfur, can cause plugging or deactivation of the CO catalyst, greatly shortening its service life and increasing periodic replacement costs. Even the relatively low concentrations of heavy metals predicted for the IGCC combustion turbine exhaust may adversely affect the performance and longevity of a catalytic oxidation system. Therefore, oxidation catalysts are considered to be technically infeasible for this project.

The Florida Department of Environmental Protection recently established a precedent for the use of an oxidation catalyst as BACT for CO at an IGCC facility in Florida. Specifically, Florida published its Technical Evaluation and Preliminary Determination document on June 16, 2006 for the Curtis H. Stanton Energy Center Unit B proposed by OUC & Southern Power Company – Orlando Gasification LLC. This document includes the Department's BACT analysis for the Stanton project, which found that use of a CO oxidation catalyst is cost effective for that application. However that finding pertained to an unsteablished demonstration IGCC technology that cannot be considered in PMEC (the KBR "Transport Gasfier" in a subbituminous coal-fueled IGCC process) and did not refute the concerns expressed above regarding the serious technical feasibility issues with regard to power plant reliability.

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[6] "Supporting Material for BACT Review for Large Gas Turbines used in Electrical Power Production", California Air Resources Board, http://www.arb.ca.gov/energy/powerpl/appcfin.pdf

[7] ERPI CoalFleet IGCC Permitting Guidelines Manual, Electric Power Research Institute, March 2006.

The Department obtained costs from a CO catalyst vendor, but apparently no written guarantee that the control system would perform at the level to meet the levels of 4.1 ppmvd CO and 2.4 ppmvd VOC, which were included in the facility's permit. The agency proposes that the oxidation catalyst be installed during the second year of the IGCC unit's operation to allow time for stabilization of the gasifier system and implement additional changes, such as better syngas cleaning, if necessary. This use of oxidation catalyst is not an instance of the oxidation catalyst technology having been proven in practice. In addition, as a demonstration project selected for funding assistance by the Department of Energy, the Stanton Project will receive $235 million of the total cost of $557 million from DOE, an advantage not shared by PMEC.

Good Combustion Practices

Good combustion practices (GCPs) include operational and combustor design elements to control the amount and distribution of excess air in the flue gas in order to ensure that enough oxygen is present for complete combustion. Such control practices applied to the proposed PMEC combustion turbines can achieve CO emission levels of 15 ppm during steady state, full load operation. At lower combustion turbine loads (50-70%), the combustion efficiency drops off notably, and CO emissions would be higher. However, the PMEC combustion turbines are expected to operate for only 50 hours or less per year in startup mode, and this profile (15 ppmvd at 15% O_2) was used as the basis of the BACT analysis.

GCPs are a technically feasible method of controlling CO emissions from the proposed IGCC combustion turbines.

B-1.7.4.3 Rank Control Technologies

The only CO control technology found to be technically feasible for the PMEC combustion turbines burning syngas fuel is presented in Table B-1-7

TABLE B-1-7
RANKING OF FEASIBLE CO CONTROL TECHNOLOGIES FOR GAS TURBINES

Control Technology	Removal Efficiency Range (%)	Controlled Emission Level
GCPs	Not Applicable (baseline)	15 ppmv @ 15% O_2 2,740 lb/hr (startup)

B-1.7.4.4 Select Control Technologies

GCP is considered the baseline and only feasible and commercially demonstrated CO control technology for IGCC combustion turbines. The conditions that led to the recent finding in favor of CO catalyst technology a BACT for Curtis H. Stanton Energy Center Unit B project do not exist for the PMEC. Additionally, GCP has been selected as BACT for all other recent IGCC permits. PMEC proposes that the CO BACT-based limit should be 15 ppmvd @ 15 percent O_2 on a 3-hour average during non-startup operation, using Good Combustion Practices (GCPs). Similarly, for the maximum CO emission limit during turbine startup with GCP is proposed to be 2,740 lb/hr, with an assumed level of 50 hours per year of startup operation for each turbine for purposes of estimating annual emissions.

B-1.7.5 PARTICULATE MATTER BACT ANALYSIS

Particulate matter emissions from natural gas-fired combustion sources consist of inert contaminants in natural gas, sulfates from fuel sulfur, dust drawn in from the ambient air that passes through the combustion turbine inlet air filters and particles of carbon and hydrocarbons resulting from incomplete combustion. Therefore, units firing fuels with low ash content and high combustion efficiency exhibit correspondingly low particulate matter emissions. Clean gaseous fuel, such as syngas, will also be low emitting. In the PMEC process, as in other IGCC systems, the hot syngas exiting the gasifier is cooled and sent to a water scrubbing system for particulate matter removal prior to other gas treatment processes such as AGR.

The EPA has indicated that particulate matter control devices are not typically installed on combustion turbines and that the cost of installing a particulate matter control device is prohibitive (EPA, September 1977). When the NSPS for Stationary Gas Turbines (40 CFR 60 Subpart GG) was promulgated in 1979, the EPA acknowledged, "Particulate emissions from stationary gas turbines are minimal." Similarly, the recently revised Subpart GG NSPS (2004) did not impose a particulate emission standard. Therefore, performance standards for particulate matter control of stationary gas turbines have not been proposed or promulgated at a federal level.

Post combustion controls, such as electrostatic precipitators (ESPs) or baghouses, have never been applied to commercial combustion turbines burning gaseous fuels. Therefore, the use of ESPs and baghouses is considered technically infeasible, and does not represent feasible control technology.

In the absence of add-on controls, the most effective control method demonstrated for gas-fired combustion turbines is the use of low ash fuel, such as natural gas or syngas. Proper combustion control and the firing of fuels with negligible or zero ash content (such as natural gas or syngas) is the predominant control method listed.

The use of clean syngas fuel and good combustion control is proposed as BACT for PM/PM_{10} control in the proposed PMEC combustion turbines. These operational controls will limit filterable plus condensable PM/PM_{10} emissions to 24 lb/hr, based on 0.01 lb/MMBtu input to the gasifier when operating on syngas.

PMEC is proposing to build enclosed solid fuel storage to improve storage management and minimize particulate emissions.

B-1.7.6 MERCURY BACT ANALYSIS

Since mercury occurs naturally in PBR coals, the PMEC syngas cleanup processes include a system to control mercury that may remain in the syngas. Downstream of the AGR system, the syngas passes through fixed beds of activated carbon that are specially impregnated to remove mercury. Multiple beds in series are used to obtain optimized adsorption. The lower temperature and lower moisture content of the syngas after the Selexol® or equivalent step allows the carbon beds to operate at higher efficiencies. The activated carbon capacity for mercury ranges up to 20% by weight of the carbon. The mercury removal system will remove enough mercury from the syngas so that the mercury content of the syngas fuel is no more than 10% of

the mercury contained in the solid IGCC feed stock. After mercury removal, the product syngas is moisturized, heated, and diluted with nitrogen for control of nitrogen oxides (NO_x) before being used as fuel for power generation in the CTGs.

PMEC's mercury emission calculations assume that the mercury remaining in the syngas after carbon adsorption is emitted in the exhaust of the combustion turbines and other combustion units,. On this basis, the mercury emissions for both combustion turbines are estimated to be 58 lbs per year. Much smaller amounts would be released from the flare, tank vent oxidizer, auxiliary boiler and cooling tower. However, these smaller sources account for less than 2 lbs per year.

B-1.7.6.1 Identify Control Options

Among IGCC facilities that have achieved operating status, only one was found to have permitted emission limits that directly address mercury emissions. Based on engineering development in support of later IGCC permit applications, the use of carbon adsorption is the only technology that has been proposed as a technically feasible method of control specifically for mercury. The following list summarizes the nature of mercury emission limits or proposed control technologies for several IGCC facilities:

- SG Solutions, Wabash River Generating Station, Indiana (Operating)
  - No mercury limits in NSR permit.
- Tampa Electric Company, Polk Power Station, Florida (Operating)
  - Maximum allowable mercury limits in NSR permit for "demonstration period" of 0.025 lb/hr and 0.11 tons per year, and for "post-demonstration" period of 0.0034 lb/hr and 0.017 tons per year.
  - Testing requirement to prove compliance with limits
- Global Energy Inc., Kentucky Pioneer Energy, LLC, Kentucky (Permitted)
  - Stack emission limits of 0.080 milligrams per dry standard cubic foot
  - Testing requirement to prove initial compliance with limit
- Mesaba Energy Project, Minnesota – 1,200 MW(Proposed)
  - Carbon adsorption proposed as control technology
  - Proposed mercury emissions in NSR application based on not less than 90% removal of mercury present in the fuel feedstock, which corresponds to maximum annual emissions of 54 lbs/year[8].
  - Project will comply with NSPS for Coal-Fired Electric Steam Generating Units (40 CFR 60, Subpart Da(b)) standard for IGCC units of 0.000020 lb/MWh (0.0025 ng/J) based on gross electric output.

[8] Mercury emissions presented in the Mesaba air permit application were estimated based on an emission factor of 0.5 lb/10^{12} Btu of feedstock for PRB coal. PMEC has conservatively estimated its mercury emissions using an emission factor of 1.2 lb/10^{12} Btu, which is at the high end of measured Hg levels for PRB coal. This explains the comparable annual emissions estimates for the two facilities, despite the fact that the Mesaba calculations pertain to a 1200 MW IGCC facility while the PMEC will generate only 600 MW.

- Curtis H. Stanton Energy Center, Orlando, Florida – 285 MW (Proposed)
  - Carbon adsorption proposed as control technology
  - Annual emissions are less than BACT significance level for mercury, which is 200 lb/yr
  - Proposed mercury emissions in NSR application were based on average of 90% removal of mercury in present in the fuel feedstock.
  - Agency-proposed permit limit is 0.000010 lb/MWh, which is half of the limit in NSPS (40 CFR 60, Subpart Da(b)) for IGCC units, and corresponds to approximately 22 lb/yr.

B-1.7.6.2 Evaluate Control Options

Operating experience with IGCC processes is relatively limited, so the long-term reliability and performance of specific emission controls for mercury is not well-demonstrated at the commercial scale. At very least, the volume of activated carbon needed for high efficiency adsorption of mercury must be adjusted to account for the potential loss of capacity due to adsorption of sulfur compounds, or other species in the syngas. There is no reported experience to judge the required frequency of replacement for activated carbon in syngas cleanup service.

Consideration of the physical process of adsorption in a carbon bed suggests that higher removal levels would not be achieved by simply increasing the volume of carbon. When a fresh or regenerated bed of carbon is brought into service, the material nearest the gas entrance will capture the contaminant until its surface is essentially "saturated", or it approaches its equilibrium capacity for that prevailing inlet concentration. As unabsorbed molecules travel further into the bed, additional carbon surface becomes saturated. In this manner, an "adsorbing zone" travels through the bed in the direction of gas travel. The exit gas concentration of the contaminant is established by gas-solid equilibrium factors (i.e., surface activity, temperature, pressure, and concentration), rather than mass transfer limits. Enlarging the carbon bed will extend the time before "breakthrough", the point when the entire bed is saturated, but will not appreciably reduce the exit concentration of the contaminant.

In the mercury material balance used to estimate emissions, the primary process specification is that sufficient adsorption capacity will be provided to capture 90% of the mercury in the fuel feedstock. Conservatively, it has been assumed in this application that all of the feedstock mercury will be converted to a gaseous mercury species in the gasifier. In actuality, the feedstock mercury will partition between the gasifier slag and the product gas, in a proportion that is variable and not accurately calculable without measurements for a specific fuel blend.

B-1.7.6.3 Proposed BACT Limit

Given the uncertainty inherent in the mercury balance calculations, and the lack of commercial demonstration of the single feasible control technology, there is no justification to identify BACT control options that are more stringent than the applicable NSPS. For these sources, the BACT "floor" is the recently-revised and relatively stringent limit of a 12-month rolling average of 0.000020 lb/MWh (0.0025 ng/J) based on gross electric output (40 CFR 60.45 Da(b)). With the exception of the most recent proposed permit for the IGCC in Orlando, Florida, all of the prior permits for IGCC have contained limits equivalent to or less stringent than the NSPS. It

remains to be seen whether the Florida permit limit of 0.00001 lb/MWh can be achieved, given the chemical equilibrium limitations on carbon adsorption of mercury.

For mercury emissions from the IGCC combustion turbines, the carbon adsorption design will deliver at least 90% removal of the mercury contained in the feedstock fuel. For PRB coal, this results in a maximum emission rate of 0.0033 lb/hr per turbine (0.000011 lb/MWh) Based on information recently presented in the Mesaba IGCC New Source Review permit application, the mercury content in PRB coal is higher than in petroleum coke. Thus, the emissions estimate based on this coal mercury content represent a worst-case for the PMEC facility. This limit is proposed as the BACT limit for the PMEC project. The estimated maximum annual emission rate of 29 pounds of mercury per year from each of the PMEC combustion turbines is compliant with the NSPS standard.

B-1.8 BACT DETERMINATION - PRECEDENTS FOR SOLID FUEL HANDLING FACILITIES

Various types of industrial facilities include solid fossil fuel handling operations. To review recent BACT precedents for these operations, the RBLC database was surveyed for utility plants and other coal handling operations. These precedents are summarized in Table B-1-8. The control technologies and BACT limits identified in these recent precedents offer guidance for evaluation of BACT options for the PMEC solid fuel unloading, handling and storage operations. The control technologies that may practically establish a BACT emission limit for particulate emission sources in this case are fabric filter baghouses, ESPs, wet scrubbers, and mechanical cyclones. The following general analysis of particulate control technology options feeds into the discussions on BACT for specific IGCC processes involving bulk fuel handling in Sections B-1.9, B-1.10 and B-1.11.

Fabric Filter Baghouse – A fabric filter baghouse collects particulate matter by passing the exhaust gas stream through a series of filters that are constructed of a porous fabric. As the gas passes through the fabric, the dust particles gather on the surface to form a “cake”, which further assists in collecting particulate matter. The method with which the cake is removed is critical to the overall success of the control device. If too much of the cake is removed, there will be additional particulate matter emissions, as the baghouse works to reform the cake. If not enough of the cake is removed, the pressure drop across the baghouse will continue to increase, putting a strain on the system itself.

Two common methods for removing the particulate matter dust cake include reversing the air flow periodically (reverse-air baghouse) or using a pulsed jet of compressed air periodically (pulse-jet baghouse). The selection of the fabric material used is also critical to the overall performance of the baghouse. The material must be able to withstand the maximum temperature and flow-rate of the exhaust gas stream, as well as be chemically compatible with both the exhaust gas and the dust that is being collected.

Electrostatic Precipitator – An ESP uses electrical forces to collect particulate matter from the exhaust gas stream. The particles are first passed through a corona where they acquire an electrical charge before being collected on plates, which are oppositely charged. The particulate matter is knocked loose from the plates in such a manner that it is not re-entrained in the exhaust

gas stream, and is then transferred to a hopper for disposal. However, the low moisture and high solids loading that characterize the exhaust gas make an ESP less efficient than a fabric filter baghouse.

Wet Scrubber – Wet scrubbers reduce emissions by entraining particulate matter in the exhaust gas stream in water droplets. These droplets are then separated from the remaining gas stream. There are three methods in which the particulate matter is entrained in a water droplet:

- Impaction – the particle collides directly with the water droplet;
- Interception – the particle is captured as it moves close to the water droplet; and
- Diffusion – the particle is circulated through the exhaust gas until it can be captured by the water droplet.

In order to be successful at removing particulate matter, the scrubber must be able to create and effectively control water droplet dispersion.

Mechanical Cyclones – A mechanical cyclone can be used to collect particulate matter from exhaust gases by working in a manner similar to a centrifuge. As the exhaust gas flows through the cyclone, the particulate matter is forced to the sides of the cyclone where it is trapped along the wall. Gravity then pulls the particulate matter down the cyclone where it is collected in a hopper.

In addition to a control device, it is important to note that in order for such "end-of-pipe" devices to be effective, the particulate matter emissions need to be captured. Additional measures are usually included with the control device to constitute a complete capture and control system. These control options are discussed in more detail below.

Full and Partial Enclosures – Particulate matter emissions can be effectively limited by covering equipment or emission points with either full or partial enclosures. The types of

TABLE B-1-8
REVIEW OF RECENT BACT DETERMINATIONS FOR SOLID FEED STOCK OPERATIONS

Permit or RBLC ID	Permit Issuance Date	Location	Company	System Description	Maximum Production Rate	Limit(s)	Control Option	Basis
CO-0055	02-03-06	Powers County, CO	Lamar Utilities Board DBA Lamar Light & Power	Coal Handling and Preparation	150 ton/hr	PM_{10} – 0.02 lb/ton	High Efficiency Fabric Filter Baghouses (99.50% Efficiency)	BACT-PSD
AR-0082	08-30-05	Independence County, AR	Arkansas Lime Company	Coal/Coke Bin Vent	NA	PM_{10} – 0.0150 gr/dscf 5% opacity	Dust Collector (99% efficiency)	BACT-PSD
CO-0057	07-05-05	Pueblo County, CO	Public Service Company of Colorado	Coal Handling and Storage	NA	PM – 0.01 gr/dscf PM_{10} – 0.01 gr/dscf	Controls include use of water sprays, lowering well, dust suppressants, enclosures and baghouses where feasible.	BACT-PSD
MN-0061	06-26-05	St. Louis, MN	Mesabi Nugget LLC	Coal Pulverizer	36 MMBtu/hr	CO – 3 lb/hr NO_X – 1.8 lb/hr PM – 0.01 gr/dscf PM_{10} – 0.0150 gr/dscf VOC – 0.19 lb/hr 10% opacity	Fabric Filter	BACT-PSD
ND-0021	06-03-05	Bowman County, ND	Montana Dakota Utilities / Westmoreland Power	Coal Handling	400 ton/hr	PM – 0.0050 gr/dscf 5% opacity	Baghouses (99.9% Efficiency)	BACT-PSD
IN-0119	05-31-05	Dekalb County, IN	Auburn Nugget	Coal Car Unloading	165 ton/hr	PM – 0.0052 gr/dscf 3% opacity	Baghouse	BACT-PSD
NV-0036	05-05-05	Eureka County, NV	Newmont Nevada Energy Investment LLC	Coal Handling Operations	NA	PM_{10} – 0.01 gr/dscf	Baghouse	BACT-PSD
VA-0292	11-02-04	Buchanan County, VA	Island Creek Coal	Coal Handling and Transfer Operations	3.5 MMton/yr	PM – 16.95 ton/yr PM_{10} – 3.35 ton/yr	Wet Suppression	BACT-PSD
ND-0020	08-04-04	Stark County, ND	Red Trail Energy LLC	Coal Handling	27 ton/hr	PM_{10} – 0.0040 gr/dscf 0% opacity	Baghouse (99.8% Efficiency)	BACT-PSD
SC-0104	02-05-04	Berkeley County, SC	Santee Cooper	Coal Handling	26.28 MMton/yr	PM – 1.4 lb/hr	Baghouse (99.50% Efficiency)	Other Case-by-Case

B-1.9 BACT ANALYSIS FOR RAILCAR UNLOADING AND TRANSFER POINTS

B-1.9.1 PROCESS DESCRIPTION

Energy Northwest expects that fuel selection throughout the lifetime of the PMEC will respond to market conditions and economic considerations. The primary feed stocks will be petroleum coke and coal; natural gas will be the backup fuel. Either petroleum coke or coal feedstocks may be received by rail in dedicated unit trains. However, most petroleum coke is expected to be delivered by barge, and emission control options for the PMEC barge unloading facilities are assessed in Section B-1.10. The following BACT analysis for the rail car unloading facility is based on the solid fuel selection with the highest pollutant emission rates among the anticipated range of fuels.

The proposed unloading building will house supporting facilities for railcar unloading operations and facilitates control of dust emissions, noise abatement, and visual shielding. The railcar coal receiving system will incorporate the use of high-capacity aluminum-steel railcar bottoms dumping to an under-rail pit-hopper system. During unloading of a unit train, the railcars will move at a slow speed (approximately 0.3 mph) through the unloading building. The end doors of the building will be covered with plastic slat covers to reduce transport of emissions to the outside air. The load will be dumped from the bottom of each car into a dump hopper under the track. Multiple collecting conveyors will move the dumped fuel from the hopper to an inclined take-away conveyor that moves the solid fuel from the building to the storage domes.
Nominal design capacity for the railcar unloading facility is 4,300 tons of coal per hour, which forms the basis for the emission estimates used in this BACT analysis. Significant emissions from the railcar unloading facility consist only of particulate matter (PM) and particulates less than 10 microns diameter (PM_{10}). Two separate emission units associated with this facility are included in this BACT analysis:

- Railcar unloading pit-hopper; and
- Conveyor and transfer point.

The proposed BACT for both emission points is enclosure in the unloading building, with the entire building maintained at negative pressure for effective capture of generated dust. The under-track conveyor and transfer point will be enclosed. The exhaust air stream from the unloading building will be treated by a high-efficiency fabric-filter baghouse before being vented to atmosphere.

B-1.9.2 COMMERCIALLY AVAILABLE CONTROL TECHNOLOGIES

Based on current practices for solid material handling systems, several types of commercially available control technologies can be identified for the railcar fuel unloading process at the proposed PMEC facility. An RBLC Database survey indicates that commercially available controls include:

- Unloading building with restricted end door openings and operated at negative pressure with vent stream routed to high-efficiency fabric filter;

- Enclosed batch drop and transfer points with high-efficiency fabric filter;
- Transfer point and batch drop point water sprays,
- Transfer point enclosures only

Based on review of BACT precedents, the emission control option of enclosures with baghouse filters for railcar unloading, handling and storage of petroleum coke and coal had control efficiencies that varied from 99.0% to 99.9%. In addition, water sprays and enclosures are also considered to be available control options for PM_{10} emissions. The ranges of coal handling emission limits for recently permitted sources are as follows:

- PM = 0.0050 gr/dscf to 0.01 gr/dscf (baghouse exhaust limit)
- PM10 = 0.0040 gr/dscf to 0.01 gr/dscf (baghouse exhaust limit)
- Opacity = 0% to 10%

B-1.9.3 INFEASIBLE CONTROL MEASURES

None of the identified emission control options for this source would be viewed as technically infeasible.

B-1.9.4 RANKING OF AVAILABLE CONTROL MEASURES

In approximate order of decreasing stringency these control technology options are:

- Complete enclosure for railcar unloading building and below-grade conveyor and building vented through high-efficiency fabric filter units;
- Railcar unloading pit-hopper enclosure and transfer point enclosures with water or suppressant sprays;
- Enclosed below-grade pit and conveyor only
- Water suppression on railcar unloading bin-hopper and transfer point

B-1.9.5 PROPOSED BACT LIMITS AND CONTROL OPTION

PMEC proposes to adopt the most stringent control option among those identified for this type of particulate emission source. As noted in the discussion of the top-down BACT procedure in the beginning of Section B-1.2, an evaluation of any potential environmental and energy impacts resulting from the implementation of the selected control option must be provided, even when the top-ranked control option is chosen. . The only potential impact associated with a fabric filter baghouse includes an environmental impact associated with the disposal of existing bags when they are replaced with new bags. This is a relatively minor potential environmental impact, such that use of a fabric filter baghouse is reasonably considered to be the top-ranked control option.
PMEC will adopt a fabric filter performance specification of 99% particulate removal from the airstreams sent to the baghouse. In combination with an estimated particulate collection efficiency of 80% for the entire railroad unloading system, this results in 89.2% removal of all particulate emissions associated with this process.

B-1.10 BACT ANALYSIS FOR SHIP/BARGE UNLOADING FACILITY AND TRANSFER TO STORAGE

As an alternative to receipt of fuel by railcar, PMEC will be furnished with dock and ship unloading equipment for receipt and unloading of petroleum coke and coal feedstocks from ships. The existing Port of Kalama wharf will be extended by the Port to accommodate vessels delivering feed stock for PMEC. Unloading of the oceangoing vessels will be accomplished by means of a rail-mounted, continuous bucket crane (vertical leg type) ship unloader. The ship unloader will be configured to transfer feedstocks onto the dock conveyor at any point along the working limits of the machine. The crane unloader and dock conveyor will be totally or partially enclosed (depending on final design), with the vent stream containing captured particulate routed to a high-efficiency fabric filter baghouse.

The dock conveyor will be approximately 660 feet in length, with a height of about 27 feet above the top of the dock. A reclaim conveyor reaches into the hold of the ship, and gathers the solid fuel material. This conveyor is partially enclosed to reduce entrainment of dust, and accommodate the entry of material to the conveyor. The reclaim conveyor transfers material onto the dock conveyor. As part of the proposed BACT option, the dock conveyor is to be completely enclosed beyond the load point, and partially enclosed (open-topped with windscreens) for receipt of feed stocks from the ship unloader. The conveyor will terminate in a fully enclosed transfer structure, and the transfer point from the conveyor will be provided with a second fabric filter baghouse for control of captured dusts.

Nominal design capacity for this facility is 4,300 tons per hour (set equivalent to the railcar system for purpose of emission estimates). Significant emissions from the ship unloading facility consist only of particulate matter (PM) and particulates less than 10 microns diameter (PM_{10}). There are two emission units for the ship unloading facility that are included in this BACT analysis:

- Continuous bucket unloader unit; and
- Transfer point to the dock conveyor.
- B-1.10.1 Commercially Available Control Technologies

Based on current practices for solid material handling systems, several types of commercially available control technologies can be identified for the fuel unloading and storage systems at the proposed PMEC facility. An RBLC Database survey indicates that high efficiency fabric filter baghouses, water sprayers, dust suppressants, and enclosures are potential BACT options for ship unloading facilities and the associated transfer of petroleum coke and coal to storage facilities. Baghouse efficiencies varied from 99.0% to 99.9%. In addition, water sprays and various levels of facility and/or conveyor enclosures are also considered to be available control options for PM_{10} emissions. The ranges of fuel handling emission limits for recently permitted sources are as follows:

- PM = 0.0050 gr/dscf to 0.01 gr/dscf (baghouse exhaust limit)
- PM_{10} = 0.0040 gr/dscf to 0.01 gr/dscf (baghouse exhaust limit)
- Opacity = 0% to 10%

B-1.10.2 INFEASIBLE CONTROL MEASURES

Of the identified emission control options for this source, only the complete enclosure of the ship unloading facility would be viewed as technically infeasible. The large size of the entire dock operation, and the need for ship access over water would suggest a very complex and very costly structure, unlike anything currently used in commercial ship unloading.

B-1.10.3 RANKING OF AVAILABLE CONTROL MEASURES

In approximate order of decreasing stringency the feasible control technology options are:

- Effective enclosure of collecting and dock conveyors to the extent practical, with air drawn from enclosures and routed to high-efficiency fabric filters;
- Enclosure of dock conveyor and transfer points, with water or suppressant sprays for dust control;
- Water suppression on collecting conveyor and dock conveyor transfer points.

B-1.10.4 PROPOSED BACT LIMITS AND CONTROL OPTION

PMEC proposes to adopt the most stringent control option among those identified as feasible for this type of particulate emission source. As noted in the discussion of the top-down BACT procedure in the beginning of Section B-1.2, a review of any potential environmental and energy impacts resulting from the implementation of the control option must be addressed, even if the top-ranked control option is chosen. The only potential impact associated with a fabric filter baghouse includes an environmental impact associated with the disposal of existing bags when they are replaced with new bags. This is a relatively minor potential environmental impact, such that use of a fabric filter baghouse is reasonably considered to be the top-ranked control option.

PMEC will adopt a fabric filter performance specification of 99% particulate removal from the airstreams sent to the baghouse. In combination with an estimated particulate collection efficiency of 80% for the entire ship unloading system, this results in 89.2% removal of all particulate emissions associated with this process.

B-1.11 BACT ANALYSIS FOR FEEDSTOCK STORAGE DOME VENT

Both the railcar and ship unloading facilities will supply feedstock via enclosed conveyors to two aluminum dome structures to provide control of fugitive dusts and noise emissions, and an enhanced visual appearance. The fuel storage basis will be a minimum of 30 days of feedstock storage. The upper dome areas will be furnished with low-speed fan powered ventilator units for control and exhaust of heat buildup. The ventilation units will be equipped with power-operated shut-off dampers and will be operated only after the airborne dusts generated within the domes during stockout operations have settled out following each loading period. This limited loading cycle operation was applied to develop a realistic estimate of the maximum potential to emit for this equipment. The unloading equipment for both railcars and ships have higher hourly capacities than that of the gasifier. Thus, the potential to emit for these solids handling sources can be considered to be limited by the capacity of the downstream gasifier system.

Each of the domes will be fed from, and will feed back to, a central transfer tower structure, which will be the receiving point of independent inclined conveyor systems running from the railcar and ship unloading facilities. Reclaiming from each dome will be by means of an underground conveyor feeding to a common surge hopper area in the base of the transfer tower. This hopper will transfer feedstock to one or two inclined conveyors forwarding feedstock to downstream processing facilities. As part of the proposed BACT measures, the transfer tower structure will be fully enclosed for dust capture and furnished with fabric filter baghouse systems for control of captured dusts.

B-1.11.1 COMMERCIALLY AVAILABLE CONTROL OPTIONS

Commercially available PM/PM_{10} control options were identified from review of the EPA's RBLC database. A list of recent PM_{10} BACT determinations for storage facilities at petroleum coke and coal facilities is included in Table B-1-8. The add-on control technologies that may practically be considered to establish a BACT emission limit for the storage dome vent emission point include:

- Fabric Filter Baghouse
- Electrostatic Precipitator (ESP)
- Wet Scrubber; and
- Mechanical Cyclone.

All of the control options identified above are considered technically feasible for controlling PM_{10} emissions from the proposed PMEC storage dome vents.

B-1.11.2 RANKING OF AVAILABLE CONTROL MEASURES

The following is a list of the available control options ranked by control effectiveness:

- Fabric Filter Baghouse – control efficiency greater than 99.9 percent for PM_{10} (typical specification of 0.01 grains per dry standard cubic foot);
- Electrostatic Precipitator – control efficiency approximately 95 percent for PM_{10};
- Wet Scrubber – control efficiency approximately 90 percent for PM_{10}; and
- Mechanical Cyclones – control efficiency up to 80 percent for PM_{10}.

B-1.11.3 CONSIDERATION OF ENERGY, ENVIRONMENTAL AND COST FACTORS

PMEC has elected to use the top-ranked control option to reduce PM_{10} emissions from the storage dome vents. As noted in the top-down BACT procedure discussed in the beginning of Section B-1.2, any potential environmental and energy impacts resulting from the implementation of the selected control option must be addressed even if the top control option is chosen.. The only potential impact associated with a fabric filter baghouse includes an environmental impact associated with the disposal of existing bags when they are replaced with new bags. However, even considering this potential environmental impact, use of a fabric filter baghouse is still considered to be the top-ranked control option.

B-1.11.4 PROPOSED BACT LIMITS AND CONTROL OPTION

Based on the foregoing discussion, the proposed option to establish BACT emission limits for PM/PM_{10} emissions from the storage domes is the use of fabric filter baghouses. The emission control efficiency proposed for the baghouse is 99.9%, which is equivalent to the more stringent prior BACT determinations, based on those identified in Table B-1-8

B-1.12 GASIFICATION FLARE BACT ANALYSIS

B-1.12.1 PROCESS DESCRIPTION

The coal/petcoke gasification process includes an elevated enclosed flare to burn partially combusted natural gas and scrubbed/desulfurized off-specification syngas during unit startups, or on-specification syngas during short-term combustion turbine outages. Syngas sent to the flare during normal planned flaring events will be filtered, water-scrubbed and further treated in the Selexol® or equivalent and mercury removal systems to remove regulated contaminants prior to flaring. Flaring of untreated syngas or other streams within the plant would only occur as an emergency safety measure during unplanned plant upsets or equipment failures. The flame will be enclosed in a refractory-lined combustion chamber, effectively eliminating any visible flame and significantly reducing noise levels.

The gasification process flare will emit criteria pollutants that are products of combustion. However, the chemical compositions of the predominant gaseous fuels that would be flared, i.e., syngas and natural gas, results in very low emissions of PM_{10}, SO_x and VOC. For the syngas case, there is very little unoxidized carbon in the fuel, which limits the formation of particulate matter during combustion even below the rate for natural gas. Formation of SO_x is limited by the pre-treatment of the syngas flare stream using Selexol® or equivalent, and the inherently low sulfur content of pipeline natural gas. The rate of VOC emission can be conservatively represented by the EPA Document AP-42 factor for external combustion of natural gas. This factor is expected to overestimate VOC emission rates during flaring of syngas, because that fuel is relatively higher in hydrogen and lower in total carbon.

