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):

Pre-Combustion Process Controls (fuel specification)

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

Combustion Controls

- Good combustion practices (GCP)

Post-Combustion Controls

- 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

Preliminary

Sulfur in syngas reduction to 10 ppm

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 COST!	= (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.

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

Preliminary

SCR System for sulfur removal to 1 ppm

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

Preliminary

Sulfur in syngas reduction to 1 ppm

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 COST	= (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.

REDACTED

Best Available Control Technologies for the Baldwin Generating Station, Baldwin, Illinois

Expert Report of

Matt Haber

Prepared for the United States in connection with:
United States v. Illinois Power Company And Dynegy Midwest Generation, Inc.,
Civil Action No. 99-833-MJR
in the U.S. District Court for the Southern District of Illinois

APRIL 2002

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LIST OF TABLES

I. INTRODUCTION AND OVERVIEW

A. Information Required for the Expert Report

The following is a listing of the items required by the Federal Rules of Civil Procedures provided with this report:

(1) This report contains my opinions, conclusions and the reasons therefor.

(2) Exhibits and tables in summary of, or in support of, these opinions are included with this report in Appendix A.

(3) The body of the report and Appendix B list the data and other information considered in forming these opinions.

(4) Appendix C includes a listing of publications authored during the past ten years.

(5) Section III presents a statement of my qualifications; my resume is attached as Appendix D.

(6) I am being compensated for the preparation of this report and my testimony as a normal part of my compensation as an employee of the US EPA.

(7) I have not provided previous testimony within the preceding four years as an expert at trial or by deposition.

B. Purpose of Report

This report is written pursuant to a request from the Department of Justice for an analysis of what controls should have been installed at the Baldwin Station when the Prevention of Significant Deterioration (PSD) regulations were triggered at each unit, as alleged in the United States' Amended Complaint. Under § 165 of the Clean Air Act ("C.A.A.") (42 U.S.C. § 7475), the permitting requirements triggered by the major modifications undertaken at the Baldwin Units would have included a requirement that Illinois Power Company (IPC) install the "Best Available Control Technology" (BACT). This report explains what BACT would have been -- for sulfur dioxide (SO_2), nitrogen oxides (NO_x), and particulate matter (PM) -- at Unit 1 in 1985, Unit 2 in 1988, and Unit 3 in 1982, when PSD was allegedly triggered. In addition, it is EPA's policy that a source that is in violation because it constructed or modified without a proper preconstruction permit must install controls that constitute BACT when the proper permit is finally issued.[1] Therefore, this report also makes a determination of BACT for all units as if

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[1] Office of Air Quality Planning and Standards, U.S. EPA, *New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting* (Draft Oct.

permits were being issued as of the date this report is submitted.

II. Summary of Conclusions

In summary, and for the reasons described herein, I have concluded that the following emission rates and technologies would have been BACT for the pollutants at issue, and the Baldwin Station Units at issue, in the time frames specified below.

	SO_2	NO_x	PM
1982 (Unit 3)	0.30 pounds per million BTU, based on 95% scrubbing and assuming coal with a 3-3.5% sulfur content, and use of a wet limestone scrubber Averaging time: 30 day rolling Monitored via CEMS[2]	0.40 pounds per million BTU, based on use of Low NO_x Burners. Averaging time: 3 hour Monitored via CEMS	0.036 pounds per million BTU, 99.4% control, based on use of (then existing) ESP Averaging time: 3 hour Monitored via EPA method 5[3], opacity monitor
1985 (Unit 1)	0.30 pounds per million BTU, based on 95% scrubbing and assuming coal with a 3-3.5% sulfur content, and use of a wet limestone scrubber Averaging time: 30 day rolling Monitored via CEMS	0.90 pounds per million BTU, based on use of selective catalytic reduction Averaging time: 3 hour Monitored via CEMS	0.003 pounds per million BTU, based on use of a baghouse Averaging time: 3 hour Monitored via EPA method 5, opacity monitor

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1990), page B.55: "the BACT emission limit in a new source permit is not set until the final permit is issued."

[2] Continuous Emissions Monitoring System

[3] See 40 C.F.R 60 Appendix A

<u>1988 (Unit 2)</u>	0.30 pounds per million BTU, based on 95% scrubbing and assuming coal with a 3-3.5% sulfur content, and use of a wet limestone scrubber Averaging time: 30 day rolling Monitored via CEMS	0.36 pounds per million BTU, based on use of selective catalytic reduction Averaging time: 3 hour Monitored via CEMS	0.003 pounds per million BTU, based on use of a baghouse Averaging time: 3 hour Monitored via EPA method 5, opacity monitor
<u>2002 (Units 1 & 2)</u>	0.095 pounds per million BTU, based on 95% scrubbing, and assuming use of coal with 0.6% sulfur content Averaging time: 30 day rolling Monitored via CEMS	0.14 pounds per million BTU, based on use of overfire air, selective catalytic reduction, and an optimization system Averaging time: 3 hour Monitored via CEMS	0.006 pounds per million BTU, based on use of a baghouse Averaging time: 3 hour Monitored via EPA method 5, triboelectric broken bag monitors
<u>2002 (Unit 3)</u>	0.095 pounds per million BTU, based on 95% scrubbing, and assuming use of coal with 0.6% sulfur content Averaging time: 30 day rolling Monitored via CEMS	0.020 pounds per million BTU, based on use of low-NO_x burners, selective catalytic reduction, and an optimization system. Limit may be adjusted as high as 0.040 pounds per million BTU if lower limit is demonstrated to be unachievable. Averaging time: 3 hour Monitored via CEMS	0.015 pounds per million BTU, based on use of a ESP. Averaging time: 3 hour Monitored via EPA method 5, PM CEMS[4]

III. <u>Qualifications</u>

I have been involved in BACT decisions in a variety of capacities at EPA's Region 9 for over twenty one years. I began work for EPA Region 9 in 1980 as a staff engineer in the New Source Section of what was then called the Enforcement Division. The primary function of this section

[4] <u>See</u> http://www.epa.gov/ttn/emc/propperf/ps-11&frnotice.pdf, proposed Performance Specification for Continuous PM Monitoring Systems.

was to perform analyses, including control technology (i.e. BACT) analyses necessary for the issuance of PSD permits, and to oversee the issuance of PSD and nonattainment NSR permits by State and local agencies I conducted technical analyses on a variety of PSD sources, including powerplants, cement plants, and waste-to-energy plants. I also reviewed BACT and Lowest Achievable Emission Rate (LAER) analyses conducted by state and local agencies in Region 9 (these include agencies in California, Nevada, Arizona and Hawaii). In 1987, I co-authored Region 9's *Best Available Control Technology Guidance Document,* which laid out a methodology for use primarily by permit applicants, their consultants, and state and local permitting authorities for conducting a BACT determination. Beginning in about 1987, I spent approximately one year in our enforcement office, focusing on two cases involving coal-fired powerplants in Arizona and Nevada: Nevada Power–Reid Gardner and Arizona Public Service–Cholla. In 1989, I became the manager of the New Source Section. I managed the Region's work in permitting new and modified air pollution sources, as well as overseeing the permit issuance work of our state and local agencies. In addition, my group had the responsibility for review and action on permit rules submitted to EPA for inclusion in the State Implementation Plan, as well as reviews of state programs to determine–after the fact–the efficacy of their permitting programs, including their BACT reviews. In 2000, I began a one-year assignment as Associate Director of the Air Division. One of my responsibilities was managing the Region's response to the western energy shortage, a responsibility I continued when I became the Region's Senior Energy Advisor, the position I currently hold. One responsibility of my current position is to advise staff in the Permits Office on decisions related to powerplants, including BACT decisions.

I speak frequently on Clean Air Act issues. During the past ten years, I have spoken to groups such as the environmental section of the Arizona Bar Association, the annual environmental section conference of the California Bar Association, and numerous industry conferences, such as several sessions of the Summer Issues Seminar of the California Council for Environmental and Economic Balance, a company-wide conference of Granite Construction, the 2000 CADER Distributed Generation Conference, the 1999 Utility Environmental Conference, and others. Most of my talks were solely or primarily about New Source Review and the control technology requirement (BACT and LAER) under the NSR regulations. I have also created and presented New Source Review training courses for several audiences. In about 1991, staff under my direction and I created and presented a comprehensive (2-3 day) New Source Review training for Region 9's 44 state and local permitting authorities. About 150 people attended four training sessions. That training was followed by internal training of about 50 EPA Region 9 staff. Between about 1994 and 1997, I presented several short (several-hour) new source review training modules as part of a larger University of California extension course about the Clean Air Act. Most recently (March 2001), I was invited to present a paper to the second conference of the European Union nations on NO_x and N_2O control ("NO_xCONF 2001"). My paper was titled *NO_x Emissions Controls at Refineries: US Regulatory Drivers and Results.*

IV. What is BACT?

When a new major source of air pollution is proposed to be constructed, or when an existing major source is modified in such a manner that its emissions will be increased by a significant amount, a permit is required from EPA or a State[5] authorized under the New Source Review ("NSR") program. Because the Baldwin plant is located in an area that is in attainment of the National Ambient Air Quality Standards for the pollutants at issue here, NSR regulations for attainment areas, known as the Prevention of Significant Deterioration ("PSD") regulations apply.[6] State-of-the-art-emissions controls, known as Best Available Control Technology ("BACT") are one of the key requirements of the PSD permit.

BACT is defined as:

> "an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under [the Clean Air Act] which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60[7] and 61. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for

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[5] In this context, "state" may mean a state agency, or a local agency authorized under state law and federal regulations to carry out air pollution control functions.

[6] These regulations are codified at 40 C.F.R. § 52.21, and are incorporated into the Illinois PSD program. Definitions of the terms "major source," "major modification," and "significant" can be found in these regulations.

[7] 40 C.F.R. Part 60 is generally known as New Source Performance Standards. This section requires a minimum, uniform level of control technology for new or modified construction of categories of sources of air pollution, such as coal fired powerplants, petroleum refineries, pulp mills and the like.

compliance by means which achieve equivalent results."[8]

In a typical BACT process, the applicant performs an analysis that is then submitted to a permitting authority, typically a state or local air pollution control agency. The applicant must submit information supporting its proposal, including information specific to its proposed plant, as well as information about other facilities and other BACT determinations it believes are relevant. That agency reviews the proposal, asks for clarifying information from the applicant, gathers information independently, and then proposes a permit that contains its own independent review, analysis and proposed BACT decision. The public, including the applicant, the public at large, and EPA then have an opportunity to review and comment on the proposed decision by the permitting authority. After the close of the comment period, the permitting authority reviews all comments, modifies the proposed decision (where appropriate) based on its analysis of the comments, and issues a permit containing emission limits and control technologies that reflect its BACT decision. The permit should also contain monitoring and testing requirements to ensure that the BACT limit is attained on an ongoing basis.

The BACT analyses contained in this report are, by necessity, different from most in several respects. A typical BACT analysis is conducted before construction of a new source or modification has begun; because Illinois Power failed to obtain timely PSD permits prior to its construction of changes that triggered BACT, this analysis is being conducted after the modifications at the Baldwin powerplant have been completed. Also, my analysis is based largely on my own research, because Illinois Power has not, to date, submitted a BACT analysis to review.[9]

V. The Typical BACT Determination Process

Over the years, EPA has issued policy guidance on the BACT process several times. Most notably, EPA published in 1980 the *Prevention of Significant Deterioration Workshop Manual,*[10]

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[8] 40 C.F.R. § 52.21(b)(12).

[9] In addition to my own research, I cite below to the work of Ellison Consultants, who have performed a review of the historical installation of technologies, and to the work of staff in EPA's Office of Air Quality Planning and Standards, who have performed a review of the cost-effectiveness of certain technologies, at my request. See Attachments 1 and 2. The information contained in these reports, which I have reviewed and agree with, is among the types of information that might be submitted by an applicant, or presented by another permitting authority. Just as in a traditional BACT analysis, I have utilized this data in reaching the BACT determinations described herein.

[10] Leigh Hayes, et al, TRW Incorporated, *Prevention of Significant Deterioration Workshop Manual* (Oct. 1980) EPA 450/2-80-081.

and in 1990 published the *New Source Review Workshop Manual* (draft),[11] accompanied by the *"Top-Down" Best Available Control Technology Guidance Document.*[12] Also, EPA's Region 9 office published, in about 1987, its *BACT Guidance Document.*[13] The following description reflects the process generally used to perform a BACT analysis today.

During each BACT analysis, which is done on a case-by-case basis, the reviewing authority evaluates the energy, environmental, economic and other costs associated with each alternative technology, and the benefit of reduced emissions that the technology would bring. The reviewing authority then specifies an emissions limitation for the source that reflects the maximum degree of reduction achievable for each pollutant regulated under the Act. In no event can a technology be selected which would not meet any applicable standard of performance under 40 C.F.R. Parts 60 (New Source Performance Standards) and 61 (National Emission Standards for Hazardous Air Pollutants).

In brief, the process provides that all available control technologies be ranked in descending order of control effectiveness. The PSD applicant first examines the most stringent--or "top"--alternative. That alternative is established as BACT unless the applicant demonstrates, and the permitting authority in its informed judgment agrees, that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not "achievable" in that case. If the most stringent technology is eliminated in this fashion, then the next most stringent alternative is considered, and so on. This is known as the "top-down" process.

The first step in a "top-down" analysis is to identify, for the emissions unit in question, all "available" control options. Available control options are those air pollution control technologies or techniques with a practical potential for application to the emissions unit and the regulated pollutant under evaluation. Air pollution control technologies and techniques include the application of production process or available methods, systems, and techniques, including clean fuels, fuel cleaning or treatment or innovative fuel combustion techniques for control of the affected pollutant. This analysis includes a review of technologies employed both within and

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[11] Office of Air Quality Planning and Standards, U.S. EPA, *New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting* (Draft Oct. 1990).

[12] Office of Air Quality Planning and Standards, U.S. EPA, *"Top-Down" Best Available Control Technology Guidance Document* (Mar. 15, 1990). This document was shared with other EPA Regions and States, who would have considered it in their own BACT analyses.

[13] Matt Haber et al., U.S. EPA Region 9, *Best Available Control Technology Guidance Document.*

outside of the United States.[14] As discussed later, in some circumstances, inherently lower-polluting processes are appropriate for consideration as available control alternatives. The control alternatives evaluated should include not only existing controls for the source category in question, but also (through technology transfer) controls applied to similar source categories and gas streams, and innovative control technologies. In addition, the technology that will achieve the greatest emission reduction technically possible (which is *required* in areas not attaining the National Ambient Air Quality Standards, and known as lowest achievable emission rate (LAER)[15]) is considered available for BACT purposes, must also be included as a control alternative and usually represent the "top" alternative.[16]

In the course of the BACT analysis, one or more of the options may be eliminated from consideration because they are demonstrated to be technically infeasible or have unacceptable energy, economic, and environmental impacts on a case-by-case (or site-specific) basis. However, at the outset, applicants should initially identify all control options with potential application to the emissions unit under review.[17]

Next, the technical feasibility of the control options identified in step one is evaluated with respect to the source-specific (or emissions unit-specific) factors. Any demonstration of technical infeasibility must be clearly documented in the analysis to show, based on physical, chemical, or engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review. Technically infeasible control options are then eliminated from further consideration in the BACT analysis.[18]

For example, in cases where the level of control in a permit is not expected to be achieved in practice (e.g., a source has received a permit but the project was canceled, or every operating source at that permitted level has been physically unable to achieve compliance with the limit), and supporting documentation showing why such limits are not technically feasible is provided, the level of control (but not necessarily the technology) may be eliminated from further

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[14] Office of Air Quality Planning and Standards, U.S. EPA, *"Top-Down" Best Available Control Technology Guidance Document* (Mar. 15, 1990), page B.11. "Also, technologies in application outside the United States to the extent the technologies have been successfully demonstrated in practice on full scale operations [should be considered]."

[15] LAER is defined as the lowest emission rate achieved in practice, or in a SIP, for that class or category of source (C.A.A. § 171).

[16] Office of Air Quality Planning and Standards, U.S. EPA, *"Top-Down" Best Available Control Technology Guidance Document* (Mar. 15, 1990).

[17] Ibid.

[18] Ibid.

consideration. However, a permit from another facility requiring the application of a certain technology or emission limit to be achieved for such technology usually is sufficient justification to assume the technical feasibility of that technology or emission limit.[19]

All remaining control alternatives not eliminated above are listed in rank order of overall control effectiveness for the pollutant under review, with the most effective control alternative at the top. A list should be prepared for each pollutant and for each emissions unit (or grouping of similar units) subject to a BACT analysis. The list should present the array of control technology alternatives and should include the following types of information:[20]

- control efficiencies (percent pollutant removed, where appropriate);
- expected emission rate (concentration or mass per unit production);
- economic impacts (cost effectiveness);
- environmental impacts (includes any significant or unusual other media impacts (e.g., water or solid waste), and, at a minimum, the impact of each control alternative on emissions of toxic or hazardous air contaminants); and
- energy impacts (to the extent not already included in the economic impacts).

After the identification of available and technically feasible control technology options, the energy, environmental, and economic impacts should be considered to arrive at the final level of control. For each option, the applicant is responsible for presenting an objective evaluation of each impact. Beneficial and adverse impacts are discussed and, where possible, quantified. In general, the BACT analysis focuses on the direct impact of the control alternative. Indirect impacts, such as the environmental impact from the generation of electricity needed to run fans for an air pollution control device, are not included in the BACT analysis.

However, an applicant proposing the top control alternative need not provide cost and other detailed information in regard to other control options. In such cases the applicant should document that the control option chosen is, indeed, the top, and review that option only for collateral environmental impacts.[21]

Economic impacts are considered in terms of dollars per ton of pollutant removed. This factor is

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[19] Ibid.

[20] Ibid.

[21] Ibid.

known as "cost effectiveness." Using this common unit of measurement facilitates a comparison of similar data across technology options. Other measures, such as dollars invested in control equipment compared to fraction of total capital investment, or dollars per unit of product, should not be used in BACT determinations. Cost effectiveness for the purpose of a BACT analysis is always measured as total cost effectiveness and, sometimes, by incremental cost effectiveness. Total cost effectiveness is the cost, in dollars per ton of pollutant removed, of all emissions removed compared to a baseline emissions level. That baseline is usually the legal limit that would exist but for the BACT determination. In many cases, that limit is equal to uncontrolled emissions, since no legal or practical limit may exist for a particular pollutant. Incremental cost effectiveness is defined as the cost, in dollars per ton of pollutant removed, of additional emissions removed compared to the next less effective control option. When comparing a particular calculated cost effectiveness with a potential cost benchmark, it is essential to ascertain whether the values are total or incremental cost effectiveness, as incremental cost effectiveness is always much larger than total cost effectiveness. EPA does not set a bright line for acceptable costs for BACT. The cost expectations for a particular industry and across all industrial sectors are expected to evolve over time, and may vary from area to area and from permitting authority to permitting authority. The focus of the economic cost portion of the BACT analysis is to ensure that a permit applicant may propose elimination of a control option if its costs for that option are disproportionately high compared to other sources using that control option, or the cost for that control alternative is significantly higher than the range of costs associated with BACT costs for that type of facility or BACT in general.

If the applicant accepts the top alternative in the listing as BACT, the applicant proceeds to consider whether impacts of unregulated air pollutants or impacts in other media would justify selection of an alternative control option. If there are no outstanding issues regarding collateral environmental impacts, the analysis is ended and the results are proposed as BACT. In the event that the top candidate is shown to be inappropriate, due to energy, environmental, or economic impacts, the rationale for this finding should be documented by the permitting authority for the public record. Then the next most stringent alternative in the listing becomes the new control candidate and is similarly evaluated. This process continues until the technology under consideration cannot be eliminated by any source-specific environmental, energy, or economic impacts which demonstrate that alternative to be inappropriate as BACT.[22]

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[22] Prior to the formalization of the "top-down"BACT process described above, the BACT process did not require that the applicant begin with an analysis of the most stringent technology option; however, the other key elements are very much the same. The process I describe has been formally in place since 1987, when EPA headquarters issued guidance ("Potter memo") for the improvement of the BACT determination process, after a series of evaluations of state and local permitting programs gave rise to concern at EPA that control technology (BACT) determinations defaulted too often to the minimum floor for emissions controls. After EPA headquarters issued its Potter memo, EPA's expectation was that permitting authorities would use that guidance in preparing their BACT determinations. My analysis for the 1988 and later timeframes largely conforms to the methodology of the Potter memo and later guidance.

VI. Baldwin Station: Background

Baldwin Station consists of three coal-fired steam electric generation units, each with a capacity of approximately 585 megawatts (MW). The Baldwin plant combusted local Illinois coal with a heating value of approximately 10,400 to 10,800 British Thermal Units (BTU) per pound, a sulfur content of approximately 3% by weight, and an ash content of approximately 10% to 11% by weight[23] until 1999, when the facility began use of Powder River Basin (PRB) coal with a heating value of 8600-8800 BTU/lb, a sulfur content of 0.25%, and an ash content of 4.6-4.8%.[24]

Unit 1 began operation in 1970, and operates a cyclone fired boiler.[25] Unit 1 has a gross output of 584 megawatts (MW).[26] Its air pollution equipment includes of an electrostatic precipitator (ESP) initially designed to remove 99% of the particulate matter (PM) contained in the boiler exhaust gas. The ESP was upgraded in1999.[27] The upgraded ESP was expected to remove 99.4% of particulate matter.[28] For NO_x control, an over-fire air system was installed in 1999,[29] as was the infrastructure for selective catalytic reduction (SCR).[30] However, at least as of November

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However, the only substantive difference between the current (1987 and later) and earlier (1980) guidance is that the current guidance recommends that the top (i.e. most effective at controlling pollution) technology be listed first, and then rejected only if compelling reasons, consistent with the law, are found. In contrast, the earlier guidance recommend assessment of each control technology, and selection of the "best" technology based on the statutory criteria. My analysis in the 1982 and 1985 timeframes is consistent with the 1980 publication. While the processes laid out in the 1980 document and the 1987 Potter memo (and later guidance) were different, the results should have been the same.

[23] Department of Energy, Energy Information Administration (Form EIA-767) for 1985.

[24] Department of Energy, Energy Information Administration (Form EIA-767) for 2000.

[25] Ibid.

[26] Sargent & Lundy Engineers Engineering Data, Unit 1 Baldwin Power Station. IPPRO-0085676-744.

[27] IP Permit Application dated March 30, 1998. IPPRO-0019396.

[28] Ibid.

[29] IP Permit Application dated September 8, 1999. IPPRO-0028775.

[30] IEPA Construction Permit. EPA 5775.

2000, the SCR system does not contain catalyst, and is not currently operating.[31] There are no SO_2 controls in place at Baldwin Unit 1.

Unit 2 also employs a cyclone fired boiler and has a gross capacity of 586 MW.[32] Unit 2 began operation in 1973.[33] The Unit 2 ESP was initially designed to remove 99% of the exhaust gas PM.[34] Although the ESP was modified in 1999 by adding additional collection fields,[35] and installation of a flue gas conditioning system,[36] no information has been provided regarding the new removal efficiency or emission rate. With respect to NO_x, an over-fire air system was installed in 1999,[37] as was an SCR system infrastructure. However, at least as of November 2000 no catalyst was installed, and the SCR system is not currently operating.[38] There are no SO_2 controls in place at Baldwin Unit 2.

Unit 3 is a tangentially fired unit with a gross output of 586 MW,[39] and began operation in 1975.[40] Its air pollution controls include an ESP initially designed to remove 99.5% of exhaust gas PM.[41] Although the ESP was upgraded in 2000,[42] no information has been provided regarding the new performance level in terms of PM removal efficiency or emission rate. With

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[31] Deposition testimony of Aric Diericx, November 10, 2000.

[32] Ratings of Illinois Power Company Fossil Fuel Fired Generating Units; Report by Power Technologies, Inc. December, 1987 - IPPRO-00151120

[33] Department of Energy, Energy Information Administration (Form EIA-767) for 1985.

[34] Department of Energy, Energy Information Administration (Form EIA-767) for 1985.

[35] IP Permit Application dated November 25, 1998. IPPRO-0019250.

[36] IP Permit Application dated December 20, 1999. IPPRO-0028865

[37] IP Permit Application dated September 8, 1999. IPPRO-0028775.

[38] Deposition testimony of Aric Diericx, November 10, 2000.

[39] Sargent & Lundy Engineers Engineering Data, Unit 3 Baldwin Power Station. IPPRO-0085900.

[40] Department of Energy, Energy Information Administration (Form EIA-767) for 1985.

[41] Ibid.

[42] IP Permit Application dated November 25, 1998. IPPRO-0019250.

respect to NO_x, in 1994, low NO_x burners, with an overfire air system were installed.[43] There are no SO_2 controls in place at Baldwin Unit 3.

VII. BACT Determinations for the Baldwin Station

A. BACT Determination for Baldwin Unit 3: 1982

Unit 3 is a tangentially fired unit with a gross output of 586 MW, and began operation in 1975.[44] It was designed to fire up to 294 tons per hour[45] of coal with a heating value of 10,460 BTU per pound.[46]

1. Sulfur Dioxide

As of 1982, Baldwin Unit 3 was uncontrolled for emissions of SO_2, and was burning coal with a sulfur content of 3%-3.5%.[47] Actual emissions for the unit were about 85,000 tons per year (TPY) of SO_2.[48]

a. Technical Feasibility

Two SO_2 emissions control options were potentially available in 1982. I analyzed the following options to determine technical feasibility, availability and cost effectiveness for SO_2 control:

1. Wet Limestone Scrubber
2. Wet Lime scrubbing buffered by Magnesium Oxide

All wet scrubbing type sulfur removal controls employ absorption by passing the flue gasses

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[43] IP Permit Application dated January 19, 1993. IPPRO-0032541.

[44] Ibid.

[45] Ibid.

[46] Sargent & Lundy Engineers Engineering Data, Unit 3 Baldwin Power Station. IPPRO-0085900

[47] Department of Energy, Energy Information Administration (Form EIA-767) for 1985.

[48] See Expert Report of Ranajit (Ron) Sahu, April, 2002, compiling CEMS data submitted by Illinois Power Company to U.S. EPA.

through an injected mist of reagent - generally limestone or lime.[49] The reagent is crushed into a fine powder, hydrated into a wet slurry, and then injected into the flue gas stream via specialized high pressure pumps and nozzles. The airborne slurry mist absorbs the sulfur and precipitates out of the injection chamber where it is de-watered and neutralized for landfill. In many cases, the by-product material is of sufficient quality it can be sold as wallboard-quality gypsum. The use of magnesium oxide as a buffering agent may increase the effectiveness of SO_2 removal.

Both of the technologies under consideration were technically feasible and available, as both wet scrubbing technologies had been in widespread use by 1982. For example, in the U.S., at least eight other facilities were operating using wet limestone systems by the end of 1982, and twelve facilities were using magnesium oxide (MgO) enhanced lime. Design removal efficiencies for these facilities ranged from 80 to 95%.[50] Wet scrubbers were put in place at the above facilities for a variety of reasons, but by 1982 there were at least two Federal requirements for the use of scrubbers for SO_2 control.

The first of these federal requirements is the New Source Performance Standards (NSPS) for coal fired powerplants. The NSPS had been amended in 1979, and applies to powerplants constructed or modified after 1978.[51] Those standards require removal of up to 90% of flue gas SO_2 (depending on the sulfur content of the coal). NSPS is set at level that is technically feasible, and cost effective.[52]

The second requirement is the BACT requirement of the PSD regulations, which, in 1982, had been in effect for almost four years.[53] At least seven coal fired powerplants were issued PSD permits between 1978 and 1983 with the requirement for between 80 and 95% control.[54] For

[49] "Estimating Costs of Air Pollution Control," 1990, Vatavuk, W.M., Lewis Publishers, Chelsea, MI., pp. 194-199.

[50] See report of William Ellison, PE, Ellison Consultants, developed in connection with United States v. Illinois Power and Dynegy Midwest Generation, Inc.

[51] See 40 C.F.R. § 60.40a (1979), "Standards of Performance for Electric Utility Steam Generating Units for Which Construction is commenced after September 18, 1978."

[52] See C.A.A.§ 111(a)(1).

[53] In 1978, EPA revised its regulations pursuant to the 1977 Clean Air Act Amendments. Prior to that date, BACT was defined to be equal to NSPS, where an NSPS existed. The 1978 regulation conformed the regulations to the new statutory language, and provided that the permit applications that were "complete" prior to the new regulation would be processed under the old regulations.

[54] See Appendix A, Table 5: RACT/BACT/LAER summary: 1982 timeframe.

example, Nevada Power's Harry Allen Station was issued a permit in early 1981 with a 95% removal requirement and an emission rate of 0.1 pound/million BTU.[55] In 1980, the Platte River Power Authority, Rawhide Station was issued a permit with an 80% removal requirement and an emission rate limit of 0.13 pound/million BTU.[56] In addition, in 1982, the Allegheny Power, Mitchell 33 Unit, a powerplant firing up to 2.9% sulfur coal, began operation of a scrubber removing 95% of the stack gas.[57]

Taken together, it is clear that by 1982, scrubbing technologies to remove SO_2 were required of many powerplants and in place at many others. Both wet limestone scrubbers and wet lime scrubbers with magnesium buffering had been used and had demonstrated removal efficiencies of up to 95%. These two wet scrubbing technologies, with efficiencies of up to 95%, were therefore both technologically feasible and well demonstrated in practice.

b. Cost Analysis

Both of the available wet scrubbing options were analyzed to determine their cost effectiveness. Both scrubbing options were analyzed at the 95% efficiency level.

The cost for scrubbers capable of removing 95% of flue gas SO_2 were analyzed based on a study conducted by Illinois Power in 1991 to install flue gas desulfurization systems on Unit 1.[58] Most of the methodology used in 1991 would also apply in 1982.[59] Based on this analysis, the capital costs for the limestone system, would be approximately $176 million (in 1982 dollars). Operating costs would range from $3.3 million to 4.7 million, depending on whether waste from the

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[55] Ibid.

[56] Ibid.

[57] See report of William Ellison, PE, Ellison Consultants, "Table 5, Pre-1983, Tangentially-Fired, Low NO_x Burner Installations", developed in connection with United States v. Illinois Power and Dynegy Midwest Generation, Inc.

[58] Babcock and Wilcox, Contract Research Division and Environmental Equipment Division, Volumes I-IV of Proposal for Full-Scale Demonstration of Integrated Flue Gas Desulfurization System with Reburning NO_x Control, B&W Proposal #90-071 (May 1991). IPPRO-0128923-0129035, IPPRO-0128096-0128265, IPPRO-0127849-0128091, IPPRO-0127567-0127848.

[59] See report of Dan Mussatti and Larry Sorrels, "Estimated Costs for the Installation of SO_2, NO_x and PM Control Devices at Illinois Power's Baldwin Station," developed in connection with United States v. Illinois Power and Dynegy Midwest Generation, Inc. The cost data adjustment was based on information found at website address http://www.enr.com/cost/costcci.asp.

scrubber system would have been sold. When these costs are converted to annualized costs[60], the annual cost would have been between $22.0 and 23.4 million.[61] Based on 95% control of SO_2 emissions, a wet limestone scrubber system installed on Baldwin's Unit 3 would remove 106,600 tons per year of SO_2. Its cost effectiveness in 1982 would have been approximately $220/ton.[62] The wet lime scrubber with magnesium buffering would have had both higher capital and operating costs than the wet limestone scrubber.[63] Therefore, unless the wet limestone scrubber were to be rejected on other grounds (such as lesser other environmental impacts), it would no longer need to be considered.

In order to ensure that the costs estimated for the scrubber are not excessive, I reviewed other BACT determinations and EPA policy documents.[64] I reviewed the cost effectiveness of eighteen powerplants permitted between 1979 and 1999 with BACT requirements for scrubbers. Of those where a dollar per ton cost effectiveness was listed, the range (once converted to 1982 dollars) was $145 to 4405/ton.[65] Also, in 2001, EPA issued guidance related to presumptive BACT for NO_x at refineries being modified to meet EPA mandates for making cleaner burning

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[60] Annualizing a cost is method to determine the annual equivalent value of the initial investment over its life.

[61] Ibid.; the cost data adjustment was based on information found at website address http://www.enr.com/cost/costcci.asp.

[62] See Table 8a: SO_2 Emission Calculations and Cost Effectiveness for Baldwin Unit 3, 1982.