B-1.12.2 COMMERCIALLY AVAILABLE CONTROL TECHNOLOGIES

Review of the federal RBLC database and selected state permit information indicates that low emission design/low NOx burners and regulation of the chemical composition of the flared gases are currently (since 2004) the prevalent BACT options for flares. Table B-1-9 lists recent examples of BACT determinations for flare add-on devices for destruction of emissions to provide guidance in the selection and ranking of commercially proven technology options. For purposes of identifying available control technology options, this portion of the PMEC process can be viewed as substantially similar to hydrocarbon flares in petroleum refineries. Control technologies that may be considered potentially available for the gasification process flare include:

TABLE B-1-9
REVIEW OF RECENT BACT DETERMINATIONS FOR INDUSTRIAL FLARES

Permit or RBLC ID	Permit Issuance Date	Location	Company	System Description	Maximum Production Rate	Limit(s)	Control Option	Basis
AZ-0046	04-14-05	Yuma, AZ	Arizona Clean Fuels	Refinery Emergency Flares	N/A	No visible emissions. Exit velocity > 60 fps. Max H_2S 0.10 gr/dscf	Flare and burner design. Natural gas purge and steam assisted pilot	PSD-BACT
VT-0019	12-16-04	Orleans County, VT	New England Waste Services Inc	Landfill gas Flare	5000 scfm	CO – 0.37 lb/MMBtu NO_x – 0.0680 lb/MMBtu	Low Emission Design	Other Case-by-Case
IA-0074	08-16-04	Linn County, IA	Archer Daniels Midland Corn Processing	Flare (Natural Gas)	27 MMBtu/hr	SO_2 - 0.02 lb/hr NO_X – 4.05 lb/hr	Natural gas only and low NO_x burner on flare	BACT-PSD
AR-0077	07-22-04	Mississippi County, AR	Steelcorr Inc	Degasser Hotwell Flare (Natural gas)	N/A	PM_{10} – 7.32 lb/hr SO_2 – 0.09 lb/hr VOC – 1.06 lb/hr CO – 1.06 lb/hr NO_x – 0.01 lb/hr	Hotwell and only natural gas combustion	BACT-PSD

Good Combustion Practices - A certain level of flame temperature control can be exercised for the enclosed flare by implementing fuel/air ratio control. In its most sophisticated form, this control utilizes feedback control from oxygen monitors to modulate fuel and air rates in order to maintain the load demand, while reducing pollutant formation. Flare BACT options that have been achieved in practice in California and Texas (e.g., California Air Pollution Control Officers Association [CAPCOA] BACT Clearinghouse) indicate the incorporation of "proper burner management and monitoring" are used to control the emissions of CO, VOCs and NO_x.

Air-Assisted or Steam-Assisted Pilot Burner - Particulate emissions from flares are controlled by using steam injection or air assist to promote proper mixing and complete combustion. This measure provides a reduction in visible emissions that could result from incomplete combustion. In addition, the BACT guidance for flare sources issued by the TNRCC requires monitoring of flame integrity and smokeless design by using air-assist or water- or steam-injection.

Add-On Controls - The gasification system flare is not a candidate for add-on abatement systems. It is generally recognized in the chemical process industries that adoption of add-on control can impede the ability of a flare to respond to unexpected upset conditions. For plant safety, the flare must provide a "fail-safe" that is available regardless of the functioning of pollution control devices.

Chemical Composition of the Flared Gases – This option generally addresses the emissions of PM_{10}, SO_2 and VOC from the flare. As described above, the flaring of either syngas or natural gas results in relatively low emissions of these pollutants, in part because of the relatively low carbon to hydrogen ratio in syngas. It is accepted practice in the chemical process and utility industries that control of SO_2 is achieved by using natural gas-fired pilots or limiting the sulfur content of the flared gases. Prior BACT determinations for flares at refineries have also imposed limits on the hydrogen sulfide (H_2S) content of the flared gases. In keeping with these precedents, the PMEC will use Selexol® or equivalent cleaning of syngas streams sent to the flare.

B-1.12.3 TECHNICALLY INFEASIBLE OPTIONS

Low-NO_x burners (LNB) and ultralow NO_x burners (ULNB) technology is not available for enclosed, ground-level flares, which do not have a confined combustion zone that would allow staged introduction of fuel and air streams. Such designs alter air to fuel ratio in the combustion zone by staging the introduction of the air to promote a "lean-premixed" flame. This results in lower combustion temperatures and reduced NOx formation.

In industrial practice, add-on controls are not considered feasible, or even advisable from a plant safety standpoint. The elevated operating temperature regime of the exhaust gas eliminates from consideration most add-on controls. It is generally recognized in the chemical process industries that adoption of add-on control can impede the ability of a flare to respond to unexpected upset conditions. For plant safety, the flare must provide a "fail-safe" that is available regardless of the functioning of pollution control devices. A flare system is intended to be an inherently simple and reliable system with as few failure modes as possible. Should an add-on control device not

be operational on an occasion when flaring was necessary, it would likely be damaging to both the flare and the control if the hot gases were released with the control device off-line.

B-1.12.4 PROPOSED BACT LIMITS AND CONTROL OPTION

The flare for the PMEC facility will be designed to meet the BACT achieved-in-practice conditions achieved in California (SCAQMD) and Texas (TCEQ). For example, the flares have been designed to maintain an exit velocity above 60 feet per second under all conditions. In addition, the flare will have a natural gas purge and steam or air-assisted mixing at the pilot flame to achieve negligible particulate emissions. These design features are included in the emission calculations for the flare during upset conditions, as presented in this Application.

B-1.13 BACT ANALYSIS TANK VENT COLLECTION AND VAPOR DESTRUCTION SYSTEN

B-1.13.1 PROCESS DESCRIPTION

A tank vent collection and vapor destruction system is proposed to convert off-gas components in various process tank vents to oxidized forms (SO_x, NO_x, H_2O, and CO_2) before venting them to the atmosphere. For the gasification and syngas cleanup processes, the tank vent streams are composed primarily of air purged through various in-process storage tanks. Heat recovery will be accomplished by steam generation in a heat exchanger contacting the hot exhaust gas from the tank vent incinerator before it is directed to a stack. Treated streams may include:

- Air purged through various in-process storage tanks and the slag handling dewatering system off-gas. This tank purge gas may contain very small amounts of sulfur-bearing components.
- In the blending of gasifier feed (that can include treated recycled water and slag fines recycled from other areas of the gasification plant), tanks, drums and other areas of potential fuel exposure to the atmosphere will be covered and vented into the tank vent collection system for emission control.
- Sweep nitrogen introduced into the sulfur pit (to prevent the accumulation of an otherwise potentially explosive mixture of H_2S and air) is collected and fed to the tank vent gas incinerator.

The combined vent streams will generally contain components similar to those in syngas, creating a unique fuel stream that is unlike any found for permitted combustors in the RBLC database (see Table B-1-10). For this reason, pollutant emissions are addressed on an individual basis in this analysis, and compared to existing facilities where appropriate. The combustor emissions are largely dependent on burner specifications for this unique fuel.

TABLE B-1-10
REVIEW OF RECENT BACT DETERMINATIONS TANK VENT COLLECTION / DESTRUCTION SYSTEM

Permit or RBLC ID	Permit Issuance Date	Location	Company	System Description	Maximum Production Rate	Limit(s)	Control Option	Basis
AZ-0046	04-14-05	Yuma, AZ	Arizona Clean Fuels	Group B Storage Tanks	47 Tanks from 378,000 to 7,560,000 gal	VOC – 99% destruction, or VOC < 20 ppm at 3% O2	Internal floating roofs with thermal oxidizer	BACT-PSD
NC-0111	07-29-04	Bertie County, NC	Avoca Inc	Rotocel operation Solvent Recycle Tanks	NA	VOC - 0.94 lb/hr	Chilled water-cooled condenser and packed tower scrubber.	BACT-PSD
	7-15-04	Minnesota	Fairbault Energy Park	IGCC Tank Vent oxidizer	40 MMBtu/hr	VOC: Oil-fired – 0.003 lb/MMBtu; Gas fired – 0.006 lb/MMBtu	Good combustion practices	BACT-PSD
	9-29-04	Minnesota	Mankato Energy Center	IGCC Tank Vent oxidizer	70 MMBtu/hr	VOC: Gas fired – 0.007 lb/MMBtu	Good combustion practices	BACT-PSD
OH-0288	06-14-04	Medina County, OH	Owens Corning	Oxidized Asphalt fixed Roof Storage Tanks	60,000 gal tank	PM – 0.01 lb/hr SO_2 – 0.21 lb/hr VOC – 0.05 lb/hr CO – 0.02 lb/hr H_2S – 0.0060 lb/hr 0% opacity	Fixed roof tank and thermal incinerator	BACT-PSD
TX-0375	03-14-02	Harris County, TX	Lyondell	Sour Water Tanks	NA	H_2S – 0.04 lb/hr	Emissions will be collected by a vapor collection system and routed to a control device with a destruction efficiency of 98%.	NSPS
TX-0375	03-14-02	Harris County, TX	Lyondell	Molten Sulfur Storage Tanks	NA	H_2S – 0.0010 lh/hr		

B-1.13.2 NITROGEN OXIDES BACT ANALYSIS

Identification of Available Control Options

For a tank vent collection and thermal destruction system, a number of measures may be considered potentially available for NO_x control:

- Selective Catalytic Reduction (SCR)
- Selective Non-Catalytic Reduction (SNCR)
- Low NO_x Burners (LNB)
- Flue Gas Recirculation (FGR)
- Efficient Burner Design /GCP

B-1.13.2.2 Infeasible Control Measures

In order to achieve adequate destruction efficiencies, the tank vent vapor destruction device requires a relatively high combustion flame temperature and extended residence time, both of which are fundamentally incompatible with low NO_x burner technology and flue gas recirculation (FGR). These two technologies are based on reducing the flame temperature to inhibit NO_x formation. In the case of LNB, flame temperature is reduced by staged mixing of fuel and air. The FGR system introduces cooler stack gases with reduced oxygen content into the combustion chamber. Both mechanisms reduce flame temperature in a manner that would have an adverse affect on thermal destruction efficiency. Consequently, dry low-NO_x burners and flue gas recirculation are considered technically infeasible for incineration of tank vent streams.

SCR is not considered a technically feasible control option based on all of the same disadvantages described for SCR application to IGCC turbines in Section B-1.7.1.2. The in-process tank and slag dewatering vent streams will have substantially higher sulfur content than the syngas. Even at the reduced sulfur content levels of the syngas, use of catalyst-based destruction and ammonia injection would result in heavy fouling of the catalyst module material and the downstream heat recovery device on the tank vent thermal oxidizer.

There are two related reasons why SNCR is viewed as technically infeasible for the tank vent gas destruction device. Primarily, there are anticipated to be unacceptable levels of fouling of heat transfer surfaces in the heat recovery section if ammonia is injected upstream. If instead the ammonia is injected downstream of the heat recovery section, the gas temperature will be too low for effective conversion of NO_x . Therefore, this technology is not feasible for the tank vent thermal incinerator.

B-1.13.2.3 Proposed BACT Control Option and Emission Limits

Efficient burner design and good combustion practices are proposed as the BACT option for the tank vent oxidizer unit. The burner for the proposed thermal oxidizer unit would be specified by the vendor to minimize NO_x formation, while accommodating the variable composition of the

unique process gas stream. No add-on combustion controls are technically feasible for this application. The proposed BACT-based limit for this source is 0.3 lb NO_x/MMBtu, based on anticipated performance specifications from the vendor.

B-1.13.3 SULFUR DIOXIDE AND PM_{10} BACT ANALYSIS

Tank purge gases may contain very low levels of sulfur-bearing compounds, which will contribute to SO_2 and PM_{10} emissions during thermal destruction of these gases. The proposed vapor destruction incinerator will offer oxidizing conditions to convert any H_2S present in the tank vents to SO_2.

B-1.13.3.1 Identification of Available Control Options

Sulfur dioxide emissions from any combustion process are directly related to the sulfur content of the fuel, which is also a key factor determining the magnitude of PM_{10} emissions. Potentially available controls for the tank vent oxidizer include pre-combustion controls to limit the sulfur content of the treated streams, combustion controls, or scrubbing the SO_2 from the exhaust gas (post-combustion control):

<u>Pre-Combustion Process Controls (fuel specification)</u>

- Chemical Absorption Acid Gas Removal (AGR), e.g., MDEA
- Physical Absorption, e.g., Selexol®, Rectisol®
- Use of low-sulfur pipeline natural gas

<u>Combustion Controls</u>

- Good combustion practices (GCP)

<u>Post-Combustion Controls</u>

- Flue Gas Desulfurization (FGD)

B-1.13.3.2 Evaluation of Potentially Available Control Options

A discussion of the pre-combustion controls related to syngas production was provided in Section B-1.7.2. Combustion controls consist of good combustion practices, which as shown in Table B-1-11, is currently the prevalent control option for thermal destruction devices. FGD, which is the sole post-combustion control that is considered potentially available for this oxidizer, has not been demonstrated in practice for such sources or for the gas streams that will be incinerated, and is viewed as infeasible.

B-1.13.3 3 Proposed BACT Limits and Control Option

Emissions of SO_2 (and indirectly PM_{10}) can be effectively controlled by limiting the sulfur content of streams routed to the vent gas collection system. Therefore, the control of chemical composition of the treated streams, combined with good combustion practices are the options

proposed as the BACT option to limit SO_2 emissions from this process. The numerical emission limits are dependent upon the averaging time selected, as discussed below.

The anticipated compositions of the syngas, natural gas supply, and other treated streams routed to the tank vent oxidizer were evaluated to estimate the suitable BACT-based emission limits for oxidizer SO_2 emissions. For the PMEC combustion turbines, the syngas sulfur level representing short-term maximum concentration is estimated at 50 ppmvd (expressed as H_2S) in the undiluted syngas, on a 1-hour average basis. Substantially lower sulfur content would be achieved over longer averaging times; for example, 15 ppmvd is foreseen as the maximum concentration on a 24-hour average basis. The treated stream from the sulfur pit would be at comparable worst-case concentrations, but its contribution would be limited by its relatively small flow rate. These worst-case sulfur content levels can be used as the basis for BACT emission limits of 5.8 lb/hr SO_2 on a 1-hour average, and 4.2 lb/hr on a 24-hour average.

Good combustion practices represent the primary control that affects PM_{10} emissions. For the tank vent oxidizer the proposed BACT limit based on this technology, for combustion of either natural gas or syngas, is 0.01 lb/MMBtu PM_{10}.

B-1.13.4 VOLATILE ORGANIC COMPOUND BACT ANALYSIS

B-1.13.4.1 Identification of Available Control Options

Review of the federal RBLC database and selected state permit information indicates that several technologies have been identified in BACT determinations for destruction of VOC-containing off-gases from storage or process vessels. For identification of commercially available control technologies, this portion of the PMEC process can also be viewed as analogous to tank farms or process tanks in conventional petroleum refineries, chemical process plants, and loading terminals. However, because the use of a thermal oxidizer is included as part of the process, only VOC controls related to external combustion devices were considered.

Recent BACT determinations for refineries, chemical facilities, and IGCC facilities permitted in Minnesota with small (< 100 MMBtu/hr) natural gas-fired boilers were subject to the requirements listed in Table B-1-10. The commercially available VOC controls for the tank vent oxidizer are limited to good combustion practices.

The waste syngas and natural gas streams that will be the predominant gas streams routed to the vent gas collection system both have a relatively low potential to generate VOC in the combustion process. The syngas is relatively high in hydrogen and CO, with very small amounts of hydrocarbons. So the negligible level of uncombusted VOC emissions in the gas streams to the incinerator do not warrant extensive add-on controls.

B-1.13.4.2 Proposed BACT Limits and Control Option

VOC emissions from the tank vent thermal oxidizer would generally be products of incomplete combustion. Good combustion practices represent the primary control that affects VOC emissions. For the tank vent oxidizer the proposed BACT limit based on this technology, for combustion of either natural gas or syngas, is 0.004 lb VOC/MMBtu.

B-1.13.5 CARBON MONOXIDE BACT ANALYSIS

B-113.5.1 Identification of Available Control Options

Review of the federal RBLC database and selected state permit information indicates that BACT determinations for CO emissions from thermal destruction of organic gas streams consistently specify good combustion practices as the sole control measure required. Several recent BACT determinations for refineries, chemical facilities, and IGCC facilities permitted in Minnesota with small (< 100 MMBtu/hr) natural gas-fired boilers are listed in Table B-1-11.

B-113.5.2 Proposed BACT Limits and Control Option

Emissions of CO from the tank vent thermal oxidizer would generally be products of incomplete combustion. As the proposed BACT option, CO emissions from this external combustion device will be controlled by good combustion practices. For the tank vent oxidizer the proposed BACT limit based on this technology, for combustion of either natural gas or syngas, is 0.09 lb/MMBtu.

B-1.14 AUXILIARY BOILER BACT ANALYSIS

B-1.14.1 PROCESS DESCRIPTION

One auxiliary boiler will serve the two PMEC generating trains, will provide steam for pre-startup equipment warmup and for other miscellaneous purposes when steam from the gasifiers or HRSGs is not available. This boiler will provide steam in addition to, or in lieu of, the steam that can be generated from the HRSG units provided on the tank vent incinerators. The auxiliary boiler will produce a maximum of about 100,000 lb/hr of steam and will be fueled only by pipeline quality natural gas.

Pollutant emissions from natural gas boiler units include NO_x, PM_{10}, CO, SO_2, and VOCs. Annual operation of the boiler will be equivalent to or less than 25% of the year at maximum capacity.

B-1.14.2 COMMERCIALLY AVAILABLE CONTROL TECHNOLOGIES

Review of the federal RBLC database and selected state permit information indicates that several technologies have been identified in BACT determinations. This portion of the PMEC process can be viewed as substantially similar to auxiliary boilers that are often included in combined cycle power generation units fired on natural gas. Table B-1-11 lists a number of typical BACT determinations in recent years for auxiliary and industrial boiler equipment. The RBLC database survey results indicate that available BACT options for the pollutants emitted from auxiliary boilers include:

- Good Combustion Practices (GCP)
- Staged Air/Fuel Combustion or Overfire Air Injection (OFA)
- Low NOx burners (LNB)
- CO Oxidation Catalysts

- Flue Gas Recirculation (FGR)
- Selective Catalytic Reduction (SCR)
- Low sulfur fuels

B-1.14.3 NO_X BACT ANALYSIS

Several combustion and post-combustion controls are commercially available for the auxiliary boiler. These controls include staged air/fuel combustion, Low-NO_x burners, flue gas recirculation, and SCR. The range of BACT NO_x emission limits for recently permitted auxiliary boilers (since 2004) is from 0.011 lb/MMBtu to 0.7 lb/MMBtu.

B-1.14.3.1 Ranking of Available Control Technologies

The identified control technologies are considered technically feasible for gaseous fuel fired boilers. Consequently, these controls will be ranked and evaluated for each pollutant for which BACT is required. In top-down order of decreasing stringency, the feasible NO_x controls are listed with the approximate level of emission reduction afforded by each technology:

- Low NO_X Burners with SCR 0.011 lb/MMBtu
- Low NO_X Burners with FGR 0.020 lb/MMBtu
- Low NO_X Burners with GCP 0.036 lb/MMBtu
- FGR Alone 0.20 lb/MMBtu
- Staged air/fuel or OFA 0.25 lb/MMBtu
- GCP, Conventional Burners 0.30 lb/MMBtu (BACT Baseline)

B-1.14.3.2 Consideration of Energy, Environmental And Cost Factors

Alternative add-on emission control techniques are available and technically feasible for reduction in NO_X emissions from auxiliary boilers. These are in addition to combustion controls, namely GCP in combination with Low-NO_X burners.

With respect to energy factors, add-on post-combustion controls on an auxiliary boiler of this capacity range will noticeably reduce the thermal efficiency of the unit. Catalyst modules increase the back-pressure downstream of the combustion chamber by several tenths of an inch of water, depending upon design. In addition, there are thermal losses associated with the heat-up of the catalyst modules of an SCR.

TABLE B-1-11
REVIEW OF RECENT BACT DETERMINATIONS FOR AUXILIARY BOILERS

Permit or RBLC ID	Permit Issuance Date	Location	Company	System Description	Maximum Production Rate	Limit(s)	Control Option	Basis
MN-0062	12-22-05	Sibley County, MN	Heartland Corn Products	Boiler	198 MMBtu/hr	NO_X – 0.04 lb/MMBtu CO – 0.04 lb/MMBtu	Not Described	BACT-PSD
NC-0101	09-25-05	Forsyth County, NC	Forsyth Energy Projects, LLC	Auxiliary Boiler	110.2 MMBtu/hr	NO_X – 15.13 lb/hr (0.14 lb/MMBtu) SO_X – 0.61 lb/hr (0.0055 lb/MMBtu) CO – 9.08 lb/hr (0.082 lb/MMBtu) VOC – 0.59 lb/hr PM_{10} – 0.82 lb/hr	Low NO_X burners, Good Combustion Control, Clean Burning, and Low-Sulfur Fuel	BACT-PSD
OR-0046	01-06-05	Marion County, OR	Calpine	Auxiliary Boiler	417,904 MMBtu/yr	CO – 0.0380 lb/MMBtu NO_X – 0.0110 lb/MMBtu VOC – 0.0044 lb/MMBtu	SCR	BACT-PSD
WI-0228	10-19-04	Marathon County, WI	Wisconsin Public Service	Auxiliary Boiler	229.8 MMBtu/hr	PM_{10} – 0.0075 lb/MMBtu SO_2 – 0.0006 lb/MMBtu NO_X – 0.10 lb/MMBtu CO – 0.08 lb/MMBtu VOC – 0.0054 lb/MMBtu Hg - 0.0001 lb/hr	Low NOx burners, Good Combustion Practices, and only natural gas.	BACT-PSD
MI-0368	09-08-04	Calhoun County ,MI	Michigan Paperboard Company	Boiler	185 MMBtu/hr	SO_2 – 280 lb/hr (1.51 lb/MMBtu)	Not Described	BACT-PSD
NE-0024	06-22-04	Washington County, NE	Cargill, Inc.	Boiler	198 MMBtu/hr	NO_X – 0.07 lb/MMBtu 20% Opacity	Low NO_X burners and Induced Draft Flue Gas Recirculation	Other Case-by-Case

TABLE B-1-11 (Continued)
REVIEW OF RECENT BACT DETERMINATIONS FOR AUXILIARY BOILERS

Permit or RBLC ID	Permit Issuance Date	Location	Company	System Description	Maximum Production Rate	Limit(s)	Control Option	Basis
MS-0069	06-08-04	Harrison County, MS	E.I. Dupont De Nemours	Boiler	231 MMBtu/hr	PM_{10} – 1.76 lb/hr NO_X – 0.09 lb/MMBtu	Low NO_X burners with FGR	BACT-PSD
OH-0241	05-27-04	Butler County, OH	Miller Brewing Company	Boiler	238 MMBtu/hr	PM_{10} – 0.01 gr/acf NO_X – 0.70 lb/MMBtu VOC – 2.6 lb/hr CO – 20 lb/hr SO_2 – 1.6 lb/MMBtu	Baghouse, Over fire and side fire air	BACT-PSD
ID-0015	04-05-04	Power County, ID	JR Simplot Company	Boiler	175 MMBtu/hr	NO_X – 7 lb/hr (0.0400 lb/MMBtu)	Low NO_X Burners	RACT
WV-0023	03-02-04	Monongahela County, WV	Longview Power, LLC	Auxiliary Boiler	225 MMBtu/hr	CO – 0.04 lb/MMBtu NO_X – 0.0980 lb/MMBtu PM & PM_{10} – 0.0022 lb/MMBtu SO_2 – 0.0040 lb/hr VOC – 0.0054 lb/MMBtu 10% opacity	Good Combustion Practices, use of low sulfur natural gas, and Low NOX burners	BACT-PSD

Environmental factors associated with post-combustion catalytic systems have affected many recent boiler installations. Generally, these involve the need for ammonia reagent, in the case of SCR, and the effects of spent catalyst module. Both of these factors remain disadvantages of catalyst-based add-on controls. Ammonia slip, the amount of unreacted ammonia that is released from boilers equipped with SCR remains an additional environmental impact. This is usually mitigated by using predictive feed rate control, based on the real-time firing rate or percentage of full-load. Initial performance testing usually includes ammonia slip tests to verify that the control logic is maintaining ammonia emissions within permitted limits.

Differential cost is the primary factor that argues against costly add-on control technologies for auxiliary boilers. As these boilers are not continuously operated, but rather are used during relatively infrequent start-up cycles, the emissions abated can be shown not to warrant the investment in capital and operating costs associated with such controls. An annualized cost analysis for the proposed PMEC auxiliary boiler has been conducted to demonstrate this cost barrier. This cost analysis separately considered the two more stringent levels of control above that proposed by PMEC, namely, the use of FGR and SCR as additional control for NO_x emissions. The findings of these cost analyses are summarized in Table B-1-12 (refer to Attachment X2 for further details).

TABLE B-1-12
ECONOMIC ANALYSIS OF POST-COMBUSTION NO_X CONTROLS FOR PMEC AUXILIARY BOILER

Additional Control Option	Controlled Emissions Basis	Estimated Total Capital Investment	Estimated Annualized Costs ($/yr)	Baseline Emissions or Reduction (tons/yr)	Cost Effectiveness ($ / ton)
SCR	0.011 lb/MMBtu, 70% reduction	$813,700	$182,997	4.34	$42,214
FGR	0.2 lb/MMBtu, 45% reduction	$115,500	$34,191	3.06	$11,174
Baseline Option (GCP, Low-NO_X Burner)	4.7 lb/hr	---	---	5.1 (Controlled Emissions)	---

Both the SCR and FGR add-on control technologies for the auxiliary boiler would be cost prohibitively expensive in terms of cost per ton of NO_x abated. The implementation of FGR has an estimated annualized cost of over $34,000, and provides a reduction of 3.06 tons per year compared with the baseline option of GCP. Similarly, the addition of an SCR system on this unit has an estimated annualized cost of $182,987 and would provide a reduction of 4.34 tons per year. From these results, the cost effectiveness of FGR and SCR options are conservatively estimated to be not less than $11,000 and $42,000 per ton, respectively.

B-1.14.3.3 Proposed BACT Limits and Control Option

As illustrated in Table B-1-12, the limited operating period for the auxiliary boiler results in prohibitively high annualized cost per ton abated for technically feasible post-combustion controls. This cost factor, in combination with the environmental and energy related drawbacks of such controls, leads to the proposed NO_x BACT option of GCP with Low-NO_x burners. Boiler vendor information indicates that the hourly emissions for this unit with these technologies will be about 0.036 lb/MMBtu NO_x. This rate, or a corresponding lb/hour emission rate, is proposed as the BACT NO_x limit for emissions from the auxiliary boiler emission unit.

B-1.14.4 CO BACT ANALYSIS

Only one post-combustion control is commercially available for the auxiliary boiler. This control is the implementation of an oxidation catalyst module. Based on the RBLC review presented in Table B-1-11, the range of BACT CO emission limits for recently permitted auxiliary boilers (since 2004) is from 0.038 lb/MMBtu to 0.08 lb/MMBtu. BACT for CO on most units is GCP.

B-1.14.4.1 Ranking of Available Control Technologies

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

- Oxidation Catalyst and GCP 90% control
- GCP 0.74 lb/MMBtu (BACT baseline)

B-1.14.4.2 Consideration of Energy, Environmental and Cost Factors

The use of oxidation catalyst modules as add-on emission control is available and technically feasible for reduction in CO emissions from auxiliary boilers. These are in addition to combustion controls, namely GCP in combination with Low-NO_x burners.

With respect to energy factors, add-on post-combustion controls on an auxiliary boiler of this capacity range will noticeably reduce the thermal efficiency of the unit. Catalyst modules increase the back-pressure downstream of the combustion chamber by several tenths of an inch of water, depending upon design. Environmental factors associated with post-combustion catalytic systems have affected many recent boiler installations. Generally, these involve the effects of spent catalyst module disposal.

Prohibitively high annualized cost is the primary factor that argues against costly add-on control technologies for auxiliary boilers. Since the boiler is not continuously operated, but rather used during relatively infrequent start-up cycles, the emissions abated can be shown to not warrant the investment in capital and operating costs. An annualized cost analysis for the proposed PMEC auxiliary boiler is provided to demonstrate this cost barrier. The findings of these cost analyses are summarized in Table B-1-13. (refer to Attachment _X2 for additional details)

TABLE B-1-13
ECONOMIC ANALYSIS OF POST-COMBUSTION CO CONTROLS FOR PMEC AUXILIARY BOILER

Additional Control Option	Controlled Emissions Basis	Estimated Total Capital Investment	Estimated Annualized Costs ($/yr)	Baseline Emissions or Reduction (tons/yr)	Cost Effectiveness($ / ton)
Catalytic Oxidizer	0.0074 lb/MMBtu, 90% reduction	$625,382	$153,346	9.45	$16,227
Baseline Option (GCP)	9.6 lb/hr	---	---	10.5	---

The add-on CO control technology for the auxiliary boiler would be cost prohibitive in terms of cost per ton abated. The implementation of a catalytic oxidizer module has an estimated annualized cost of over $153,000, and provides a reduction of 9.45 tons per year, compared with the baseline option of GCP. From these results, the cost effectiveness of the catalytic oxidizer option is conservatively estimated to be not less than $16,000 per ton.

B-1.14.4.3 Proposed BACT Limits and Control Option

As illustrated in Table B-1-12, the limited operating period for the auxiliary boiler results in prohibitively high annualized cost per ton abated for feasible post-combustion controls. This cost factor, in combination with the environmental and energy related drawbacks, leads to the proposed BACT option of GCP for CO emissions. Boiler vendor information indicates that the worst case hourly emissions for this unit with these technologies will be 0.074 lb CO/MMBtu. This rate, or a corresponding lb/hour emission rate, is proposed as the BACT limit for CO emissions from the auxiliary boiler emission unit.

B-1.14.5 SO_2, VOC, PM_{10} BACT ANALYSIS

B-1.14.5.1 Ranking of Available Control Technologies

For these pollutants, the commercially available control measures that are identified in the most-stringent BACT determinations are use of low-sulfur, pipeline quality natural gas, and GCP. Based on review of the RBLC database in Table B-1-11, add-on controls were not implemented to achieve BACT limits for these pollutants. The ranges of BACT emission limits for these pollutants are:

- SO_x = 0.0006 lb/MMBtu to 0.082 lb/MMBtu
- VOC = 0.0044 lb/MMBtu to 0.0054 lb/MMBtu
- PM_{10} = 0.0044 lb/MMBtu to 0.0075 lb/MMBtu

The two most-stringent available technologies are to be adopted for the PMEC auxiliary boiler, so further evaluation is unnecessary.

B-1.14.5.2 Proposed BACT Limits and Control Option

The limited operating period for the auxiliary boiler results in relatively low emissions of SO_2, VOC and PM_{10}, meaning that an investment in complex add-on controls is not warranted. Therefore, the use of pipeline natural gas and GCP are proposed as the BACT options for this source. Boiler vendor information indicates that the worst case hourly emissions for this unit with these technologies will be 0.005 lb SO_2/MMBtu, 0.004 lb VOC /MMBtu and 0.005 lb PM_{10}/MMBtu.These rates, or corresponding lb/hour emission rates, are proposed as BACT limits for the auxiliary boiler emission unit

B-1.15 COOLING TOWER BACT ANALYSIS

B-1.15.1 PROCESS DESCRIPTION

The proposed cooling system at the PMEC consists of a circulating water system that will utilize a larger (12-cell) mechanical draft cooling tower to support operations of the steam turbine generators. Each of the two generating plants will have independent cooling tower sections, with 6 cells per plant in a combined structure approximately 400 feet long, 120 feet wide, and 40 feet high. A second, smaller tower is also included in the design to support the cooling needs of the remainder of the PMEC, including syngas production and cleanup.

Wet (evaporative) cooling towers emit aqueous aerosol “drift” particles that evaporate to leave crystallized solid particles that are considered PM_{10} emissions. The proposed control technology for PM_{10} is high-efficiency drift eliminators to capture drift aerosols upstream of the release point to the atmosphere.

B-1.15.2 COMMERCIALLY AVAILABLE CONTROL TECHNOLOGIES

Utility generation facilities, refineries, and other large chemical processing plants utilize wet mechanical draft cooling towers for heat rejection. This portion of the PMEC plant can be viewed as substantially similar to such processes.

Review of the federal RBLC database and recent Washington state permits for utility-scale cooling towers indicates that high efficiency drift eliminators and limits on total dissolved solids (TDS) concentration in the circulating water are the techniques which set the basis for cooling tower BACT emission limits. The efficiency of drift eliminator designs is characterized by the percentage of the circulating water flow rate that is lost to drift. The drift eliminators to be used on the proposed cooling tower will be designed such that the drift rate is less than a specified percentage of the circulating water. Typical geometries for the drift eliminators include chevron blade, honeycomb, or wave form patterns, to attempt to optimize droplet impingement at minimal pressure drop.

Table B-1-14 summarizes recent BACT determinations for utility-scale mechanical draft cooling towers. The commercially available techniques listed to limit drift PM_{10} releases from utility-scale cooling towers include:

- Use of Dry Cooling (no water circulation) Heat Exchanger Units
- High-Efficiency Drift Eliminators, as low as 0.0005% of circulating flow
- Limitations on TDS concentrations in the circulating water
- Combinations of Drift Eliminator efficiency rating and TDS limit
- Installation of Drift Eliminators (no efficiency specified)

The use of high-efficiency drift eliminating media to de-entrain aerosol droplets from the air flow exiting the wetted-media tower is commercially proven technique to reduce PM_{10} emissions. Compared to "conventional" drift eliminators, advanced drift eliminators reduce the PM_{10} emission rate by more than 90 percent.