[63] See report of Dan Mussatti and Larry Sorrels, Estimated Costs for the Installation of SO_2, NO_x and PM Control Devices at Illinois Power's Baldwin Station, developed in connection with United States v. Illinois Power and Dynegy Midwest Generation, Inc.

[64] Specifically, as part of the economic analysis here and throughout the report, I compared the cost effectiveness of available control options to a variety of other benchmarks. This comparison assisted in determining whether a particular scenario's cost effectiveness should be deemed unreasonable. For example, to the extent available, I looked at contemporaneously issued PSD permits, as well as PSD permits issued later. In addition, I considered more generalized data applicable to source types or regulatory schemes that are expected to use a lower cost effectiveness. For example, I have compared potential control costs at the Baldwin station to costs calculated for control measures imposed to attain the National Ambient Air Quality Standards. These control measures are usually known as Reasonably Available Control Technology (RACT). RACT level emissions controls are considered to be a less stringent control technology requirement than BACT, and therefore are less expensive. Therefore, the use of RACT level controls should yield a conservative (i.e. lower cost) measure against which to compare potential BACT options.

[65] See Table 11, Cost Effectiveness of BACT Determinations for SO_2.

gasoline.[66] That guidance used $10,000/ton as an upper bound for BACT cost effectiveness. When that value is converted to1982 dollars it becomes $6,148/ton. The estimated costs for wet limestone scrubbing at Baldwin Unit 3 in 1982 is at the low end of the range of these permits and EPA guidance. The cost is therefore not unreasonable.

c. Other Environmental Impacts

Wet scrubbers produce a sludge that may have economic use. If not used, it must be disposed in a landfill. This sludge is not considered hazardous waste. No other significant environmental effect occur due to the use of scrubbers.

d. Conclusion

Based on the above data, I conclude that BACT at Baldwin Unit 3 in 1982 would have been an emission rate of 0.3 pound/million BTU,[67] 30 day rolling average, based on the use of a wet limestone scrubber removing 95% of the SO_2 from coal having a sulfur content of 3-3.5%. Compliance with the limit would have been monitored by use of a Continuous Emissions Monitoring System (CEMS).[68]

2. *Nitrogen Oxides*

In 1982, Unit 3, based limited data available, had uncontrolled NO_x emission rates that appear to average about 0.47 pound/million BTU, and range as high as 0.75 pound/million BTU.[69] Several emissions control options were potentially available in 1982. I analyzed the following options to determine technical feasibility, availability and cost effectiveness for NO_x control:

1. Low NO_x Burners ("LNB")
2. Overfire Air ("OFA")

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[66] See memorandum from John S. Seitz, Director, OAQPS, to Air Division Directors regarding BACT and LAER for Emissions of Nitrogen Oxides and Volatile Organic Compounds at Tier 2/Gasoline Refinery Projects, dated January 19, 2001. This information can be found at website address: http://www.epa.gov/rgytgrnj/programs/artd/air/nsr/nsrmemos/t2bact.pdf

[67] The limit of 0.3 pounds per million BTU is derived from 95% removal of coal with 3.5% sulfur and 10,900 BTU/pound. See Table 8a, SO_2 Emission Calculations and Cost Effectiveness for Baldwin Unit 3, 1982

[68] See 40 C.F.R Part 60, Appendix B, Performance Specification 2.

[69] See Compilation of CEMS Data for the Baldwin Station, submitted by Illinois Power Company to U.S. EPA.

3. Selective Catalytic Reduction ("SCR")
4. Flue Gas Recirculation ("FGR")

a. Technical Feasibility

Low NO_x burners limit NO_x formation by controlling both the stoichiometric and temperature profiles of the combustion process in each burner flame zone. This control is achieved with mechanical designs that regulate the aerodynamic distribution and mixing of the fuel and air which results in reduced oxygen concentration in the primary combustion zone, reduced flame temperature, or reduced residence time at the peak NO_x formation temperature. There are many types of Low-NO_x burners for use on many types of boilers (except cyclone boilers.)[70]

LNBs were installed in numerous facilities by 1982. At least seven plants were operating with LNBs worldwide by 1982.[71] At least one burner manufacturer had developed a burner capable of reaching levels of less than 0.4 pound NOx/million BTU. That burner was installed at Utah Power and Light's Hunter Unit 2 and started operation in 1981.[72,73] At least two other powerplants were permitted by 1982 with emission rates near 0.4 pound NOx/million BTU–Nevada Power's Harry Allen Station, and Tucson Electric Power's (TEP) Springerville Unit 3.[74] Units 1 and 2 at TEP's Springerville, permitted in 1978, have achieved levels of approximately 0.4 pounds per million BTU.[75] All of the foregoing powerplants were designed as tangentially fired boilers.

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[70] Babcock & Wilcox, *Steam/its generation and use* (39th ed. 1978).

[71] See report of William Ellison, PE, Ellison Consultants, "Table 5, Pre-1983, Tangentially-Fired, Low NO_x Burner Installations," developed in connection with United States v. Illinois Power and Dynegy Midwest Generation, Inc.

[72] See report of William Ellison, PE, Ellison Consultants, "Table 5, Pre-1983, Tangentially-Fired, Low NO_x Burner Installations," developed in connection with United States v. Illinois Power and Dynegy Midwest Generation, Inc.

[73] Conversion from parts per million to pounds per million BTU based on *Emissions standards handbook: air pollutant standards for coal-fired power plants*, Appendix, Hermine N. Soud, IEA Coal Research, December 1991.

[74] See Appendix A, Table 1.

[75] See U.S. EPA, Clean Air Markets Division, "Emissions Scorecard." This information can be found at website address: http://www.epa.gov/airmarkets/emissions/score00/index.html. TEP's emission rate for 2000 was reported to have been 0.39 pounds/MMBTU. TEP has presumably maintained the same burners since the boilers were built.

The relevant NSPS requirement was an emission rate of 0.6 pound/million BTU for coal fired powerplants burning bituminous coal, which is the coal that Illinois Power was burning in 1982. In 1982, several plants were in operation[76] or were permitted for lower levels using LNBs.[77] These installations demonstrate that, using LNBs, facilities would be capable of reaching lower emission rates than the NSPS requires.

Overfire air is a combustion control technique where a percentage (~5 - 20%) of the total combustion air is diverted from the burners and injected through ports about the top burner level. The zone where the coal is injected is slightly oxygen deficient (sub-stoichiometric) thereby suppressing production of NO_x. Combustion is completed in the over-fire air zone. Overfire air is sometimes called air staging. Overfire air limits NO_x emissions by two mechanisms: (1) thermal NO_x formation is delayed and suppressed because of the lower flame temperature and extended combustion zone, and (2) fuel NO_x formation is suppressed because of the lower oxygen concentration in the lower furnace and the lower temperature.[78] Overfire air was installed in numerous facilities by 1982. By 1982, at least five plants were operating worldwide using OFA. However, OFA installations in the 1892 time frame in tangentially fired boilers appear to be an integral part of LNB designs, and also appear designed to meet a limit of 0.7 pound per million BTU. [79]

Selective Catalytic Reduction involves injecting ammonia into the flue gas before the gas reaches a catalyst, at a specific temperature. The catalyst lowers the energy required to complete the reaction of the ammonia with the NO_x to form nitrogen and water, therefore the catalyst can be placed in a lower temperature zone of the boiler. The most common catalysts are a vanadium/titanium composition, with vanadium pentoxide (V2O5) as the active catalyst and a titanium support, and operate at about 750F in hot side SCR systems. Zeolite catalysts are crystalline aluminosilicate compounds and can operate at a lower temperature, typically found

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[76] See report of William Ellison, PE, Ellison Consultants, "Table 5, Pre-1983, Tangentially-Fired, Low NO_x Burner Installations," developed in connection with United States v. Illinois Power and Dynegy Midwest Generation, Inc.

[77] See Appendix A, Table 1.

[78] See U.S. EPA, Office of Air and Radiation, Office of Air Quality Planning and Standards, "Alternative Control Technologies Document NO_x Emissions from Utility Boilers" March 1994. This information can be found at website address: http://www.epa.gov/ttn/catc/dir1/utboiler.pdf.

[79] See report of William Ellison, PE, Ellison Consultants, "Table 5, Pre-1983, Tangentially-Fired, Low NO_x Burner Installations," developed in connection with United States v. Illinois Power and Dynegy Midwest Generation, Inc.

after the preheater. Zeolite catalysts would be used in cold side SCR systems.[80]

Selective Catalytic Reduction was in use by 1982 on at least five coal fired powerplants worldwide.[81],[82] It therefore must be considered technically feasible, an important consideration in the BACT analysis. However, the largest boiler with SCR installed at this time was 350 MW, which is much smaller than Baldwin Unit 3, at almost 600 MW. In addition, in 1982, there were roughly two years of world-wide experience with SCR systems. To be most conservative in this retrospective analysis, I would conclude that the uncertainty associated with the newness of the technology and scale-up would mean that the technology was not available for use on Baldwin's Unit 3, and therefore was not a candidate for further BACT evaluation.

Flue gas recirculation involves reintroducing flue gas from the economizer or air heater into the furnace for NO_x control using ductwork and an additional fan. The method was originally developed for controlling superheater and reheater steam temperatures. NO_x is reduced by lowering the temperature in combustion zone and therefore suppressing NO_x formation.

By 1982, flue gas recirculation was in use at a large number of combustion processes.[83] All of these installations appear to be designed to meet an emissions limit of 0.7 pounds/MMBTU.[84] However, little data are available suggesting use and effectiveness of FGR for NO_x control at coal fired boilers. For that reason, I have excluded FGR from further analysis as a BACT option.

b. <u>Cost Analysis</u>

This section presents costs for the installation of LNBs at Baldwin Unit 3.[85] A state-of-the-art

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[80] <u>See</u> U.S. EPA, Office of Air and Radiation, Office of Air Quality Planning and Standards, "Alternative Control Technologies Document NO_x Emissions from Utility Boilers" March 1994. This information can be found at website address: http://www.epa.gov/ttn/catc/dir1/utboiler.pdf.

[81] <u>See</u> report of William Ellison, PE, Ellison Consultants, "Table 2, SCR Installations," developed in connection with <u>United States v. Illinois Power and Dynegy Midwest Generation, Inc.</u>

[82] <u>See</u> Ando, Jumpei, "SO_2 and NO_x Removal for Coal Fired Boilers in Japan," presented at the Seventh Symposium on Flue Gas Desulfurization, May, 1982.

[83] <u>See</u> report of William Ellison, PE, Ellison Consultants, developed in connection with <u>United States v. Illinois Power and Dynegy Midwest Generation, Inc.</u>

[84] Ibid.

[85] OFA was excluded from further analysis because installations using OFA, in 1982, were emitting at about the same rate as Baldwin Unit 3 was, i.e. 0.7 pound/MMBTU.

LNB in 1982 would have been capable of reducing emissions to less than 0.4 pound/million BTU. The annualized cost of a LNB would have been $3.19 million, yielding a cost effectiveness of $589/ ton of NO_x reduced.[86]

These costs compare favorably to relevant, historical, PSD permits and cost analyses performed for air quality planning needs. For example, the New Jersey Department of Environmental Protection issued permits in 1990 and 1991 that were based on a cost effectiveness of $13,200/ton.[87] When converted to 1982 dollars, the New Jersey permits would require controls at a cost effectiveness of $10,600/ton.[88] Also, in 1982 the South Coast AQMD (SCAQMD) adopted a revision to its air quality management plan.[89] That plan adopted control measures in order for the area to meet the National Ambient Air Quality Standards (NAAQS) for nitrogen dioxide (NO2). Control measures for areas violating the NAAQS apply to a broad range of source categories, and are almost always retrofit measures. Consequently, the costs of these measures are generally less than BACT costs. The Los Angeles area, which is part of the jurisdiction of the SCAQMD, was the only area in the country not attaining the NAAQS for NO2. The plan shows a number of control measures, some of which would be implemented immediately, and some over time. For rules projected to be adopted between 1983 and 1986, the cost effectiveness was between $700/ton and $7,600/ton in 1987 dollars. When those values are adjusted to 1982 dollars, the range becomes $617 to $6700/ton. Lastly, in 2001 EPA issued guidance related to presumptive BACT for NO_x at refineries being modified to meet EPA mandates for making cleaner burning gasoline.[90] That guidance used $10,000/ton as an upper bound for BACT cost effectiveness. When that value is converted to1982 dollars it becomes $6,148/ton.

The average cost per ton for NO_x reductions at Baldwin Unit 3 in 1982 using LNBs is substantially lower than the acceptable high end for costs used by NJDEP and EPA in the two

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[86] See report of Dan Mussatti and Larry Sorrels, "Estimated Costs for the Installation of SO_2, NO_x and PM Control Devices at Illinois Power's Baldwin Station," developed in connection with United States v. Illinois Power and Dynegy Midwest Generation, Inc.

[87] See Keystone Cogeneration Facility BACT for Nitrogen Oxides Addendum, June 1990, ENSR Consulting and Engineering.

[88] See http://www.enr.com/cost/costcci/asp for cost adjustments.

[89] Final Air Quality Management Plan, 1982 Revision, South Coast Air Quality Management District and Southern California Association of Governments, October 1982.

[90] See memorandum from John S. Seitz, Director, OAQPS, to Air Division Directors regarding BACT and LAER for Emissions of Nitrogen Oxides and Volatile Organic Compounds at Tier 2/Gasoline Refinery Projects, dated January 19, 2001. This information can be found at website address: http://www.epa.gov/rgytgrnj/programs/artd/air/nsr/nsrmemos/t2bact.pdf

examples above, and similar to or less than the costs for most of the control measures in the SCAQMD plan. Therefore, the costs for LNBs at Baldwin Unit 3 in 1982 are not unreasonable.

c. Other Environmental Impacts

No significant environmental impacts would have occurred as a result of using LNBs.

d. Conclusion

In summary, I conclude that an emission rate of 0.40 pounds per million BTU (three hour average) based on the use of LNBs was BACT for NO_x at Baldwin #3 in 1982. Compliance with the limit would be monitored by use of a Continuous Emissions Monitoring System (CEMS).

3. Particulate Matter

As of 1982, Baldwin Unit 3 was equipped with an electrostatic precipitator. Data reported by Illinois Power show that it was achieving a removal efficiency of about 99.4-99.5%.[91]

The following emissions control options were available for consideration in 1982.

1. Electrostatic Precipitator (ESP)

2. Baghouse

a. Technical Feasibility

An ESP was in use on Baldwin Unit 3 in 1982. It was therefore, technically feasible and available. A baghouse is also a feasible option. Several facilities were reported to be using baghouses in 1982, and achieving limits as low as .005 gr/ACF.[92] (This equates to 99.7% control at Baldwin Unit 3.)[93] Baghouses were therefore also technically feasible and available.

The removal efficiency that Baldwin Unit 3 was achieving in 1982 compares favorably with the

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[91] Department of Energy, Energy Information Administration (Form EIA-767) for 1982. IPPRO-0104439-0104464.

[92] See report of William Ellison, PE, Ellison Consultants, developed in connection with United States v. Illinois Power and Dynegy Midwest Generation, Inc.

[93] See Table 7 for derivation of control level.

baghouses in 1982, and achieving limits as low as .005 gr/ACF.[92] (This equates to 99.7% control at Baldwin Unit 3.)[93] Baghouses were therefore also technically feasible and available.

The removal efficiency that Baldwin Unit 3 was achieving in 1982 compares favorably with the permitted emission rate for the Harry Allen Station [94] (where a particulate matter emission rate of 0.015 pound/MMBTU was required, based on a removal rate of 99.76%). Although that permit assumed that a baghouse would be required to meet the removal rate, it also allowed the applicant to use an ESP if data were submitted demonstrating that the ESP was likely to be able to achieve that rate. Baldwin Unit 3's ESP was controlling emissions to about 99.4% in 1982.[95] If Illinois Power had been required to add controls (likely to be an additional baghouse or another field in its ESP) to control its emissions to the then state of the art (i.e. to about 99.7% control), the costs would likely have been substantial.

b. Conclusion

I have concluded that BACT for PM at Baldwin unit 3 in 1982 would have been an emission rate of 0.036 pounds per million BTU, based on 99.4% removal and the emissions controls already in place at Baldwin Unit 3 in 1982. Compliance would have been monitored using EPA method 5 and an opacity monitor.