In addition to the use of high efficiency drift eliminators, management of the tower water balance to control the concentration of dissolved solids in the cooling water can also reduce particulate emissions. Dissolved solids accumulate in the cooling water due to increasing concentration of dissolved solids in the make-up water as the circulating water evaporates, and, secondarily, to addition of anti-corrosion, anti-biocide additives. However, to maintain reliable operation of the tower without the environmental impact of frequent acid wash cleanings, the water balance must be considered. The proposed PMEC tower will be based on 12 cycles of concentration, that is, the circulating water will be on average 12 times the dissolved solids concentration of the make-up water that is introduced. The proposed cooling tower is to be operated at a design level of total dissolved solids (TDS) concentration of 2,400 ppmw in the cooling water, based on 200 ppmw in the make up water.

Lastly, the substitution of a dry cooling tower is a commercially available option that has been adopted (usually because of concerns other than air emissions) by utility-scale combined cycle plants in arid climates. This option involves use of a very large, finned-tube water-to-air heat exchanger through which one or more large fans force a stream of ambient dry air to remove heat from the circulating water in the tube-side of the exchanger.

B-1.15.3 INFEASIBLE CONTROL MEASURES

One measure that has been adopted in arid, low precipitation climates is the use of a dry, i.e., non-evaporative cooling tower for heat rejection from combined-cycle power plants. Where it has been adopted, this measure is usually a means to reduce the water consumption of the plant, rather than as BACT for PM_{10} emissions. There is a very substantial capital cost penalty in adopting this technology, in addition to the process changes (e.g., operating pressures) necessary to condense water at the ambient dry bulb temperature, rather than at ambient wet bulb temperature. The plants for which this measure has been used are, with few exceptions, smaller capacity combined-cycle plants (smaller than the PMEC facility).

TABLE B-1-14
REVIEW OF RECENT BACT DETERMINATIONS FOR COOLING TOWERS

Permit or RBLC ID	Permit Issuance Date	Location/ Facility	Company	System Description	Maximum Production Rate	Limit(s)	Control Option	Basis
IA-0082	04-19-06	Cerro Gordo County, IA	Golden Grain Energy	Cooling Tower	NA	PM_{10} – 1.33 lb/hr	Mist Eliminators	BACT-PSD
NC-0101	09-29-05	Forsyth County, NC	Forsyth Energy Projects LLC	Cooling Tower	3834 gal/min	PM – 0.0070 lb/hr PM_{10} – 0.0020 lb/hr	NA	BACT-PSD
OR-0041	08-08-05	Umatilla County, OR	Diamond Wanapa I LP	Cooling Tower	6.2 ft^3/sec	PM – 3532 ppmw	Installation of high efficiency 0.0005% drift eliminators. Limit TDS to less than 3,532 PPMW.	BACT-PSD
CO-0057	07-05-05	Pueblo County, CO	Public Service Company of Colorado	Cooling tower	140,650 gal/min	PM – NA PM_{10} - NA	RACT is drift eliminators to achieve 0.0005 % drift or less.	BACT-PSD
LA-0192	06-06-05	Orleans County, LA	Cresent City Power LLC	Cooling Tower	290,200 gal.min	PM_{10} – 2.61 lb/hr	TDS = 30,000 PPM 0.0001% drift annual average (Marley Excel Drift Eliminators)	BACT-PSD
IN-0119	05-31-05	Dekalb County, IA	Auburn Nugget	Cooling Tower	23,450 gal/min	PM – 0.0050% of Throughput 20% opacity	NA	BACT-PSD
NV-0036	05-05-05	Eureka County, NV	Newmont Nevada Energy Investment LLC	Cooling Tower	NA	PM_{10} – 0.0005% drift	Drift Eliminators	BACT-PSD

TABLE B-1-14 (Continued)
REVIEW OF RECENT BACT DETERMINATIONS FOR COOLING TOWERS

Permit or RBLC ID	Permit Issuance Date	Location/ Facility	Company	System Description	Maximum Production Rate	Limit(s)	Control Option	Basis
AZ-0046	04-14-05	Yuma, AZ	Arizona Clean Fuels LLC	Cooling Tower	NA	PM – 1.6 lb/hr	High Efficiency Drift Eliminators	BACT-PSD
NY-0093	03-31-05	Nassau County, NY	Igen-Nassau Energy Corporation	Cooling Tower	NA	PM_{10} – 0.0005% drift	NA	BACT-PSD
NE-0031	03-09-05	Otoe County, NE	Omaha Public Power District OPPD	Cooling Tower	NA	PM_{10} – 0.0010 lb/hr	Cooling tower shall be equipped with high efficiency mist eliminators with a max total liquid drift not exceed 0.0005% of circulating water flow.	BACT-PSD
WA		Cherry Point	BP Refinery	Cogeneration Cooling Tower	NA	7.2 tpy	0.001% drift	BACT-PSD
WA		Hanging Rock Energy Facility	Duke Energy	Combined Cycle Unit Cooling Tower	NA	3.6 lb/hr	Drift Eliminators	BACT-PSD
WA		Mint Farm Generation		Combined Cycle Unit Cooling Tower	NA	1.08 tpy	Drift Eliminators	BACT-PSD
WA		Wallula Power Project		Combined Cycle Unit Cooling Tower	NA	3.7 lb/hr	Water pre-treatment and 0.0005% drift rate	LAER

A dry cooling tower is at best marginally feasible for PMEC duty, especially in light of the small emissions benefit that would be obtained. Because of the high capital cost and process design changes involved in the use of a dry cooling tower, this measure is viewed as infeasible for the PMEC project.

B-1.15.4 RANKING OF AVAILABLE CONTROL MEASURES

Because all of the commercially available options that could form the basis for a BACT emission limit for PM_{10} from the cooling tower are also technically feasible, this section will rank these options. The technically feasible option of high-efficiency drift eliminators can be implemented at different levels of stringency. Development of increasingly effective de-entrainment structures now allows a cooling tower to be specified to achieve drift release no higher than 0.0005 percent of the circulating water rate. This is the most stringent BACT option. There are no significant costs or environmental factors which favor implementation of a less-stringent drift eliminator option.

In "top down" order from most to less stringent, the potentially available candidate control techniques are:

- Combinations of high-efficiency drift eliminators and TDS limit
- High-Efficiency drift eliminators to control drift to as low as 0.0005% of circulating flow
- High-efficiency drift eliminators, as low as 0.001% of circulating flow
- Limitations on TDS concentrations in the circulating water
- Installation of Drift Eliminators (no efficiency specified)

B-1.15.5 CONSIDERATION OF ENERGY, ENVIRONMENTAL AND COST FACTORS

Development of increasingly effective de-entrainment structures has resulted in equipment vendors claims that a cooling tower may be specified to achieve drift release no higher than 0.0005 percent of the circulating water rate. This is the most stringent BACT-basis for emission limits in current permits, but it has not been verified by actual testing, according to process engineers for PMEC and others. Consequently, it is reasonable to identify this very-high efficiency drift eliminator to have not been demonstrated in practice.

Even incremental improvement in drift control involves substantial changes in the tower design. First, the velocity of the draft air that is drawn through the tower media must be reduced compared to "conventional" specifications. This is necessary to use drift eliminator media with smaller passages (to improve droplet capture) without encountering unacceptably high pressure drop. Since reducing the air velocity also reduces the heat transfer coefficient of the tower, it is likely that a proportional increase in the overall size of the media will be needed. For example, a 12-cell tower may need to be expanded to 14 cells in order to accommodate higher drift eliminator efficiency for the same heat rejection duty. These changes will also result in an energy penalty in the form of larger and higher powered fans to accommodate the improved

droplet capture. More importantly, there is a substantial increase in both tower operating costs and capital costs that deliver relatively few tons of PM_{10} abatement.

Adopting a TDS limit for the circulating water is usually viewed as a measure that benefits air quality by reducing the dissolved salts that can be precipitated from drift aerosols. To reduce TDS the facility must introduce a higher volume flow of make-up water to the tower. This has the potential environmental disadvantage of increasing the overall plant water requirements.

B-1.15.6 PROPOSED BACT LIMITS AND CONTROL OPTION

Based on the information from the RBLC database survey, and the energy and cost factors described above, the proposed BACT option for the PMEC cooling towers is use of drift eliminators achieving a maximum drift of 0.001% of the circulating water. This measure, along with a limit on the circulating water TDS to an average of 2,400 ppmw is considered to be the best available control option for particulate emissions from the cooling towers. Taken together, implementation of these two measures represents the most stringent control option that is technically feasible without being cost prohibitive.

B-1.16 INTERNAL COMBUSTION ENGINE BACT ANALYSIS

B-1.16.1 PROCESS DESCRIPTION

One 2 MW emergency diesel generator will be used for the gasification island. Additionally, one nominal 300 hp diesel-driven firewater pump will be provided for each plant (one diesel, one electric). These engines will burn very low sulfur distillate oil. Other than plant emergency situations, the engines will be operated less than five hours per month per engine for routine testing, maintenance, and inspection purposes.

This equipment will emit criteria pollutants associated with diesel-fired engines. As the specific equipment has not yet been specified, the generic emission factors provided by AP-42, Section 3.4 for large stationary diesel engines were used to estimate criteria pollutant emissions. These emission calculations are presented in Appendix URS-1 [This is the URS Excel file with the criteria pollutant emissions inventory.]of this Application.

B-1.16.2 NO_X BACT ANALYSIS

B-1.16.2.1 Available Control Technologies and Technical Feasibility

There are a limited number of technically-feasible NO_x control technologies that are commercially available for internal combustion engines. In practice, the high temperature and relatively low volumetric flow of the engine exhaust eliminates most post-combustion controls. Based on the RBLC database review presented in Table B-1-15, two general types of control options have emerged as technically feasible:

Combustion Process Modifications - This option is implemented in the design of the internal combustion engine. Typical design features include an electronic fuel/air ratio and timing controllers, pre-chamber ignition, intercoolers, and lean-burn fuel mix. Currently available new

engines include these features as standard equipment; accordingly this measure is deemed the baseline case for purposes of the BACT analysis.

Selective Catalytic Reduction (SCR) - In this technology, nitrogen oxides are reduced to gaseous nitrogen by reaction with ammonia in the presence of a supported precious metal catalyst. The SCR system includes a catalyst module downstream of the engine exhaust. Just upstream of the catalyst, a reagent liquid (typically ammonia or urea solution) is injected directly into the exhaust stream.
Another potentially available technology that has been eliminated from consideration on the grounds that it is technically infeasible is:

Non-Selective Catalytic Reduction (NSCR) – Similar to automobile catalytic converters, this method employs noble metal catalysts to oxidize nitrogen oxides to molecular nitrogen. It operates in regimes with less than 4% oxygen in the exhaust, which corresponds to fuel-rich operation. The method is not feasible with lean-burn internal combustion engines.

B-1.16.2.2 Energy and Environmental Considerations

There are several distinguishing factors between the two technically-feasible options with regard to energy and environmental impacts. One drawback associated with SCR systems is the environmental risk of handling and using ammonia reagent solutions. Most SCR catalyst modules can operate well without excess reagent. However, this requires particular attention to the controlled injection of the reagent in response to changes in load, temperature, and other parameters. Absent an emergency situation, the IC engines for the PMEC facility will only operate infrequently and for brief testing/maintenance checks. These short, transient operating periods significantly reduce the effectiveness of the post-combustion controls.

Further, it should be assumed that ammonia emissions will occur under some or all operating conditions. This represents an additional air pollutant that is not emitted when SCR is not used for these engines. Also, the handling and storage of substantial volumes of the required ammonia or urea reagent solutions can pose an additional safety risk to facility personnel, and the risk of environmental harm in the event of an accidental release.

The SCR catalyst requires periodic cleaning due to fouling of the surfaces due to the presence of trace contaminants, such as sulfur compounds, particulate, and organic species. This requirement generates a secondary waste stream of contaminated cleaning solutions that must be disposed as hazardous waste.

TABLE B-1-15
REVIEW OF RECENT BACT DETERMINATIONS FOR EMERGENCY INTERNAL COMBUSTION ENGINES

Permit or RBLC ID	Permit Issuance Date	Location	Company	System Description	Maximum Production Rate	Limit(s)	Control Option	Basis
EMERGENCY ENGINES (>500 HP diesel fuel)								
CO-0055	02-03-06	Powers County, CO	Lamar Utilities Board DBA Lamar Light & Power	Diesel Engine	1500 HP	CO – 0.61 lb/MMBtu SO_2 – 0.06 lb/MMBtu PM_{10} – 0.0160 lb/MMBtu	GCP and low sulfur fuel (< 0.05 by weight)	BACT-PSD
MN-0061	06-26-05	St. Louis, MN	Mesabi Nugget LLC	Back-up Generator	549 HP	20% opacity	Fuel limited to No. 2 fuel oil with 0.05 weight percent sulfur and limited to 100 hr/yr	BACT-PSD
AZ-0046	04-14-05	Yuma, AZ	Arizona Clean Fules Yuma LLC	Emergency Generator	10.90 MMBtu/hr	NO_X – 6.4 g/kW-hr CO – 3.5 g/kW-hr PM – 0.02 g/kW-hr	"Tier 3" or "Tier 2" emission controls must be certified by manufacturer	BACT-PSD
WA-0329	02-11-05	Snohomish County, WA	Darrington Energy LLC	Standby Generator	1 MW	NO_X –Follow 40 CFR 89	Engine must be new and satisfy federal standards @ 40 CFR 89	BACT-PSD
WA-0328	01-11-05	Whatcom County, WA	BP West Coast Products LLC	Emergency Generator	1.5 MW	NO_X – Follow 40 CFR 89 SO_2 – Federal low sulfur diesel	Engine must be new and satisfy federal standards @ 40 CFR 89 & Fuel must satisfy requirements of on-road diesel at time of fuel purchase	BACT-PSD
LA-0194	11-24-04	Cameron County, LA	Sabine Pass LNG, LP	Emergency Generator	2168 HP	PM_{10} – 0.91 lb/hr NO_X – 37.96 lb/hr CO – 12.22 lb/hr VOC – 1.67 lb/hr	GCP	BACT-PSD

TABLE B-1-15 (Continued)
REVIEW OF RECENT BACT DETERMINATIONS FOR EMERGENCY INTERNAL COMBUSTION ENGINES

Permit or RBLC ID	Permit Issuance Date	Location	Company	System Description	Maximum Production Rate	Limit(s)	Control Option	Basis
AK-0061	11-05-04	Nome Census Area, AK	Nome Joint Utilities System	Electric Generator	5211 kW	NO_X – 134 lb/hr CO – 10.50 lb/hr PM – 206 lb/hr SO_2 – 0.50% Sulfur by weight	GCP	BACT-PSD
OH-0275	08-24-04	Butler County, OH	PSI Energy-Madison Station	Emergency Generator	17.21 Mmbtu/hr	SO_2 – 8.61 lb/hr NO_X – 55.07 lb/hr CO – 14.63 lb/hr VOC – 1.55 lb/hr PM_{10} – 0.27 ton/yr 20% opacity	Sulfur limited to 0.05 % by weight and limited to 499 hr/yr.	BACT-PSD
WV-0023	03-02-04	Monongahela County, WV	Longview Power LLC	Emergency Generator	1801 HP	CO – 8.85 lb/hr NO_X – 20.90 lb/hr PM_{10} – 1.13 lb/hr SO_2 – 6.5 lb/hr VOC – 1.21 lb/hr	GCP and < 500 hr/yr	BACT-PSD
WI-0207	01-21-04	Chippewa County, WI	Ace Ethanol LLC	Generator	1850 HP	PM – 0.07 g/HP-hr NO_X – 13 g/HP-hr CO – 1 g/HP-hr VOC – 0.12 g/HP-hr	Sulfur limited to 0.05 % by weight and limited to 16.7 hr/month.	BACT-PSD
EMERGENCY ENGINES (<500 HP diesel fuel)								
OK-0110	10-21-05	Muskogee County, OK	Dalitalia LLC	Emergency Generator	NA	CO – 0.0067 lb/HP-hr VOC – 0.0025 lb/HP-hr PM_{10} – 0.0022 lb/HP-hr	GCP	NA
NC-0101	09-29-05	Forsyth County, NC	Forsyth Energy Projects LLC	Emergency Generator and Firewater Pump	11.40 MMBtu/hr	NO_X – 36.48 lb/hr SO_2 – 0.58 lb/hr VOC – 1.04 lb/hr CO – 9.69 lb/hr PM_{10} – 1.14 lb/hr	Emergency use only	BACT-PSD

TABLE B-1-15 (Continued)
REVIEW OF RECENT BACT DETERMINATIONS FOR EMERGENCY INTERNAL COMBUSTION ENGINES

Permit or RBLC ID	Permit Issuance Date	Location	Company	System Description	Maximum Production Rate	Limit(s)	Control Option	Basis
LA-0192	06-06-05	Orleans County, LA	Cresent City Power LLC	Firewater Pump	425 HP	PM_{10} – 0.14 lb/hr SO_2 – 0.61 lb/hr NO_X – 8.9 lb/hr CO – 1.88 lb/hr VOC – 0.05 lb/hr	Good engine design and proper operating practices	BACT-PSD
OH-0252	12-28-04	Lawrence County, OH	Duke Energy Hanging Rock LLC	Backup Generator	500 kW each (670 HP each)	NO_X – 10.20 lb/hr CO – 12.60lb/hr VOC – 1.1 lb/hr SO_2 – 0.27 lb/hr PM_{10} – 0.59 lb/hr	500 hr/yr and Low Sulfur fuel	BACT-PSD
OH-0252	12-28-04	Lawrence County, OH	Duke Energy Hanging Rock LLC	Firewater Pump	265 HP	NOX – 8.2 lb/hr CO – 1.8 lb/hr VOC – 0.66 lb/hr SO_2 – 0.10 lb/hr PM – 0.66 lb/hr	500 hr/yr	BACT-PSD

When SCR or any add-on emission control technology is used, additional auxiliary equipment such as pumps and motors must be added. Also, the presence of the catalyst module adds an increment of pressure drop to the exhaust train. To avoid a substantial drop-off in engine performance, the SCR modules must be designed to minimize the increase in back-pressure. However, the energy requirements of auxiliary equipment and even minor back-pressure increases do reduce the net energy efficiency of the plant. In contrast, the implementation of combustion process controls does not require an add-on system with increased energy use by auxiliary equipment, or use of catalyst and ammonia materials. There is some additional complexity in the engine controls for this option. Proper engine tuning and fuel/air ratio is needed across the full load range to achieve reduced emissions while avoiding a reduction in engine efficiency. The automatic fuel/air ratio controller helps accomplish this objective.

B-1.16.2.3 Ranking of Control Options

With regard to NO_x emission abatement, the ranking of the technically-feasible options is straightforward. The use of SCR offers the highest potential level of control for the proposed diesel-fired emergency engines. Up to 90% reduction in NO_x mass emission at all load levels is claimed for typical internal combustion engines.

The option offering the next highest control level is combustion process modifications, as would be implemented as standard equipment (i.e. no additional cost) in the selected engines. Advanced combustion design allows the engines to operate at rated horsepower, while burning an optimized fuel mix. This feature includes ignition timing retard to reduce cylinder temperatures for lean mixtures. The controls are also designed to optimize the air/fuel ratio and ignition timing in response to actual operating conditions.

B-1.16.2.4 Economic Analysis for NOx Controls

Since advanced NO_x controls is a standard feature of the currently available new engines, the emissions reported by vendors for this package are taken as the base case in this BACT analysis. Addition of SCR is then analyzed as the next incremental control technology, in terms of both control level and cost. Table B-1-16 provides the results of the cost effectiveness analysis for the emergency generator and firewater pump engines.

As shown in Table B-1-16, the annualized operating costs for addition of SCR to the two PMEC IC engines range from about $79,000 to $156,000 per year. The estimated total capital investment is over $230,000 for the smaller unit, and over $500,000 for the 2 MW emergency generator, based on purchased equipment cost estimates. Capital recovery is the single largest annual expense, based on 7% prevailing interest rate, and 10-year service period. Additional maintenance charges are also encountered for operation of the systems and annual catalyst cleaning. This investment would provide 1.8 tons of NO_x reduction per year for the 2 engines combined, assuming 90% emission control efficiency. Cost effectiveness is over $96,000 per ton for the larger generator, and more than $438,000/ton for the smaller firewater pump engine, which in either case represents a prohibitively high cost for this BACT option.

TABLE B-1-16
ECONOMIC ANALYSIS OF POST-COMBUSTION SCR CONTROLS FOR PMEC IC ENGINES

Emergency Engine	Controlled Emissions Basis (90% reduction)	Estimated Total Capital Investment	Estimated Annualized Costs ($/yr)	Emissions or Reduction (tons/yr)	Cost Effectiveness ($ / ton)
2 MW Generator	0.18 tons/yr	$506,086	$155,670	1.62	$96,092
300 hp Fire Water Pump	0.02 tons/yr	$243,844	$78,900	0.18	$438,333

B-1.16.2.5 Proposed BACT for NOx

A cost effectiveness analysis for application has shown that use of SCR is cost prohibitive as a more-stringent control for the IC engines planned for the PMEC facility. The proposed BACT for these engines is the combustion modifications supplied as standard equipment with the candidate types of engines. For an annual emission limitation, it is acceptable that non-emergency hours of operation be limited to 100 hours per year.

B-1.16.3 CO BACT Analysis

Emission estimates for the engine-driven emergency generator and fire water pump using EPA Document AP-42 emission factors indicate "uncontrolled" emissions of about 0.9 tons per year. The engines that would be selected for this project will be equipped with combustion modifications that emphasize reduction in NO_x emissions, at the expense of CO. However, the engines have a relatively small number of anticipated annual operating hours.

B-1.16.3.1 Technically-Feasible Controls

For CO emissions, the commercially available control means for IC engines are:

Combustion Process Modifications - This option is implemented in the design of the internal combustion engine. Typical design features include an electronic fuel/air ratio control and ignition retard, turbocharging, intercoolers, and lean-burn fuel mix. Currently available engines include these features as standard equipment, so these measures are used as the base case for the BACT cost-effectiveness analysis.

Catalytic Oxidation – This control technology employs a module containing an oxidation catalyst that is located in the exhaust path of the engine. In the catalyst module, CO diffuses through the surfaces of a ceramic honeycomb structure coated with noble metal catalyst particles. Oxidation reaction on the catalyst surface forms carbon dioxide. Typical vendor indications are that 95% reduction in CO emissions should be achieved.

B-1.16.3.2 Cost Effectiveness Analysis

Given the low number of routine operating hours per year, the cost for catalytic oxidation for CO control will be prohibitive. The estimated annualized cost for addition of catalytic oxidation ranges from approximately $30,300 to $44,300 per unit. This investment would provide 0.24

tons of CO reduction per year for the two PMEC internal combustion engines, assuming a 95% reduction in emissions, and 100 hr/yr operating time for all units. Cost effectiveness for this equipment is well above $100,000 per ton of CO abated for these engines, which represents a prohibitively high cost for this BACT option.

B-1.16.3.3 Proposed BACT for CO

Based on the cost effectiveness analysis for application of catalytic oxidation as a more-stringent increment of control, the proposed BACT for the IC engines is the combustion modifications supplied as standard equipment with the proposed internal combustion engines. For an annual emission limitation, it is acceptable that non-emergency hours of operation be limited to 100 hours per year.

B-1.16.4 BACT ANALYSIS FOR VOLATILE ORGANIC COMPOUNDS (VOC), SO_2, AND PM_{10}

The two internal combustion engines planned for the PMEC facility would have combined annual emissions of 0.09 tons per year for VOC, and 0.05 tons per year each for SO_2 and PM_{10}. Given these low emissions, there are no available technologies beyond good combustion controls that are considered to provide feasible or cost effective emission control. Use of low-sulfur No. 2 diesel, at 0.05 weight percent sulfur, limitation of each engine's operation to no more than 100 hours per year and operation of the engines using advanced combustion controls at proper air/fuel ratios will provide relatively low emissions of VOC and PM_{10}, and are proposed as BACT measures for these pollutants.

Appendix B-1-1

BACT Cost Comparison

PMEC Project SO_2 BACT Cost Analysis Summary

Per Combustion Turbine:

Syngas fuel rate	2100 x 10^6 Btu/hr, HHV		2000 lb/ton		
Min Coal conversion efficenc	**0.719**	Syngas heating value =	242 Btu/dscf (HHV)	(Case 15E, Rawhide PSQ)	
Max Coal conversion efficenc	**0.793**	Syngas heating value =	303 Btu/dscf (HHV)	(Case 15C, Illinois No. 6)	
Gasifiers coal feed	2921 (max) x 10^6 Btu/hr (HHV)				
Hours of operation	8,760 hrs/yr				

	SO_2 Emissions				**SO_2 Reduction**		
Control Technology	**ppm S in syngas**	**lb/MMBtu (coal)**	**lb/hr**	**tons/yr**	**Total tons/yr**	**Incremental tons/yr**	**Control Efficiency**
Uncontrolled	10,000	5.0105	14,634	64,098	-		0%
NSPS Da (95% control option)		0.2505	732	3,205	60,893	-	95.00%
MDEA (Base IGCC Level)	50	0.0251	73	320	63,778	2,884	99.50%
Selexol	10	0.0050	15	64	64,034	256	99.90%
Rectisol	1	0.0005	1	6	64,092	58	99.99%

Control Technology	**Total Capital Investment**	**Annual Capital Recovery Cost**	**Total Annual Operating Expenses**	**Total Annual Costs**	**SO_2 Reduction (tons/yr)**	**Average Cost Effectiveness ($/ton)**	**Incremental SO_2 Reduction (tons/yr)**	**Incremental Cost Effectiveness ($/ton)**
MDEA (Base IGCC Level)					-		2,884	
Selexol	$20,979,560	$2,303,556	$2,891,022	$5,194,577	256	$20,260	256	$20,260
Rectisol	$39,961,066	$4,387,725	$4,105,838	$8,493,563	314	$27,043	58	$57,186

PMEC Project, Selexol AGR for IGCC Combustion Turbines
Total Capital Investment

SCR System for sulfur removal to 10 ppm

Preliminary

Item	Basis	Cost
Direct Costs		
(1) Purchased Equipment		
Selexol System	Incremental over MDEA Costs based on review of other IGCC permit applications and presentations.	$9,450,000
(a) Total Equipment		$9,450,000
(b) Freight (0.05 x [1a])	OAQPS, Sect. 1, Table 2.4	$472,500
(c) Sales Tax (0.06 x [1a])	OAQPS, Sect. 1, Table 2.5	$567,000
(d) Instrumentation (0.10 x [1a])	OAQPS, Sect. 1, Table 2.6	$945,000
Total Purchased Equipment Cost, PEC [1a thru 1d]		$11,434,500
(2) Direct Installation (0.083 x PEC)	Peters & Timmerhaus, 1991	$949,064
(3) Instrumentation Controls (installed) (0.02 x PEC)	P & T, 1991	$228,690
(4) Piping (installed) (0.073 x PEC)	P & T, 1991	$834,719
(5) Electrical (installed) (0.046 x PEC)	P & T, 1991	$525,987
TOTAL DIRECT COST (TDC) (1thru 5)		$13,972,959
Indirect Costs		
(6) Indirect Installation		
(a) General Facilities (0.05 * TDC)	OAQPS, Sect. 4, Table 2.5	$698,648
(b) Engineering and Home Office Fees (0.10 * TDC)	OAQPS, Sect. 4, Table 2.5	$1,397,296
(c) Process Contingency (0.05 * TDC)	OAQPS, Sect. 4, Table 2.5	$698,648
(7) Other Indirect Costs		
(a) Startup & Performance Tests (0.08 x TDC)	P & T, 1991	$1,117,837
TOTAL INDIRECT COST (TIC) (6+7)		$3,912,429
Project Contingency		
(8) Project Contingency ((TDC + TIC) * 0.15)	OAQPS, Sect. 4, Table 2.5	$2,682,808
Total Plant Cost (TIC + TDC + Cont.)		**$20,568,196**
(9) Preproduction Cost (0.02 * TPC)	OAQPS, Sect. 4, Table 2.5	$411,364
(10) Initial Chemical Inventory (NH3)	OAQPS, Sect. 4, Table 2.5	
SUMMARY		
TOTAL CAPITAL INVESTMENT (TCI)		**$20,979,560**

PMEC Project - BACT Cost Effectiveness Analysis for Selexol

Sulfur in syngas reduction to 10 ppm

Preliminary

Unit Characteristics

TMW	= turbine output in MW	=	300
H	= annual operating hours	=	8,760

Costs

A. Total capital investment, $	See Separate TCI Spreadsheet	=	$20,979,560
B. Direct Annual Costs, $/yr			
1. Operating labor	= (1.0/8 hr shift) x ($25/hr) x (H)	=	$27,375
2. Suervisory labor	= (0.15) x (operating labor)	=	$4,106
3. Maintenance labor and materials	= (0.015 * TCI)	=	$314,693
8. Electricity	= N/A	=	-
9. Performance loss (assume 1% penalty in net output)	= (0.010) x (TMW) x ($0.057/ KWH) x (1000 KW/ MW) x (H)	=	$1,497,960
11. Production Loss	= None	=	-
TOTAL DIRECT COSTS			**$1,844,135**
C. Indirect Annual Costs, $/yr			
1. Overhead	= (0.6) x (all labor and maintenance material costs)	=	$207,705
2. Property Taxes, insurance, admin.	= (0.04) x (total capital investment)	=	$839,182
TOTAL INDIRECT COSTS			**$1,046,887**
TOTAL ANNUAL OPERATING COSTS	= (Direct Annual Costs) + (Indirect Annual Costs)		**$2,891,022**
CAPITAL RECOVERY*	= (0.1098)CRF* x total capital investment	=	**$2,303,556**
Total Annual Cost	**= (Annual Operating Costs) + (Captial Recovery)**	**=**	**$5,194,577**

* The capital recovery factors assumes a 15 year equipment life and 7% interest.

Cells highlighted in green need further review and confirmation for final cost estimates.

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PMEC Project, Rectisol AGR for IGCC Combustion Turbines
Total Capital Investment

SCR System for sulfur removal to 1 ppm

Preliminary

Item	Basis	Cost
Direct Costs		
(1) Purchased Equipment		
Rectisol System	Inremental over Selexol; Costs based on review of other IGCC permit applications and presentations.	$18,000,000
(a) Total Equipment		$18,000,000
(b) Freight (0.05 x [1a])	OAQPS, Sect. 1, Table 2.4	$900,000
(c) Sales Tax (0.06 x [1a])	OAQPS, Sect. 1, Table 2.5	$1,080,000
(d) Instrumentation (0.10 x [1a])	OAQPS, Sect. 1, Table 2.6	$1,800,000
Total Purchased Equipment Cost, PEC [1a thru 1d]		$21,780,000
(2) Direct Installation (0.083 x PEC)	Peters & Timmerhaus, 1991	$1,807,740
(3) Instrumentation Controls (installed) (0.02 x PEC)	P & T, 1991	$435,600
(4) Piping (installed) (0.073 x PEC)	P & T, 1991	$1,589,940
(5) Electrical (installed) (0.046 x PEC)	P & T, 1991	$1,001,880
TOTAL DIRECT COST (TDC) (1thru 5)		$26,615,160
Indirect Costs		
(6) Indirect Installation		
(a) General Facilities (0.05 * TDC)	OAQPS, Sect. 4, Table 2.5	$1,330,758
(b) Engineering and Home Office Fees (0.10 * TDC)	OAQPS, Sect. 4, Table 2.5	$2,661,516
(c) Process Contingency (0.05 * TDC)	OAQPS, Sect. 4, Table 2.5	$1,330,758
(7) Other Indirect Costs		
(a) Startup & Performance Tests (0.08 x TDC)	P & T, 1991	$2,129,213
TOTAL INDIRECT COST (TIC) (6+7)		$7,452,245
Project Contingency		
(8) Project Contingency ((TDC + TIC) * 0.15)	OAQPS, Sect. 4, Table 2.5	$5,110,111
Total Plant Cost (TIC + TDC + Cont.)		**$39,177,516**
(9) Preproduction Cost (0.02 * TPC)	OAQPS, Sect. 4, Table 2.5	$783,550
(10) Initial Chemical Inventory (NH3)	OAQPS, Sect. 4, Table 2.5	
SUMMARY		
TOTAL CAPITAL INVESTMENT (TCI)		**$39,961,066**

Cells highlighted in green need further review and confirmation for final cost estimates.

PMEC Project, Rectisol AGR for IGCC Combustion Turbines

Sulfur in syngas reduction to 1 ppm

Preliminary

Unit Characteristics

TMW	= turbine output in MW	=	300
H	= annual operating hours	=	8,760

Costs

A. Total capital investment, $	See Separate TCI Spreadsheet	=	$39,961,066
B. Direct Annual Costs, $/yr			
1. Operating labor	= (1.0/8 hr shift) x ($25/hr) x (H)	=	$27,375
2. Suervisory labor	= (0.15) x (operating labor)	=	$4,106
3. Maintenance labor and materials	= (0.015 * TCI)	=	$599,416
8. Electricity	= N/A	=	-
9. Performance loss (assume 1% penalty in net output)	= (0.010) x (TMW) x ($0.057/ KWH) x (1000 KW/ MW) x (H)	=	$1,497,960
11. Production Loss	= None	=	-
TOTAL DIRECT COSTS			**$2,128,857**
C. Indirect Annual Costs, $/yr			
1. Overhead	= (0.6) x (all labor and maintenance material costs)	=	$378,538
2. Property Taxes, insurance, admin.	= (0.04) x (total capital investment)	=	$1,598,443
TOTAL INDIRECT COSTS			**$1,976,981**
TOTAL ANNUAL OPERATING COSTS	= (Direct Annual Costs) + (Indirect Annual Costs)		**$4,105,838**
CAPITAL RECOVERY*	= (0.1098)CRF* x total capital investment	=	**$4,387,725**
Total Annual Cost	**= (Annual Operating Costs) + (Captial Recovery)**	**=**	**$8,493,563**

*The capital recovery factors assumes a 15 year equipment life and 7% interest.

Cells highlighted in green need further review and confirmation for final cost estimates.

Appendix B-1-2

IC and Auxiliary Boiler Cost Comparison

TOTAL CAPITAL INVESTMENT AND ANNUAL COST CALCULATIONS
SELECTIVE CATALYST REDUCTION
Natural Gas Fired Auxiliary Boiler 130 MMBtu/hr

Cost Item	Factor	Cost
TOTAL CAPITAL INVESTMENT[1,2] = DC + IC		**813,657**
Direct Annual Costs		
Operating Labor[3]		
Operator	-----	-----
Supervisor	-----	-----
Total Operating Labor		0
Maintenance[4]		
Labor	-----	-----
Materials	-----	-----
Total Maintenance	0.015TCI	12,205
Reagent Cost[4]		
29% Ammonia Solution	6.87 ton/yr @ $0.114/lb	1,566
Utilities[4]		
Electricity	51.7 kWh load @ $0.08/kWh	9,058
Total Utilities		9,058
Catalyst Cost[5]		
Catalyst Replacement	Catalyst life > SCR Service Life	Negligible
Total Catalyst Cost	-----	-----
Miscellaneous[6]		
Performance Tests	-----	5,000
Record Keeping & Reporting	-----	1,000
Total Miscellaneous Costs		6,000
Total Direct Annual Costs (DAC)		**27,263**
Indirect Annual Costs		
Overhead[1]	60% of operating, supervisor, maintenance labor & materials	7,323
Administrative Charges[1]	0.02TCI	16,273
Property Taxes[1]	0.01TCI	8,137
Insurance[1]	0.01TCI	8,137
Capital Recovery Factor[7]	-----	0.1424
Capital Recovery[1]	(CRF)(TCI)	115,865
Total Indirect Annual Costs (IAC)		**155,734**
TOTAL ANNUAL COST = DAC + IAC		**182,997**

[1] Costs were assumed using Table 6-5 of Alternative Control Techniques Document - NOx Emissions from Industrial/Commercial/Institutional (IC) Boilers - EPA March 1994. The costs used were based on estimates for a regenerative thermal oxidizer that is limited to a maximum of 85 percent total NOx destruction.

[2] The costs were also adjusted for inflation using an inflation rate of 34.6 percent (1992 to 2004), which was determined using a Consumer Price Index (CPI) Inflation Calculator provided by the National Aeronautics and Space Administration (www.jsc.nasa.gov/bu2/inflateCPI.html).

[3] Operating and Supervisory Labor is estimated to be minimal since the SCR is a stationary device with few pieces of rotating equioment and can be operated from an exisiting control room.

[4] These factors were taken from Section 4 - NOx Controls EPA Air Pollution Control Cost Manual - 6th Edition dated 3-3-2003 (EPA-452/B-02-001)

[5] Because of the limited operation schedule for the auxiliary boilers, the initial catalyst charge would last for the projected service life of the unit.

[6] These miscellaneous costs are comparable to costs for similar functions for comparable control equipment.

[7] The capital recovery factor was calculated assuming a 10-year equipment life and a 7% interest rate

Reagent Cost Estimate

Mass Flow Flow Rate of the reagent

$m_{reagent} = (NOx_{in} * Q_B * ASR * M_{reagent}) / (M_{NOx})$ Eq. 2.32

Where:

$m_{reagent}$ (lb/hr) = mass flow rate of reagent	**1.818853**
NOx_{in} (lb/MMBtu) = inlet NOx	0.036
Q_B (MMBtu/hr) = heat input rate	130
ASR = 1.05	1.05
$M_{reagent}$ (MW of ammonia) =	17.03
M_{NOx} (MW of NO2) =	46.01

Mass flow rate of X% aqueous ammonia solution

m_{sol} = mreagent / X% Eq. 2.33

Where:

m_{sol} (lb/hr) = mass flow rate aqueous ammonia solution	**6.271906**
$m_{reagent}$ (lb/hr) = mass flow rate of reagent	1.818853
X% = percent aqueous solution	0.29

Solution Volume Flow Rate

$q_{sol} = (m_{sol} / p_{sol}) * v_{sol}$ Eq. 2.34

Where:

q_{sol} (gph) = solution volume flow rate	**0.837859**	
m_{sol} (lb/hr) = mass flow rate aqueous ammonia solution	6.271906	
p_{sol} (lb/ft^3) = density of 29% aqueous reagent solution	56	
v_{sol} (gal/ft^3) = specific volume of 29% reagent solution	7.481	
Total Solution Needed Per Year (ton/yr)	**6.867738**	**$1,565.84**
Hours of Operation per Year (hr/yr)	2190	
29% Ammonia Solution Cost ($/lb)	0.114	

Power Consumption Estimate

Power = $0.105Q_B [NOx_{in} * n_{NOx} + 0.5 (P_{duct} + n_{total} * P_{catalyst})]$

Where:

Power (kWh) = Electrical Power Usage	51.7345263	
Q_B (MMBtu/hr) = Boiler heat input	130	
NOx_{in} (lb/MMBtu) = inlet NOx	0.036	
n_{NOx} = NOx removal efficiency	85%	
P_{duct} (inch water) = pressure drop of duct	2.5	
n_{total} = number of catalyst layers	4	
$P_{catalyst}$ (inch water) = pressure drop per catyst layer	1	
Total Electricity Needed Per Year (kWh)	**113298.613**	**$9,063.89**
Hours of Operation per Year (hr/yr)	2190	
Electrical Power Cost ($/kWh)	0.08	

Catalyst Replacement Cost Estimate

Catalyst Volume

$vol_{catalyst} = 2.81 * Q_B * n_{adj} * slip_{adj} * NOx_{adj} * S_{adj} * (T_{adj} / N_{SCR})$

Where:

$vol_{catalyst}$ (ft^3) = volume of catalyst	**438.044848**	**$127,033.01**
Q_B (MMBtu/hr) = Heat input rate	130	
n_{adj} = NOx efficiency adjustment factor	1.1862	
$slip_{adj}$ = NH_3 slip adj. factor for slips btw 2 to 5 ppm	1.1701	
NOx_{adj} = NOx_{inlet} adjustment factor	0.8639488	
S_{adj} = sulfur in fuel adjustment factor		0.05%
T_{adj} = Temp. adj. Factor for temps other than 700 F		
Catalyst life (hr)	24,000	
Hours of Operation per Year (hr/yr)	2190	
Catalyst Cost Replacement ($/ft^3)	290	
Catalyst Replacement in years (yr)	10.9589041	
Ammonia Slip (ppm)	2	

TOTAL CAPITAL INVESTMENT AND ANNUAL COST CALCULATIONS
Catalytic Oxidizer
Natural Gas Fired Auxiliary Boiler 130 MMBtu/hr

Cost Item	Factor	Cost
Direct Costs		
Purchased Equipment Costs		
Catalytic Oxidizer[1,2]	A	372,157
Catalyst Repalacement Allowance[3]	-----	10,000
Sales Tax[1]	0.03A	11,165
Purchased Equipment Cost (PEC)	B	393,322
Direct Installation Costs[1]		
Foundations & Supports	0.08B	31,466
Handling & Erection	0.14B	55,065
Electrical	0.04B	15,733
Piping	0.02B	7,866
Insulation for Ductwork	0.01B	3,933
Painting	0.01B	3,933
Direct Installation Cost		117,997
Total Direct Costs (DC)		511,318
Indirect Costs		
Installation[1]		
Engineering	0.10B	39,332
Construction & Field Expenses	0.05B	19,666
Contractor Fees	0.10B	39,332
Start-Up	0.02B	7,866
Performance Test	0.01B	3,933
Contingencies	0.03B	3,933
Indirect Installation		114,063
Total Indirect Costs (IC)		114,063
TOTAL CAPITAL INVESTMENT = DC + IC		**625,382**
Direct Annual Costs		
Operating Labor[1,4]		
Operator	0.5 hours/shift	4,835
Supervisor	15% of operator	725
Total Operating Labor		5,560
Maintenance[1,4]		
Labor	0.5 hours/shift	4,835
Materials	100% of maintenance labor	4,835
Total Maintenance		9,669
Utilities[5]		
Electricity	85.1 kWh @ $0.08/kWh	14,910
Total Utilities		14,910
Total Direct Annual Costs (DAC)		**30,139**
Indirect Annual Costs		
Overhead[1]	60% of operating, supervisor, maintenance labor & materials	9,138
Administrative Charges[1]	0.02TCI	12,508
Property Taxes[1]	0.01TCI	6,254
Insurance[1]	0.01TCI	6,254
Capital Recovery Factor[6]	-----	0.1424
Capital Recovery1	(CRF)(TCI)	89,054
Total Indirect Annual Costs (IAC)		**123,207**
TOTAL ANNUAL COST = DAC + IAC		**153,346**

[1] Costs were assumed using EPA Air Pollution Control Cost Manual - 6th Edition (EPA-452/B-02-001). The costs used were based on estimates for a Fixed-Bed Catalytic Oxidizer assuming a 50% Energy Recovery that is limited to a maximum of 90 percent total CO destruction.

[2] The costs were also adjusted for inflation using an inflation rate of 13.4 percent (1999 to 2004), which was determined using a Consumer Price Index (CPI) Inflation Calculator provided by the National Aeronautics and Space Administration (www.jsc.nasa.gov/bu2/inflateCPI.html).

[3] Calalyst Replacement Allowance was assumed to be $10,000.

[4] Calculations assume 2,190 hours of operation per year, 8 hours per shift, assuming 0.5 hours per shift related to catalytic oxidizer with employees paid at the rate of $35.29 per hour (which is comparable to the wages paid for similar control equipment).

[5] The total utilities cost was caclulated assuming 85.1 kWh electricity usage at a cost of $0.08/kWh to operate the fan motor.

[6] The capital recovery factor was calculated assuming a 10-year equipment life and a 7% interest rate

TOTAL CAPITAL INVESTMENT AND ANNUAL COST CALCULATIONS
Low NOx Burners and Flue Gas Recirculation
Natural Gas Fired Auxiliary Boiler 130 MMBtu/hr

Cost Item	Factor	Cost
TOTAL CAPITAL INVESTMENT[1,2] = DC + IC		**115,487**
Direct Annual Costs		
Operating Labor[3]		
Operator	-----	-----
Supervisor	-----	-----
Total Operating Labor		0
Maintenance[4]		
Labor	-----	-----
Materials	-----	-----
Total Maintenance	0.015TCI	1,732
Utilities[5]		
Electricity	30 hp FGR fan/boiler, $0.08/kwh	4,355
Total Utilities		4,355
Miscellaneous[6]		
Performance Tests	-----	5,000
Record Keeping & Reporting	-----	1,000
Total Miscellaneous Costs		6,000
Total Direct Annual Costs (DAC)		**12,087**
Indirect Annual Costs		
Overhead[1]	60% of operating, supervisor, maintenance labor & materials	1,039
Administrative Charges[1]	0.02TCI	2,310
Property Taxes[1]	0.01TCI	1,155
Insurance[1]	0.01TCI	1,155
Capital Recovery Factor[7]	-----	0.1424
Capital Recovery[1]	(CRF)(TCI)	16,445
Total Indirect Annual Costs (IAC)		**22,104**
TOTAL ANNUAL COST = DAC + IAC		**34,191**

[1] Costs were assumed using Table 6-5 of Alternative Control Techniques Document - NOx Emissions from Industrial/Commercial/Institutional (IC) Boilers - EPA March 1994. The costs used were based on estimates for a boiler equiped with Low NOx burners and FGR that is limited to a maximum of 60 percent total NOx destruction.

[2] The costs were also adjusted for inflation using an inflation rate of 34.6 percent (1992 to 2004), which was determined using a Consumer Price Index (CPI) Inflation Calculator provided by the National Aeronautics and Space Administration (www.jsc.nasa.gov/bu2/inflateCPI.html).

[3] Operating and Supervisory Labor is estimated to be minimal since the Low NOx Burners and FGR are a stationary device with few pieces of rotating equipment and can be operated from an exisiting control room.

[4] These factors were taken from Section 4 - NOx Controls EPA Air Pollution Control Cost Manual - 6th Edition dated 3-3-2003 (EPA-452/B-02-001)

[5] Electricity cost was calculated assuming 30 hp electric fan was needed at a cost of $0.08/kWh.

[6] These miscellaneous costs are comparable to costs for similar functions for comparable control equipment.

[7] The capital recovery factor was calculated assuming a 10-year equipment life and a 7% interest rate

CONTROL COST EFFECTIVENESS

	SELECTIVE CATALYST REDUCTION	LNB + FGR	Catalytic Oxidizer
	(Controlling NOx Only)		(Controlling CO Only)
	Auxiliary Boiler		
Total Annual Cost ($)	182,997	34,191	153,346
Uncontrolled Pollutant Emissions (tons/year)	5.10	5.10	10.50
Capture Efficiency (%)	100%	100%	100%
Control Efficiency (%)	85%	60%	90%
Expected Emissions after Control (tons/year)	0.77	2.04	1.05
Expected Emission Reduction after Control (tons/year)	4.34	3.06	9.45
Control Cost per Ton of Pollutant Removed ($/ton)	**42,214**	**11,174**	**16,227**

Appendix B-2

Cooling Tower Analysis

APPENDIX B-2
PACIFIC MOUNTAIN ENERGY CENTER, COOLING TOWER MODELING

An analysis was performed of potential cooling tower impacts from the proposed Pacific Mountain Energy Center (PMEC) at the Port of Kalama, Washington. The conclusions of the modeling analysis are as follows:

- It is unlikely plume induced ground-level fogging/icing will occur significantly on nearby roads from either cooling tower
- Due to the moist climate of the region, long condensed plumes may result during periods of elevated relative humidity. However, our analysis indicates such condensed plumes usually occur during conditions of already poor or obscured visibility. During daytime hours when local weather does not obscure the plume, typical condensed plume lengths are less than 40 m and heights less than 30 m for both cooling towers.

Below is a description is included of the modeling techniques applied, the preparation of necessary input data, and the results of the analysis.

B-2.1 MODELING TECHNIQUES

The Seasonal/Annual Cooling Tower Impact (SACTI, Version 11-01-90) model was applied to assess potential impacts from the two proposed PMEC cooling towers. SACTI was developed by Argonne National Laboratory[1] for the Electric Power Research Institute (EPRI) to address the following potential adverse impacts of cooling towers:

- plume visibility
- deposition of cooling tower drift
- ground-level fogging and icing
- shadowing by the plume & reduction of solar energy

SACTI contains algorithms for both natural and mechanical draft cooling towers arranged singly or in clusters. Plume merging and associated enhanced plume rise are treated by the routines contained in the model. While any official regulatory endorsement of SACTI is unknown, this model has been applied for a number of projects where cooling tower impact assessments were required for EFSEC and the California Energy Commission. The characteristics of the tower and the preparation of the meteorological data set are discussed below.

Based on preliminary design information, the characteristics of the proposed PMEC cooling towers are listed in Table B-2-1. In addition to the parameters in Table B-2-1, assumptions

[1]Argonne National Laboratory, 1984. Users Manual: Cooling-Tower-Plume Prediction Code. Prepared for Electric Power Research Institute, 3412 Hillview Avenue, Palo Alto, CA 94303, EPRI CS-3403-CCM, April 1984.

included a salt density of 2.17 g/cm^3 and the drift droplet size distribution listed in the SACTI Users Manual for mechanical draft cooling towers. Note, unlike conventional dispersion models, the density of the exit air is a variable calculated by the model based on ambient conditions, the design parameters in Table B-2-1, and saturation conditions at the outlet.

A meteorological data set was constructed using hourly wind, solar radiation and differential temperature observations from a nearby station at the Port of Kalama (Noveon Chemical) during 1995. These local data were also used in the air quality dispersion modeling assessment for the facility. The surface data were combined with seasonal mixing heights for Salem[2] using the EPA's regulatory preprocessor program MPRM.

Relative humidity data are necessary for cooling tower assessments and hourly data are not available for the Port of Kalama site. The local meteorological data was supplemented with relative humidity data and "weather-type" observations from the National Weather Service station at Portland Airport.[3] The weather-type observations were used to interpret the results of the cooling tower modeling. Using the Portland weather observations, a flag was added to the data set to indicate periods of potential obscured visibility due to fog, ceiling heights less than 500 hundred feet, precipitation, runway visibilities less than one mile, or relative humidity greater than 98 percent. During periods of obscured visibility a condensed plume from the PMEC cooling towers might not be as noticeable as during ambient conditions conducive to good visibility.

Figure B-2-1 displays a wind rose constructed from the 1995 Port of Kalama data set. Winds exhibit a bi-modal regime, oriented with the north to south alignment of this portion of the Columbia River valley. The average wind speed is 2.7 m/s and high winds greater than 10 m/s are infrequent (4 hours in 1995). Wind speeds coded as calm in the data set also occur relatively infrequently (16 hours in 1995).

B-2.2 MODELING RESULTS

SACTI was applied to simulate plumes from each of the two proposed cooling towers using the 1995 meteorological data set and tower design characteristics described previously. Rural conditions and default options were assumed for the other input variables controlling model operation. The SACTI results were summarized to obtain annual frequency distributions for condensed plume length, condensed plume height, condensed plume radius, ground-level fogging, and icing. The simulations were performed for all hours of the year, and as a subset, daytime hours of the year without weather obscuring events.

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2 Holzworth, G.C., 1972. *Mixing Heights, Wind Speeds, and Potential for Urban Air Pollution throughout the Contiguous United States.* EPA, Office of Air Programs Publication No. AP101, Rayleigh, NC 27607.

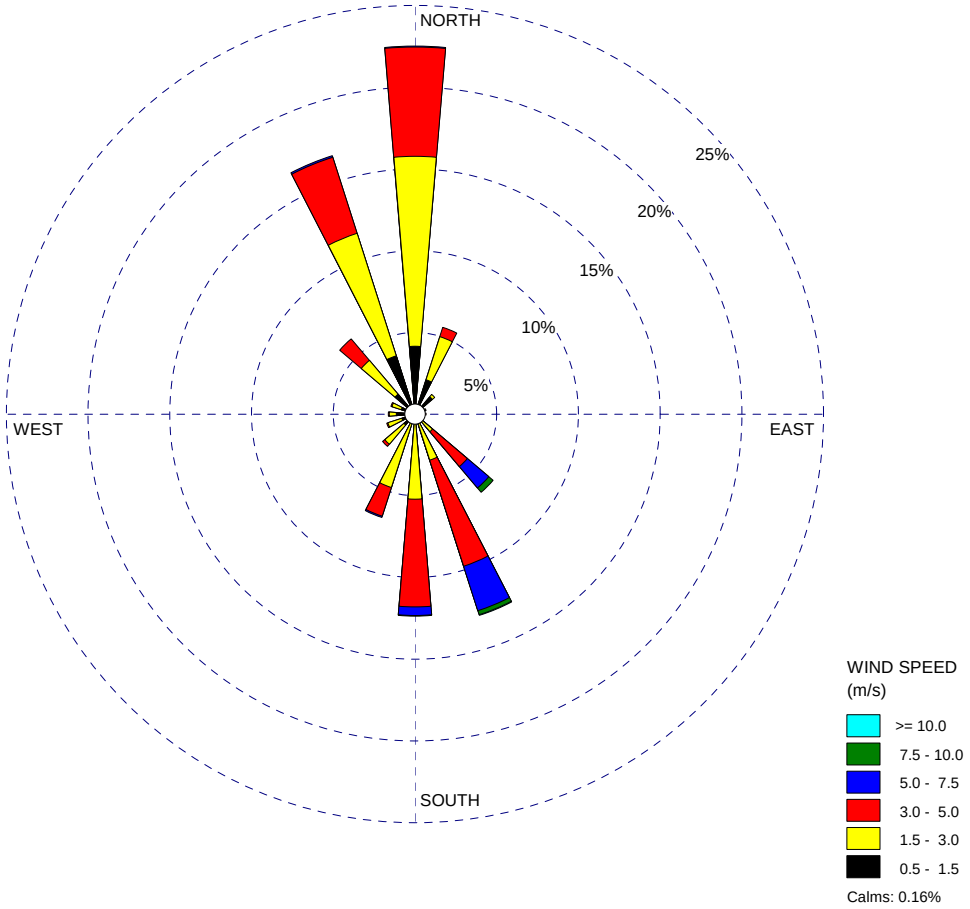
3 Relative humidity data are also available at the Kelso-Longview Airport, but the overall data recovery is not as good as the Portland Airport data set. The Kelso-Longview Airport data also do not include observations of fog and other weather variables that can be used to characterize background visual conditions.

WIND ROSE PLOT:

Port of Kalama Surface Winds for 1995

DISPLAY:

Wind Speed
Direction (blowing from)



COMMENTS:	DATA PERIOD:	COMPANY NAME:	
From Noveon	**1995** **Jan 1 - Dec 31** **00:00 - 23:00**	**Geomatrix**	
		MODELER: **kjr**	
	CALM WINDS: **0.16%**	TOTAL COUNT: **8760 hrs.**	
	AVG. WIND SPEED: **2.74 m/s**	DATE: **8/3/2006**	PROJECT NO.: **12096**

WRPLOT View - Lakes Environmental Software

GEOMATRIX

WIND ROSE FOR PORT OF KALAMA 1995
Pacific Mountain Energy Center
Kalama, Washington

Project No.
12096.000.0

Figure
B-2-1

B-2.3 CONDENSED PLUME LENGTHS

The results of the cooling tower visible plume analysis are summarized in Tables B-2-2 through B-2-7. Frequency distributions of the plume length, height and radius are listed according to downwind sector and radial distance from the center of the cooling tower array. Condensed plume lengths predicted for the Power Block cooling tower in Table B-2-2 are greater than 50 m, 100 m, 500 m and 1000 m, for 31%, 19%, 18%, and 18% of the annual hours, respectively. For the ASU Cooling Tower (Table B-2-5), predicted condensed plume lengths are greater than 50 m, 100 m, 500 m and 1000 m, for 38%, 20%, and 18% of the annual hours, respectively.

Condensed plumes might be visible during daytime hours or when illuminated during the night. The relatively longer condensed plumes occur during conditions of high relative humidity when the ambient air is near saturation. The model does not account for low overcast conditions or fog that would tend to obscure the plume during such conditions. In addition to high relative humidity, stable atmospheric stratification and cool temperatures also foster a long condensed plume. These conditions may produce long visible plumes during the hours near sunrise and sunset, but generally occur during the night when the condensed plume would not be visible.

Figure B-2-2 and Figure B-2-3 display contour plots constructed from the condensed plume length frequencies in Table B-2-2 and Table B-2-5, respectively. As distance increases from the site, condensed plumes more frequently occur along the north-to-south axis of the annual prevailing winds. Although annual winds from the north occur more frequently, more frequent long condensed plumes are predicted for southerly winds. Such winds are more often associated with cool moist conditions that foster long condensed plume lengths. More frequent short to moderate length condensed plumes are predicted for the smaller ASU cooling tower that is oriented normal to the prevailing wind directions. However, longer condensed plumes extending to the north and north-northwest are predicted relatively more frequently from the Power Block cooling tower aligned with the prevailing winds. Westerly winds at the site are infrequent and prolonged condensed plumes traveling directly toward Interstate 5 are rare.

B-2.4 DAYTIME CONDENSED PLUMES EXCLUDING PERIODS OF WEATHER OBSCURING EVENTS

Additional SACTI simulations were conducted to further investigate condensed plume lengths during periods when the plume might be visible. Nighttime periods and observations during natural weather obscuring events were excluded from the data set an, a condensed plume from the cooling tower would probably be obscured by fog, low clouds or would not be visible unless illuminated during the night. For the 1995 Port of Kalama data set, these conditions account for 59% of the total observations.

Table B-2-8 and Table B-2-9 summarize the results of daytime SACTI simulations after periods of weather obscuring visual conditions have been removed from the meteorological data set. Figure B-2-4 and Figure B-2-5 display contour plots constructed from these tables. Figure B-2-6 compares these results with the SACTI simulations discussed previously. The average number of hours of a condensed plume is reduced significantly when fog and nighttime conditions are

removed from consideration. Condensed plume lengths are also shorter due to the less humid, warmer conditions that occur during the day. At a radial distance of 1000 m from the cooling towers, SACTI predicts a condensed plume for about 500 hours per year when summed across all wind directions.

Condensed plumes longer than 1000 m are predicted for about 6 percent of the daytime hours. Long condensed plumes are sometimes predicted when meteorological conditions promote large plume rise even when ground level conditions are well below saturation. During such conditions, the predicted condensed plumes may be indistinguishable from clouds also present above the condensation level.

B-2.5 GROUND-LEVEL FOGGING

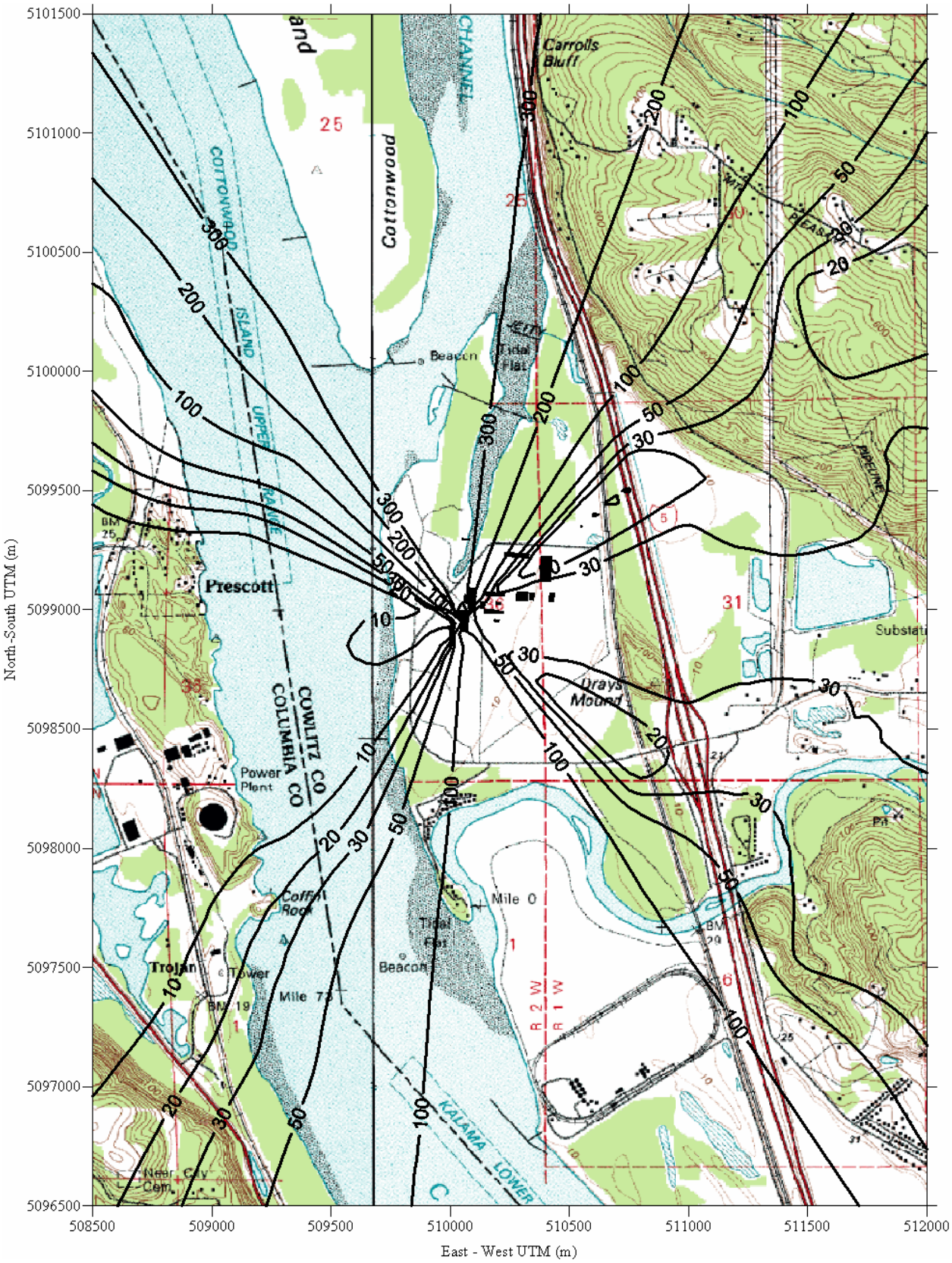
The potential for ground-level fogging and icing on local roadways was also evaluated. In order for these effects to occur, cooling tower plumes must touchdown on the roadway, be condensed, and for icing, the temperature must be below freezing. This requires high winds (low plume rise), the right wind direction, low dew-point depression, and low temperatures (for icing).

The annual average numbers of hours of predicted fogging are shown in Table B-2-10 and Table B-2-11, for the Power Block and ASU Cooling Towers, respectively. According to the SACTI simulations, these effects are rare for the PMEC cooling towers and meteorological conditions at the site. Plume induced ground-level fog is very infrequent, occurring only a few hours a year. Ground level fogging was predicted for a few hours at a distance of 100 m north-northwest of each of the towers, well away from major roads in the study area. During the 1995 simulation period, no hours of ground-level icing were predicted by SACTI.

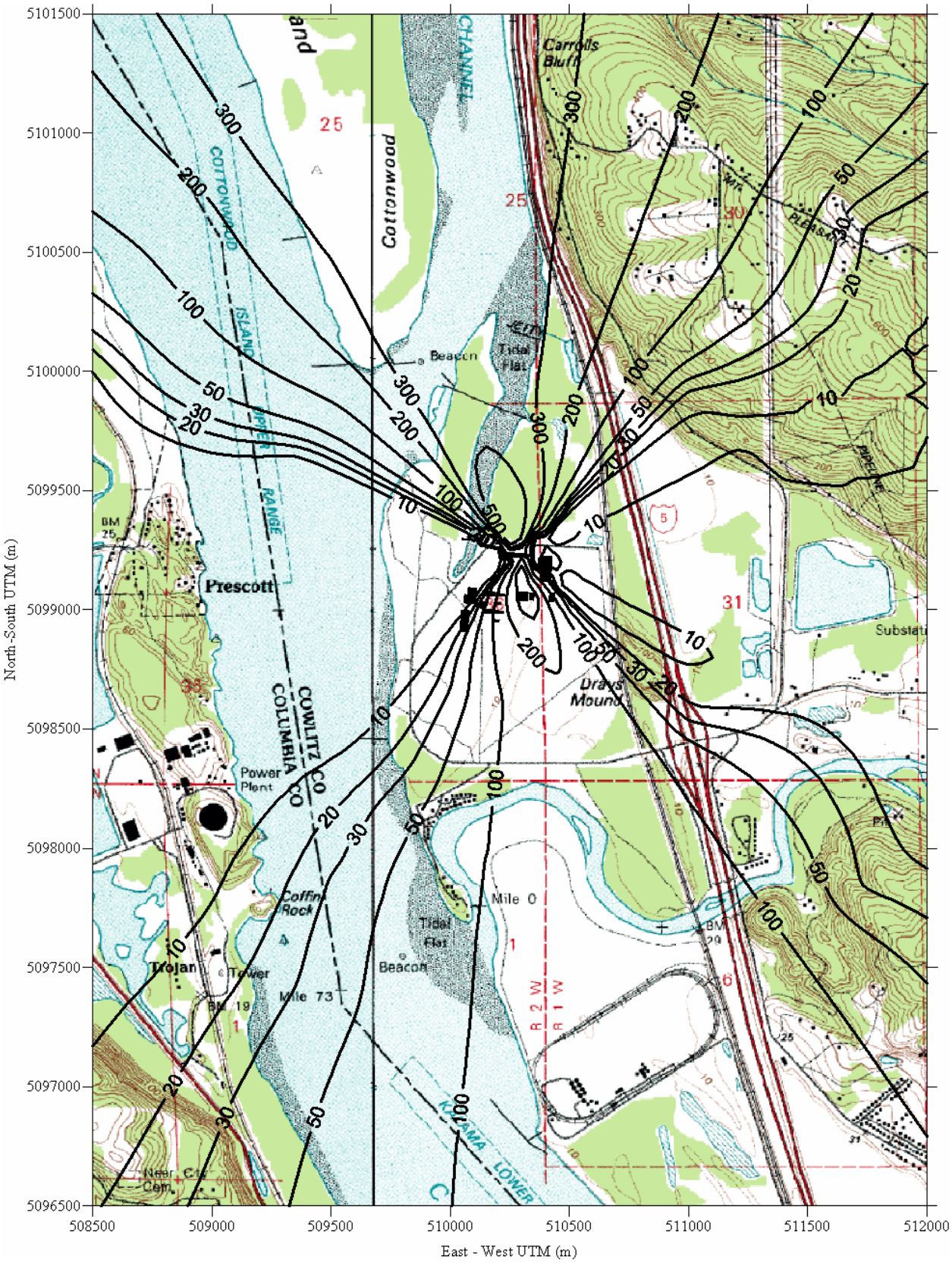
B-2.6 SUMMARY

A cooling tower modeling analysis was conducted using SACTI and year of Port of Kalama meteorological data supplemented with relative humidity and weather-type data from Portland Airport. The simulations indicate condensed plumes would typically not touchdown and cause ground-level fogging or icing. Fogging conditions occur for only about one to four hours per year close to the towers and no periods of icing are predicted based on the 1995 meteorological data.