B. BACT Determination For Baldwin Unit 1: 1985

Unit 1 is a cyclone fired boiler with a gross output rating of 584 megawatts (MW)[96] and began operation in 1970.[97] It is designed to fire 267 tons per hour of coal[98] with a heating value of

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[92] See report of William Ellison, PE, Ellison Consultants, developed in connection with United States v. Illinois Power and Dynegy Midwest Generation, Inc.

[93] See Table 7 for derivation of control level.

[94] See EPA permit for Harry Allen Station, NV-77-01 and associated National Ambient Air Quality Impact Report.

[95] Department of Energy, Energy Information Administration, (Form EIA-767) for year 1982.

[96] Sargent & Lundy Engineers Engineering Data, Unit 1 Baldwin Power Station. IPPRO-0085676-744.

[97] Ibid.

[98] Department of Energy, Energy Information Administration, (Form EIA-767) for year 1985.

1985.[100]

The available control technologies are the same as those that were potentially applicable to Unit 3 in 1982.

a. Technical Feasibility

By 1985, at least thirty-five additional (compared to 1982) coal fired powerplants were in operation with scrubbers to remove SO2 from their exhaust gas. Most of these scrubbers were wet limestone or wet lime buffered with magnesium oxide.[101],[102] These two types of scrubbers were technically feasible in 1985.

b. Cost Analysis

The cost in 1985 of scrubbers capable of removing 95% of flue gas SO_2 was analyzed based on a study conducted by Illinois Power in 1991 to install flue gas desulfurization systems on Unit 1.[103] Most of the methodology used in 1991 would also apply to Unit 1 in 1985. According to that study, capital costs for the wet limestone scrubber are estimated to have been approximately \$189 million.[104] Operating costs would have ranged from \$3.53 million to 5.04 million, depending on whether waste from the scrubber system would have been sold.. When these costs are converted to annualized costs, the annual cost would have been between \$23.5 and 25.0 million. Analysis of wet lime scrubber buffed with magnesium oxide shows it to be more

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[100] See Expert Report of Ranajit (Ron) Sahu, April 2002, compiling CEMS data submitted by Illinois Power Company to U.S. EPA.

[101] See report of William Ellison, PE, Ellison Consultants, "Table 2, SCR Installations," developed in connection with United States v. Illinois Power and Dynegy Midwest Generation, Inc.

[102] See "Table 30: Flue Gas Desulfurization (FGD) Capacity in Operation at U.S. Electric Utility Plants as of December 1999." This information can be found at website address: http://www.eia.doe.gov/cneaf/electricity/epav2/html_tables/epav2t30p1.html and following pages

[103] Babcock and Wilcox, Contract Research Division and Environmental Equipment Division, Volumes I-IV of Proposal for Full-Scale Demonstration of Integrated Flue Gas Desulfurization System with Reburning NO_x Control, B&W Proposal #90-071 (May 1991), IPPRO-0128923-0129035, IPPRO-0128096-0128265, IPPRO-0127849-0128091, IPPRO-0127567-0127848.

[104] See report of Dan Mussatti and Larry Sorrels, "Estimated Costs for the Installation of SO_2, NO_x and PM Control Devices at Illinois Power's Baldwin Station," developed in connection with United States v. Illinois Power and Dynegy Midwest Generation, Inc.

expensive for the same level of control as the wet limestone scrubber, therefore only the wet limestone option received further consideration.[105] The wet limestone scrubber would remove 96,800 tons per year of SO_2. Therefore, the cost effectiveness of a limestone FGD system would have been approximately $258/ton in 1985.[106]

In order to ensure that the costs estimated for the scrubber are not excessive, I reviewed other BACT determinations and EPA policy documents. I reviewed the cost effectiveness of eighteen powerplants permitted between 1979 and 1999 with BACT requirements for scrubbers. Of those where a dollar per ton cost effectiveness was listed, the range (once converted to 1985 dollars) is $155 to 4715/ton.[107] Also, in 2001, EPA issued guidance related to presumptive BACT for NO_x at refineries being modified to meet EPA mandates for making cleaner burning gasoline.[108] That guidance used $10,000/ton as an upper bound for BACT cost effectiveness. When that value is converted to1985 dollars it becomes $6,581/ton. The estimated costs for wet limestone scrubbing at Baldwin Unit 1 in 1985 is at the low end of the range of these permits and EPA guidance. The cost is therefore not unreasonable.

c. Other Environmental Impacts

Wet scrubbers produce a sludge that may have economic use. If not used, it must be disposed in a landfill. This sludge is not considered hazardous waste. No other significant environmental effect occur due to the use of scrubbers.

d. Conclusion

Based on the above data, I conclude that BACT for SO_2 at Baldwin Unit 1 in 1985 would have been an emission rate of 0.30 pound/million BTU,[109] 30 day rolling average, based on the use of a wet limestone scrubber removing 95% of the SO_2 from coal having a sulfur content of 3-3.5%. Compliance with the limit would have been monitored by use of a Continuous Emissions Monitoring System (CEMS).[110]

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[105] Ibid; also see http://www.enr.com/cost/costcci.asp for cost adjustments.

[106] See Table 8b for calculations.

[107] See Table 11, Cost Effectiveness of BACT Determinations for SO_2.

[108] See memorandum from John S. Seitz, Director, OAQPS, to Air Division Directors regarding BACT and LAER for Emissions of Nitrogen Oxides and Volatile Organic Compounds at Tier 2/Gasoline Refinery Projects, dated January 19, 2001. This information can be found at website address: http://www.epa.gov/rgytgrnj/programs/artd/air/nsr/nsrmemos/t2bact.pdf

[109] See Table 8b for calculations.

[110] See 40 C.F.R Part 60, Appendix B, Performance Specification 2.

2. *Nitrogen Oxides*

As of 1985, Baldwin Unit 1 had no controls in place for NO_x emissions.[111] Unit 1's NO_x emissions are estimated to have been approximately 1.8 pounds per million BTU.[112] The relevant NSPS requirement was an emission rate of 0.6 pound/million BTU for coal fired powerplants burning bituminous coal, which is the coal that Illinois Power was burning in 1985.

a. Technical Feasibility

For Unit 1, in 1985, I considered the feasibility of LNBs, OFA, SCR and SNCR. LNBs were not technically feasible because they simply have not been developed for use on cyclone fired boilers. As to OFA, from the vantage point of 2001, for cyclone fired boilers, OFA would appear to have been technically feasible, but no installations on cyclone boilers appear to have been in place by 1985.[113] Therefore, in my judgement, given the technical difficulty of engineering an overfire air system for a cyclone fired boiler, I would consider that technology also to be unavailable for use on Unit 1 in 1985.

However, in contrast to1982, by 1985, SCR had been used for coal fired boilers for at least five years. For example, by 1985, at least three Japanese facilities (i.e., Shiminoseki, Shin Ube and Tomatoatsuma) had operated five years.[114] In addition, at least sixteen SCR systems on coal fired powerplant boilers in Japan were in operation or under construction by this time, including both new and retrofit facilities. These powerplant boilers ranged in size from 125 to 700 megawatts in size.[115] Planned reduction rates are not available for all of these facilities, but for a subset in operation by 1984, reduction ranged from 57 to 81%.[116] Operational problems experienced in the

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[111] Department of Energy, Energy Information Administration (Form EIA-767) for 1985.

[112] See Expert Report of Ranajit (Ron) Sahu, April, 2002, compiling CEMS data submitted by Illinois Power Company to U.S. EPA.

[113] See report of William Ellison, PE, Ellison Consultants, developed in connection with United States v. Illinois Power and Dynegy Midwest Generation, Inc. No instance of OFA were located in the relevant timeframe.

[114] See report of William Ellison, PE, Ellison Consultants, developed in connection with United States v. Illinois Power and Dynegy Midwest Generation, Inc.

[115] See Ando, Jumpei, "*SO_2 and NO_x Removal For Coal-Fired Boilers in Japan,*" presented to the Seventh Symposium on Flue Gas Desulfurization, May, 1982.

[116] See U.S. EPA, Air and Energy Engineering Research Laboratory, Office of Environmental Engineering and Technology, "Recent Developments in SO_2 and NO_x Abatement Technology," September 1985.

early stages of SCR development had been solved by this time.[117] Two German facilities that would begin operation in 1986 were likely under construction.[118] Also, by 1985, SCR had begun to be used in the United States. For example, use of SCR, by 1984, resulted in a Lowest Achievable Emission Rate (LAER) emission rate for combined cycle gas turbines.[119],[120]

An additional technology that would have been considered in 1985 is Selective Non-Catalytic Reduction (SNCR). This process involves injection of ammonia into the combustion chamber at a point where the temperature is in a precise range.[121] SNCR systems have lower capital costs than SCR, but typically have higher ammonia emissions levels compared to SCR, i.e. 30 to 40 parts per million (ppm) compared to as little as 1 ppm for SCR systems.[122] Beginning in about 1985, many coal fired powerplants were permitted using SNCR.[123] However, none of these were cyclone fired boilers.[124] Therefore, I would conclude that SNCR was not available in 1985 for

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[117] Ibid, page 5-2.

[118] See report of William Ellison, PE, Ellison Consultants, "Table 2, SCR Installations," developed in connection with United States v. Illinois Power and Dynegy Midwest Generation, Inc.

[119] Personal conversation with Robert Pease, Air Quality Analysis/Compliance Supervisor, South Coast AQMD, September 19, 2001. Mr. Pease visited Japan in June 1984 to observe the operation of SCR on a large gas turbine. In July 1984, Mr. Pease prepared a report for the AQMD about its operation, and shortly thereafter began to require combined gas turbines to meet a 9 ppm NO_x limit.

[120] LAER is generally the most effective emission limit that has been achieved for a source category. Consequently, the LAER emission rate, and the technology on which it is based, would generally be the most effective emission control option in a BACT analysis, and must be considered.

[121] See U.S. EPA, Office of Air and Radiation, Office of Air Quality Planning and Standards, "Alternative Control Technologies Document NO_x Emissions from Utility Boilers" March 1994. This information can be found at website address: http://www.epa.gov/ttn/catc/dir1/utboiler.pdf.

[122] See U.S. EPA, Office of Air and Radiation, Office of Air Quality Planning and Standards, "Alternative Control Technologies Document NO_x Emissions from Utility Boilers" March 1994. This information can be found at website address: http://www.epa.gov/ttn/catc/dir1/utboiler.pdf.

[123] References: PSD permit #s SE 85-01, 85-05, SJ 85-06, SJ 85-07, SJ SE 86-04, SJ 86-08, 86-09.

[124] See report of William Ellison, PE, Ellison Consultants, developed in connection with United States v. Illinois Power and Dynegy Midwest Generation, Inc. See also U.S. EPA, Office of Air

use on cyclone fired boilers.

In summary, SCR was the sole NO_x control technology available for cyclone fired boilers in 1985. Moreover, a 55% reduction in emissions was well demonstrated for SCR based on the technical feasibility above. However, there is little information in the literature as to the effectiveness of SCR as the boiler undergoes changes in load. Current day control systems are able to react and adjust operation of the SCR to maintain a given level of control; systems in the mid '80s were less capable. In order to account for this lesser level of effectiveness of the SCR system during load changes, I assigned slightly less efficiency, 50%, to the SCR system, which could have been easily achieved on Baldwin's Unit 1 in 1985. A 50% reduction applied to uncontrolled emissions of 1.8 pound/million BTU yields an emission rate of 0.90 pounds per million BTU.

b. Cost Analysis

The estimated cost of an SCR system at Baldwin Unit 1 in 1985 was based on Illinois Power's study for installation SCR at Units 1 and 2.[125] Since that study was conducted in 1990, the costs were adjusted to reflect 1985 dollars. The capital cost of SCR in1985 is estimated to be $88.6 million, and annual operating costs are estimated to be $3.43 million. The annualized cost would be $20.2 million.[126] This yields a cost effectiveness of $1368/ton reduced.[127,128] These costs are likely to be conservative. For example, the 1990 study was for an installation that would remove

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and Radiation, Office of Air Quality Planning and Standards, "Alternative Control Technologies Document NO_x Emissions from Utility Boilers" March 1994, page 49. This information can be found at website address: http://www.epa.gov/ttn/catc/dir1/utboiler.pdf.

[125] See report of Dan Mussatti and Larry Sorrels, "Estimated Costs for the Installation of SO_2, NO_x and PM Control Devices at Illinois Power's Baldwin Station," developed in connection with United States v. Illinois Power and Dynegy Midwest Generation, Inc.

[126] Ibid.

[127] See Table 3b for calculations.

[128] This cost estimate assumes that the catalyst would be replaced every three years. That assumption may be very conservative. At least one early SCR installation, at Knepper Unit C in Germany, went into service in 1986, and, as of 1998, was operating with 56% of its original catalyst. Another plant, Velthiem, began operation in 1989, and as of 1998, was operating with all of its original catalyst, together with an additional amount of catalyst added after two to three years of operation. See "Development and Commercial Operating Experience of SCR deNO$_x$ Catalysts for Wet-Bottom Coal-Fired Boilers," Isato Morita *et al*, Presented to Power-Gen International '98, December 1998. This document may be found at website address http://www.babcock.com/pgg/tt/pdf/BR-1665.pdf.

85% of NO_x from the exhaust stream. In contrast, a 55% reduction of NO_x was used for this analysis. The lower removal rate should reduce costs in two ways. First, less catalyst would be required, reducing capital cost, and secondly, less ammonia would need to be injected into the SCR system, reducing operating cost. Lastly, because less catalyst would initially be used, less catalyst would need to be periodically replaced. In spite of these likely cost reductions, our cost estimate did not take the lower removal rate into account. Therefore, these cost estimates are likely to be quite conservative.

This cost compares favorably to some of the same relevant benchmarks mentioned above. For example, the New Jersey Department of Environmental Protection issued permits in 1990 and 1991 that were based on a cost effectiveness of $13,200/ton. When converted to1985 dollars, the New Jersey permits would require controls at a cost effectiveness of $11,700.[129] Also, in 1982 the South Coast AQMD (SCAQMD) adopted a revision to its air quality management plan.[130] That plan adopted control measures in order for the area to meet the National Ambient Air Quality Standards (NAAQS) for nitrogen dioxide (NO2). Control measures for areas violating the NAAQS apply to a broad range of source categories, and are almost always retrofit measures. Consequently, the costs of these measures are generally less than BACT costs. The Los Angeles area, which is part of the jurisdiction of the SCAQMD, was the only area in the country not attaining the NAAQS for NO2. The plan shows a number of control measures, some of which would be implemented immediately, and some over time. For rules projected to be adopted between 1983 and 1986, the cost effectiveness was between $700/ton and $7,600/ton in 1987 dollars. When those values are adjusted to 1985 dollars, the range becomes $660 to $7180/ton. Lastly, in 2001 EPA issued guidance related to presumptive BACT for NO_x at refineries being modified to meet EPA mandates for making cleaner burning gasoline.[131] That guidance used $10,000/ton as an upper bound for BACT cost effectiveness. When that value is converted to1985 dollars it becomes $6,620/ton.

The average cost per ton for NO_x reductions using SCR at Baldwin Unit 1 in 1985 is substantially lower than the acceptable high end for costs used by NJDEP and EPA in the two examples above, and similar to or less than the costs for most of the control measures in the SCAQMD plan. Therefore, the costs for LNBs at Baldwin Unit 1 in 1985 are not unreasonable.

c. Other Environmental Impacts

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[129] See http://www.enr.com/cost/costcci/asp for cost adjustments.

[130] Final Air Quality Management Plan, 1982 Revision, South Coast Air Quality Management District and Southern California Association of Governments, October 1982.