High relative humidity at the site contributed to predictions of long condensed plumes. In many instances, the longer plumes occur at night or during weather conditions that obscure the plume. During conditions when the cooling tower plume would most likely be visible, typical condensed plume lengths are less than 40 m and heights less than 30 m. Condensed plumes longer than 1000 m occur for about 6% of the daytime hours. During such conditions, the predicted condensed plumes may be indistinguishable from clouds also present above the condensation level.



GEOMATRIX	PMEC POWER BLOCK COOLING TOWER CONDENSED PLUME LENGTHS CONTOURS OF HOURS PER YEAR WITH PLUME OVERHEAD Pacific Mountain Energy Center, Kalama, Washington	Project No. 12096.000.0 Figure **B-2-2**

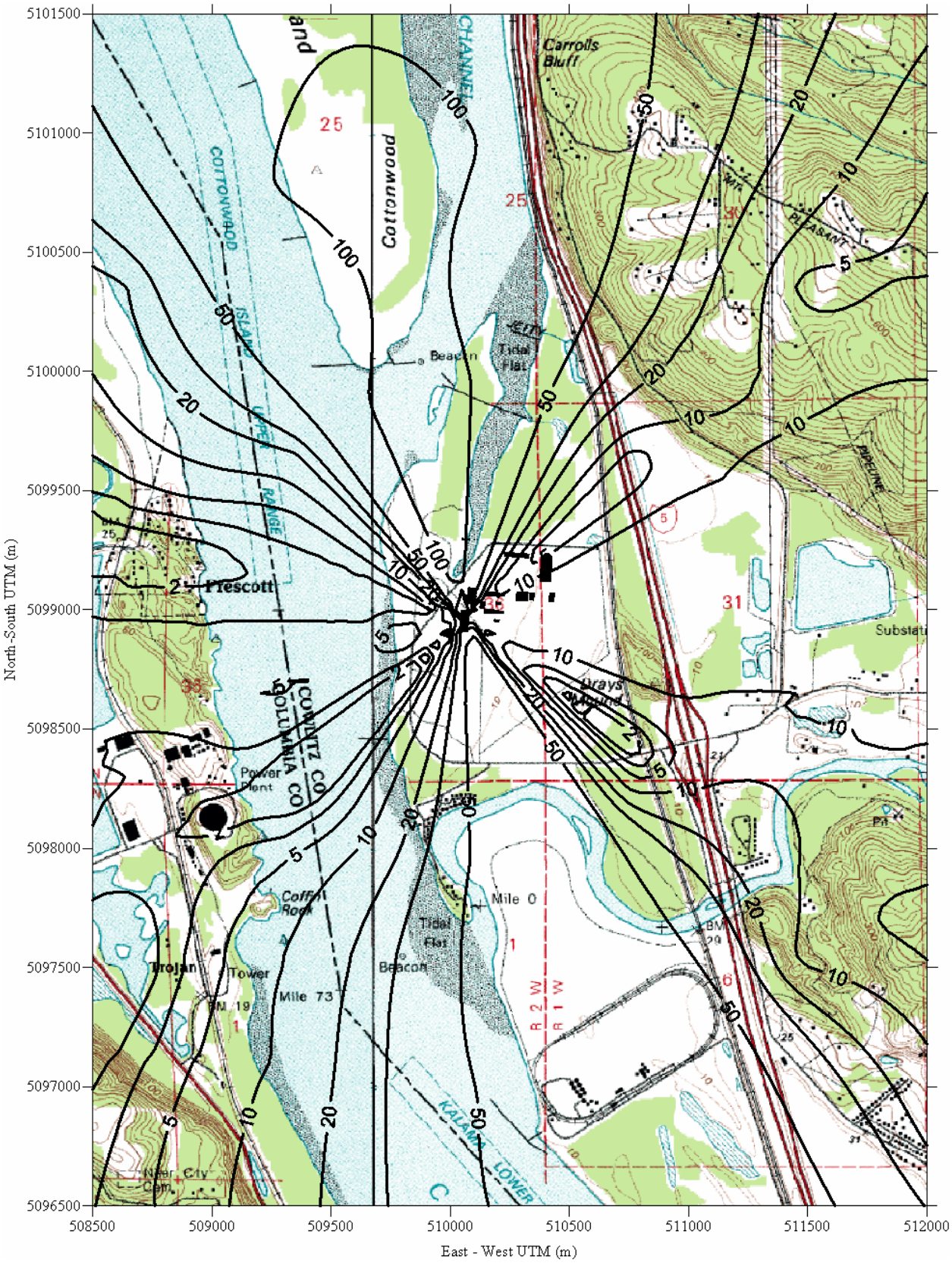


GEOMATRIX

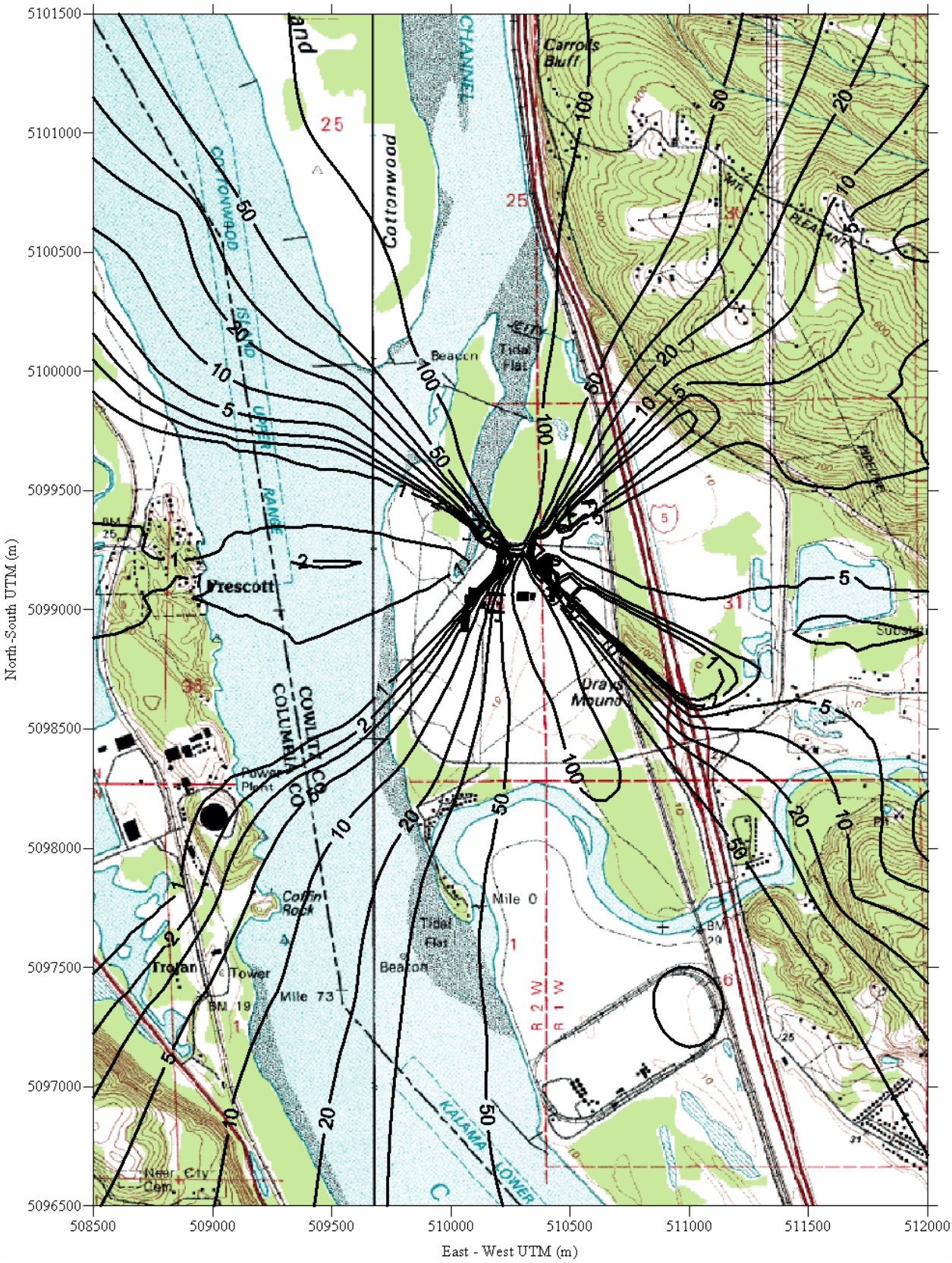
PMEC ASU COOLING TOWER CONDENSED PLUME LENGTHS
CONTOURS OF HOURS PER YEAR WITH PLUME OVERHEAD
Pacific Mountain Energy Center, Kalama, Washington

Project No.
12096.000.0

Figure
B-2-3



GEOMATRIX	PMEC POWER BLOCK COOLING TOWER CONDENSED PLUME LENGTHS DAYTIME HOURS PER YEAR WITHOUT WEATHER OBSCURATION Pacific Mountain Energy Center, Kalama, Washington	Project No. 12096.000.0 Figure **B-2-4**

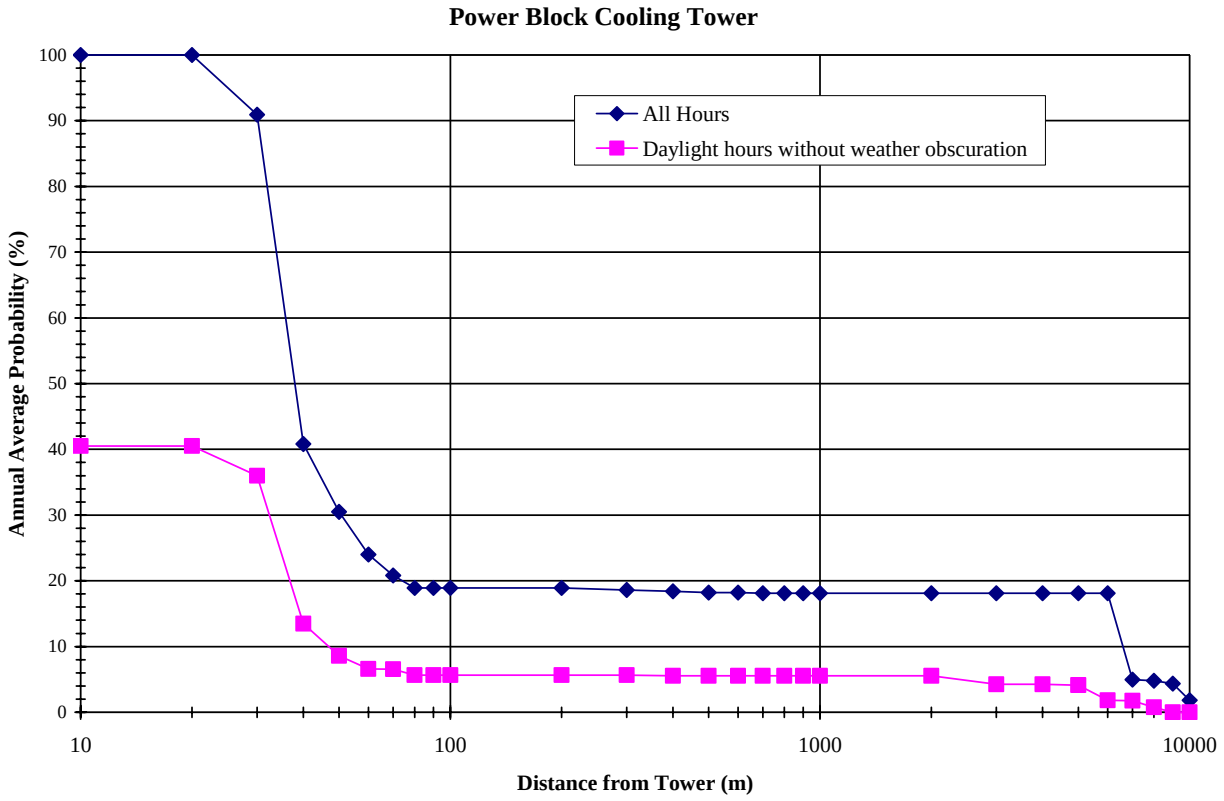


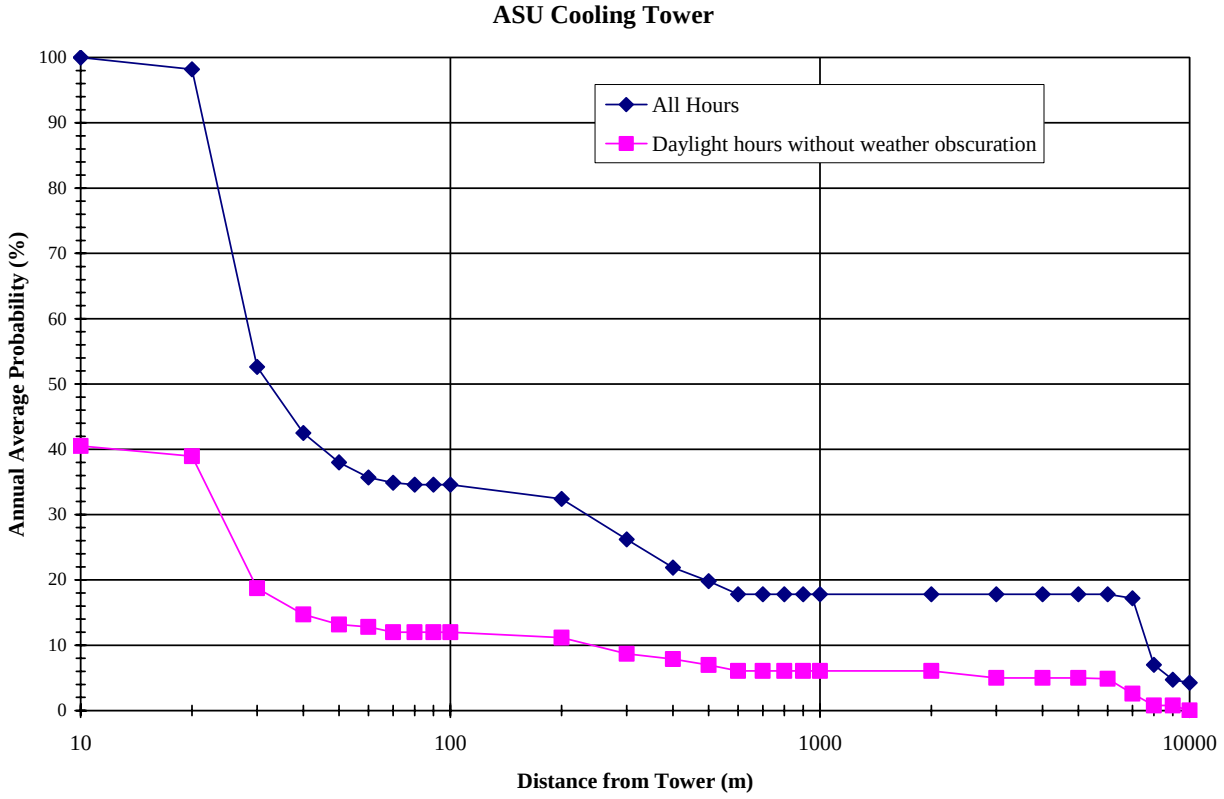
GEOMATRIX

PMEC ASU COOLING TOWER CONDENSED PLUME LENGTHS
DAYTIME HOURS PER YEAR WITHOUT WEATHER OBSCURATION
Pacific Mountain Energy Center, Kalama, Washington

Project No.
12096.000.0

Figure
B-2-5





GEOMATRIX

ANNUAL AVERAGE PROBABILITY OF CONDENSED PLUME LENGTHS
Pacific Mountain Energy Center
Kalama, Washington

Project No.
12096.000.0

Figure
B-2-6

TABLE B-2-1
\PMEC COOLING TOWER CHARACTERISTICS

Parameter	ASU Cooling Tower	Power Block Cooling Tower
Type	linear mechanical draft 1 tower, 7 cells	linear mechanical draft 2 towers, 12 cells (2 rows of 6)
Heat Dissipation Rate (MW)	297	510
Water Circulation Rate (lb/hr)	67,670,000	116,000,000
Total Air Flow (acfm) @ density of 0.070 lb/ft^3	9,590,000	16,440,000
Max Drift Rate (%)	0.001	0.001
Salt Content in Drift (ppmw)	2,400	2,400
Orientation	aligned 86 degrees, clockwise from a north-to-south axis	aligned 4.5 degrees, clockwise from a north-to-south axis
Overall Dimensions (ft)	55 by 330	110 by 290
Height (ft)	48	48
Cell Diameter (ft)	33	33
Exit Velocity & Temperature	variable, calculated by the model assuming saturation conditions	variable, calculated by the model assuming saturation conditions

TABLE B-2-2
PMEC POWER BLOCK COOLING TOWER PLUME LENGTH FREQUENCY DISTRIBUTION

Dist. From Tower (m)	Condensed Plume Length Annual Frequency (%) by Downwind Sector																Sum
	S	SSW	SW	WSW	W	WNW	NW	NNW	N	NNE	NE	ENE	E	ESE	SE	SSE	
10	22.20	5.68	1.57	0.73	0.69	0.55	6.00	13.30	12.00	6.81	2.49	1.86	1.61	1.66	5.80	17.00	100.0
20	22.20	5.68	1.57	0.73	0.69	0.55	6.00	13.30	12.00	6.81	2.49	1.86	1.61	1.66	5.80	17.00	100.0
30	21.40	5.23	0.57	0.73	0.69	0.55	4.83	13.20	12.00	6.77	1.34	1.86	1.61	1.66	2.05	16.40	90.90
40	4.46	1.49	0.26	0.16	0.17	0.18	3.36	10.10	8.03	4.62	0.64	0.62	0.52	0.49	0.84	4.94	40.80
50	2.74	0.99	0.07	0.16	0.17	0.18	2.04	8.17	6.45	3.67	0.30	0.62	0.52	0.49	0.44	3.47	30.50
60	1.84	0.65	0.07	0.16	0.17	0.18	2.04	6.32	4.97	2.71	0.30	0.62	0.52	0.49	0.44	2.54	24.00
70	1.53	0.53	0.03	0.16	0.17	0.18	1.32	5.81	4.44	2.33	0.20	0.62	0.52	0.49	0.29	2.18	20.80
80	1.34	0.41	0.03	0.16	0.17	0.18	1.32	5.10	3.96	2.10	0.20	0.62	0.52	0.49	0.29	1.97	18.90
90	1.34	0.41	0.03	0.16	0.17	0.18	1.32	5.10	3.96	2.10	0.20	0.62	0.52	0.49	0.29	1.97	18.90
100	1.34	0.41	0.03	0.16	0.17	0.18	1.32	5.10	3.96	2.10	0.20	0.62	0.52	0.49	0.29	1.97	18.90
200	1.34	0.41	0.03	0.16	0.17	0.18	1.32	5.10	3.96	2.10	0.20	0.62	0.52	0.49	0.29	1.97	18.90
300	1.34	0.41	0.03	0.16	0.14	0.14	1.32	5.10	3.96	2.10	0.20	0.55	0.50	0.42	0.29	1.97	18.60
400	1.34	0.41	0.03	0.15	0.13	0.14	1.32	5.10	3.96	2.10	0.20	0.44	0.47	0.37	0.29	1.97	18.40
500	1.34	0.41	0.03	0.10	0.09	0.13	1.32	5.10	3.96	2.10	0.20	0.37	0.42	0.33	0.29	1.97	18.20
600	1.34	0.41	0.03	0.10	0.09	0.13	1.32	5.10	3.96	2.10	0.20	0.37	0.42	0.33	0.29	1.97	18.20
700	1.34	0.41	0.03	0.10	0.09	0.13	1.32	5.09	3.96	2.10	0.20	0.37	0.42	0.33	0.29	1.97	18.10
800	1.34	0.41	0.03	0.10	0.09	0.13	1.32	5.09	3.96	2.10	0.20	0.37	0.42	0.33	0.29	1.97	18.10
900	1.34	0.41	0.03	0.10	0.09	0.13	1.32	5.09	3.96	2.10	0.20	0.37	0.42	0.33	0.29	1.97	18.10
1000	1.34	0.41	0.03	0.10	0.09	0.13	1.32	5.09	3.96	2.10	0.20	0.37	0.42	0.33	0.29	1.97	18.10
2000	1.34	0.41	0.03	0.10	0.09	0.13	1.32	5.09	3.96	2.10	0.20	0.37	0.42	0.33	0.29	1.97	18.10
3000	1.34	0.41	0.03	0.10	0.09	0.13	1.32	5.09	3.96	2.10	0.20	0.37	0.42	0.33	0.29	1.97	18.10
4000	1.34	0.41	0.03	0.10	0.09	0.13	1.32	5.09	3.96	2.10	0.20	0.37	0.42	0.33	0.29	1.97	18.10
5000	1.34	0.41	0.03	0.10	0.09	0.13	1.32	5.09	3.96	2.10	0.20	0.37	0.42	0.33	0.29	1.97	18.10
6000	1.34	0.41	0.03	0.10	0.09	0.13	1.32	5.09	3.96	2.10	0.20	0.37	0.42	0.33	0.29	1.97	18.10
7000	0.25	0.03	0.00	0.01	0.02	0.03	0.64	1.10	1.11	0.49	0.13	0.09	0.16	0.12	0.13	0.65	4.97
8000	0.25	0.03	0.00	0.01	0.02	0.03	0.64	1.10	1.11	0.49	0.13	0.05	0.10	0.06	0.13	0.65	4.81
9000	0.25	0.03	0.00	0.01	0.02	0.03	0.25	1.10	1.11	0.49	0.08	0.05	0.10	0.06	0.10	0.65	4.35
10000	0.09	0.00	0.00	0.01	0.01	0.01	0.25	0.34	0.42	0.15	0.08	0.02	0.05	0.02	0.10	0.28	1.84

TABLE B-2-3
PMEC POWER BLOCK COOLING TOWER PLUME HEIGHT FREQUENCY DISTRIBUTION

Height From Tower (m)	Condensed Plume Height Annual Frequency (%) by Downwind Sector																Sum
	S	SSW	SW	WSW	W	WNW	NW	NNW	N	NNE	NE	ENE	E	ESE	SE	SSE	
10	22.24	5.68	1.57	0.73	0.69	0.55	6.00	13.28	11.99	6.81	2.49	1.86	1.61	1.66	5.80	17.04	100.0
20	22.24	5.68	1.57	0.73	0.69	0.55	6.00	13.28	11.99	6.81	2.49	1.86	1.61	1.66	5.80	17.04	100.0
30	13.13	3.92	0.82	0.44	0.40	0.39	4.83	12.29	10.96	6.24	1.51	1.16	1.14	1.15	1.98	11.49	71.86
40	2.53	0.88	0.07	0.16	0.21	0.18	2.04	7.50	5.96	3.34	0.30	0.65	0.61	0.56	0.44	3.22	28.65
50	1.53	0.53	0.03	0.16	0.17	0.18	1.32	5.80	4.44	2.33	0.19	0.62	0.52	0.49	0.29	2.18	20.78
60	1.34	0.41	0.03	0.16	0.17	0.18	1.32	5.09	3.96	2.10	0.19	0.62	0.52	0.49	0.29	1.97	18.84
70	1.34	0.41	0.03	0.16	0.17	0.18	1.32	5.09	3.96	2.10	0.19	0.62	0.52	0.49	0.29	1.97	18.84
80	1.34	0.41	0.03	0.16	0.17	0.18	1.32	5.09	3.96	2.10	0.19	0.62	0.52	0.49	0.29	1.97	18.84
90	1.34	0.41	0.03	0.16	0.17	0.18	1.32	5.09	3.96	2.10	0.19	0.62	0.52	0.49	0.29	1.97	18.84
100	1.34	0.41	0.03	0.16	0.17	0.18	1.32	5.09	3.96	2.10	0.19	0.62	0.52	0.49	0.29	1.97	18.84
200	1.34	0.41	0.03	0.16	0.17	0.18	1.32	5.09	3.96	2.10	0.19	0.62	0.52	0.49	0.29	1.97	18.84
300	1.34	0.41	0.03	0.10	0.09	0.13	1.32	5.09	3.96	2.10	0.19	0.37	0.42	0.33	0.29	1.97	18.14
400	1.34	0.41	0.03	0.10	0.09	0.13	1.32	5.09	3.96	2.10	0.19	0.37	0.42	0.33	0.29	1.97	18.14
500	1.34	0.41	0.03	0.10	0.09	0.13	1.32	5.09	3.96	2.10	0.19	0.37	0.42	0.33	0.29	1.97	18.14
600	1.34	0.41	0.03	0.10	0.09	0.13	1.32	5.09	3.96	2.10	0.19	0.37	0.42	0.33	0.29	1.97	18.14
700	1.34	0.41	0.03	0.10	0.09	0.13	1.32	5.09	3.96	2.10	0.19	0.37	0.42	0.33	0.29	1.97	18.14
800	1.34	0.41	0.03	0.10	0.09	0.13	1.32	5.09	3.96	2.10	0.19	0.37	0.42	0.33	0.29	1.97	18.14
900	1.34	0.41	0.03	0.10	0.09	0.13	1.32	5.09	3.96	2.10	0.19	0.37	0.42	0.33	0.29	1.97	18.14
1000	1.34	0.41	0.03	0.10	0.09	0.13	1.32	5.09	3.96	2.10	0.19	0.37	0.42	0.33	0.29	1.97	18.14

TABLE B-2-4
PMEC POWER BLOCK COOLING TOWER PLUME RADIUS FREQUENCY DISTRIBUTION

Radius (m)	Condensed Plume Radius Annual Frequency (%) by Downwind Sector																Sum
	S	SSW	SW	WSW	W	WNW	NW	NNW	N	NNE	NE	ENE	E	ESE	SE	SSE	
10	22.24	5.68	1.57	0.73	0.69	0.55	6.00	13.28	11.99	6.81	2.49	1.86	1.61	1.66	5.80	17.04	100.0
20	15.05	3.79	0.77	0.73	0.69	0.55	5.06	12.93	11.82	6.64	1.59	1.86	1.61	1.66	2.25	14.23	81.23
30	2.75	0.96	0.30	0.16	0.17	0.18	3.55	8.10	6.40	3.67	0.74	0.62	0.52	0.49	1.05	3.53	33.20
40	1.34	0.41	0.07	0.16	0.17	0.18	2.04	5.09	3.96	2.10	0.30	0.62	0.52	0.49	0.44	1.97	19.85
50	1.34	0.41	0.03	0.15	0.13	0.14	1.32	5.09	3.96	2.10	0.19	0.44	0.47	0.37	0.29	1.97	18.38
60	1.34	0.41	0.03	0.10	0.09	0.13	1.32	5.09	3.96	2.10	0.19	0.37	0.42	0.33	0.29	1.97	18.14
70	1.34	0.41	0.03	0.10	0.09	0.13	1.32	5.09	3.96	2.10	0.19	0.37	0.42	0.33	0.29	1.97	18.14
80	1.34	0.41	0.03	0.10	0.09	0.13	1.32	5.09	3.96	2.10	0.19	0.37	0.42	0.33	0.29	1.97	18.14
90	1.34	0.41	0.03	0.10	0.09	0.13	1.32	5.09	3.96	2.10	0.19	0.37	0.42	0.33	0.29	1.97	18.14
100	1.34	0.41	0.03	0.10	0.09	0.13	1.32	5.09	3.96	2.10	0.19	0.37	0.42	0.33	0.29	1.97	18.14
200	1.34	0.41	0.03	0.10	0.09	0.13	1.32	5.09	3.96	2.10	0.19	0.37	0.42	0.33	0.29	1.97	18.14
300	1.34	0.41	0.03	0.10	0.09	0.13	1.32	5.09	3.96	2.10	0.19	0.37	0.42	0.33	0.29	1.97	18.14
400	1.34	0.41	0.03	0.10	0.09	0.13	1.32	5.09	3.96	2.10	0.19	0.37	0.42	0.33	0.29	1.97	18.14
500	1.09	0.38	0.03	0.09	0.07	0.09	0.68	3.99	2.85	1.60	0.07	0.32	0.32	0.27	0.16	1.32	13.33
600	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
700	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
800	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
900	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

TABLE B-2-5
PMEC ASU COOLING TOWER PLUME LENGTH FREQUENCY DISTRIBUTION

Dist. From Tower (m)	Condensed Plume Length Annual Frequency (%) by Downwind Sector																Sum
	S	SSW	SW	WSW	W	WNW	NW	NNW	N	NNE	NE	ENE	E	ESE	SE	SSE	
10	22.20	5.68	1.57	0.73	0.69	0.55	6.00	13.30	12.00	6.81	2.49	1.86	1.61	1.66	5.80	17.00	100.0
20	21.40	5.33	1.57	0.73	0.69	0.55	6.00	13.20	11.90	6.79	2.49	1.86	1.61	1.66	5.80	16.60	98.20
30	6.13	1.78	0.63	0.71	0.53	0.50	4.82	10.50	8.48	4.95	1.40	1.67	1.37	1.47	1.99	5.67	52.60
40	4.85	1.55	0.39	0.32	0.24	0.23	3.72	9.75	7.70	4.47	0.91	1.03	0.66	0.76	1.21	4.73	42.50
50	4.85	1.55	0.10	0.14	0.13	0.14	2.27	9.75	7.70	4.47	0.38	0.46	0.50	0.37	0.49	4.73	38.00
60	4.04	1.40	0.09	0.07	0.07	0.10	1.98	9.60	7.66	4.47	0.32	0.24	0.24	0.22	0.44	4.72	35.70
70	3.96	1.40	0.07	0.07	0.07	0.10	1.64	9.55	7.64	4.47	0.26	0.24	0.24	0.22	0.37	4.63	34.90
80	3.96	1.40	0.07	0.03	0.05	0.03	1.64	9.55	7.64	4.47	0.26	0.14	0.22	0.13	0.37	4.63	34.60
90	3.96	1.40	0.07	0.03	0.05	0.03	1.64	9.55	7.64	4.47	0.26	0.14	0.22	0.13	0.37	4.63	34.60
100	3.96	1.40	0.07	0.03	0.05	0.03	1.64	9.55	7.64	4.47	0.26	0.14	0.22	0.13	0.37	4.63	34.60
200	3.48	1.29	0.07	0.03	0.05	0.03	1.64	9.00	7.23	4.18	0.26	0.14	0.22	0.13	0.37	4.25	32.40
300	2.43	0.86	0.07	0.03	0.05	0.03	1.64	7.40	5.91	3.39	0.26	0.14	0.22	0.13	0.37	3.25	26.20
400	1.88	0.69	0.07	0.03	0.05	0.03	1.64	6.19	4.96	2.75	0.26	0.14	0.22	0.13	0.37	2.55	21.90
500	1.62	0.57	0.07	0.03	0.05	0.03	1.64	5.50	4.43	2.42	0.26	0.14	0.22	0.13	0.37	2.36	19.80
600	1.37	0.45	0.07	0.03	0.05	0.03	1.64	4.90	3.96	2.11	0.26	0.14	0.22	0.13	0.37	2.05	17.80
700	1.37	0.45	0.07	0.03	0.05	0.03	1.64	4.90	3.96	2.11	0.26	0.14	0.22	0.13	0.37	2.05	17.80
800	1.37	0.45	0.07	0.03	0.05	0.03	1.64	4.90	3.96	2.11	0.26	0.14	0.22	0.13	0.37	2.05	17.80
900	1.37	0.45	0.07	0.03	0.05	0.03	1.64	4.90	3.96	2.11	0.26	0.14	0.22	0.13	0.37	2.05	17.80
1000	1.37	0.45	0.07	0.03	0.05	0.03	1.64	4.90	3.96	2.11	0.26	0.14	0.22	0.13	0.37	2.05	17.80
2000	1.37	0.45	0.07	0.03	0.05	0.03	1.64	4.90	3.96	2.11	0.26	0.14	0.22	0.13	0.37	2.05	17.80
3000	1.37	0.45	0.07	0.03	0.05	0.03	1.64	4.90	3.96	2.11	0.26	0.14	0.22	0.13	0.37	2.05	17.80
4000	1.37	0.45	0.07	0.03	0.05	0.03	1.64	4.90	3.96	2.11	0.26	0.14	0.22	0.13	0.37	2.05	17.80
5000	1.37	0.45	0.07	0.03	0.05	0.03	1.64	4.90	3.96	2.11	0.26	0.14	0.22	0.13	0.37	2.05	17.80
6000	1.37	0.45	0.07	0.03	0.05	0.03	1.64	4.90	3.96	2.11	0.26	0.14	0.22	0.13	0.37	2.05	17.80
7000	1.37	0.45	0.03	0.03	0.03	0.01	1.34	4.90	3.96	2.11	0.22	0.13	0.17	0.09	0.29	2.05	17.20
8000	0.41	0.10	0.00	0.01	0.01	0.01	0.63	1.91	1.79	0.85	0.13	0.03	0.07	0.02	0.13	0.88	6.99
9000	0.26	0.05	0.00	0.01	0.01	0.01	0.63	1.09	1.13	0.50	0.13	0.03	0.07	0.02	0.13	0.66	4.74
10000	0.26	0.05	0.00	0.01	0.01	0.01	0.24	1.09	1.13	0.50	0.08	0.02	0.05	0.02	0.10	0.66	4.25