[131] See memorandum from John S. Seitz, Director, OAQPS, to Air Division Directors regarding BACT and LAER for Emissions of Nitrogen Oxides and Volatile Organic Compounds at Tier 2/Gasoline Refinery Projects, dated January 19, 2001. This information can be found at website address: http://www.epa.gov/rgytgrnj/programs/artd/air/nsr/nsrmemos/t2bact.pdf

SCR and SNCR use ammonia, which could cause environmental effects if emitted in large amounts. However, ammonia slip (unreacted ammonia emitted to the atmosphere) is limited by design in SCR systems to about 3 ppm, so effects would not be likely to occur. SNCR typically has a higher ammonia slip; as high as 30 ppm. Because of the higher ammonia slip rate for SNCR, SCR would usually be preferred because of its lower other environmental impacts.

d. Conclusion

I conclude that an emission rate of 0.90 pound/million BTU (3 hour average) based on the use of SCR was BACT for Baldwin Unit 1 in 1985. Compliance with the limit would have been monitored by use of a Continuous Emissions Monitoring System (CEMS).[132]

3. *Particulate Matter*

In 1985, Baldwin Unit 1 was operating with an ESP to control particulate emissions. Based on Illinois Power's reported efficiency, which started at 96% in 1982 and decreased over time to 90% in 1985,[133] it appears that the ESP was in need of significant maintenance or repair. Illinois Power also performed periodic tests of the ESP. Based on the 1984 tests, I estimate emissions to have been approximately 580 pounds per hour[134] but, based on other tests performed before and after that date, showing that emissions were highly variable, I conclude that emissions could have been as high as 879 pounds per hour in 1985.

a. Technical Feasibility

In order to reduce emissions further, one of the following actions would need to be taken at Baldwin Unit 1:

- Replacement of current ESP with new ESP or baghouse,
- Upgrade of ESP.

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[132] See 40 C.F.R Part 60, Appendix B, Performance Specification 2.

[133] See EIA Reports numbered IPPRO-0104246; IPPRO-0104275; IPPRO-0104304; IPPRO-0104333; IPPRO-0104370; IPPRO-0104404; IPPRO-0104456; IPPRO-0104457; IPPRO-0104480; IPPRO-0104481; IPPRO-0104503 and IPPRO-0104504.

[134] See Summary of Stack Test Data (0.1 pound/MMBTU); 5,824 MMBTU/hr derived from document number B&W02758. IPPRO-0021437; IPPRO-0016781; IPPRO-0020203; EPA-6427; IPPRO-0049695; IPPRO-0057472; IPPRO-0020445; IPPRO-0016913; IPPRO-0017018; IPPRO-0018463; IPPRO-0002372; IPPRO-0020345; IPPRO-0071136; IPPRO-0018582; IPPRO-0016835; IPPRO-0021387; IPPRO-0070999.

For this analysis, I have assessed only the option of replacing the ESP with either a new ESP or a baghouse. In 1991, Illinois Power analyzed the options to increase particulate control at Units 1 and 2.[135] They concluded that a replacement ESP would be more cost effective than an upgrade of the existing ESP. Illinois Power did not analyze the cost of replacing the ESP with a baghouse. Among the conclusions of that study was that the existing ESP was in "poor condition," and that a "major upgrade and refurbishment of the existing ESP will be required in order to obtain another 30 years of service."[136] Since this study was conducted only about five years after 1985, I believe its conclusions would generally have applied in 1985, i.e., that the existing ESP was near the end of its useful life and that a new or refurbished control device would be soon be needed.

i. Baghouse

In 1985, it would have been technically feasible for Illinois Power to substantially improve its particulate control with a baghouse. By 1985, at least 29 coal fired powerplants had installed baghouses designed to achieve levels of PM less than 0.01 grain/ACF (actual cubic foot).[137] Of those 29, many were designed to achieve levels of between 0.001 and 0.005 gr/ACF.[138] This level is approximately equal to a 98.3 to 99.6% reduction of uncontrolled emissions at Baldwin Unit 1.[139] An emission rate of .003 gr/ACF is equivalent to 99.7% control at Baldwin Unit 1.[140]

ii. ESP

As of 1982, Illinois Power operated an ESP on Unit 3 with a removal efficiency of approximately 99.4% (see 1982 analysis, above). This alone demonstrates the technical feasibility of an ESP at Baldwin at that removal efficiency.

a. Cost Analysis

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[135] See Burns and McDonnell report, "Baldwin Unit 1 Electrostatic Precipitator Study" (1991). IPPRO-0058084 through IPPRO-0058136.

[136] Ibid., page II-1. IPPRO-0058092.

[137] See report of William Ellison, PE, Ellison Consultants, developed in connection with United States v. Illinois Power and Dynegy Midwest Generation, Inc.

[138] See report of William Ellison, PE, Ellison Consultants, developed in connection with United States v. Illinois Power and Dynegy Midwest Generation, Inc.

[139] See Appendix A, Table 4b: Emissions Calculations and Cost Effectiveness for Particulate Matter in 1985.

[140] See Table 4c for calculations.

Based on a design to remove 99.6% of particulate matter (based on the capability of a baghouse, as discussed in the 1982 analysis, above), an ESP is estimated to have an annualized cost of about $19 million (and a capital cost of $105 million).[141] A baghouse with similar capabilities would have an annualized cost of $10.9 million (and a capital cost of $55 million).[142] Since the baghouse would be less expensive for the same level of emissions reduction, that is the option that I considered for further analysis. The total cost effectiveness of the baghouse would be $811/ton.

Comparable cost effectiveness values are not available for cyclone fired boilers (which have much lower inlet PM loadings than tangentially fired boilers). However, construction cost data are available for powerplants constructed in the 1985 timeframe. These data show that the estimated construction cost for a baghouse is similar to that of other contemporaneous sources. For example, Arizona Public Service's Four Corners Unit 4 (818 MW), built in 1982, reported a capital cost of $90 million for its baghouse removing 99.8% of PM. Tampa Electric's Big Bend Unit 4 (445 MW), built in 1985, reported a capital cost of $76.8 million for its ESP removing 99.7% of PM. Paradise Unit 1 (704 MW), built in 1983, reported a capital cost of $210 million for its ESP removing 99.9% of PM. The estimated costs for a baghouse at Baldwin Unit 1 in 1985 are within the range of costs for similar facilities at that time, and are therefore not unreasonable.[143]

b. Other Environmental Impacts

No significant environmental impacts would occur from the use of a baghouse. Collected ash from the baghouse would need to be disposed of, but is not considered hazardous waste.

c. Conclusion

I have determined that BACT for particulate matter for Unit 1 in 1985 would have been an emission limit of 0.003 pound/million BTU and the use of a baghouse and 99.6% removal.[144] Compliance would have been monitored using EPA method 5 and an opacity CEMS.

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[141] See report of Dan Mussatti and Larry Sorrels, "Estimated Costs for the Installation of SO_2, NO_x and PM Control Devices at Illinois Power's Baldwin Station," developed in connection with United States v. Illinois Power and Dynegy Midwest Generation, Inc.

[142] Ibid.

[143] Department of Energy, Energy Information Administration (Form EIA-767) for 2000.

[144] See Table 4b for calculations.

C. BACT Determination for Baldwin Unit 2: 1988

Unit 2 is a a cyclone fired boiler and has a gross capacity of 587 MW.[145] Unit 2 began operation in 1973.[146] It was designed to fire up to 267 tons per hour[147] of coal with a heating value of 10,460 BTU per pound.[148]

1. *SO_2 Control*

As of 1988, Baldwin Unit 2 was uncontrolled for emissions of SO_2, and was burning coal with a sulfur content of 3%.[149]

a. Technical Feasibility

Control options for SO_2 control in 1988 were similar to the options available in 1985, as I discussed previously (see Baldwin Unit 2, 1985, above). However, by 1988, powerplant owners had more experience with all the scrubber options. In addition, many new facilities had come on line by 1988 utilizing scrubbers to remove SO2. Over 148 coal fired powerplants with scrubbers were in operation in the U.S. by the end of 1988. Most of these scrubbers were operating at a removal efficiency of 80 to 95%.[150] Outside the U.S. similar increases in scrubber capacity occurred. Most significant is the Preussen Electric Borken 2 and 3 facilities, which started operation in 1988, and which employed scrubbers with a design removal efficiency of 97% of SO_2.[151] Since there was only one powerplant operating at 97%, I continued to analyze scrubber

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[145] Ratings of Illinois Power Company Fossil Fuel Fired Generating Units; Report by Power Technologies, Inc. December, 1987. IPPRO-00151120

[146] Department of Energy, Energy Information Administration (Form EIA-767) for 1985.

[147] Ibid.

[148] Sargent & Lundy Engineers Engineering Data, Unit 3 Baldwin Power Station. IPPRO-0085900

[149] Department of Energy, Energy Information Administration (Form EIA-767) for 1988.

[150] See "Table 30: Flue Gas Desulfurization (FGD) Capacity in Operation at U.S. Electric Utility Plants as of December 1999." This information can be found at website address: http://www.eia.doe.gov/cneaf/electricity/epav2/html_tables/epav2t30p1.html and following pages

[151] See report of William Ellison, PE, Ellison Consultants, "Table 1, FGD Installations," developed in connection with United States v. Illinois Power and Dynegy Midwest Generation, Inc.

options based on 95% control.

By 1988, scrubber technologies were mature. Both scrubbers previously analyzed (i.e. wet limestone and wet lime buffered by magnesium oxide) had been well demonstrated.

b. Cost Analysis

Capital and operating costs for wet limestone and wet lime with magnesium buffering were analyzed for the 1985 scenario. That analysis (see analysis for Unit 1, 1985) showed that wet limestone scrubbing was the less expensive option. The least cost option continues to be wet limestone scrubbing in 1988. Capital costs for the limestone system would be approximately $204 million (1988 dollars). Operating costs would range from $3.8 million and 5.4 million, depending on whether waste from the scrubber system would have been sold or not. When these costs are converted to annualized costs, the annual cost would be approximately $27.1 million. The scrubber system would remove approximately 96,800 tons per year of SO_2. Therefore, the cost effectiveness the limestone FGD system would have been approximately $280/ton.[152]

As with the analysis of scrubbers in 1985, this cost compares very favorably to the cost effectiveness of eighteen powerplants permitted between 1979 and 1999 with BACT requirements for scrubbers. Of those where a dollar per ton cost effectiveness was listed, the range (once converted to 1988 dollars) is $167 to 5092/ton.[153] As also noted above, EPA's 2001 guidance related to presumptive BACT for NO_x at refineries cited $10,000/ton as an upper bound for BACT cost effectiveness. When that value is converted to1988 dollars it becomes $7,149/ton. The estimated costs for wet limestone scrubbing at Baldwin Unit 2 in 1988 is at the low end of the range of these permits and EPA guidance. The cost is therefore not unreasonable.

c. Other Environmental Impacts

Wet scrubbers produce a sludge that may have economic use. If not used, it must be disposed in a landfill. This sludge is not considered hazardous waste. No other significant environmental effect occur due to the use of scrubbers.

d. Conclusion

Based on the above data, I conclude that BACT at Baldwin Unit 2 in 1988 would have been an

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[152] See report of Dan Mussatti and Larry Sorrels, "Estimated Costs for the Installation of SO_2, NO_x and PM Control Devices at Illinois Power's Baldwin Station," developed in connection with United States v. Illinois Power and Dynegy Midwest Generation, Inc.; cost data adjusted based on http://www.enr.com/cost/costcci.asp.

[153] See Table 11, Cost Effectiveness of BACT Determinations for SO_2.

emission rate of 0.30 pound/million BTU,[154] 30 day rolling average, based on the use of a wet limestone scrubber removing 95% of the SO_2 from coal having a sulfur content of 3-3.5%. Compliance with the limit would have been monitored by use of a Continuous Emissions Monitoring System (CEMS).[155]

2. *NO_x Control*

Like Unit 1, as of 1988, Baldwin Unit 2 had no controls for NO_x emissions.[156]

a. Technical Feasibility

For Unit 2 in 1988, I again considered the feasibility of LNBs, OFA, SNCR and SCR. Of these options, LNBs were not technically feasible in 1988, because they have not today been developed for cyclone fired boilers. OFA was also not technically feasible by 1988. While OFA had been used on other types of coal combustion, it had not been used on cyclone fired boilers.[157] SNCR had been demonstrated by 1988 on a number of facilities overseas firing high sulfur coal, as well as many fluidized bed coal fired boilers permitted and under construction in the U.S. using low sulfur coal. By 1988, at least seven coal fired power plants in the U.S. were required to use SNCR to control NO_x.[158] Emissions reductions of approximately 50% were expected at these facilities, and the permits included emissions limits in the range of 0.09-0.15 pounds/million BTU.[159],[160]

With respect to SCR, by 1988, significant additional experience had been gained worldwide in the application of this technology to coal fired boilers. SCR had been installed on at least two

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[154] See Table 8c for calculations.

[155] See 40 C.F.R Part 60, Appendix B, Performance Specification 2.

[156] Department of Energy, Energy Information Administration (Form EIA-767) for 1988.

[157] See report of William Ellison, PE, Ellison Consultants, "Table 1, FGD Installations," developed in connection with United States v. Illinois Power and Dynegy Midwest Generation, Inc.

[158] See PSD permit #s SE 85-01, 85-05, SJ 85-06, SJ 85-07, SJ SE 86-04, SJ 86-08, 86-09.

[159] Ibid.

[160] See Kern County Air Pollution Control District, Engineering Analysis of Mt.Poso/Pyropower Cogeneration Facility, November 1986, page 67. "...an emission rate of 0.092 pound NO_x/MMBTU satisfies NO_x LAER requirement."

cyclone, (or "wet bottom") boilers, as well as many other coal fired powerplants.[161] By 1988, twenty-five coal fired boilers in Japan, six in Germany and two in Austria had begun commercial operation of SCR systems for NO_x control.[162] These installations were across a wide range of boiler size. For example, the German boilers vary in capacity from 153 MWe (Walheim, wet bottom boiler) to 770 MWe (Ibbenbuehren), and burn coal with sulfur contents up to 1.3%.[163] The use of SCR at these boilers achieved NO_x control efficiencies ranging from 67 to 92 percent. Six other facilities were under construction overseas and would begin operation by 1992.[164]

Because all but one of these German facilities had SCR with design NO_x reduction levels of approximately 80% or greater,[165] I have determined that level of reduction was technically feasible in 1988.

b. Cost Analysis

SCR was the top, or most effective, option for available in 1988. Unless it were to be rejected on the grounds of unacceptable environmental or economic cost, SCR would be chosen as BACT. As in the 1985 analysis above, the cost for SCR was estimated using Illinois Power's study[166] for installing SCR on units 1 and 2 in 1990. The costs were then adjusted to 1988 values.[167] These adjustments yield an annualized cost of $22.6 million. SCR would reduce Unit 1 emissions by about 23,604 tons/year, based on a 1.8 pound NO_x/MMBTU inlet concentration and a 66.7

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[161] Ibid.

[162] See ENSR Consulting and Engineering, "Keystone Cogeneration Facility BACT for Nitrogen Oxides, Addendum," June 1990.

[163] See report of William Ellison, PE, Ellison Consultants, "Table 2, SCR Installations," developed in connection with United States v. Illinois Power and Dynegy Midwest Generation, Inc.

[164] Ibid.

[165] See report of William Ellison, PE, Ellison Consultants, "Table 2, SCR Installations," developed in connection with United States v. Illinois Power and Dynegy Midwest Generation, Inc.

[166] See SCR Cost Evaluation for Illinois Power, Baldwin Units 1 & 2, May 17, 1990. Prepared by Burns & McDonnell, Kansas City, MO.

[167] See report of Dan Mussatti and Larry Sorrels, "Estimated Costs for the Installation of SO_2, NO_x and PM Control Devices at Illinois Power's Baldwin Station," developed in connection with United States v. Illinois Power and Dynegy Midwest Generation, Inc.

percent capacity factor, and an SCR system that removes 80% of the inlet NO_x.[168] The annualized cost of an SCR system is estimated to have been approximately $22.6 million. This results in a cost effectiveness of $959/ton.

As in 1985, this cost per ton compares very favorably with relevant PSD permits and cost analysis performed for air quality planning purposes. As noted above, the New Jersey Department of Environmental Protection issued permits in 1990 and 1991 that were based on a cost effectiveness of $13,200/ton. When converted to1988 dollars, the New Jersey permits would require controls at a cost effectiveness of $12,640.[169] Also, as noted above, in 1982 the SCAQMD adopted an air quality management plan[170] establishing control measures to help bring the area into compliance with the NAAQS. For rules projected to be adopted between 1983 and 1986, the cost effectiveness was between $700/ton and $7,600/ton in 1987 dollars. When those values are adjusted to 1988 dollars, the range becomes $713 to $7,750/ton. Lastly, in 2001 EPA issued guidance related to presumptive BACT for NO_x at refineries being modified to meet EPA mandates for making cleaner burning gasoline.[171] That guidance used $10,000/ton as an upper bound for BACT cost effectiveness. When that value is converted to1988 dollars it becomes $7,150/ton. The estimated costs for SCR at Baldwin Unit 2 in 1988 is at the low end of the range of these permits and EPA guidance. The cost is therefore not unreasonable.

c. Other Environmental Impacts

SCR and SNCR use ammonia, which could cause environmental effects if emitted in large amounts. However, ammonia slip (unreacted ammonia emitted to the atmosphere) is limited by design in SCR systems to about 3 ppm, so effects would not be likely to occur. SNCR typically has a higher ammonia slip; as high as 30 ppm. Because of the higher ammonia slip rate for SNCR, SCR would usually be preferred because of its lower other environmental impacts.

d. Conclusion

Based on the analysis above, I conclude that an emission limit of 0.36 pounds/MMBTU, 3 hour average based on the use of SCR with 80% removal was BACT for Unit 2 in 1988. Compliance

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[168] Ibid.

[169] See http://www.enr.com/cost/costcci/asp for cost adjustments.

[170] Final Air Quality Management Plan, 1982 Revision, South Coast Air Quality Management District and Southern California Association of Governments, October 1982.

[171] See memorandum from John S. Seitz, Director, OAQPS, to Air Division Directors regarding BACT and LAER for Emissions of Nitrogen Oxides and Volatile Organic Compounds at Tier 2/Gasoline Refinery Projects, dated January 19, 2001. This information can be found at website address: http://www.epa.gov/rgytgrnj/programs/artd/air/nsr/nsrmemos/t2bact.pdf

with the limit would have been monitored with a CEMS.

3. *Particulate Matter*

As of 1988, Baldwin Unit 2 was operating with an ESP that had demonstrated efficiencies ranging from 93 to 97%, with an apparent downward trend in efficiency.[172]

In order to reduce emissions further, one of the following actions would need to be taken at Baldwin Unit 2:

- Replacement of current ESP with new ESP or baghouse,
- Upgrade of ESP.

a. Technical feasibility

For this analysis, I have again assessed only the option of replacing the ESP at Baldwin with either a new, more efficient ESP or a baghouse. The ESP for Unit 2 was designed for 99% removal efficiency, but had performed at significantly lower removal efficiencies,[173] suggesting that the unit would need significant repair or upgrade. As noted above, Illinois Power's study of PM controls for Unit 1, which is very similar to Unit 2, showed that the least cost option would be replacement, rather than upgrade, of the existing ESP (Illinois Power did not analyze the option of replacing the ESP with a baghouse).[174] Those conclusions should be equally applicable to Unit 2.

i. Baghouse

In 1985, it would have been technically feasible for Illinois Power to substantially improve its particulate control with a baghouse. As of 1988, at least 32 coal fired powerplants had installed baghouses designed to achieve levels of PM less than 0.01 grain/ACF (actual cubic foot).[175] Of

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[172] See EIA Reports numbered IPPRO-0104246; IPPRO-0104275; IPPRO-0104304; IPPRO-0104333; IPPRO-0104370; IPPRO-0104404; IPPRO-0104456; IPPRO-0104457; IPPRO-0104480; IPPRO-0104481; IPPRO-0104503 and IPPRO-0104504.

[173] Department of Energy, Energy Information Administration (Form EIA-767) for 1988.

[174] See Burns and McDonnell report, "Baldwin Unit 1 Electrostatic Precipitator Study" (1991). IPPRO-0058084 through IPPRO-0058136.

[175] See report of William Ellison, PE, Ellison Consultants, developed in connection with United States v. Illinois Power and Dynegy Midwest Generation, Inc.

those 32, many were designed to achieve levels of between 0.001 and 0.005 gr/ACF.[176] An emission rate of .003 gr/ACF is equivalent to 99.7% control at Baldwin Unit 1.[177]

ii. ESP

As of 1982, Illinois Power operated an ESP on Unit 3 with a removal efficiency of approximately 99.4% (see 1982 analysis, above). This alone demonstrates the technical feasibility of an ESP at Baldwin at that removal efficiency.

a. Cost Analysis

Based on a design to remove 99.7% of particulate matter, the annualized cost of installing a new ESP at Baldwin Unit 1 in 1988 is estimated to have been about $20.2 million ($113 million capital cost).[178] A baghouse with similar capabilities would have had an annualized cost of $11.6 million ($55 million capital cost).[179] Since the baghouse would have been vastly less expensive for the same level of emissions reduction, that is the option that I considered for further analysis. The total cost effectiveness of the baghouse would have been $857/ton.

Comparable cost effectiveness values are not available for cyclone fired boilers (which have much lower inlet PM loadings than tangentially fired boilers). However, construction cost data are available for powerplants constructed in the 1988 timeframe. These data show that the estimated construction cost for a baghouse is similar to that of other contemporaneous sources. For example, Northern States Power's Sherburn County Unit 3 (809 MW), built in 1987, reported a capital cost of $73.1 million for its baghouse removing 99.9% of PM. Tampa Electric's Big Bend Plant (445 MW), referenced in my 1985 analysis, is also relevant in 1988. Its capital cost was 76.8 million.[180] The costs for a baghouse at Baldwin Unit 1 in 1988 are therefore note unreasonable.

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[176] See report of William Ellison, PE, Ellison Consultants, developed in connection with United States v. Illinois Power and Dynegy Midwest Generation, Inc.

[177] See Table 4c for calculations.

[178] See report of Dan Mussatti and Larry Sorrels, "Estimated Costs for the Installation of SO_2, NO_x and PM Control Devices at Illinois Power's Baldwin Station," developed in connection with United States v. Illinois Power and Dynegy Midwest Generation, Inc.

[179] Ibid.

[180] Department of Energy, Energy Information Administration (Form EIA-767) for 2000.

b. Other Environmental Impacts

No significant environmental impacts would occur from the use of a baghouse. Collected ash from the baghouse would need to be disposed of, but is not considered hazardous waste.

c. Conclusion

I conclude that an emission limit of 0.003 pound/million BTU based on the use of the use of a baghouse removing 99.7% of PM represented BACT at Baldwin Unit 1 in 1988. Compliance would have been monitored with EPA method 5 and use of an opacity CEMS.

D. BACT Determinations for Baldwin Station: 2002

1. BACT Determination at Baldwin Units 1 and 2

I am analyzing these two units together because they have designs that are virtually identical for the purposes of this analysis. These two units are currently burning coal from the Powder River Basin with a sulfur content of approximately 0.25%. They both also have overfire air installed, as well as infrastructure for SCR, although no catalyst is installed. Units 1 and 2 underwent upgrades to their ESPs in 1999. Although none of the results of these upgrades and changes are enforceable as permit conditions,[181] the SO_2 and NO_x controls IP has employed to date are presumably the result of Illinois Power's need to comply with acid rain (Title IV) provisions of the Clean Air Act.

a. SO_2 Control

To be analyzed together with Unit 3, below.

b. NO_x Control

The available control options are:

1. SCR
2. OFA
3. SNCR
4. Coal or Gas Reburning
5. Optimization system

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[181] Joint Construction and Operating Permit issued February 19, 1999 (EPA 5776); Operating Permit issued January 5, 1996 (IPPRO-0019014); Operating Permit issued December 4, 1998 (IPPRO-0019233); Operating Permit issued June 20, 1996 (IPPRO-0018725); Construction Permit issued April 14, 1998 (EPA 5775); Operating Permit issued June 26, 1997 (IPPRO-0019094).

i. Technical Feasibility

SCR systems are now in wide use in the U.S. and worldwide, and have been applied to meet BACT emission limits for coal fired powerplants since 1990.[182] Reported reduction efficiencies are up to 90%. At least 229 units at coal fired powerplants worldwide, including at least thirteen in the U.S., are now using SCR to control NO_x emissions.[183][184]

OFA has also become a very widely used technology. In fact, Illinois Power installed OFA at Baldwin Units 1 and 2 in approximately 1999.[185] OFA can reduce emissions by as much as 50% in cyclone fired boilers. Illinois Power achieved reductions of about 62 % with its OFA installations.[186]

Reburn is a NO_x control technology that involves diverting a portion of the fuel from the burners to a second combustion area (reburn zone) above the main combustion zone. Additional air is then added above the reburn zone to complete fuel burnout. The reburn fuel can be either natural gas, oil, or pulverized coal; however, most experience to date is with natural gas reburning. There are many technical issues in applying reburn, such as maintaining acceptable boiler performance when a large amount of heat input is moved from the main combustion zone to a different area of the furnace. Utilizing all the carbon in the fuel has been a problem in the past when pulverized coal is the reburn fuel.[187] Notwithstanding these concerns, at least one demonstration project on a cyclone fired boiler showed reburn technology achieving a NO_x reduction of 50%, with minimal

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[182] See, *e.g.* New Jersey Department of Environmental Protection, permit number 01-89-3086, issued on December 26, 1990 to Chambers Cogeneration Limited Partnership.

[183] See "Performance of Selective Catalytic Reduction on Coal-Fired Steam Generating Units," USEPA, June, 1997. This document may be found at website address: http://www.epa.gov/airmarkt/arp/nox/scrfinal.pdf.

[184] See SCR Installations Spreadsheet, EPA Clean Air Markets Division, 2001.

[185] Deposition testimony of Aric Diericx, November 10, 2000.

[186] See "Appendix B-1: Compliance Results for All NOx Affected Units in 2000". This document may be found at website address http://www.epa.gov/airmarkets/cmprpt/arp00/appendixb1200.pdf. The reported emission rate for Baldwin Units 1 and 2 are 0.66 and 0.70 pound per million BTU, respectively. This is more than a 50% reduction compared to the uncontrolled rate of 1.8 pounds/MMBTU.

[187] See U.S. EPA, Office of Air and Radiation, Office of Air Quality Planning and Standards, "Alternative Control Technologies Document NO_x Emissions from Utility Boilers" March 1994. This information can be found at website address: http://www.epa.gov/ttn/catc/dir1/utboiler.pdf.

operational problems.[188]

SNCR has been described earlier. Emissions reductions of up to 80% of NO_x have been demonstrated using SNCR on coal fired boilers.[189]

Optimization systems are new technologies that I have not described previously. Although these systems are often known generically as "neural nets," different manufacturers use various software and hardware. Optimization systems attempt to reduce NO_x and improve boiler efficiency by monitoring a number of parameters, and then providing information to a plant's distributed control system. More than 200 boilers, most of them coal fired, are using an optimization technology. Reductions of as much as 40% are possible with optimization systems.[190]

Some of the above technologies may be used effectively in conjunction with one another, and feasible combinations therefore should be considered. Specifically either SCR or SNCR may follow almost any other NO_x emissions control technology. For example, use of OFA may be followed by an SCR system. OFA and reburning (both coal and gas) are considered to modify the combustion process, while SCR and SNCR are post-combustion processes. Emissions reductions achieved through use of combustion modification followed by SCR or SNCR are multiplicative. In other words, an emission reduction of 50% from an LNB followed by 80% control via SNCR will yield an overall reduction of 90% reduction. One exception to this rule is optimization systems, which operate on the combustion process. Little information is available as to the effect of optimization systems in conjunction with other emissions reductions retrofits.

Because of the high NO_x emission rate of an uncontrolled cyclone fired boiler (compared with tangentially fired boilers), effective NO_x emissions control requires both combustion control as well as post combustion control. Illinois Power evaluated the options for controls at units 1 and 2 in the early 90s and concluded that OFA would be a more cost effective option than reburning;[191] for that reason I did not analyze reburning further. Therefore, the options available are SCR or SNCR and OFA together, or OFA alone (*i.e* with no additional control). All three options are

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[188] See "Demonstration of Coal Reburning for Cyclone Boiler NO_x Control," McDermott International Inc, 2001. This information can be found at website address: http://www.mtiresearch.com/expernce.html#Demonstration of Coal Reburn.

[189] See report of William Ellison, PE, Ellison Consultants, "Table 2, SCR Installations," developed in connection with United States v. Illinois Power and Dynegy Midwest Generation, Inc.

[190] See "What's New in the Power Industry," World Bank, 2001, found at website address http://www.worldbank.org/html/fpd/em/power_industry10.htm.

[191] See Illinois Power "Gas at Baldwin" report, dated May 1990 (IPPRO - 0003712).

amenable to the use of an optimization system.

The next step is to determine an appropriate emission limit. In order to determine the emission limit, I considered both the effectiveness of the controls as well as the fact that this would be a retrofit to a thirty year old powerplant.[192] Based on Illinois Power's experience to date on Units 1 and 2, I determined that the OFA system, operating together with the optimization system, would easily achieve a 50% reduction. An SCR system is capable of controlling an additional 90%, and perhaps as high as 95% of NO_x. In determining the appropriate emission limit, I considered the potential emissions reductions achievable with each technology and the fact that this would be a retrofit, rather than a new installation.

I also reviewed the proposed emission rates and permitted emission rates for recently announced or permitted coal fired powerplants.[193] Most of these powerplants are subject to the BACT requirement under PSD. All of these plants would emit less than 0.15 pound/million BTU, because that is the maximum allowed under the NSPS.[194] However, cyclone fired boilers without controls emit far more NO_x than other coal burning technologies, and of the currently proposed plants would be cyclone fired boilers. Therefore, it is difficult to make a direct comparison between recent BACT levels and the appropriate level for Baldwin Units 1 and 2. It is, instead, necessary to derive a BACT emission limit for Baldwin Units 1 and 2 based on the performance of demonstrated NO_x control technologies.

Based on the performance of the technologies discussed above, and the reductions achievable from these technologies, the "top" option for NO_x control for Units 1 and 2 would be the combined use of overfire air, an optimization system, and SCR, as this combination would provide the greatest control efficiency. The overfire air system would reduce emission by at least 50%, and SCR could reduce emissions by a further 90%. I assumed a combined removal effectiveness of approximately 92% from use of OFA and SCR. This rate assumes that OFA will reduce emissions between 60 and 70%, and SCR between 80 and 90%. As I discussed above, I did not assign a specific amount of emission reduction to the optimization system. Rather, the optimization system should improve the overall performance and cost effectiveness of NO_x control. On the basis of IP's uncontrolled emission rate of 1.8 pound/million BTU, this combination of controls could result in removal of 92% of emissions, resulting in a controlled emission rate of 0.14 pound/million BTU. This combination, i.e. OFA, SCR and optimization system, is the most effective control option available for NO_x emissions control at Baldwin Units 1 and 2 today.

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[192] See PSD Appeal No. 94-1 (Masonite Corporation), 5 EAD 551, page 10. This document may be found at website address http://www.epa.gov/eab/eabpsd.htm.

[193] See National Coal-Fired Utility Projects Spreadsheet, EPA Region 7, March 1, 2002.

[194] See 40 C.F.R. § 60.40a (1979), "Standards of Performance for Electric Utility Steam Generating Units for Which Construction is commenced after September 18, 1978."

ii. Other Environmental Effects

Most of the options for NO_x emissions control would have no significant other environmental effects. SCR and SNCR use ammonia, which could cause environmental effects if emitted in large amounts. However, ammonia slip is limited by design to about 3 ppm, so effects would not be likely to occur.

iii Cost Effectiveness

The annual cost for SCR, OFA and an optimization system would be approximately $8.4 million for Unit 1 and $8.7 million for Unit 2.[195] Based on a controlled rate of 0.14 pounds/MMBTU (controlling approximately 10,000 TPY of NO_x), the cost effectiveness of these controls would be $877 and 842/ton for Units 1 and 2, respectively.[196] The costs associated with the combination of controls is conservative because I included the cost of installing OFA systems at Units 1 and 2, even though both already have OFA installed.

This compares very favorably to the cost points I have used throughout the report. For example, as noted above, the New Jersey Department of Environmental Protection based on a cost effectiveness of $13,200/ton (in 1990/91 dollars). EPA's guidance related to presumptive BACT for NO_x at refineries used $10,000/ton as an upper bound for BACT cost effectiveness. In comparison to these benchmarks, the cost of SCR, OFA and an optimization system is not unreasonable.

iv. Conclusion

Based on all of the above factors, I have determined that an emission limit of 0.14 pound/million BTU, 30 day rolling average, based on use of the combination of OFA, SCR capable of 90% control, and an optimization system, represents current day BACT for emissions of NO_x at Baldwin Units 1 and 2. Compliance with this limit would be monitored via use of a CEMS.

c. Particulate Matter

i. Technical Feasibility

Control technologies available for particulate control are essentially the same as those discussed earlier: ESPs and baghouses. Two kinds of baghouses are currently available for consideration for coal fired powerplants: pulse-jet baghouses and reverse air baghouses. The difference

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[195] See report of Dan Mussatti and Larry Sorrels, "Estimated Costs for the Installation of SO_2, NO_x and PM Control Devices at Illinois Power's Baldwin Station," developed in connection with United States v. Illinois Power and Dynegy Midwest Generation, Inc.