TABLE B-2-6
PMEC ASU COOLING TOWER PLUME HEIGHT FREQUENCY DISTRIBUTION

Height From Tower (m)	Condensed Plume Height Annual Frequency (%) by Downwind Sector																Sum
	S	SSW	SW	WSW	W	WNW	NW	NNW	N	NNE	NE	ENE	E	ESE	SE	SSE	
10	22.24	5.68	1.57	0.73	0.69	0.55	6.00	13.28	11.99	6.81	2.49	1.86	1.61	1.66	5.80	17.04	100.0
20	22.24	5.68	1.57	0.73	0.69	0.55	5.93	13.27	11.99	6.81	2.48	1.86	1.61	1.66	5.78	17.04	99.89
30	6.10	2.06	0.76	0.33	0.30	0.24	4.40	10.36	8.41	4.97	1.25	1.11	0.82	0.84	1.78	6.34	50.06
40	3.96	1.40	0.09	0.14	0.13	0.14	1.98	9.54	7.64	4.47	0.32	0.46	0.50	0.37	0.44	4.63	36.20
50	3.96	1.40	0.07	0.05	0.06	0.07	1.64	9.54	7.64	4.47	0.26	0.19	0.23	0.16	0.37	4.63	34.73
60	3.96	1.40	0.07	0.03	0.05	0.03	1.64	9.54	7.64	4.47	0.26	0.14	0.22	0.13	0.37	4.63	34.57
70	3.96	1.40	0.07	0.03	0.05	0.03	1.64	9.54	7.64	4.47	0.26	0.14	0.22	0.13	0.37	4.63	34.57
80	3.48	1.29	0.07	0.03	0.05	0.03	1.64	8.99	7.23	4.18	0.26	0.14	0.22	0.13	0.37	4.25	32.36
90	3.00	1.16	0.07	0.03	0.05	0.03	1.64	8.49	6.76	3.89	0.26	0.14	0.22	0.13	0.37	3.83	30.06
100	2.75	1.02	0.07	0.03	0.05	0.03	1.64	7.94	6.40	3.64	0.26	0.14	0.22	0.13	0.37	3.52	28.20
200	2.75	1.02	0.07	0.03	0.05	0.03	1.64	7.94	6.40	3.64	0.26	0.14	0.22	0.13	0.37	3.52	28.20
300	1.37	0.45	0.07	0.03	0.05	0.03	1.64	4.90	3.96	2.11	0.26	0.14	0.22	0.13	0.37	2.05	17.78
400	1.37	0.45	0.07	0.03	0.05	0.03	1.64	4.90	3.96	2.11	0.26	0.14	0.22	0.13	0.37	2.05	17.78
500	1.37	0.45	0.07	0.03	0.05	0.03	1.64	4.90	3.96	2.11	0.26	0.14	0.22	0.13	0.37	2.05	17.78
600	1.37	0.45	0.07	0.03	0.05	0.03	1.64	4.90	3.96	2.11	0.26	0.14	0.22	0.13	0.37	2.05	17.78
700	1.37	0.45	0.07	0.03	0.05	0.03	1.64	4.90	3.96	2.11	0.26	0.14	0.22	0.13	0.37	2.05	17.78
800	1.37	0.45	0.07	0.03	0.05	0.03	1.64	4.90	3.96	2.11	0.26	0.14	0.22	0.13	0.37	2.05	17.78
900	1.37	0.45	0.07	0.03	0.05	0.03	1.64	4.90	3.96	2.11	0.26	0.14	0.22	0.13	0.37	2.05	17.78
1000	1.37	0.45	0.07	0.03	0.05	0.03	1.64	4.90	3.96	2.11	0.26	0.14	0.22	0.13	0.37	2.05	17.78

TABLE B-2-7
PMEC ASU COOLING TOWER PLUME RADIUS FREQUENCY DISTRIBUTION

Radius (m)	Condensed Plume Radius Annual Frequency (%) by Downwind Sector																Sum
	S	SSW	SW	WSW	W	WNW	NW	NNW	N	NNE	NE	ENE	E	ESE	SE	SSE	
10	22.24	5.68	1.57	0.73	0.69	0.55	6.00	13.28	11.99	6.81	2.49	1.86	1.61	1.66	5.80	17.04	100.0
20	12.73	3.29	0.63	0.66	0.46	0.45	4.82	12.85	11.35	6.45	1.40	1.59	1.26	1.33	1.99	10.96	72.22
30	4.49	1.50	0.32	0.07	0.07	0.10	3.44	9.87	8.02	4.66	0.78	0.24	0.24	0.22	1.05	4.96	40.03
40	2.75	1.02	0.07	0.03	0.05	0.03	1.64	7.94	6.40	3.64	0.26	0.14	0.22	0.13	0.37	3.52	28.20
50	1.37	0.45	0.07	0.03	0.05	0.03	1.64	4.90	3.96	2.11	0.26	0.14	0.22	0.13	0.37	2.05	17.78
60	1.37	0.45	0.07	0.03	0.05	0.03	1.64	4.90	3.96	2.11	0.26	0.14	0.22	0.13	0.37	2.05	17.78
70	1.37	0.45	0.07	0.03	0.05	0.03	1.64	4.90	3.96	2.11	0.26	0.14	0.22	0.13	0.37	2.05	17.78
80	1.37	0.45	0.07	0.03	0.05	0.03	1.64	4.90	3.96	2.11	0.26	0.14	0.22	0.13	0.37	2.05	17.78
90	1.37	0.45	0.07	0.03	0.05	0.03	1.64	4.90	3.96	2.11	0.26	0.14	0.22	0.13	0.37	2.05	17.78
100	1.37	0.45	0.07	0.03	0.05	0.03	1.64	4.90	3.96	2.11	0.26	0.14	0.22	0.13	0.37	2.05	17.78
200	1.37	0.45	0.07	0.03	0.05	0.03	1.64	4.90	3.96	2.11	0.26	0.14	0.22	0.13	0.37	2.05	17.78
300	1.37	0.45	0.07	0.03	0.05	0.03	1.64	4.90	3.96	2.11	0.26	0.14	0.22	0.13	0.37	2.05	17.78
400	1.37	0.45	0.07	0.03	0.05	0.03	1.64	4.90	3.96	2.11	0.26	0.14	0.22	0.13	0.37	2.05	17.78
500	1.11	0.40	0.07	0.01	0.02	0.02	1.01	3.81	2.83	1.60	0.14	0.05	0.08	0.06	0.24	1.39	12.84
600	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
700	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
800	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
900	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

TABLE B-2-8
PMEC POWER BLOCK COOLING TOWER PLUME LENGTH FREQUENCY DISTRIBUTION
During Daytime Hours Excluding Periods of Visibility Obscuring Weather

Dist. From Tower (m)	Condensed Plume Length Annual Frequency (Hours per Year)) by Downwind Sector																Sum
	S	SSW	SW	WSW	W	WNW	NW	NNW	N	NNE	NE	ENE	E	ESE	SE	SSE	
10	749	114	32	19	29	22	143	359	462	223	78	76	54	63	322	806	3550
20	749	114	32	19	29	22	143	359	462	223	78	76	54	63	322	806	3550
30	721	110	14	19	29	22	107	350	447	219	38	76	54	63	94	785	3153
40	159	42	6	6	5	3	47	241	257	121	11	19	17	12	23	211	1182
50	76	21	2	6	5	3	26	160	169	73	8	19	17	12	13	142	753
60	55	16	1	6	5	3	20	120	124	53	4	19	17	12	8	113	579
70	54	16	1	6	5	3	20	120	124	53	4	19	17	12	8	113	575
80	46	11	1	6	5	3	20	104	103	44	4	19	17	12	8	93	497
90	46	11	1	6	5	3	20	104	103	44	4	19	17	12	8	93	497
100	46	11	1	6	5	3	20	104	103	44	4	19	17	12	8	93	497
200	46	11	1	6	5	3	20	104	103	44	4	19	17	12	8	93	497
300	46	11	1	6	5	3	20	104	103	44	4	19	17	12	8	93	497
400	46	11	1	5	3	3	20	104	103	44	4	15	15	9	8	93	486
500	46	11	1	5	3	3	20	104	103	44	4	15	15	9	8	93	486
600	46	11	1	5	3	3	20	104	103	44	4	15	15	9	8	93	486
700	46	11	1	5	3	3	20	103	103	44	4	15	15	9	8	93	486
800	46	11	1	5	3	3	20	103	103	44	4	15	15	9	8	93	486
900	46	11	1	5	3	3	20	103	103	44	4	15	15	9	8	93	486
1000	46	11	1	5	3	3	20	103	103	44	4	15	15	9	8	93	486
2000	46	11	1	5	3	3	20	103	103	44	4	15	15	9	8	93	486
3000	37	7	1	2	1	0	20	84	82	34	4	6	6	4	8	75	373
4000	37	7	1	2	1	0	20	84	82	34	4	6	6	4	8	75	373
5000	37	7	0	2	1	0	17	84	82	34	1	6	6	4	6	75	362
6000	16	4	0	1	1	0	6	32	47	8	1	5	3	2	0	35	162
7000	16	4	0	0	1	0	6	32	47	8	1	1	1	2	0	35	154
8000	8	1	0	0	0	0	6	11	20	3	1	0	0	0	0	16	66
9000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

TABLE B-2-9
PMEC ASU COOLING TOWER PLUME LENGTH FREQUENCY DISTRIBUTION

During Daytime Hours Excluding Periods of Visibility Obscuring Weather

Dist. From Tower (m)	Condensed Plume Length Annual Frequency (Hours per Year) by Downwind Sector																Sum
	S	SSW	SW	WSW	W	WNW	NW	NNW	N	NNE	NE	ENE	E	ESE	SE	SSE	
10	749	114	32	19	29	22	143	359	462	223	78	76	54	63	322	806	3550
20	689	105	32	19	29	22	143	352	458	221	78	76	54	63	322	742	3412
30	211	45	14	16	18	17	102	259	289	133	42	61	40	47	95	251	1640
40	168	42	8	8	9	9	62	245	256	120	20	33	20	24	50	214	1289
50	168	42	5	3	3	3	36	245	256	120	9	14	12	8	17	214	1154
60	168	42	4	1	2	2	24	245	256	120	9	11	6	6	13	214	1122
70	142	42	1	1	2	1	19	235	253	120	4	7	6	4	8	205	1051
80	142	42	1	1	2	1	19	235	253	120	4	7	6	4	8	205	1051
90	142	42	1	1	2	1	19	235	253	120	4	7	6	4	8	205	1051
100	142	42	1	1	2	1	19	235	253	120	4	7	6	4	8	205	1051
200	121	40	1	1	2	1	19	221	239	113	4	7	6	4	8	191	976
300	84	26	1	1	2	1	19	167	189	86	4	7	6	4	8	154	760
400	75	21	1	1	2	1	19	155	169	74	4	7	6	4	8	142	689
500	67	17	1	1	2	1	19	133	147	66	4	7	6	4	8	125	611
600	57	16	1	1	2	1	19	115	125	54	4	7	6	4	8	110	533
700	57	16	1	1	2	1	19	115	125	54	4	7	6	4	8	110	533
800	57	16	1	1	2	1	19	115	125	54	4	7	6	4	8	110	533
900	57	16	1	1	2	1	19	115	125	54	4	7	6	4	8	110	533
1000	57	16	1	1	2	1	19	115	125	54	4	7	6	4	8	110	533
2000	57	16	1	1	2	1	19	115	125	54	4	7	6	4	8	110	533
3000	48	12	1	1	1	0	19	94	109	40	4	5	3	2	8	89	437
4000	48	12	1	1	1	0	19	94	109	40	4	5	3	2	8	89	437
5000	48	12	1	1	1	0	19	94	109	40	4	5	3	2	8	89	437
6000	48	12	0	1	0	0	17	94	109	40	1	4	2	0	6	89	426
7000	28	8	0	0	0	0	6	47	65	18	1	0	0	0	0	51	225
8000	8	2	0	0	0	0	6	11	20	3	1	0	0	0	0	15	66
9000	8	2	0	0	0	0	6	11	20	3	1	0	0	0	0	15	66
10000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

TABLE B-2-10
PMEC POWER BLOCK COOLING TOWER FOGGING FREQUENCY DISTRIBUTION

Dist. From Tower (m)	Ground Level Fogging Annual Frequency (Hours per Year) by Downwind Sector																Sum
	S	SSW	SW	WSW	W	WNW	NW	NNW	N	NNE	NE	ENE	E	ESE	SE	SSE	
100	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.19
200	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.19
300	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00
400	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00
500	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
600	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
700	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
800	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
900	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1100	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1200	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1300	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1400	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1500	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1600	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

TABLE B-2-11
PMEC ASU COOLING TOWER FOGGING FREQUENCY DISTRIBUTION

Dist. From Tower (m)	Ground Level Fogging Annual Frequency (Hours per Year) by Downwind Sector																Sum
	S	SSW	SW	WSW	W	WNW	NW	NNW	N	NNE	NE	ENE	E	ESE	SE	SSE	
100	0.00	0.00	0.00	0.00	0.00	0.00	1.00	1.88	1.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.88
200	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.38	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.38
300	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
400	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
500	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
600	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
700	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
800	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
900	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1100	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1200	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1300	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1400	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1500	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1600	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

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Appendix B-3

Emission Calculations

Appendix B-3-1

Criteria Pollutant Emission Calculations

Energy Northwest
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COMBUSTION TURBINE EMISSION ESTIMATES

Basis: Typical Siemens SGT6-5000F emission estimates or estimated worst case for other suppliers

Short-term Emissions on Syn Gas

Syngas fuel rate per CTG 2100 x 10^6 Btu/hr, HHV (calculated)
1960 x 10^6 Btu/hr, LHV (from Siemens)
Assumed coal conversion efficency **0.76** Undiluted syngas heating value= 240 to 280 Btu/dscf (HHV)
Assumed gasifiers coal feed (per CTG) 2760 x 10^6 Btu/hr (HHV)

Syngas Short-term Emission Rates			
	lb/hr (per stack)	**lb/10^6 Btu coal**	**Basis***
NOx	32	0.012	3 ppmvd (@15% O2), based on 80% removal SCR system and 15 ppm inlet NOx**
NOx (uncontrolled)	160	0.058	15 ppmvd (@ 15% O2)
CO	98	0.036	15 ppmvd (@ 15% O2)
PM10***	24	0.009	filterable (front-half) + condensible (back half)
VOC	9.0	0.003	2.4 ppmvd (@ 15% O2)
NH3	20	0.007	5 ppmvd (@ 15% O2) ammonia slip

* Typical mass emission rates from Siemens for basis stated except CO and PM10, which are allowances for expected guarantees from other suppliers. Siemens currently quotes lower CO and PM10 emission rates than shown.
** The ecomonic tradeoff between CTG combustor NOx emission and SCR size (i.e., diluition nitrogen versus NOx removal efficiency) may be optimized during later engineering.
*** Includes 3 lb/hr ammonium sulfate formed from SO3 and SCR ammonia slip.

Syngas Short-term SO2 Emission Rates			
Avg time	**Syn gas avg sulfur, ppm**	**SO2, lb/hr (per stack)**	**lb/10^6 Btu coal**
1-hr	50	74	0.027
3-hr	30	44	0.016
8-hr	20	29	0.011
24-hr	15	22	0.0080
30-day	10	15	0.0053

Example calculations for SO2
(From Ideal Gas Law, 1 lbmol gas = 380 scf, scf defined @ 60 deg F, 1 atm)
Max SO2 for 10 ppmv total sulfur in fuel
= (2100 x10^6 Btu/hr)/(240 Btu/scf) x (10 scf sulfur/10^6 scf) x (64 lb SO2/380 scf) = 15 lb SO2/hr/CTG

Short-term Emissions on Natural Gas (backup fuel)

Nat gas fuel rate per CTG= 2254 x 10^6 Btu/hr, HHV (supplier data)

Short-term Emission Rates		
	lb/hr (per stack)	**Basis***
NOx	43	5 ppmvd (@15% O2), based on 80% removal SCR system and 25 ppm inlet NOx
NOx (uncontrolled)	215	25 ppmvd (@ 15% O2)
CO	78	15 ppmvd (@ 15% O2)
PM10**	20	filterable (front-half) + condensible (back half)
VOC	9.0	2.4 ppmvd (@ 15% O2)
SO2	6.4	1 grain sulfur/100 scf in pipeline nat gas.
NH3	16	5 ppmvd (@ 15% O2) ammonia slip

* Typical mass emission rates from Siemens for basis stated except CO and PM10, which are allowances for expected guarantees from other suppliers. Siemens currently quotes lower CO and PM10 emission rates than shown.
** Includeds 2 lb/hr ammonium sulfate formed from SO3 and SCR ammonia slip.

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COMBUSTION TURBINE EMISSION ESTIMATES

CTG Startup/shutdown Emissions per CTG (supplier data)

	Avg Startup/shutdown Emission, lb/hr			
	Hot Start	**Warm Start**	**Cold Start**	**Worst Case, lb/hr**
NOx	108	116	121	121
CO	2116	2740	2205	2740
PM10	10	11	11	11
VOC	204	263	212	263
Typical duration	52 min	81 min	101 min	(N/A)

Notes: - NOx, CO and VOC hourly average startup emission rates exceed normal full load operation emission rates.
- NOx, CO and VOC shutdown emission rates (not shown) will also exceed normal full load emission rates, but are less than worst-case startup emissions.
- CTG fuel consumption and, therefore, also SO2 emissions are less during startup/shutdown than normal full load operation

Worst Case Estimated Annual Emissions

Worst Case Annual Emissions			
	ton/yr (per stack)	**avg lb/hr (per stack)**	**Basis**
NOx*	147	34	100 hr/yr startup/shutdown w/o SCR, plus 440 hr nat gas full load operation, balance on syn gas at full load*
CO	561	128	100 hr/yr startup/shutdown, balance of year on syn gas at full load*
PM10	105	24	8760 hr/yr on syn gas at full load
VOC	52	12	100 hr/yr startup/shutdown, balance of year on syn gas at full load*
SO2	65	15	10 ppm ann avg sulfur in fuel, 8760 hr/yr on syn gas at full load
NH3	86	20	8760 hr/yr on syn gas at full load
NOx (uncontrolled)	711	162	100 hr/yr startup/shutdown w/o SCR, plus 440 hr nat gas full load operation, balance on syn gas at full load* No SCR

* Startup/shutdown based on approximately 25 starts per year per CTG and about 4 hours per event.

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TANK VENT OXIDIZER EMISSION RATES

Basis: ConocoPhillips estimates and supplier data for similar equipment

TVO emission factors (lb/10^6 Btu fired)

	SG	NG	Basis
SO2	*	0.00286	1 grain S/100 scf nat gas
NOx	0.3	0.3	supplier data for similar equipment
CO	0.09	0.09	60 ppmvd (12% O2), supplier data for similar equipment
PM10	0.01	0.01	supplier data for similar equipment
VOC	0.004	0.004	CoP estimate

(SG = syngas, NG = natural gas)

* See emission table below

SO2 from sulfur in tank vent gas during normal oper = 3.5 lb/hr (CoP estimate)

	Capacities, 10^6 Btu/hr	
Operating Modes	SG	NG
Gasifier outage		40
Startup	10	30
Maximum operation, short-term	65	
Normal operation, long-term	15	

assumed syngas HHV = 240 Btu/dscf

Worst Case SO2 Emissions							
	Emission Averaging Time						
Operating Modes	1-hr	3-hr	8-hr	24-hr	30-day	12-mo avg	Ton/yr
Gasifier outage, hrs							
Startup, hrs							
Max operation, short-term hrs	1	3	8	24	100	400	
Normal operation, long-term hrs					620	8,360	
SG consumed, 10^6 Btu	65	195	520	1560	15,800	151,400	
NG consumed, 10^6 Btu	0	0	0	0	0	0	
Sulfur in SG, ppmv	50	30	20	15	10	10	
SO2 from SG, lb/10^6 Btu SG*	0.035	0.021	0.014	0.011	0.007	0.007	
SO2 from SG or NG, lbs	2	4	7	16	111	1,064	
SO2 from tank vent gas, lbs	3.5	10.5	28	84	2,520	30,660	
Total SO2, lb/hr	5.8	4.9	4.4	4.2	3.7	3.6	15.9

* Example SO2 emission factor calculations,

SO2 (syngas) = (10 scf S/10^6 scf fuel) x (64 lb SO2/380 scf S)/(240 Btu/scf fuel) = 0.0070 lb SO2/10^6 Btu

SO2 (natural gas) = 1 grain S/100 scf x 10^3 scf/10^6 Btu x 1 lb/7000 grain x 2 lb SO2/lb S = 0.00286 lb SO2/10^6 Btu

Worst Case Non-Sulfur Emissions							
	Emission Averaging Time						
Operating Modes	1-hr	3-hr	8-hr	24-hr	30-day	12-mo avg	Ton/yr
Gasifier outage, hrs					620	720	
Startup, hrs						263	
Max operation, short-term hrs	1	3	8	24	100	400	
Normal operation, long-term hrs						7,377	
SG consumed, 10^6 Btu	65	195	520	1560	6,500	139,285	
NG consumed, 10^6 Btu	0	0	0	0	24,800	36,690	
NOx,lb/hr	19.5	19.5	19.5	19.5	13.0	6.0	26.4
CO, lb/hr	5.9	5.9	5.9	5.9	3.9	1.81	7.9
PM10, lb/hr	0.7	0.7	0.7	0.7	0.4	0.20	0.9
VOC, lb/hr	0.3	0.3	0.3	0.3	0.2	0.1	0.4

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AUXILIARY BOILER EMISSION ESTIMATES

(Mainly used for startups, could be used for other purposes, primarily during power block outages)

Maximum steam generation 100,000 lb/hr
Maximum heat release 130 10^6 Btu/hr, HHV
Natural gas fuel, only

Emission factors

	lb/10^6 Btu, HHV	Basis
SO2	0.00286	1.0 grain total sulfur/100 scf pipeline natural gas
NOx	0.036	Low NOx burner, based on similar equipment from previous project
CO	0.074	Similar equipment from previous project
PM10	0.005	Similar equipment from previous project
VOC	0.004	Similar equipment from previous project

Emission calulations

	Max short-term lb/hr (1)	Annual average ton/yr (2)
SO2	0.37	0.41
NOx	4.7	5.1
CO	9.6	10.5
PM10	0.65	0.71
VOC	0.52	0.57

Notes:
(1) Maximum 1-hr, 3-hr, 8-hr, 24-hr, and 30-day average emission rates.
(2) Maximum annual capacity factor of 25% (i.e., annual fuel consumption less than 0.25 x 8760 hr/yr x 130 million Btu/hr = 285 billion Btu/yr)

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ENCLOSED GROUND FLARE EMISSION RATES

Emission Factors

	lb/10^6 Btu fired, HHV		
	SG	**NG**	**Basis**
SO2	see table	0.00286	1 grain sulfur/100 scf pipeline natural gas
NOx	0.07	0.07	Equipment supplier estimate
CO	1.54	0.55	Assumed 99% destruction of CO in SG (1), TRNCC factor for NG (2)
PM10	0.008	0.008	Very little unoxidized carbon in syngas, therefore very little PM, used AP-42 factor for NG in boiler (a small value) (3)
VOC	0.006	0.006	Virtually no VOC in syngas, used AP-42 factor for NG in boiler (a small value) (3)

Notes:

(1) CO emission factor based on 50 vol % CO in flared gas, assumed 99% destruction efficiency, and 240 Btu/scf HHV,
CO = (0.50 scf/scf) x (1 - 0.99)/(240 Btu/scf) x (28 lb/380 scf) x (10^6/10^6) = 1.54 lb/10^6 Btu, HHV

(2) Texas Natural Resource Conservation Commission (now Texas Commission on Environmental Quality),
Technical Guidance Package for Chemical Sources, Flares and Oxidizers (RG-109), May 1997

(3) U.S. EPA, AP-42, Table 1.4-2

		Capacities, 10^6 Btu/hr		
Operating Modes		SG	NG	
Steady state (pilot only)			2	
Gasifier Startup	1 Hour	270		(flared gas is partially oxidized natural gas, similar to syngas,
	3 Hour	260		or incompletely oxidized syngas)
	8 Hour	190		
	24 Hour	100		
	50 Hours	75		Heatup/startup - average entire time frame per gasifer
Gasifier shutdown	8 hour	50		Gasifier deslag - average time per shutdown
Flaring syn gas, max 1-hr avg		3730		(85% of max capacity for two gasifiers)
Flaring syn gas, max > 1-hr avg		3510		
Flaring syn gas, max >8-hr avg		1755		

Syngas HHV = 240 Btu/dscf

Operating Mode	SO2	NOx	CO	PM10	VOC
Pilot only emissions, lb/hr	0.0057	0.14	1.10	0.016	0.012
stack exit flow (ft3/s)	1200				
stack exit velocity (m/s)	0.186				

Normal Worst-Case Emissions							
	Emission Averaging Time						
Operating Modes	1-hr	3-hr	8-hr	24-hr	12-mo avg	Ton/yr	Notes
Steady state (pilot only) hrs	1	3	8	24	8760		Includes one gasifier starting up and shutting down 12 times per year
Startup flaring hrs syngas	1	3	8	24	600		
Shutdown deslag flaring hrs SG					96		
Normal flaring hrs syngas					200		
Syngas flared, 10^6 Btu	270	780	1,520	2,400	400,800		
NG consumed, 10^6 Btu	2	6	16	48	17520		
Sulfur in SG, ppmv	50	30	20	15	10		
SO2 from SG, lb/10^6 Btu SG	0.035	0.021	0.014	0.011	0.007		
SO2,lb/hr (total SG + NG)	9.49	5.49	2.68	1.06	0.3	1.4	
NOx,lb/hr	19.04	18.34	13.44	7.14	3.3	14.6	
CO, lb/hr	415.57	400.22	292.77	154.61	71	312	
PM10, lb/hr	2.18	2.10	1.54	0.82	0.38	1.7	
VOC, lb/hr	1.63	1.57	1.15	0.61	0.29	1.3	
stack exit flow (ft3/s)	8,021	7,727	5,662	3,008	1,408		Scaled from the maximum 1 hour upset flow
stack exit velocity (m/s)	1.245	1.199	0.879	0.467	0.219		

Worst Case Emergency Upset Emissions					
	Emission Averaging Time				
Operating Modes	1-hr	3-hr	8-hr	24-hr	Notes
Steady state (pilot only) hrs	1	3	8	24	Facility Upset assumes 85% of maximum syngas capacity for two gasifiers
Flaring hrs syn gas, max 1-hr	1				
Flaring hrs syn gas, max >1-hr		3	8		
Flaring hrs gas, max >8-hr				24	
SG flared, 10^6 Btu	3730	10530	28080	42120	
NG consumed, 10^6 Btu	2	6	16	48	
Sulfur in SG, ppmv	400	300	100	50	
SO2 from SG, lb/10^6 Btu SG	0.281	0.211	0.070	0.035	
SO2,lb/hr (total SG + NG)	1,048	740	247	62	
NOx,lb/hr	261	246	246	123	
CO, lb/hr	5,727	5,389	5,389	2,695	
PM10, lb/hr	29.9	28.1	28.1	14.1	
VOC, lb/hr	22.4	21.1	21.1	10.5	
stack exit flow (ft3/s)	110,000	103,512	103,512	51,756	Scaled from the maximum 1 hour upset flow
stack exit velocity (m/s)	17.076	16.069	16.069	8.034	

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COOLING TOWER EMISSION RATE

Basis: Similar equipment from previous project.

Cooling Tower Operating Data and Emission Calculation			
Parameter	**Power Block**	**Gasification/ ASU**	**Basis**
Heat rejected, million Btu/hr	1740	1015	Typical plant performance
Cooling water (CW) circulation rate, million lb/hr	116	68	Typical cooling tower design
Max CW dissolved solids, ppmw	2400	2400	TDS of water supply and 12 cycles of concentration
Drift, fraction of circulating CW	0.0010%	0.0010%	Typical supplier guarantee
PM10 emission rate, lb/hr	2.8	1.6	Calculated
PM10 emission rate, ton/yr	12.2	7.1	Calculated

Total PM10 cooling tower emission 19.3 ton/yr

Example calculation: (TO BE CONFIRMED)
Maximum expected total dissolved solids (TDS) in makeup water = 200 parts per million by weight (ppmw)
Maximum expected TDS in circulating cooling water at twelve cycles of concentration = 12 x 200 = 2400 ppmw
Power Block cooling tower PM10 = (116 x 10^6 lb/hr) x (0.00001 lb drift/lb) x (2400 lb PM/10^6 lb drift)
= 2.8 lb PM10/hr

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EMERGENCY DIESEL ENGINES EMISSION RATES

Short-term Emission Rates						
	Total	Emission Factor or Emission Rate				
Engines	**hp**	**SO2**	**NOx**	**CO**	**PM10**	**VOC**
Emission Factors						
NONROAD Tier 1 Light Commercial Generator Sets >1200hp		0.0004	0.0137	0.0018	0.0004	0.0006
NONROAD Tier 1 Light Commercial Pumps 300-600hp		0.0004	0.0134	0.0030	0.0004	0.0005
Emission Rates						
Emergency Generator, 2 MW - emission, lb/hr	2682	1.0	37	5	1.0	1.7
1 Emergency Fire Water Pump Engine, 300 hp - emission, lb/hr*	300	0.1	4	0.9	0.1	0.1

* Two pumps will be provided, one will be electric engine-driven. Emissions for one engine shown for worst case permitting.

Note: the EPA NONROAD emissions will meet the BACT requirement

Fuel sulfur = 0.05 wt%
1 MW = 1341 bhp

Annual Emission Rates**						
		Emission Rate, ton/yr				
Engines		**SO2**	**NOx**	**CO**	**PM10**	**VOC**
Emergency Generator, 2 MW - emission, ton/yr		0.05	1.8	0.2	0.05	0.09
1 Emergency Fire Water Pump Engine, 300 hp - emission, ton/yr		0.01	0.2	0.0	0.01	0.01
Total		**0.05**	**2.04**	**0.28**	**0.05**	**0.09**

** Maximum annual emission based on 100 hr/yr normal maintenance operation per engine.

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FUGITIVE PARTICULATE MATTER

Annual Coal/Coke Requirement

	15930	Amount of coal/coke delivered per train (tons/train)
	150	Number of deliveries per year (trains/year)
	2,389,500	Annual amount of coal/coke delivered (tons/year)

For modeling purposes the total annual coal/coke requirement is assumed to arrive by either train or ship.

Emission Factor

AP-42 Section 13.2.4 Aggregate Handling

E = uncontrolled PM_{10} emissions (lb/ton) = k * (0.0032) * $(U/5)^{1.3}$ / $(M/2)^{1.4}$

k	0.35	particle size multiplier (dimensionless)
U	2.27	mean wind speed (miles per hour [mph]) = 200 ft/min from negative pressurization of train unloading building
M	4.5	material moisture content (%) - Table 13.2.4-1 Coal-fired power plant for coal as received
E =	0.000129	lb/ton PM10 uncontrolled
assume	79.2	% control efficiency (80% capture and 99% control = 79% reduction)
E =	0.000027	lb/ton PM10 controlled

Train Unloading

Dumps to underground hopper and the train is inside a building with plastic flaps across the ends
The unloading building is under negative pressure and dust is collected and sent to a baghouse

	5	hours per train to unload
	3186	Maximum hourly unloading rate (ton/hr)
	15930	Maximum daily unloading rate (ton/day)
Emissions	0.085	Maximum hourly PM_{10} emission rate (lb/hr)
	0.018	Maximum daily PM_{10} emission rate (lb/hr)
	0.0320	Maximum annual PM_{10} emission rate (ton/yr)

Storage Dome Transfer Point

All coal/coke tranfered from the train unloading station and/or the ship unloading station into the storage domes passes through this point and the PM emissions are controlled with a baghouse.

	3186	Maximum hourly unloading rate (ton/hr) either trains or ships
	45600	Maximum daily unloading rate (ton/day) either trains or ships
	2,389,500	Maximum annual unloading rate (ton/yr) either trains or ships
Emissions	0.085	Maximum hourly PM_{10} emission rate (lb/hr)
	0.051	Maximum daily PM_{10} emission rate (lb/hr)
	0.0320	Maximum annual PM_{10} emission rate (ton/yr)

Ship Unloading

Alternative to train unloading. Assume same amount of coal/coke delivered as on trains.
Ship unloads by bucket crane to a conveyor belt, particulate is suctioned to a baghouse
The mean wind speed for this source is the mean outdoor wind speed, since the drop from the bucket crane to the conveyor belt occurs outside.

Emission Factor

AP-42 Section 13.2.4 Aggregate Handling

E = uncontrolled PM_{10} emissions (lb/ton) = k * (0.0032) * $(U/5)^{1.3}$ / $(M/2)^{1.4}$

k	0.35	particle size multiplier (dimensionless)
U	10	mean wind speed (miles per hour [mph])
M	4.5	material moisture content (%) - Table 13.2.4-1 Coal-fired power plant for coal as received
E =	0.000886	lb/ton PM10 uncontrolled
assume	79.2	% control efficiency (80% capture and 99% control = 79% reduction)
E =	0.000184	lb/ton PM10 controlled
	2,389,500	Annual amount of coal/coke delivered (tons/year)
	70000	Maximum ship capacity (tons)
	34	ships/year
	1900	Maximum hourly unloading rate (ton/hr)
	37	hours per ship to unload
	45600	Maximum daily unloading rate (ton/day)
Emissions	0.350	Maximum hourly PM_{10} emission rate (lb/hr)
	0.350	Maximum daily PM_{10} emission rate (lb/hr)
	0.2202	Maximum annual PM_{10} emission rate (ton/yr)

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FUGITIVE PARTICULATE MATTER

Storage Dome Ventilation

Storage Dome Ventilation will not occur during loading of the domes or until most of the particulate has settled
although fine particules will still hang in the air in the domes.
Calculate emissions based on total coal/coke stacked in dome.

	3186	Maximum hourly unloading rate (ton/hr) either trains or ships
	45600	Maximum daily unloading rate (ton/day) either trains or ships
	2,389,500	Maximum annual unloading rate (ton/yr) either trains or ships
Emissions	0.085	Maximum hourly PM_{10} emission rate (lb/hr)
	0.051	Maximum daily PM_{10} emission rate (lb/hr)
	0.032	Maximum annual PM_{10} emission rate (ton/yr)

Note: Emissions will occur from either the train unloading area or the ship unloading area but not both, as the total annual coal/coke
Note: Short-term emissions from the storage dome ventilation system will not occur at the same time as emissions from the train and

Summary PM10 Emissions

		Maximum Hourly		Maximum Daily		Annual Emissions	
Scenario		lb/hr	g/s	lb/hr	g/s	ton/yr	g/s
1 - Train Unloading	Train Unloading	0.085	0.011	0.018	0.002	0.032	0.001
	Storage Domes	0.085	0.011	0.051	0.006	0.032	0.001
	Total	**0.171**	**0.022**	**0.069**	**0.009**	**0.064**	**0.002**
2 -Ship Unloading	Storage Domes	0.085	0.011	0.051	0.006	0.032	0.001
	Ship Unloading	0.350	0.044	0.350	0.044	0.220	0.006
	Total	**0.436**	**0.055**	**0.401**	**0.051**	**0.252**	**0.007**
3 - Dome Ventilation	Ventilation	0.085	0.011	0.051	0.006	0.032	0.001
Maximum Short-term Emissions		**0.436**	**0.055**	**0.401**	**0.051**		
unloading emissions plus the dome ventilation						**0.284**	**0.008**

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Stack Parameters

Source	Combustion Turbines(ea)	Tank Vent Oxidizer	Auxiliary Boiler	Flare	Cooling Towers (per cell)(1)
Stack height, ft above grade(2)	150	210	40	100	48
Stack diameter, ft	20	6	5	50	33
Stack outlet temp, deg F	250	584	300	1600	104
Stack exit flow, act ft3/sec	21,200(3)	785(4)	625	1200 to 110,000(5)	22,833

Notes:

(1) Twelve cells estimated for power block cooling tower, seven cells estimated for ASU/gasification cooling tower.

(2) Minimum stack height assumed for worst-case dispersion.

(3) Value shown in table is based on full load syn gas combustion (relatively constant for varying ambient temperatures). Corresponding full load stack flow for natural gas combustion will vary from about 19,000 act ft3/sec during warm summer ambient temperatures to about 22,400 act ft3/sec at cold winter ambient temperatures.

(4) Based on 65 million Btu/hr syn gas or natural gas combustion. Assumed 12% O_2. Stack exit flows for other heat input rates may be assumed proportional to the heat input rate for each fuel.

(5) Estimated flare exhaust gas rates for stated range of heat input from 40 to 3730 million Btu/hr.

Appendix B-3-2

Hazardous Air Pollutant Emission Calculations

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PACIFIC MOUNTAIN ENERGY CENTER
HAPs EMISSION SUMMARY

CAS # or MPCA #	Compound	Federally Listed Compound HAP	Washington State TAP	Daily HAP Emission (lb/hr) CTGs	TVO	Flare	Fugitive	Auxiliary Boiler	Power Cooling Tower	Gas/ASU Cooling Tower	Emergency Fire Pump	Emergency Generator	Total	Washington State ASIL (ug/m3) Class A	Class B	Small Quantity Emission Rate Exemption Level Class A lb/yr	Class B lb/yr	Class B lb/hr	Washington State Class B 24-hour Modeling Required
106-99-0	1,3-Butadiene	Yes	Yes								8.21E-05		8.21E-05	0.0036	-	0.5	-	-	No
75-07-0	Acetaldehyde	Yes	Yes	9.94E-03	1.17E-04	9.00E-05					1.61E-03	4.73E-04	1.22E-02	0.45	-	50	-	-	No
107-02-8	Acrolein	Yes	Yes								1.94E-04	1.48E-04	3.42E-04	-	0.02	-	175	0.02	No
7664-41-7	Ammonia	No	Yes	3.94E+01			2.88E-02						3.94E+01	-	100	-	17500	2	Yes
7440-36-0	Antimony	Yes	Yes	6.07E-03	1.95E-04	1.50E-04							6.42E-03	-	1.7	-	175	0.02	No
7440-38-2	Arsenic	Yes	Yes	1.32E-02	1.03E-03	7.90E-04		2.48E-05	5.80E-06	3.38E-06			1.51E-02	0.00023	-	**	-	-	No
7440-39-3	Barium	No	Yes					5.45E-04					5.45E-04	-	1.7	-	175	0.02	No
71-43-2	Benzene	Yes	Yes	1.32E-02	1.96E-02	1.51E-02	1.78E-04	2.60E-04			1.96E-03	1.46E-02	6.49E-02	0.12	-	20	-	-	No
7440-41-7	Beryllium	Yes	Yes	1.44E-03	5.85E-06	4.50E-06		1.49E-06					1.45E-03	0.00042	-	**	-	-	No
106-97-8	Butane	No	Yes					2.60E-01					2.60E-01	-	6300	-	43748	5	No
7440-43-9	Cadmium	Yes	Yes	5.30E-02	3.90E-05	3.00E-05		1.36E-04					5.32E-02	0.00056	-	**	-	-	No
75-15-0	Carbon disulfide	Yes	Yes	2.54E-01	2.99E-03	2.30E-03	9.50E-04						2.60E-01	-	100	-	17500	2	No
463581	Carbonyl sulfide	Yes	Yes				1.70E-03						1.70E-03	-	***	-	-	-	No
7782-50-5	Chlorine (Cl)	Yes	Yes						2.90E-03	1.69E-03			4.59E-03	-	5	-	175	0.02	No
18540-29-9	Chromium, (hexavalent)	Yes	Yes	8.45E-04	2.18E-04	1.68E-04		1.73E-04					1.40E-03	0.000083	-	**	-	-	No
7440-48-4	Cobalt	Yes	Yes	1.44E-03	8.32E-04	6.40E-04		1.04E-05					2.92E-03	-	0.17	-	175	0.02	No
7440-50-8	Copper	No	Yes					1.05E-04					1.05E-04	-	0.67	-	175	0.02	No
57-12-5	Cyanide (Cyanide ion, Inorganic cyanides, Isocyanide)	Yes	Yes	3.15E-02	3.25E-03	2.50E-03	2.78E-04						3.75E-02	-	17	-	1750	0.2	No
100-41-4	Ethyl benzene	Yes	Yes		2.20E-02	1.69E-02	1.57E-07						3.89E-02	-	160	-	22750	2.6	No
7782-41-4	Fluorine (F)	No	Yes						3.48E-04	2.03E-04			5.51E-04	-	5.3	-	175	0.02	No
50-00-0	Formaldehyde	Yes	Yes	9.38E-02	1.11E-03	8.50E-04	3.30E-08	9.29E-03			2.48E-03	1.48E-03	1.09E-01	0.077	-	20	-	-	No
110-54-3	Hexane	Yes	Yes				4.33E-08	2.23E-01					2.23E-01	-	200	-	22750	2.6	No
7647-01-0	Hydrochloric acid	Yes	Yes	7.18E-02	6.42E-04	4.94E-04	3.06E-03						7.60E-02	-	7	-	175	0.02	Yes
7664-39-3	Hydrogen fluoride (Hydrofluoric acid)	Yes	Yes	2.76E-01	3.90E-05	3.00E-05							2.76E-01	-	8.7	-	175	0.02	Yes
6/4/7783	Hydrogen sulfide	Yes	Yes				1.17E-01						1.17E-01	-	0.9	-	175	0.02	Yes
7439-92-1	Lead	Yes	Yes	3.09E-03	2.77E-05	2.13E-05			1.16E-06	6.77E-07			3.14E-03	0.5*	-	50	-	-	No
7439-96-5	Manganese	Yes	Yes	5.74E-03	1.64E-03	1.27E-03		4.70E-05	2.32E-03	1.35E-03			1.24E-02	-	0.4	-	175	0.02	No
7439-97-6	Mercury	Yes	Yes	6.62E-03	4.55E-04	3.50E-05		3.22E-05	5.80E-07	3.38E-07			7.15E-03	-	0.33	-	175	0.02	No
74-83-9	Methyl bromide (Bromomethane)	Yes	Yes	2.63E-01	8.00E-03	6.15E-03							2.77E-01	-	5	-	175	0.02	Yes
74-87-3	Methyl chloride (chloromethane)	Yes	Yes		4.10E-03	3.15E-03							7.25E-03	-	340	-	43748	5	No
75-09-2	Methylene chloride (Dichloromethane)	Yes	Yes	1.21E-02	3.84E-04	2.95E-04							1.28E-02	0.56	-	50	-	-	No
7439-98-7	Molybdenum	No	Yes					1.36E-04					1.36E-04	-	33	-	5250	0.6	No
91-20-3	Naphthalene	Yes	Yes	1.38E-02	5.59E-04	4.30E-04	7.30E-07	7.55E-05			1.78E-04	2.44E-03	1.75E-02	-	170	-	22750	2.6	No
7440-02-0	Nickel	Yes	Yes	2.15E-03	2.91E-03	2.24E-03		2.60E-04					7.55E-03	0.0021	-	0.5	-	-	No
109-66-0	Pentane	No	Yes					3.22E-01					3.22E-01	-	6000	-	43748	5	No
108-95-2	Phenol	Yes	Yes	2.03E-01	8.19E-03	6.30E-03	2.27E-09						2.18E-01	-	63	-	10500	1.2	No
115-07-1	Propylene	Yes	No								5.42E-04	5.24E-02	5.29E-02	-	-	-	-	-	No
7784-49-2	Selenium	Yes	Yes	3.09E-03	1.63E-04	1.25E-04		2.97E-06	1.16E-05	6.77E-06			3.40E-03	-	0.67	-	175	0.02	No
7440-22-4	Silver	No	Yes						1.16E-06	6.77E-07			1.84E-06	-	0.33	-	175	0.02	No
7664-93-9 14808-79-8	Sulfuric acid and sulfates	No	Yes	3.16E+00	3.72E-02	1.88E-01							3.38E+00	-	3.3	-	175	0.02	Yes
108-88-3	Toluene	Yes	Yes	1.82E-04	7.74E-03	5.95E-03	1.88E-05	4.21E-04			8.59E-04	5.28E-03	2.04E-02	-	400	-	43748	5	No
7440-62-2	Vanadium	No	Yes					2.85E-04					2.85E-04	-	0.17	-	175	0.02	No
1330-20-7	Xylenes	Yes	Yes		8.78E-03	6.75E-03	2.89E-07				5.99E-04	3.62E-03	1.97E-02	-	1500	-	43748	5	No
Polyaromatic Hydrocarbon (PAH)		Yes	Yes											0.00048	-	**	-	-	No
PAH	Benzo(a)pyrene	No	Yes					1.49E-07			3.95E-07	4.82E-06	5.37E-06						
PAH	Benz(a)anthracene	No	Yes	1.27E-05	1.50E-07	1.15E-07		2.23E-07			3.53E-06	1.17E-05	2.84E-05						
PAH	Benzo(b)fluoranthene	No	Yes					2.23E-07			2.08E-07	2.08E-05	2.13E-05						
PAH	Chrysene	No	Yes					2.23E-07			7.41E-07	2.87E-05	2.97E-05						
PAH	Dibenzo(a,h)anthracene	No	Yes					1.49E-07			1.22E-06	6.50E-06	7.87E-06						
PAH	Indeno(1,2,3-cd)pyrene	No	Yes					2.23E-07			7.88E-07	7.77E-06	8.78E-06						
PAH	2-Methylnaphthalene	No	No					2.97E-06					2.97E-06						
PAH	3-Methylchloranthrene	No	No					2.23E-07					2.23E-07						
PAH	7,12-Dimethylbenz(a)anthracene	No	No					1.98E-06					1.98E-06						
PAH	Acenaphthene	No	No					2.23E-07			2.98E-06	8.79E-05	9.11E-05						
PAH	Acenaphthylene	No	No					2.23E-07			1.06E-05	1.73E-04	1.84E-04						
PAH	Anthracene	No	No					2.97E-07			3.93E-06	2.31E-05	2.73E-05						
PAH	Benzo(g,h,i)perylene	No	No					1.49E-07			1.03E-06	1.04E-05	1.16E-05						
PAH	Benzo(k)fluoranthene	No	No					2.23E-07			3.26E-07	4.09E-06	4.64E-06						
PAH	Fluoranthene	No	No					3.71E-07			1.60E-05	7.57E-05	9.20E-05						
PAH	Fluorene	No	No					3.47E-07			6.13E-05	2.40E-04	3.02E-04						
PAH	Phenanathrene	No	No					2.10E-06			6.17E-05	7.66E-04	8.30E-04						
PAH	Pyrene	No	No					6.19E-07			1.00E-05	6.97E-05	8.03E-05						
	Total federal HAPs			1.34E+00	9.50E-02	7.28E-02	1.23E-01	2.34E-01	5.24E-03	3.06E-03	8.68E-03	8.19E-02	1.96						
	Total Washington State TAPs			4.39E+01	1.32E-01	2.61E-01	1.52E-01	8.17E-01	5.59E-03	3.26E-03	7.97E-03	2.81E-02	45.32						

Notes:
(1) See following spreadsheets for more detailed emission calculations per source
(2) For the CAA112 requirements the combination of all Polyaromatic Hydrocarbons (PAH) will be considered Polycylic Organic Matter (POM), each individual PAH is not a HAP. For the Washington State requirements, the combination of the first 6 PAHs in the table is compared with the ASIL.
* Lead Class A ASIL 24-hour averaging time
** the ASIL is less than the threshold for use with the Small Quantity Emission Rate Exemption Levels
*** Listed as a Class B pollutant, but there is no Small Quantity Emission Rate Exemption Level

Energy Northwest
Fluor & URS Calculations
Aug 22-06

PACIFIC MOUNTAIN ENERGY CENTER
HAPs EMISSION SUMMARY

CAS # or		Federally Listed Compound	Washington State	Annual Average HAP Emission (ton/yr)										Washington State ASIL (ug/m3)		Small Quantity Emission Rate Exemption Level			Washington State Class A Annual Modeling Required	Washington State Class B 24-Hour Modeling Required
MPCA #	Compound	HAP	TAP	CTGs	TVO	Flare	Fugitive	Auxiliary Boiler	Power Cooling Tower	Gas/ASU Cooling Tower	Emergency Fire Pump	Emergency Generator	Total	Class A	Class B	Class A lb/yr	Class B lb/yr	Class B lb/hr		
106-99-0	1,3-Butadiene	Yes	Yes								4.11E-06		4.11E-06	0.0036	-	0.5	-	-	No	No
75-07-0	Acetaldehyde	Yes	Yes	4.35E-02	1.58E-04	3.94E-04					8.05E-05	2.37E-05	4.42E-02	0.45	-	50	-	-	Yes	No
107-02-8	Acrolein	Yes	Yes								9.71E-06	7.40E-06	1.71E-05	-	0.02	-	175	0.02	No	No
7664-41-7	Ammonia	No	Yes	1.73E+02			1.26E-01						1.73E+02	-	100	-	17500	2	No	Yes
7440-36-0	Antimony	Yes	Yes	2.66E-02	2.63E-04	6.57E-04							2.75E-02	-	1.7	-	175	0.02	No	No
7440-38-2	Arsenic	Yes	Yes	5.80E-02	1.38E-03	3.46E-03		2.71E-05	2.54E-05	1.48E-05			6.29E-02	0.00023	-	**	-	-	Yes	No
7440-39-3	Barium	No	Yes					5.97E-04					5.97E-04	-	1.7	-	175	0.02	No	No
71-43-2	Benzene	Yes	Yes	5.80E-02	2.65E-02	6.61E-02	7.79E-04	2.85E-04			9.80E-05	7.28E-04	1.53E-01	0.12	-	20	-	-	Yes	No
7440-41-7	Beryllium	Yes	Yes	6.29E-03	7.88E-06	1.97E-05		1.63E-06					6.32E-03	0.00042	-	**	-	-	Yes	No
106-97-8	Butane	No	Yes					2.85E-01					2.85E-01	-	6300	-	43748	5	No	No
7440-43-9	Cadmium	Yes	Yes	2.32E-01	5.26E-05	1.31E-04		1.49E-04					2.32E-01	0.00056	-	**	-	-	Yes	No
75-15-0	Carbon disulfide	Yes	Yes	1.11E+00	4.03E-03	1.01E-02	4.16E-03						1.13E+00	-	100	-	17500	2	No	No
463581	Carbonyl sulfide	Yes	Yes				7.45E-03						7.45E-03	-	***	-	-	-	No	No
7782-50-5	Chlorine (Cl)	Yes	Yes						1.27E-02	7.41E-03			2.01E-02	-	5	-	175	0.02	No	No
18540-29-9	Chromium, (hexavalent)	Yes	Yes	3.70E-03	2.94E-04	7.36E-04		1.90E-04					4.92E-03	0.000083	-	**	-	-	Yes	No
7440-48-4	Cobalt	Yes	Yes	6.29E-03	1.12E-03	2.80E-03		1.14E-05					1.02E-02	-	0.17	-	175	0.02	No	No
7440-50-8	Copper	No	Yes					1.15E-04					1.15E-04	-	0.67	-	175	0.02	No	No
57-12-5	Cyanide (Cyanide ion, Inorganic cyanides, Isocyanide)	Yes	Yes	1.38E-01	4.38E-03	1.10E-02	1.22E-03						1.54E-01	-	17	-	1750	0.2	No	No
100-41-4	Ethyl benzene	Yes	Yes		2.96E-02	7.40E-02	6.87E-07						1.04E-01	-	160	-	22750	2.6	No	No
7782-41-4	Fluorine (F)	No	Yes						1.52E-03	8.89E-04			2.41E-03	-	5.3	-	175	0.02	No	No
50-00-0	Formaldehyde	Yes	Yes	4.11E-01	1.49E-03	3.72E-03	1.45E-07	1.02E-02			1.24E-04	7.41E-05	4.27E-01	0.077	-	20	-	-	Yes	No
110-54-3	Hexane	Yes	Yes				1.90E-07	2.44E-01					2.44E-01	-	200	-	22750	2.6	No	No
7647-01-0	Hydrochloric acid	Yes	Yes	3.14E-01	8.65E-04	2.16E-03	1.34E-02						3.31E-01	-	7	-	175	0.02	No	Yes
7664-39-3	Hydrogen fluoride (Hydrofluoric acid)	Yes	Yes	1.21E+00	5.26E-05	1.31E-04							1.21E+00	-	8.7	-	175	0.02	No	Yes
6/4/7783	Hydrogen sulfide	Yes	Yes				5.11E-01						5.11E-01	-	0.9	-	175	0.02	No	Yes
7439-92-1	Lead	Yes	Yes	1.35E-02	3.73E-05	9.32E-05			5.08E-06	2.96E-06			1.37E-02	0.5*	-	50	-	-	Yes	No
7439-96-5	Manganese	Yes	Yes	2.51E-02	2.22E-03	5.54E-03		5.15E-05	1.02E-02	5.93E-03			4.90E-02	-	0.4	-	175	0.02	No	No
7439-97-6	Mercury	Yes	Yes	2.90E-02	6.13E-04	1.53E-04		3.52E-05	2.54E-06	1.48E-06			2.98E-02	-	0.33	-	175	0.02	No	No
74-83-9	Methyl bromide (Bromomethane)	Yes	Yes	1.15E+00	1.08E-02	2.69E-02							1.19E+00	-	5	-	175	0.02	No	Yes
74-87-3	Methyl chloride (chloromethane)	Yes	Yes		5.52E-03	1.38E-02							1.93E-02	-	340	-	43748	5	No	No
75-09-2	Methylene chloride (Dichloromethane)	Yes	Yes	5.32E-02	5.17E-04	1.29E-03							5.50E-02	0.56	-	50	-	-	Yes	No
7439-98-7	Molybdenum	No	Yes					1.49E-04					1.49E-04	-	33	-	5250	0.6	No	No
91-20-3	Naphthalene	Yes	Yes	6.04E-02	7.53E-04	1.88E-03	3.20E-06	8.27E-05			8.90E-06	1.22E-04	6.33E-02	-	170	-	22750	2.6	No	No
7440-02-0	Nickel	Yes	Yes	9.43E-03	3.92E-03	9.79E-03		2.85E-04					2.34E-02	0.0021	-	0.5	-	-	Yes	No
109-66-0	Pentane	No	Yes					3.52E-01					3.52E-01	-	6000	-	43748	5	No	No
108-95-2	Phenol	Yes	Yes	8.90E-01	1.10E-02	2.76E-02	9.94E-09						9.28E-01	-	63	-	10500	1.2	No	No
115-07-1	Propylene	Yes	No								2.71E-05	2.62E-03	2.65E-03	-	-	-	-	-	No	No
7784-49-2	Selenium	Yes	Yes	1.35E-02	2.19E-04	5.48E-04		3.25E-06	5.08E-05	2.96E-05			1.44E-02	-	0.67	-	175	0.02	No	No
7440-22-4	Silver	No	Yes						5.08E-06	2.96E-06			8.04E-06	-	0.33	-	175	0.02	No	No
7664-93-9 14808-79-8	Sulfuric acid and sulfates	No	Yes	1.38E+01	5.01E-02	8.24E-01							1.47E+01	-	3.3	-	175	0.02	No	Yes
108-88-3	Toluene	Yes	Yes	7.98E-04	1.04E-02	2.61E-02	8.22E-05	4.61E-04			4.29E-05	2.64E-04	3.81E-02	-	400	-	43748	5	No	No
7440-62-2	Vanadium	No	Yes					3.12E-04					3.12E-04	-	0.17	-	175	0.02	No	No
1330-20-7	Xylenes	Yes	Yes		1.18E-02	2.96E-02	1.27E-06				2.99E-05	1.81E-04	4.16E-02	-	1500	-	43748	5	No	No
Polyaromatic Hydrocarbon (PAH)		Yes	Yes											0.00048	-	**	-	-	Yes	No
PAH	Benzo(a)pyrene	No	Yes					1.63E-07			1.97E-08	2.41E-07	4.24E-07							
PAH	Benz(a)anthracene	No	Yes	5.56E-05	2.01E-07	5.04E-07		2.44E-07			1.76E-07	5.84E-07	5.73E-05							
PAH	Benzo(b)fluoranthene	No	Yes					2.44E-07			1.04E-08	1.04E-06	1.30E-06							
PAH	Chrysene	No	Yes					2.44E-07			3.71E-08	1.44E-06	1.72E-06							
PAH	Dibenzo(a,h)anthracene	No	Yes					1.63E-07			6.12E-08	3.25E-07	5.49E-07							
PAH	Indeno(1,2,3-cd)pyrene	No	Yes					2.44E-07			3.94E-08	3.89E-07	6.72E-07							
PAH	2-Methylnaphthalene	No	No					3.25E-06					3.25E-06							
PAH	3-Methylchloranthrene	No	No					2.44E-07					2.44E-07							
PAH	7,12-Dimethylbenz(a)anthracene	No	No					2.17E-06					2.17E-06							
PAH	Acenaphthene	No	No					2.44E-07			1.49E-07	4.39E-06	4.79E-06							
PAH	Acenaphthylene	No	No					2.44E-07			5.31E-07	8.66E-06	9.44E-06							
PAH	Anthracene	No	No					3.25E-07			1.96E-07	1.15E-06	1.68E-06							
PAH	Benzo(g,h,i)perylene	No	No					1.63E-07			5.13E-08	5.22E-07	7.36E-07							
PAH	Benzo(k)fluoranthene	No	No					2.44E-07			1.63E-08	2.05E-07	4.65E-07							
PAH	Fluoranthene	No	No					4.07E-07			7.99E-07	3.78E-06	4.99E-06							
PAH	Fluorene	No	No					3.80E-07			3.07E-06	1.20E-05	1.55E-05							
PAH	Phenanathrene	No	No					2.30E-06			3.09E-06	3.83E-05	4.37E-05							
PAH	Pyrene	No	No					6.78E-07			5.02E-07	3.48E-06	4.66E-06							
	Total federal HAPs			5.87E+00	1.28E-01	3.19E-01	5.38E-01	2.56E-01	2.29E-02	1.34E-02	4.34E-04	4.10E-03	7.15							
	Total Washington State TAPs			1.92E+02	1.78E-01	1.14E+00	6.64E-01	8.94E-01	2.45E-02	1.43E-02	3.98E-04	1.40E-03	195.28							

Notes:
(1) See following spreadsheets for more detailed emission calculations per source
(2) For the CAA112 requirements the combination of all Polyaromatic Hydrocarbons (PAH) will be considered Polycylic Organic Matter (POM), each individual PAH is not a HAP. For the Washington State requirements, the combination of the first 6 PAHs in the table is compared with the ASIL.
* Lead Class A ASIL 24-hour averaging time
** the ASIL is less than the threshold for use with the Small Quantity Emission Rate Exemption Levels
*** Listed as a Class B pollutant, but there is no Small Quantity Emission Rate Exemption Level

Energy Northwest
Fluor Contract A2RE
3/10/2006

COMBUSTION TURBINE HAPs EMISSION SUMMARY

Plant Performance

Syngas fuel 2100 x 10^6 Btu/hr/CTG, HHV

Assumed Coal conversion efficency **0.76** (PRB coal)

Gasifiers coal feed, total both CTGs 5520 x 10^6 Btu/hr, HHV (total for two gasifiers)

CAS # or MPCA #	Compound	Emission Factor (lb/10^{12} Btu coal)	Short-term Emission (lb/hr)	Annual Emission (ton/yr)	Emission Factor Source
75-07-0	Acetaldehyde	1.8	0.010	0.044	NETL, Table 2-17 (see Reference 1)
7440-36-0	Antimony (1)	1.1	0.0061	0.027	Wabash River test data
7440-38-2	Arsenic (1)	2.4	0.0132	0.058	Wabash River test data
56-55-3	Benz[a]anthracene	0.0023	0.000013	5.6E-05	NETL, Table 2-17 (see Reference 1)
71-43-2	Benzene	2.4	0.013	0.058	Wabash River test data
7440-41-7	Beryllium (1)	0.26	0.0014	0.006	Wabash River test data
7440-43-9	Cadmium (1)	9.6	0.05	0.232	Wabash River test data
75-15-0	Carbon disulfide	46	0.25	1.112	NETL, Table 2-17 (see Reference 1)
0-00-5	Chromium, total (1)	0.51	0.0028	0.012	Wabash River test data
18540-29-9	Chromium, (hexavalent)	0.15	0.00084	0.004	Portion of total chromium emitted in +6 valenece state, assumed to be 30% of total
7440-48-4	Cobalt (1)	0.26	0.0014	0.006	Wabash River test data
57-12-5	Cyanide (Cyanide ion, Inorganic cyanides, Isocyanide)	5.7	0.031	0.138	NETL, Table 2-6 (see Reference 1)
50-00-0	Formaldehyde	17	0.09	0.411	NETL, Table 2-17 (see Reference 1)
7647-01-0	Hydrochloric acid	13	0.072	0.314	Wabash River test data
7664-39-3	Hydrogen fluoride (Hydrofluoric acid) (3)	50	0.28	1.209	NETL, Table 2-5 (see Reference 1)
7439-92-1	Lead (1)	0.56	0.0031	0.014	Wabash River test data
7439-96-5	Manganese (1)	1.0	0.0057	0.025	Wabash River test data
7439-97-6	Mercury (1)	1.2	0.0066	0.029	(See Note 2)
74-83-9	Methyl bromide (Bromomethane)	47.7	0.26	1.153	Wabash River test data
75-09-2	Methylene chloride (Dichloromethane)	2.2	0.012	0.053	Wabash River test data
91-20-3	Naphthalene	2.5	0.014	0.060	Wabash River test data
7440-02-0	Nickel (1)	0.39	0.0022	0.009	Wabash River test data
108-95-2	Phenol	36.8	0.20	0.890	Wabash River test data
7784-49-2	Selenium (1)	0.56	0.0031	0.014	Wabash River test data
7664-93-9 14808-79-8	Sulfuric acid and sulfates	572	3.2	13.830	(See Note 4)
108-88-3	Toluene	0.033	0.00018	0.001	NETL, Table 2-17 (see Reference 1)
7664-41-7	Ammonia (5)	7141	39.42	172.66	5 ppmv ammonia slip from the SCR

Notes:

(1) Wabash factors for HAP metals and HCl are adjusted assumed worst-case PMEC feed composition.

(2) Mercury factor based on 90% overall removal for PRB coal feed.

Worst case mercury feed (PRB) = 0.14 ppmwd Hg and approx 12,000 Btu/lb HHV, dry: Hg = 0.14 lb/10^6 lb x 1 lb/12,000 Btu x 0.1 x 10^{12}

= 1.2 lb Hg/10^12 Btu coal

(3) Hydrofluoric acid is estimated using fraction of total feed fluorine measured in the LGTI combustion turbine stacks, as reported in Reference 1, and the highest expected concentration of fluorine in the PMEC feed steams.

(4) Sulfuric acid calculated asuming 7% of SOx in HRSG exhaust converts to SO3 which reacts with water to form H2SO4. Assuming 10 ppmvd total sulfur in fuel, 240 Btu/ft3 HHV, and 0.76 coal energy conversion to syngas,

Sulfuric acid = 0.07 x 10/10^6 x 1 ft3/240 Btu x 98 lb/380 ft3 x 0.76 x 10^{12} = 572 lb/10^12 Btu coal

(5) Ammonia slip from the SCR (5 ppmvd (@ 15% O2) - provided by Fluor - see Criteria Pollutant emission spreadsheet for details

References:

(1) NETL - National Energy Technology Laboratory, U.S. Dept of Energy,*Major Environmental Aspects of Gasification-based Power Generation Technologies, Final Report,* December 2002.

Energy Northwest
Fluor Contract A2RE
3/10/2006

TANK VENT OXIDIZER HAPs EMISSION SUMMARY

Syngas fuel consumption rates 65 x 10^6 Btu/hr, HHV (max, use for short-term emission calculation)
20 x 10^6 Btu/hr, HHV (avg, use for annual emission calculation)

CAS # or MPCA #	Compound	Emission Factor ($lb/10^{12}$ Btu syngas) (1)	Short-term Emission (lb/hr)	Annual Emission (ton/yr)	Emission Factor Source
75-07-0	Acetaldehyde	1.8	1.2E-04	1.6E-04	NETL, Table 2-17 (see Reference 1)
7440-36-0	Antimony	3.0	2.0E-04	2.6E-04	Wabash River test data
7440-38-2	Arsenic	15.8	1.0E-03	1.4E-03	Wabash River test data
56-55-3	Benz[a]anthracene	0.0023	1.5E-07	2.0E-07	NETL, Table 2-17 (see Reference 1)
71-43-2	Benzene	302	2.0E-02	2.6E-02	Wabash River test data
7440-41-7	Beryllium	0.09	5.9E-06	7.9E-06	NETL, Table 2-11 (see Reference 1)
7440-43-9	Cadmium	0.60	3.9E-05	5.3E-05	Wabash River test data
75-15-0	Carbon disulfide	46	3.0E-03	4.0E-03	NETL, Table 2-17 (see Reference 1)
0-00-5	Chromium, total	11.2	7.3E-04	9.8E-04	Wabash River test data
18540-29-9	Chromium, (hexavalent)	3.4	2.2E-04	2.9E-04	Portion of total chromium emitted in +6 valenece state, assumed to be 30% of total
7440-48-4	Cobalt	12.8	8.3E-04	1.1E-03	Wabash River test data
57-12-5	Cyanide (Cyanide ion, Inorganic cyanides, Isocyanide)	50	3.3E-03	4.4E-03	Wabash River test data
100-41-4	Ethyl benzene	338	2.2E-02	3.0E-02	Wabash River test data
50-00-0	Formaldehyde	17	1.1E-03	1.5E-03	NETL, Table 2-17 (see Reference 1)
7647-01-0	Hydrochloric acid	9.9	6.4E-04	8.7E-04	Wabash River test data (for syngas)
7664-39-3	Hydrogen fluoride (Hydrofluoric acid)	0.6	3.9E-05	5.3E-05	NETL, Table 2-5 (see Reference 1)
7439-92-1	Lead	0.43	2.8E-05	3.7E-05	Wabash River test data (for syngas)
7439-96-5	Manganese	25.3	1.6E-03	2.2E-03	Wabash River test data
7439-97-6	Mercury	7.0	4.6E-04	6.1E-04	Wabash River test data
74-83-9	Methyl bromide (Bromomethane)	123	8.0E-03	1.1E-02	Wabash River test data
74-87-3	Methyl chloride (Chloromethane)	63	4.1E-03	5.5E-03	Wabash River test data
75-09-2	Methylene chloride (Dichloromethane)	5.9	3.8E-04	5.2E-04	Wabash River test data
91-20-3	Naphthalene	8.6	5.6E-04	7.5E-04	Wabash River test data
7440-02-0	Nickel	44.7	2.9E-03	3.9E-03	Wabash River test data
108-95-2	Phenol	126	8.2E-03	1.1E-02	Wabash River test data
7784-49-2	Selenium	2.5	1.6E-04	2.2E-04	Wabash River test data
7664-93-9 14808-79-8	Sulfuric acid and sulfates	572	3.7E-02	5.0E-02	(See Note 2)
108-88-3	Toluene	119	7.7E-03	1.0E-02	Wabash River test data
1330-20-7	Xylenes	135	8.8E-03	1.2E-02	Wabash River test data

Notes:
(1) Hydrofluoric acid is estimated using the fraction of total feed fluorine measured in the LGTI incinerator stack, as reported in Reference 2, and the highest expected concentrations of fluorine in the Mesaba feed steams.
(2) Sulfuric acid and sulfates calculated using same emission factor as CTGs.