[196] See Table 3d for calculations.

between the two technologies relates to the way in which captured particles are removed from the bags after the bags collect the particles. Emission rates for new facilities controlled by ESPs and baghouses range from about 0.015 to 0.020 pound/MMBTU. These emission rates reflect control of approximately 99.7% (see also PM analyses, 1985 and 1988).[197]

ii. Other Environmental Impacts

Neither baghouses nor ESPs would have any significant other environmental effects. The material collected in baghouses and ESPs is not considered hazardous, and may be disposed of in accordance with regulations for non-hazardous waste.

iii. Cost Analysis

I analyzed the cost of complying with the lowest limit currently proposed for new powerplants: 0.015 pound/million BTU. As discussed in the earlier timeframes, (see 1985 and 1988 analyses above), a baghouse was the least expensive option. The same conclusion was reached for the present day. Therefore, only options for using a baghouse to control emissions were analyzed. Of the two baghouse options, the pulse jet design is less expensive, with a initial capital investment of $46.1 million, and annual operating costs of approximately $1.1 million. The total annualized cost for a pulse-jet baghouse would be $8.3 million.[198]

I estimate that the total cost effectiveness would be $302/ton of particulate removed (assuming that the baghouse would replace the current ESP).

As I have noted earlier, comparable cost effectiveness values are not available for cyclone fired boilers (which have much lower inlet PM loadings than tangentially fired boilers). However, construction cost data are available for powerplants constructed in the 2002 timeframe. These data show that the estimated construction cost for a baghouse is similar to that of other contemporaneous sources. For example, Public Service Electric & Gas Company's Mercer Unit (326 MW, about half the size of the Baldwin units), built in 1994, reported a capital cost of $38.9 million for its ESP removing 99.8% of PM.[199] Data reported from powerplants constructed earlier, discussed in the 1985 and 1988 timeframes, also show that the capital cost estimated for a new pulse-jet baghouse at Baldwin Units 1 and 2 is at the low end compared to these other powerplants. The cost is therefore not unreasonable.

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[197] See National Coal-Fired Utility Projects Spreadsheet, EPA Region 7, March 1, 2002.

[198] See report of Dan Mussatti and Larry Sorrels, "Estimated Costs for the Installation of SO_2, NO_x and PM Control Devices at Illinois Power's Baldwin Station," developed in connection with United States v. Illinois Power and Dynegy Midwest Generation, Inc.

[199] Department of Energy, Energy Information Administration (Form EIA-767) for 2000.

iv. Conclusion

I therefore conclude that an emission rate of 0.006 pounds per million BTU[200] based on use of a 99.6% efficient pulse jet baghouse is BACT for particulate matter at Baldwin Units 1 and 2. Monitoring would be via EPA method 5, and triboelectric broken bag monitors.

2. *BACT Determination for Baldwin Unit 3*

Unit 3 is also currently burning coal from the Powder River Basin with a sulfur content of approximately 0.25%. Unit 3 was retrofitted with a low NO_x burner in 1994.[201] The ESP was upgraded in 2000.[202] Although none of the results of these upgrades and changes are enforceable as permit conditions,[203] the SO_2 and NO_x controls IP has employed to date are presumably the result of Illinois Power's need to comply with acid rain (Title IV) provisions of the Clean Air Act.

a. SO_2 Control (applicable to Units 1, 2 and 3)

The following options are available for SO_2 control:

b. Wet Limestone Scrubbing
c. Wet Lime scrubbing buffered by Magnesium Oxide
d. Dry Scrubbing.

i. Technical Feasibility

I have previously addressed the technical feasibility of the two wet scrubbing options. To summarize, both wet scrubbing options are currently available, and demonstrated with removal efficiencies of up to 97%.

In the dry scrubbing process, flue gas is sent to a spray dryer absorber (SDA). In the SDA, a fine mist of lime slurry is sprayed into the flue gas. Heat from the flue gas evaporates the moisture in the slurry cloud while the alkaline slurry simultaneously absorbs the SO2in the flue gas. The result is the conversion of the calcium hydroxide component of the slurry into a fine powder of calcium/sulfur compounds, and lowering of the flue gas temperature. Removal efficiencies of up

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[200] See Table 4d for calculations.

[201] IP Permit Application dated January 19, 1993. IPPRO-0032541.

[202] Operating Permit issued June 26, 1997. IPPRO-0019094.

[203] Ibid., and IP Permit Application dated January 19, 1993. IPPRO-0032541.

to 90% with PRB coal have been demonstrated.[204]

Illinois Power has now been using PRB coal since 1999, which, for the purpose of this analysis, has a sulfur content of approximately 0.6%.A large number of facilities are burning western coal and scrubbing 90% or greater, using one of the above technologies. Several plants using coal with less than 1% sulfur coal are removing 95% of the SO_2 from the flue gas. For example, Bonanza Unit 1-1 (owned by Deseret Generation and Transmission Co-op) is using coal with a 0.5% sulfur, and removing 95% of the emitted SO_2 with a wet limestone scrubber.[205]

All three scrubbing technologies are technically feasible and available. Both wet scrubbing technologies have been demonstrated to remove over 95% of SO_2 from western coal, and up to 97% of SO_2 from eastern, high sulfur coals. Dry scrubbing has been demonstrated to remove up to 90% of SO_2 from western coal. Wet scrubbing is therefore the "top," or most effective option.

ii. Other Environmental Impacts

Wet scrubbers produce a sludge that requires may have economic use. If not used, it must be disposed in a landfill. This sludge is not considered hazardous waste. Dry scrubbers produce a powder that may also be disposed in a landfill, and is also not considered hazardous waste. No other significant environmental effect occur due to the use of scrubbers.

iii. Cost Effectiveness

The capital cost to install a wet limestone scrubber[206] today would be $71.4 million at each of Baldwin units. Annual operating costs for Units 1 and 2 would be $8.0 to 8.3 million per unit; annual operating costs for Unit 3 would be $8.4 to 8.7 million (the difference reflects the higher assumed capacity factor for Unit 3). Total annualized cost would be approximately $15.9 million per unit for Units 1 and 2, and $16.3 million for Unit 3.[207] Assuming a removal efficiency of

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[204] See "Retrofitting Lime Spray Dryers at Public Service Company of Colorado," R. Telesz et. al., Presented to Power-Gen International 2000, November 200. This document may be found at website address: http://www.babcock.com/pgg/tt/pdf/BR-1707.pdf.

[205] See "Table 30: Flue Gas Desulfurization (FGD) Capacity in Operation at U.S. Electric Utility Plants as of December 1999." This information can be found at website address: http://www.eia.doe.gov/cneaf/electricity/epav2/html_tables/epav2t30p1.html and following pages.

[206] Prior analyses (see e.g. 1982 analysis) offered in this report establish this technology as the lower cost wet scrubbing option, compared to wet lime scrubbing buffered magnesium oxide.

[207] See report of Dan Mussatti and Larry Sorrels, "Estimated Costs for the Installation of SO_2, NO_x and PM Control Devices at Illinois Power's Baldwin Station," developed in connection with

95%, the cost effectiveness, therefore, would be approximately $652/ton for Units 1 and 2, and $570/ton for Unit 3.[208]

In order to ensure that the costs estimated for the scrubber are not excessive, I reviewed other BACT determinations and EPA policy documents. I reviewed the cost effectiveness of eighteen powerplants permitted between 1979 and 1999 with BACT requirements for scrubbers. Of those where a dollar per ton cost effectiveness was listed, the range (once converted to 2001 dollars) is $234 to 7129/ton.[209] Also, as noted, EPA's guidance related to presumptive BACT for NO_x at refineries used $10,000/ton as an upper bound for BACT cost effectiveness. The estimated costs for wet limestone scrubbing at the Baldwin powerplant today is toward the low end of the range of these permits and EPA guidance. The cost is therefore not unreasonable.[210]

iv. Conclusion

Based on the above information, I have determined that BACT for SO_2 at Baldwin station today is an emission rate of 0.095 pounds per million BTU based on 95% scrubbing and assuming use of coal with 0.6% sulfur.[211] Compliance with this limit would be monitored with a CEMS.

b. NO_x Control

The available control options are:

1. LNB
2. SCR
3. OFA
3. SNCR
4. Coal or Gas Reburning
5. Optimization system

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[208] See Table 8d and 8e for calculations.

[209] See Table 11, Cost Effectiveness of BACT Determinations for SO_2. Most of the higher cost effectiveness values attach to facilities burning lower sulfur coal, while lower cost effectiveness correlates to facilities burning higher sulfur coal.

[210] The cost estimate presented here may, in fact, be conservative. Some literature suggests that SO2 scrubber costs have recently gone down. See "Cost of SO2 Scrubbers Down to $100/KW, Douglas Smith, Senior Editor, Power Engineering, September, 2001.

[211] Calculated by using a controlled emission rate of 533 pound/hr and 5587 million BTU/hr.

i. Technical Feasibility

As with Units 1 and 2, several NO_x control options may be used singly or in combination at Baldwin Unit 3. The same options discussed above as currently feasible for NO_x control on Units 1 and 2 are technically feasible and demonstrated for use on Unit 3. In addition, as I discussed in the 1982 time frame, low NO_x burners are also technically feasible and available for tangentially fired boilers such as Baldwin's Unit 3. In fact, Illinois Power installed a low-NO_x burner in Unit 3 in 1994. Emission rates from IP's 1994 installation were about 0.3 pound/million BTU[212]. Emission rates from LNBs have improved dramatically since the 1994 installation. At least three manufacturers have demonstrated LNBs that attain NO_x emission rates around 0.15 pound/million BTU.[213,214,215] OFA is often an integral part of the design of newer LNBs (in fact, the currently installed LNBs at Unit 3 include integral OFA[216]), or may be added in a location near the burner in the boiler.[217] In addition to LNBs, SCR or SNCR may be used as a post-combustion control. Most new coal fired powerplants that are permitted with SCR also use combustion controls such as LNBs.[218] They may also use optimizations systems to enhance boiler efficiency and reduce NO_x.

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[212] See "Emissions Data and Compliance Reports," USEPA. These data may be found at website address: http://www.epa.gov/airmarkets/emissions/index.html

[213] Tangential Low NO_x System at Reliant Energy's Limestone Unit 2 Cuts Texas Lignite, PRB and Pet Coke NO_x, Ron Pearce, Reliant Energy and John Grusha, Foster Wheeler Energy Corporation, May 30, 2001.

[214] Maximize PRB Coal Usage in Conjunction with In-Furnace NO_x Solutions to Minimize Cost of NO_x Compliance, James Topper, Herb Blue, Jim Pomaranski, Consumers Energy, Ed Rebula, Robert Lewis, ALSTOM Power, undated.

[215] "4 X 550 MWe Boiler Operating Experience at 0.15 lb/MMBTU NO_x Emission Level Firing a Broad Range of Coals," A.D. La Rue et. al., Presented at EPRI-DOE-EPA Combined Utility Air Pollutant Control Symposium, August 1999. This document can be found at website address:http://www.babcock.com/pgg/tt/pdf/BR-1682.pdf.

[216] Deposition testimony of Aric Diericx, November 10, 2000.

[217] See "B&W's Experience Reducing NO_x Emissions in Tangentially-Fired Boilers–2001 update," A. Kokkinos et. al., Presented to Power-Gen International 2001, December 2001. This document may be found at website location: http://www.babcock.com/pgg/tt/pdf/BR-1726.pdf.

[218] See, eg, "PREVENTION OF SIGNIFICANT DETERIORATION CONSTRUCTION PERMIT 888 REVIEW DOCUMENT," issued to Kansas City Power and Light for the Hawthorn Generating Station.

Just as with Units 1 and 2, some of the above technologies may be used effectively in conjunction with one another, and feasible combinations therefore should be considered. Specifically either SCR or SNCR may follow almost any other NO_x emissions control technology.

Several powerplants have recently been built or modified with a combination of LNBs and SCR. For example, the Chambers Cogeneration facility, an new plant permitted in 1990, has both LNBs and SCR,[219] as does the Hawthorn facility, a new plant permitted in 2001.[220]

The currently installed LNB at Unit 3 achieves levels of about 0.3 pound/million BTU NO_x. With the additional use of an SCR system removing 90% of the NO_x exiting the burner, emissions of 0.04 pound/million BTU are readily achievable using the current LNB. Replacement of the current LNB with a state-of-the-art LNB would, together with the use of SCR, allow Unit 3 to reach an emissions level of 0.015 pounds/MMBTU NO_x. However, since this is a retrofit, rather than a new powerplant, it may be difficult to achieve the lowest levels reached by new plants. Therefore, I would conclude that an emission rate of 0.02 pounds/MMBTU would represent the most effective level of NO_x. control currently achievable at Baldwin Unit 3. A limit of 0.02 pound/million BTU appears to be somewhat lower than limits in recently issued PSD permits for coal fired powerplants.[221] However, as I have shown above, it is readily achievable using currently available controls (i.e. SCR, LNB and optimization). For example, the AES Somerset plant in New York, a 675 MW boiler, has reduced its emissions to 0.05 pounds per million BTU, a 90% reduction using only SCR.[222]

ii. Other Environmental Effects

Most of the options for NO_x emissions control would have no significant other environmental effects. SCR and SNCR use ammonia, which could cause environmental effects if emitted in

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[219] See New Jersey Department of Environmental Protection, permit number 01-89-3086, issued on December 26, 1990 to Chambers Cogeneration Limited Partnership.

[220] See "PREVENTION OF SIGNIFICANT DETERIORATION CONSTRUCTION PERMIT 888 REVIEW DOCUMENT," issued to Kansas City Power and Light for the Hawthorn Generating Station.

[221] See National Coal-Fired Utility Projects Spreadsheet, EPA Region 7, March 1, 2002.

[222] See Selective Catalytic Reduction Retrofit of a 675 MW Boiler at AES Somerset and Update of SCR Retrofit on a 675MW Boiler at AES Somerset, Nischt et al, Presented to ICAC NO_x Forum, March 2000, and to ASME Joint Power Generation Conference, July 2000. These documents can be found at web site addresses http://www.babcock.com/pgg/tt/pdf/BR-1698.pdf . http://www.babcock.com/pgg/tt/pdf/BR-1703.pdf.

large amounts. However, ammonia slip is limited by design to about 3 ppm, so effects would not be likely to occur.

iii. Cost Effectiveness

The top BACT option be the use of LNBs, SCR, and an optimization system. The annualized cost of an SCR system at Baldwin Unit 3 today would be $8.3 million.[223] This cost is higher than the estimated cost for an SCR system at Units 1 and 2 because those two units already have significant portions of the necessary SCR infrastructure installed, while Unit 3 does not.[224,225] The annualized cost of new LNBs would be $1.5 million, and the annualized cost of an optimization system would be $18,000.[226,227] The total annualized cost would be $9.8 million, and would reduce approximately 3,900 TPY (this reduction is substantially smaller than potential reductions at Units 1 and 2 because Units 1 and 2 have a substantially larger uncontrolled NO_x emission rate). The cost effectiveness of this combined option would be $2539/ton.[228]

The costs of achieving 0.02 pound/MMBTU are well within the range of costs estimated in recent PSD permits for coal fired powerplants. For example, coal fired powerplants permitted since 1990 have been required to install controls with predicted cost effectiveness that ranges from $1690 (in 1999) to $13,196/ton (in 1990).[229]

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[223] See report of Dan Mussatti and Larry Sorrels, "Estimated Costs for the Installation of SO_2, NO_x and PM Control Devices at Illinois Power's Baldwin Station," developed in connection with United States v. Illinois Power and Dynegy Midwest Generation, Inc.

[224] Ibid.

[225] Deposition testimony of Aric Diericx, November 10, 2000.

[226] See report of Dan Mussatti and Larry Sorrels, "Estimated Costs for the Installation of SO_2, NO_x and PM Control Devices at Illinois Power's Baldwin Station," developed in connection with United States v. Illinois Power and Dynegy Midwest Generation, Inc.