References:
(1) NETL - National Energy Technology Laboratory, U.S. Dept of Energy, *Major Environmental Aspects of Gasification-based Power Generation Technologies, Final Report,* December 2002.

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FLARE HAPs EMISSION SUMMARY

Syngas combustion rates 50 x 10^6 Btu/hr, HHV (annual average) (1)

CAS # or MPCA #	Compound	Emission Factor ($lb/10^{12}$ Btu syngas) (2)	Short-term Emission (lb/hr)	Annual Emission (ton/yr)	Emission Factor Source
75-07-0	Acetaldehyde	1.8	9.0E-05	3.9E-04	NETL, Table 2-17 (see Reference 1)
7440-36-0	Antimony	3.0	1.5E-04	6.6E-04	Wabash River test data
7440-38-2	Arsenic	15.8	7.9E-04	3.5E-03	Wabash River test data
56-55-3	Benz[a]anthracene	0.0023	1.2E-07	5.0E-07	NETL, Table 2-17 (see Reference 1)
71-43-2	Benzene	302	1.5E-02	6.6E-02	Wabash River test data
7440-41-7	Beryllium	0.09	4.5E-06	2.0E-05	NETL, Table 2-11 (see Reference 1)
7440-43-9	Cadmium	0.60	3.0E-05	1.3E-04	Wabash River test data
75-15-0	Carbon disulfide	46	2.3E-03	1.0E-02	NETL, Table 2-17 (see Reference 1)
0-00-5	Chromium, total	11.2	5.6E-04	2.5E-03	Wabash River test data
18540-29-9	Chromium, (hexavalent)	3.4	1.7E-04	7.4E-04	Portion of total chromium emitted in +6 valenece state, assumed to be 30% of total
7440-48-4	Cobalt	12.8	6.4E-04	2.8E-03	Wabash River test data
57-12-5	Cyanide (Cyanide ion, Inorganic cyanides, Isocyanide)	50	2.5E-03	1.1E-02	Wabash River test data
100-41-4	Ethyl benzene	338	1.7E-02	7.4E-02	Wabash River test data
50-00-0	Formaldehyde	17	8.5E-04	3.7E-03	NETL, Table 2-17 (see Reference 1)
7647-01-0	Hydrochloric acid	9.9	4.9E-04	2.2E-03	Wabash River test data (for syngas)
7664-39-3	Hydrogen fluoride (Hydrofluoric acid)	0.6	3.0E-05	1.3E-04	NETL, Table 2-5 (see Reference 1)
7439-92-1	Lead	0.43	2.1E-05	9.3E-05	Wabash River test data (for syngas)
7439-96-5	Manganese	25.3	1.3E-03	5.5E-03	Wabash River test data
7439-97-6	Mercury (3)	0.7	3.5E-05	1.5E-04	Wabash River test data, reduced by 90%
74-83-9	Methyl bromide (Bromomethane)	123	6.2E-03	2.7E-02	Wabash River test data
74-87-3	Methyl chloride (Chloromethane)	63	3.2E-03	1.4E-02	Wabash River test data
75-09-2	Methylene chloride (Dichloromethane)	5.9	3.0E-04	1.3E-03	Wabash River test data
91-20-3	Naphthalene	8.6	4.3E-04	1.9E-03	Wabash River test data
7440-02-0	Nickel	44.7	2.2E-03	9.8E-03	Wabash River test data
108-95-2	Phenol	126	6.3E-03	2.8E-02	Wabash River test data
7784-49-2	Selenium	2.5	1.3E-04	5.5E-04	Wabash River test data
7664-93-9 14808-79-8	Sulfuric acid and sulfates	3,761	1.9E-01	8.2E-01	(See Note 4)
108-88-3	Toluene	119	6.0E-03	2.6E-02	Wabash River test data
1330-20-7	Xylenes	135	6.8E-03	3.0E-02	Wabash River test data

Notes:
(1) Combustion rates shown are for normal operations, which includes plant startups
(2) No Wabash River emission test data are available for the flare. HAPs emissions are estimated using the same emission factors as the tank vent oxid and the assumed syngas combustion rate in the flare. The notes for the tank vent oxidizer HAPs emission summary also apply to the flare.
(3) Mercury emission factor based on the TVO factor reduced by 90 %, since most gas routed to the flare will flow through the normal syngas treating sy including the activated carbon beds for mercury removal.
(4) Sulfuric acid calculated asuming 7% of SOx in combustion products converts to SO3 which reacts with water to form H2SO4.
Assuming 50 ppmvd total sulfur in flared gas and about 240 Btu/ft3 HHV,
Sulfuric acid = 0.07 x $50/10^6$ x 1 ft3/240 Btu x 98 lb/380 ft3 x 10^{12} = 3761 lb/10^12 Btu

References:
(1) NETL - National Energy Technology Laboratory, U.S. Dept of Energy, *Major Environmental Aspects of Gasification-based Power Generation Technologies, Final Report,* December 2002.

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HAPs Metals Emission Factor Adjustment for Treated Syngas

Element	Wabash Actual Feed Conc, mg/kg (1)	Wabash HAP Actual Feed Conc lb/10^12 Btu coal	Wabash Measured Syngas HAP Emission Factor lb/10^12 Btu coal (2)	Fraction of Feed HAP in Wabash Product Syngas (3)	PMEC Worst Case Feed Conc, mg/kg (4)	PMEC Worst Case Feed Conc, Conc lb/10^12 Btu coal	PMEC Worst Case HAP Emission Factor for Syngas lb/10^12 Btu coal (5)
Antimony	3.5	292	1.1	0.0038	3.5	292	1.1
Arsenic	7.6	633	2.4	0.0038	7.6	633	2.4
Beryllium	1.8	150	0.26	0.0017	1.8	150	0.26
Cadmium	0.3	25	9.6	0.3840	0.3	25	9.6
Chromium	5.6	467	0.41	0.00088	7.0	583	0.51
Cobalt	7.3	608	0.26	0.00043	7.3	608	0.26
Lead	17.3	1442	0.56	0.00039	17.3	1442	0.56
Manganese	12.3	1025	0.43	0.00042	30	2500	1.0
Mercury	**(90% O/A removal, see calc below)**				0.14	11.7	1.2
Nickel	370	30833	0.39	0.000013	370	30833	0.39
Selenium	3.0	250	0.56	0.0022	3.0	250	0.56
Chlorides	100	8333	2.6	0.00031	500	41667	13.0

Notes:
(1) Estimated composition of Wabash River feed based on the larger of either feed coal composition data reported to U.S. DOE or petcoke data provided by CoP.
(2) Calculated from reported HAPs concentration measurements in Wabash River product syngas during various test programs from 1997 to 2005.
(3) Ratio of syngas concentration to feed concentration.
(4) Highest expected PMEC feed concentration based on Fluor data for PRB coal and limited data for U.S petcoke *(to be confirmed)*.
(5) Predicted emission factor for PMEC product syngas using HAPs fraction in syngas from Wabash River test program.

Assumption: Solid feed nominal heating value = 12,000 Btu/lb, dry HHV

Example calcs:
<u>HAPs in feed</u>
Cr = 5.6 mg/kg = 5.6 x 10^{-3} g Cr/10^{3} g dry feed x 1 lb/12,000 Btu x 10^{12} = 467 lb/10^12 Btu
<u>Fractrion in syngas</u>
Fraction Cr in syngas = 0.41 lb/10^{12} Btu/(467 lb/10^{12} Btu) = 0.00088
<u>PMEC HAPs emission factor</u>
Predicted Cr emission factor for PMEC syngas = 0.00088 x 583 lb/10^{12} Btu = 0.51 lb/10^12 Btu
<u>Mercury</u>
Mercury based on PRB feed, 0.14 ppmwd avg Hg
Hg = (0.10) x 0.14 lb/10^{6} lb /(12,000 Btu/lb) x 10^{12} = 1.2 lb/10^12 Btu

FUGITVE HAPs EMISSION SUMMARY

(Typical Two-train 600 MW E-Gas IGCC)

Process Stream [1]		Raw Syngas			SourSyngas			Product Syngas			Acid Gas			SRU and Tail Gas			Sour CO2 gas		
Total process fluid leak rate, lb/hr[2]		1.1			0.72			0.24			0.28			1.5			0.084		
CAS # or MPCA #	Compound	Emission factor ppm(wt)	Basis[3]	Emission lb/hr	Emission factor ppm(wt)	Basis[3]	Emission lb/hr	Emission factor ppm(wt)	Basis[3]	Emission lb/hr	Emission factor ppm(wt)	Basis[3]	Emission lb/hr	Emission factor ppm(wt)	Basis[3]	Emission lb/hr	Emission factor ppm(wt)	Basis[3]	Emission lb/hr
	Federal HAPs																		
71-43-2	Benzene	95	A	0.0001	95	A	0.0001	20	A	4.9E-06									
75-15-0	Carbon disulfide	575	A	0.0006	439	A	0.0003	2.7	A	6.5E-07									
463581	Carbonyl sulfide	1,300	B	0.001	83	B	0.00006	4.8	B	0.000001	700	B	1.9E-04				30.0	B	0.000003
100-41-4	Ethyl benzene	0.076	A	8.38E-08	0.076	A	5.46E-08	0.076	A	1.843E-08									
50-00-0	Formaldehyde	0.016	A	1.76E-08	0.016	A	1.15E-08	0.016	A	3.881E-09									
110-54-3	Hexane	0.021	A	2.3E-08	0.021	A	1.5E-08	0.021	A	5.1E-09									
7647-01-0	Hydrochloric acid	0.017	A	1.9E-08	0.017	A	1.2E-08	0.017	A	4.1E-09									
74-90-8	Hydrogen cyanide	83	B	0.00009	83	B	0.00006	0	B	0							1,000	B	0.0001
91-20-3	Naphthalene	0.4	A	4.4E-07	0.4	A	2.9E-07	0.008	A	1.9E-09									
108-95-2	Phenol	0.0011	A	1.2E-09	0.0011	A	7.9E-10	0.0011	A	2.7E-10									
108-88-3	Toluene	10.3	A	0.00001	10.3	A	7.4E-06	0.066	A	1.6E-08									
1330-20-7	Xylenes	0.14	A	1.54E-07	0.14	A	1.01E-07	0.14	A	3.396E-08									
	Total Federal HAPs			0.002			0.001			6.8E-06			0			0			0.0001
	Other																		
7664-41-7	Ammonia	4,000	B	0.004	6.5	B	4.7E-06	0	B	0.0E+00							74,000	B	0.006
7783-06-4	Hydrogen sulfide[6]	15,000	B	0.01	18,000	B	0.01	50	B	5.6E-06	460,000	B	0.06	58,000	B	0.04	27,000	B	0.001
	AGR solvent																		
	VOC[4]			0.002			0.001			6.7E-06			1.9E-04			0.000			0.000
	TRS[5]			0.01			0.01			7.4E-06			0.06			0.04			0.00

Process Stream		Rich AGR solvent			Lean AGR solvent			Sour Water			Stripped Sour Water			Recoverd Oil			Total Estimated		
Total process fluid leak rate, lb/hr[2]		0.32			0.65			0.60			0.14			0.11			Gaseous Fugitive Emissions		
CAS # or MPCA #	Compound	Emission factor ppm(wt)	Basis[3]	Emission lb/hr	Emission factor ppm(wt)	Basis[3]	Emission lb/hr	Emission factor ppm(wt)	Basis[3]	Emission lb/hr	Emission factor ppm(wt)	Basis[3]	Emission lb/hr	Emission factor ppm(wt)	Basis[3]	Emission lb/hr		lb/hr	ton/yr
	Federal HAPs																		
71-43-2	Benzene																	0.00018	0.00078
75-15-0	Carbon disulfide																	0.0010	0.0042
463581	Carbonyl sulfide	25	B	7.9E-06				2	B	1.2E-06								0.0017	0.0074
100-41-4	Ethyl benzene																	1.6E-07	6.9E-07
50-00-0	Formaldehyde																	3.3E-08	1.4E-07
110-54-3	Hexane																	4.3E-08	1.9E-07
7647-01-0	Hydrochloric acid							4000	B	0.002	4700	B	0.001					0.0031	0.013
74-90-8	Hydrogen cyanide							70	B	0.00004								0.00028	0.0012
91-20-3	Naphthalene																	7.3E-07	3.2E-06
108-95-2	Phenol																	2.3E-09	9.9E-09
108-88-3	Toluene																	1.9E-05	8.2E-05
1330-20-7	Xylenes																	2.9E-07	1.3E-06
	Total Federal HAPs			0			0			0.002			0.001			0		***0.0062***	***0.027***
	Other																		
7664-41-7	Ammonia			0			0	30,000	B	0.02	300	B	0.0000			0		0.029	0.13
7783-06-4	Hydrogen sulfide[6]	20,000	B	0.00	350	B	0.0001	1,500	B	0.0004			0			0		0.12	0.5
	AGR solvent	500,000	B	0.2	500,000	B	0.3			0			0			0		0.48	2.1
	VOC[4]			0.158			0.323			0.000			0.000	1E+06	B	0.11		0.59	2.6
	TRS[5]			0.00			0			0.0004			0			0		0.12	0.5

[1]Process stream descriptions for fugitive emission estimates:

Stream	Description	Stream	Description
Raw syngas	Gasifier outlet to COS hyrolysis reactor outlet	Rich AGR solvent	H2S/CO2-laden solvent from absorber to acid gas stripper
Sour syngas	Hydrolysis reactor outlet to AGR/AGE absorbers overhead	Lean AGR solvent	Regenerated solvent from stripper to absorber (incl storage)
Product syngas	AGR/AGE to CTGs	Sour water	Sour water from various sources to sour water stripper
Acid gas	Acid gas stripper overhead to SRU inlet	Stripped SW	Stripper bottoms to slurry recycle and ZLD
SRU and tail gas	SRU inlet through tail gas recycle to gasifier	Recovered oil	Oil recovered from drainage oily water separator
Sour CO2 gas	Sour water degassing column to AGR		

[2]Estimated fugitive emission quantities for the total process stream components based on U.S. EPA average emission factors (see next page). This value is multiplied by each component concentration. to determine the individual component emission rates. ***Example:*** Benzene fugitive emission from raw syngas = 1.1 lb/hr x 95 lb/10^6 lb = 0.00010 lb/hr.

[3]Basis for emission factors; "A" denotes test results from the Wabash River gasification facility, "B" denotes calculated from the ConocoPhillips/Fluor material balance.

[4]Volatile organic compounds (VOC) include AGR solvent, benzene, carbon disulfide, carbonyl sulfide, ethyl benzene, hexane, hydrogen cyanide, naphthalene, toluene, and xylenes.

[5]Total reduced sulfur (TRS) includes carbon disulfide, carbonyl sulfide, and hydrogen sulfide.

FUGITVE HAPs EMISSION SUMMARY
(Typical Two-train 600 MW E-Gas IGCC)

[6]Hydrogen sulfide emissions estimated to be 46% of component count emission estimate, good engineering will ensure this emission level is met.

Fugitve Emission Sources Estimates[1]

	Gas		Light Liquid		Heavy Liquid			Sample
Process Stream	**Valves**	**Comp seals**	**Valves**	**Pumps**	**Valves**	**Pumps**	**Connectors**	**Connects**
Raw syngas	510						500	1
Sour syngas	230	4					230	1
Product syngas	80						100	2
Acid gas	120						100	1
SRU and tail gas	480	9					560	
Sour CO2 gas	40						40	
Rich AGR solvent					350		340	
Lean AGR solvent					330	19	290	
Sour water					240	21	200	
Stripped sour water					120	2	100	
Recovered oil					30	4	40	
Totals	**1460**	**13**	**0**	**0**	**1070**	**46**	**2500**	**5**

Total Fugitive Emission Rates[2]

	Gas		Light Liquid		Heavy Liquid			Sample	
	Valves	**Comp seals**	**Valves**	**Pumps**	**Valves**	**Pumps**	**Connectors**	**Connects**	
Emission factor lb.hr/source	**0.0017**	**0.0502**	**0.00142**	**0.00438**	**0.00051**	**0.019**	**0.000403**	**0.033**	**Total**
Process Stream	**Estimated emission rate, lb/hr**								
Raw syngas	0.87						0.20	0.03	1.10
Sour syngas	0.39	0.20					0.09	0.03	0.72
Product syngas	0.14						0.04	0.07	0.24
Acid gas	0.20						0.04	0.03	0.28
SRU and tail gas	0.82	0.45					0.23		1.49
Sour CO2 gas	0.07						0.02		0.08
Rich MDEA					0.18		0.14		0.32
Lean MDEA					0.17	0.36	0.12		0.65
Sour water					0.12	0.40	0.08		0.60
Stripped sour water					0.06	0.04	0.04		0.14
Recovered oil					0.02	0.08	0.02		0.11

[1]Emission source estimates based on conceptual equipment inventory and an estimate from piping and instrumentation diagrams (P&IDs) for a typical 600 MW E-Gas IGCC project. An allowance is added to account for valves and other components not shown on the P&IDs.
[2]Estimated emission rates for all components (including non-VOC and non-HAPs) in each process stream, based on *Protocol for Equipment Leak Estimates,* U.S EPA 453-R95-017, November 1995, Table 2-1. These factors are adjusted by the 90% emission control for light liquid pumps and compressors shown on Table 5-1 plus the control efficiencies shown on Table 5-2 for monthly monitoring of gas and light liquid valves and connectors.

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AUXILIARY BOILER HAPs EMISSION SUMMARY

Natural gas fuel consumption rates 130 10^6 Btu/hr, HHV
1050 Btu/scf
0.124 10^6 scf/hr

CAS #	Compound	Federally Listed Compound HAP	Washington State TAP	PAH	Emission Factor (lb/10° scf)	Short-term Emission (lb/hr)	Annual Emission (ton/yr)
7440-38-2	Arsenic	Yes	Yes	No	2.00E-04	2.48E-05	2.7E-05
7440-39-3	Barium	No	Yes	No	4.40E-03	5.45E-04	6.0E-04
71-43-2	Benzene	Yes	Yes	No	2.10E-03	2.60E-04	2.8E-04
7440-41-7	Beryllium	Yes	Yes	No	1.20E-05	1.49E-06	1.6E-06
106-97-8	Butane	No	Yes	No	2.10E+00	2.60E-01	2.8E-01
7440-43-9	Cadmium	Yes	Yes	No	1.10E-03	1.36E-04	1.5E-04
7440-47-3	Chromium	Yes	Yes	No	1.40E-03	1.73E-04	1.9E-04
7440-48-4	Cobalt	Yes	Yes	No	8.40E-05	1.04E-05	1.1E-05
7440-50-8	Copper	No	Yes	No	8.50E-04	1.05E-04	1.2E-04
50-00-0	Formaldehyde	Yes	Yes	No	7.50E-02	9.29E-03	1.0E-02
110-54-3	Hexane	Yes	Yes	No	1.80E+00	2.23E-01	2.4E-01
7439-96-5	Manganese	Yes	Yes	No	3.80E-04	4.70E-05	5.2E-05
7439-97-6	Mercury	Yes	Yes	No	2.60E-04	3.22E-05	3.5E-05
7439-98-7	Molybdenum	No	Yes	No	1.10E-03	1.36E-04	1.5E-04
91-20-3	Naphthalene	Yes	Yes	No	6.10E-04	7.55E-05	8.3E-05
7440-02-0	Nickel	Yes	Yes	No	2.10E-03	2.60E-04	2.8E-04
109-66-0	Pentane	No	Yes	No	2.60E+00	3.22E-01	3.5E-01
7782-49-2	Selenium	Yes	Yes	No	2.40E-05	2.97E-06	3.3E-06
108-88-3	Toluene	Yes	Yes	No	3.40E-03	4.21E-04	4.6E-04
7440-62-2	Vanadium	No	Yes	No	2.30E-03	2.85E-04	3.1E-04
PAH	Benzo(a)pyrene	No	Yes	Yes	1.20E-06	1.49E-07	1.6E-07
PAH	Benz(a)anthracene	No	Yes	Yes	1.80E-06	2.23E-07	2.4E-07
PAH	Benzo(b)fluoranthene	No	Yes	Yes	1.80E-06	2.23E-07	2.4E-07
PAH	Chrysene	No	Yes	Yes	1.80E-06	2.23E-07	2.4E-07
PAH	Dibenzo(a,h)anthracene	No	Yes	Yes	1.20E-06	1.49E-07	1.6E-07
PAH	Indeno(1,2,3-cd)pyrene	No	Yes	Yes	1.80E-06	2.23E-07	2.4E-07
PAH	2-Methylnaphthalene	No	No	Yes	2.40E-05	2.97E-06	3.3E-06
PAH	3-Methylchloranthrene	No	No	Yes	1.80E-06	2.23E-07	2.4E-07
PAH	7,12-Dimethylbenz(a)anthracene	No	No	Yes	1.60E-05	1.98E-06	2.2E-06
PAH	Acenaphthene	No	No	Yes	1.80E-06	2.23E-07	2.4E-07
PAH	Acenaphthylene	No	No	Yes	1.80E-06	2.23E-07	2.4E-07
PAH	Anthracene	No	No	Yes	2.40E-06	2.97E-07	3.3E-07
PAH	Benzo(g,h,i)perylene	No	No	Yes	1.20E-06	1.49E-07	1.6E-07
PAH	Benzo(k)fluoranthene	No	No	Yes	1.80E-06	2.23E-07	2.4E-07
PAH	Fluoranthene	No	No	Yes	3.00E-06	3.71E-07	4.1E-07
PAH	Fluorene	No	No	Yes	2.80E-06	3.47E-07	3.8E-07
PAH	Phenanathrene	No	No	Yes	1.70E-05	2.10E-06	2.3E-06
PAH	Pyrene	No	No	Yes	5.00E-06	6.19E-07	6.8E-07

Notes:
1) Emission factor source EPA AP-42 Section 1.4
2) Maximum annual capacity factor of 25% (i.e., annual fuel consumption less than
0.25 x 8760 hr/yr x 130 million Btu/hr = 285 billion Btu/yr)
3) Washington State PAHs determined by WAC 173-460-50
4) For the CAA112 requirements all Polyaromatic Hydrocarbons (PAH) will be considered Polycylic Organic Matter (POM)

Energy Northwest
URS Calculations
Aug 22-06

COOLING TOWER HAPs EMISSION RATE

Basis: Similar equipment from previous project.

Cooling Tower Operating Data and Emission Calculation					
Parameter			**Power Block**	**Gasification/ ASU**	**Basis**
Heat rejected, million Btu/hr			1740	1015	Typical plant performance
Cooling water (CW) circulation rate, million lb/hr			116	68	Typical cooling tower design
Max CW dissolved solids, ppmw			2400	2400	TDS of water supply and 12 cycles of concentration
Drift, fraction of circulating CW			0.0010%	0.0010%	Typical supplier guarantee

Example calculation:
Maximum expected total dissolved solids (TDS) in makeup water = 200 parts per million by weight (ppmw)
Maximum expected TDS in circulating cooling water at twelve cycles of concentration = 12 x 200 = 2400 ppmw
TAP emission rate (Power block) = (116 x 10^6 lb/hr) x (0.00001 drift) x (ppmw/10^6)

Power Block Cooling Tower

CAS #	Compound	Federal	Washington State	Emission Factor	Short-term Emission	Annual Emission	Notes
		HAP	TAP	ppmw	(lb/hr)	(ton/yr)	
7440-38-2	Arsenic	Yes	Yes	0.005	5.80E-06	2.54E-05	
7782-50-5	Chlorine (Cl)	Yes	Yes	2.5	2.90E-03	1.27E-02	ppmw value shown is one-half stated detection limit
7782-41-4	Fluorine (F)	No	Yes	0.3	3.48E-04	1.52E-03	ppmw value shown is one-half stated detection limit
7439-92-1	Lead	Yes	Yes	0.001	1.16E-06	5.08E-06	ppmw value shown is one-half stated detection limit
7439-96-5	Manganese (Mn)	Yes	Yes	2	2.32E-03	1.02E-02	
7439-97-6	Mercury	Yes	Yes	0.0005	5.80E-07	2.54E-06	ppmw value shown is one-half stated detection limit
7784-49-2	Selenium	Yes	Yes	0.01	1.16E-05	5.08E-05	ppmw value shown is one-half stated detection limit
7440-22-4	Silver	No	Yes	0.001	1.16E-06	5.08E-06	ppmw value shown is one-half stated detection limit

Gasification/ASU Cooling Tower

CAS #	Compound	Federal	Washington State	Emission Factor	Short-term Emission	Annual Emission	Notes
		HAP	TAP	ppmw	(lb/hr)	(ton/yr)	
7440-38-2	Arsenic	Yes	Yes	0.005	3.38E-06	1.48E-05	
7782-50-5	Chlorine (Cl)	Yes	Yes	2.5	1.69E-03	7.41E-03	ppmw value shown is one-half stated detection limit
7782-41-4	Fluorine (F)	No	Yes	0.3	2.03E-04	8.89E-04	ppmw value shown is one-half stated detection limit
7439-92-1	Lead	Yes	Yes	0.001	6.77E-07	2.96E-06	ppmw value shown is one-half stated detection limit
7439-96-5	Manganese (Mn)	Yes	Yes	2	1.35E-03	5.93E-03	
7439-97-6	Mercury	Yes	Yes	0.0005	3.38E-07	1.48E-06	ppmw value shown is one-half stated detection limit
7784-49-2	Selenium	Yes	Yes	0.01	6.77E-06	2.96E-05	ppmw value shown is one-half stated detection limit
7440-22-4	Silver	No	Yes	0.001	6.77E-07	2.96E-06	ppmw value shown is one-half stated detection limit

Notes:
1) Raw Water Analysis: Primary data from Kalama well water samples taken between 01/19/06 and 01/25/06 (3 samples) and analyzed between 1/23/06 and 02/07/06.

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EMERGENCY DIESEL ENGINES HAPs EMISSION RATES

1 Emergency Fire Water Pump Engine

300 hp
7000 Btu/hp-hr

CAS #	Compound	Federally Listed Compound HAP	Washington State TAP	PAH	Emission Factor (lb/10^6 Btu)	Short-term Emission (lb/hr)	Annual Emission (ton/yr)
106-99-0	1,3-Butadiene	Yes	Yes	No	3.91E-05	8.21E-05	4.11E-06
75-07-0	Acetaldehyde	Yes	Yes	No	7.67E-04	1.61E-03	8.05E-05
107-02-8	Acrolein	Yes	Yes	No	9.25E-05	1.94E-04	9.71E-06
71-43-2	Benzene	Yes	Yes	No	9.33E-04	1.96E-03	9.80E-05
50-00-0	Formaldehyde	Yes	Yes	No	1.18E-03	2.48E-03	1.24E-04
91-20-3	Naphthalene	Yes	Yes	No	8.48E-05	1.78E-04	8.90E-06
115-07-1	Propylene	Yes	No	No	2.58E-04	5.42E-04	2.71E-05
108-88-3	Toluene	Yes	Yes	No	4.09E-04	8.59E-04	4.29E-05
1330-20-7	Xylenes	Yes	Yes	No	2.85E-04	5.99E-04	2.99E-05
PAH	Benzo(a)pyrene	No	Yes	Yes	1.88E-07	3.95E-07	1.97E-08
PAH	Benzo(a)anthracene	No	Yes	Yes	1.68E-06	3.53E-06	1.76E-07
PAH	Benzo(b)fluoranthene	No	Yes	Yes	9.91E-08	2.08E-07	1.04E-08
PAH	Chrysene	No	Yes	Yes	3.53E-07	7.41E-07	3.71E-08
PAH	Dibenz(a,h)anthracene	No	Yes	Yes	5.83E-07	1.22E-06	6.12E-08
PAH	Indeno(1,2,3-cd)pyrene	No	Yes	Yes	3.75E-07	7.88E-07	3.94E-08
PAH	Acenaphthene	No	No	Yes	1.42E-06	2.98E-06	1.49E-07
PAH	Acenaphthylene	No	No	Yes	5.06E-06	1.06E-05	5.31E-07
PAH	Anthracene	No	No	Yes	1.87E-06	3.93E-06	1.96E-07
PAH	Benzo(g,h,i)perylene	No	No	Yes	4.89E-07	1.03E-06	5.13E-08
PAH	Benzo(k)fluoranthene	No	No	Yes	1.55E-07	3.26E-07	1.63E-08
PAH	Fluoranthene	No	No	Yes	7.61E-06	1.60E-05	7.99E-07
PAH	Fluorene	No	No	Yes	2.92E-05	6.13E-05	3.07E-06
PAH	Phenanthrene	No	No	Yes	2.94E-05	6.17E-05	3.09E-06
PAH	Pyrene	No	No	Yes	4.78E-06	1.00E-05	5.02E-07

1) Two pumps will be provided, one will be electric engine-driven. Emissions for one engine shown for worst case permitting.
2) Maximum annual emission based on 100 hr/yr normal maintenance operation per engine.
3) Emission factors from EPA AP-42 Section 3.3 Small Diesel Engines (<600hp)
4) Washington State PAHs determined by WAC 173-460-50
5) For the CAA112 requirements all Polyaromatic Hydrocarbons (PAH) will be considered Polycylic Organic Matter (POM)

Emergency Generator, 2 MW

2682 hp
7000 Btu/hp-hr

CAS #	Compound	Federally Listed Compound HAP	Washington State TAP	PAH	Emission Factor (lb/10^6 Btu)	Short-term Emission (lb/hr)	Annual Emission (ton/yr)
75-07-0	Acetaldehyde	Yes	Yes	No	2.52E-05	4.73E-04	2.37E-05
107-02-8	Acrolein	Yes	Yes	No	7.88E-06	1.48E-04	7.40E-06
71-43-2	Benzene	Yes	Yes	No	7.76E-04	1.46E-02	7.28E-04
50-00-0	Formaldehyde	Yes	Yes	No	7.89E-05	1.48E-03	7.41E-05
91-20-3	Naphthalene	Yes	Yes	No	1.30E-04	2.44E-03	1.22E-04
115-07-1	Propylene	Yes	No	No	2.79E-03	5.24E-02	2.62E-03
108-88-3	Toluene	Yes	Yes	No	2.81E-04	5.28E-03	2.64E-04
1330-20-7	Xylenes	Yes	Yes	No	1.93E-04	3.62E-03	1.81E-04
PAH	Benzo(a)pyrene	No	Yes	Yes	2.57E-07	4.82E-06	2.41E-07
PAH	Benz(a)anthracene	No	Yes	Yes	6.22E-07	1.17E-05	5.84E-07
PAH	Benzo(b)fluoranthene	No	Yes	Yes	1.11E-06	2.08E-05	1.04E-06
PAH	Chrysene	No	Yes	Yes	1.53E-06	2.87E-05	1.44E-06
PAH	Dibenz(a,h)anthracene	No	Yes	Yes	3.46E-07	6.50E-06	3.25E-07
PAH	Indeno(1,2,3-cd)pyrene	No	Yes	Yes	4.14E-07	7.77E-06	3.89E-07
PAH	Acenaphthene	No	No	Yes	4.68E-06	8.79E-05	4.39E-06
PAH	Acenaphthylene	No	No	Yes	9.23E-06	1.73E-04	8.66E-06
PAH	Anthracene	No	No	Yes	1.23E-06	2.31E-05	1.15E-06
PAH	Benzo(g,h,i)perylene	No	No	Yes	5.56E-07	1.04E-05	5.22E-07
PAH	Benzo(k)fluoranthene	No	No	Yes	2.18E-07	4.09E-06	2.05E-07
PAH	Fluoranthene	No	No	Yes	4.03E-06	7.57E-05	3.78E-06
PAH	Fluorene	No	No	Yes	1.28E-05	2.40E-04	1.20E-05
PAH	Phenanthrene	No	No	Yes	4.08E-05	7.66E-04	3.83E-05
PAH	Pyrene	No	No	Yes	3.71E-06	6.97E-05	3.48E-06

1) Maximum annual emission based on 100 hr/yr normal maintenance operation per engine.
2) Emission factors from EPA AP-42 Section 3.4 Large Diesel Engines (>600hp)
3) Washington State PAHs determined by WAC 173-460-50
4) For the CAA112 requirements all Polyaromatic Hydrocarbons (PAH) will be considered Polycylic Organic Matter (POM)