[227] Information from manufacturers of these systems show that these systems often yield both net cost savings and NO_x emission reductions. See "Full Scale Implementation Results for GNOCIS (tm) Plus," George Warriner, URS Corporation, Steve Logan, Southern Company Services, Steve Pascoe, Powergen, James Noblett. Presented at the USDOE-EPRI combined Power Plant Air Pollution Control Symposium, August, 2001. "At some plants, lowering NO_x can be done simultaneously with increasing efficiency."

[228] See Table 3e for calculations.

[229] See Table 10, BACT Cost Effectiveness for NO_x Controls.

iv. Conclusion

I have determined that BACT for NO_x emissions at Baldwin Unit 3 today is an emission limit of 0.020 pound/million BTU and use of LNBs, an optimization system, and the use of SCR. Illinois Power would be able to request that this limit be raised as high as 0.04 pounds/MMBTU if they could demonstrate that 0.020 is not achievable. I would provide this flexibility because this is a retrofit, and therefore more difficult. Compliance with this limit would be monitored with a CEMS.

c. Particulate Matter

Control technologies available for particulate control are the same as those discussed earlier, with improvements in efficiency and reliability. Emission rates for new facilities controlled by ESPs and baghouses range from about 0.015 to 0.02 pound/MMBTU.[230] Illinois Power upgraded its ESP in 1999 as part of its preparation to begin burning PRB coal.[231] As I discussed in the 1982 case above, the original performance of Unit 3 was far better than the performance of Units 1 and 2. Although we currently have no data about the current performance of Unit 3's ESP, it appears that the original design, together with the upgrade, may be capable of meeting a limit of 0.015, the lowest limit currently set for BACT.

However, I evaluated the cost of a replacement PM control device, in order to determine what the cost might be if the Unit 3 ESP cannot perform at the necessary level to meet BACT. Assuming an emission rate of 0.015 pound/MMBTU, the capital cost of a new baghouse at Baldwin Unit 3 would be $43.8 million, and the annualized cost would be approximately $10 million . The cost effectiveness of that baghouse would be $69/ton. This is similar to other recently permitted powerplants. For example, the cost estimated for the Chambers Works Cogeneration Project for PM control (to 0.3 pound/MMBTU) in 1989 was $78/ton.[232] More recently, the KCP&L Hawthorn Unit 5 permit application proposed use of a baghouse with a cost effectiveness of $82/ton.[233] However it is unlikely that Illinois Power would be required to incur these costs, in that Illinois Power could improve the performance of the ESP by adding a field or a "polishing" baghouse, likely at a substantially lower cost than a new device.

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[230] See National Coal-Fired Utility Projects Spreadsheet, EPA Region 7, March 1, 2002.

[231] Deposition testimony of Aric Diericx, November 10, 2000.

[232] See Best Available Control Technology Analysis for Keystone Cogeneration Facility, Bechtel Power Corporation, October, 1989.

[233] See Prevention of Significant Deterioration Construction Permit Application: Replacement of Unit 5 at the Hawthorn Generating Station, Burns and McDonnell, May 1999.

Conclusion

I therefore have determined that BACT for PM at Baldwin Unit 3 is an emission limit of 0.015 pound/million BTU, based on use of an ESP or baghouse. Compliance would be monitored with a CEMS.

Desert Rock Energy Co., PSD Appeal 08-03
Conservation Petitioners' Exhibits

EXHIBIT 29

27

BEFORE THE PUBLIC SERVICE COMMISSION

In re: Florida Power & Light Company's Petition to Determine Need for FPL Glades Power Park Units 1 and 2 Electrical Power Plant
______________________________________/

DOCKET NO.: 070098-EI

DIRECT TESTIMONY OF

RICHARD C. FURMAN

ON BEHALF OF

THE SIERRA CLUB, INC.

SAVE OUR CREEKS

FLORIDA WILDLIFE FEDERATION

ENVIRONMENTAL CONFEDERATION OF SOUTHWEST FLORIDA

ELLEN PETERSON

MARCH 7, 2007

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Table of Exhibits

I. BACKGROUND AND WORK EXPERIENCE

Q. Please State Your Name and Address for the Record.

A: My name is Richard C. Furman. My address is 10404 S.W. 128 Terrace, Perrine, Florida 33176.

Q: What Is Your Occupation?

A: I am a retired consulting engineer, and I volunteer my time to advise utilities, government agencies, environmental groups and the public about the potential benefits of using coal gasification technologies. I have testified in previous permit hearings for proposed coal plants concerning emission control technologies, applicable emission regulations and alternative technologies concerning Mercury, NO_x, SO_2, particulate and CO_2 emissions and their associated costs.

Q: How Long Have You Been Retired?

A: Since February 2003.

Q: What Was Your Occupation Before You Retired?

A: During my entire engineering career, I have worked on new energy technologies, alternative fuels for power plants, and pollution control for power plants. Prior to my retirement, I was an independent consulting engineer for 22 years to various utility companies, government agencies, process developers and research organizations on the development, technical feasibility and application of new energy technologies and alternative fuels for power plants.

Q: What Did You Do Before You Were An Independent Consulting Engineer?

A: Prior to my work as a consulting engineer, I managed Florida Power & Light's coal conversion program and fuels research and development program, which included the first conversion of a 400 megawatt (400MW) power plant from oil to a coal-oil mixture to reduce oil consumption after the second oil embargo. Prior to this, I directed the engineering study for the conversion of New England Electric's Brayton Point Power Plant, which was the first major conversion of a power plant from oil to coal after the first oil embargo.

My first engineering job was working for Southern California Edison Company to modify their power plants for two-stage combustion to reduce nitrogen oxide emissions in 1969.

Q: Please Summarize Your Formal Education.

A: I received my B.S. in Chemical Engineering from Worcester Polytechnic Institute in 1969 and a M.S. in Chemical Engineering from Massachusetts Institute of Technology in 1972. I was a researcher at MIT for the book entitled New Energy Technologies by Hottel and Howard. After researching for this book, I decided to do my Master's thesis on coal gasification because of its potential as a future energy source and its environmental benefits. My Master's thesis at MIT was entitled Technical and Economic Evaluation of Coal Gasification Processes. I was also a teaching assistant at MIT for the courses of Principles of Combustion and Air Pollution and Seminar in Air Pollution Control. A copy of my resume is attached as Exhibit RCF-1.

Q: How Does Your Education and Experience Prepare You to Provide Expert Testimony in this Case?

A: Both my education and work have required an in-depth understanding of past, present and new forms of energy technologies that can be used for power plants. My education and work experiences also involved an in-depth understanding of all the various fuels for power plants including the different types of coals, fuel oils, natural gas, petroleum coke, synthesis gas, biomass and refinery wastes. My graduate education and subsequent work experiences have provided me with a detailed understanding of the techniques and costs for controlling power plant pollution including mercury, NO_x, SO_2, CO, particulate matter and CO_2 emissions. My prior work for 3 major electric utililty companies allowed me to make use of this knowledge to help develop and utilize new fuels and emission control technologies for power plants. My current volunteer experience allows me to keep informed about the latest developments in new energy technologies, coal gasification technologies, fuels for power plants, techniques for controlling power plant emissions, costs associated with the application of these technologies for power plants and the development of new technologies that may be applicable to power plants.

II. SUMMARY OF TESTIMONY

Q: What Is Your Expert Opinion About the Proposed Plant?

A: My testimony shows that an IGCC plant in Florida can provide electricity at a lower cost than the proposed ultra-supercritical pulverized coal plant. Many utilities around the country are choosing IGCC plants due to IGCC's much lower emissions of all pollutants and its capability to capture CO_2. My testimony shows that an IGCC plant can eliminate between 50 – 90 % of the air pollution that the proposed plant will emit. Various studies have shown that IGCC plants can capture CO_2 at much lower costs than pulverized coal plants. Comparisons of recent permit applications for IGCC plants versus the proposed plant show significantly lower emissions for the IGCC plants. The Clean Air Act specifies that gasification should be evaluated to determine the Best Available Control Technology (BACT).

The additional value of an IGCC plant is its ability to use various fuels including coal, petroleum coke, natural gas, biomass and waste materials. This will enable IGCC plants to respond to future changes in fuel costs and changes in environmental regulations. This will provide significant cost savings during the life of the IGCC plants. The modular design of IGCC plants provides additional system reliability, increased efficiencies, fuel flexibility and any possible size.

Commercial IGCC plants have been in operation in the U.S. for more than 10 years. Tampa Electric Company has announced that they will build an additional 630 MW IGCC plant for operation in 2013. Chuck Black, the president of Tampa Electric Company, was quoted in Time Magazine (November 2006) as saying "it's our least cost-generating resources, so we count on it and use it every day as part of our system". Today there are approximately 130 gasification plants worldwide that produce fertilizers, fuels, steam, hydrogen and other chemicals, and electricity. Of these 130 plants, fourteen are IGCC plants. These IGCC plants have a capacity of 3,880 MW(net) and have almost one million hours of operation..

The 510 MW and 545 MW IGCC plants that started operation in Italy in 2000 and 2001 have demonstrated that IGCC plants can be built with more than one gasifier and operate with more than 90% availability without a spare gasifier. All 4 of GE's coal gasification plants that where recently built in China have been operating at greater than 90% reliability for the past 3 years. These examples demonstrate that IGCC plants can operate at the 90% availability level required by electric utilities for base load plants.

Large size IGCC plants can be built by using multiple gasifiers. This improves system reliability, increases efficiencies and provides fuel flexibility. The Nuon utility in The Netherlands and Hunton Energy Group in Texas have announced plans to build 1200 MW IGCC plants using multiple gasification "trains" and multiple combined-cycle units.

A recent DOE report lists 28 IGCC projects that are planned in the U.S. by utilities and independent power producers.

The Great Plains Synfuels Plant has been gasifying coal since 1984 to produce synthetic natural gas. It produces enough synthetic natural gas to be able to supply the fuel for 1000 MW of combined-cycle power plants. Since 2000 this gasification plant has been capturing its CO_2 and transporting it 205 miles by a new pipeline where it is sequestered underground and used for enhanced oil recovery. This demonstrates that CO_2 can be captured, transported and sequestered from a commercial gasification plant. No method of CO_2 capture is commercially available or economically viable for the proposed pulverized coal power plant.

The Eastman Chemical Company has been removing the mercury from their gasification plant for more than 20 years. Recent testing indicates that the mercury levels in the cleaned gas are at non-detectable levels.

IGCC plants produce much less solid wastes and less potential for ground water contamination than the proposed pulverized coal plant.

IGCC plants use 30% to 40% less water than pulverized coal plants.

III. PULVERIZED COAL COMBUSTION AND GASIFICATION TECHNOLOGIES

Q. What are the Differences Between Combustion and Gasification?

A: It is important to understand the difference between combustion which is used in a coal power plant and coal gasification which is used in an IGCC plant. Exhibit RCF-2 shows the differences between combustion and gasification. The coal boiler operates at 1800 F and atmospheric pressure. The coal gasifier operates at 2600 F and 40 atmospheres pressure. The flow meters show the pounds of material that need to be processed for the same amount of electricity. Prior to gasification the nitrogen is separated from the air and the oxygen alone is used in the gasifier. Therefore for the same amount of electricity the gasifier produces 173 pound of synthesis gas versus 1000 pounds of exhaust gas from the boiler. Since the gasifier operates at higher pressure there is also a much smaller volume of gas that needs to be treated for pollutants and therefore the size of the equipment and capital cost is much smaller. The exhaust gas volume that needs to be treated from a coal boiler is 160 times larger than the volume of the synthesis gas that can also be cleaned of pollutants. The form of the pollutants from the gasifier makes it possible for very efficient recovery of potential pollutants using proven commercially available equipment that is operating in the natural gas and petrochemical industries. Proven commercially available technologies are <u>not</u> presently available for the proposed new coal boilers for mercury and CO_2. This is one of the main reasons that we need to use gasification.

Q. What Is Integrated Gasification Combined Cycle (IGCC)?

A. Integrated Gasification Combined Cycle (IGCC) is the efficient integration of the coal gasification process with the pre-combustion removal of pollutants and the generation of electricity using a combined cycle power plant. Due to the high pressure and low volume of the concentrated synthesis gas that is produced it is capable of higher levels of pollutant removal at lower costs than pulverized coal (PC) combustion.

Exhibit RCF-3 shows the various parts of an IGCC plant that will be described.

IGCC is a method of producing electricity from coal and other fuels. In an IGCC plant, coal is first converted to synthesis gas (also called syngas) composed primarily of hydrogen, carbon monoxide and carbon dioxide. After removing particulate matter, sulfur, mercury and other pollutants, the cleaned syngas is combusted in a combined-cycle power plant to produce electricity.

In the first step of the IGCC process, coal is slurried with either water or nitrogen and enters the gasifier. It is mixed with oxygen, not air, which is provided to the gasifier from an air separation unit. The coal is partially oxidized at high temperature and pressure to form syngas. The syngas leaves the gasifier, while the solids are removed from the bottom of the gasifier. The operating conditions in the gasifier vitrify the solids. In other words, the solids are encased in a glass-like substance that makes them less likely to leach into groundwater when disposed of in a landfill as compared to solid wastes from a conventional coal plant.

After leaving the gasifier, the syngas undergoes several clean-up operations. Particulate matter is removed. Next, a carbon bed can be used to take out mercury. Finally, sulfur (in the form of H2S) is removed from the syngas in a combination of steps that usually involve hydrolysis followed by an adsorption operation using MDEA (methyldiethanolamine) or Selexol. The H2S that is removed from the syngas is usually converted into elemental commercial-grade sulfur using a Clauss plant.

The clean syngas enters a combustion turbine where it is burned to produce electricity. The heat from the exhaust gases is captured in a heat recovery steam generator (HRSG) and the resulting steam is used to produce more electricity. The combustion turbine, combined with the HRSG, is the same configuration commonly used for natural gas combined cycle (NGCC) plants. In Europe and Japan, some IGCC units have installed selective catalytic reduction (SCR) to control nitrous oxides (NO_x) emissions from the turbine, but in the United States, NO_x emissions at existing IGCC plants have been reduced with diluent injection only.

Q: What are the Other Advantages of Using Gasification Plants?

A: Gasification, which is also called Partial Oxidation, can use a wide range of fuels and can produce a wide range of products as shown in Exhibit RCF-4.

The fuel flexibility of gasification is demonstrated by its ability to use all types of coal, petroleum coke, biomass, refinery wastes, and waste materials. The synthesis gas that is produced consists of mainly carbon monoxide (CO) and hydrogen (H2) which are used as the raw materials to produce (or synthesis) a wide range of chemicals. This synthesis gas can also be used as fuel directly for a combined cycle power plant called an IGCC (Integrated Gasification Combined Cycle) plant. It can be further processed in a shift reactor to produce hydrogen and carbon dioxide (CO_2). The hydrogen can be used as a fuel or used to improve fuel quality in a refinery. The CO_2 can be used for enhanced oil recovery to produce addition oil from aging oil fields. The CO and H2 can also be further processed by the Fischer-Tropsch Process to produce liquid fuels. This demonstrates the wide range of products that can be produced by gasification. The production of multiple products from a single plant is called polygeneration. Economic analyses have indicated that polygeneration of fuels, chemicals and electricity improves the profitability of gasification plants.

IV. COST OF ELECTRICITY FROM PULVERIZED COAL AND IGCC PLANTS

Q. Did You Compare the Cost Of Electricity Produced from a New IGCC Plant in Florida With the Cost Of Electricity from a New Ultra-Super Critical Pulverized Coal Plant in Florida?

A. Yes.

Exhibit RCF-5 shows that the costs of electricity for the three types of proposed Pulverized Coal (PC) Plants are higher than the cost of electricity for an IGCC plant using Petroleum Coke (PetCoke) in Florida. Although the IGCC plant has a higher capital cost than the PC plants it has a significantly lower fuel cost when using petcoke. The U.S. petroleum refineries in the Gulf coast produce over 25 million tons per year of fuel-grade petcoke that can be used by IGCC plants. This petcoke can provide over 10,000 MW of new generating capacity in the U.S. At the present time almost all of this petcoke is exported to other countries that allow the higher emissions of SO_2 that petcoke produces. The use of petcoke in the U.S. requires the installation of additional FGD systems to PC plants which is usually cost prohibitive. IGCC plants can effectively remove the sulfur from petcoke and sell it as a value added product. Florida's proximity to the Gulf coast refineries enables Florida's utilities to make use of this waste material while reducing emissions and lowering their cost of electricity. Therefore the lowest cost alternative for Florida is the use of IGCC plants utilizing petcoke. Three companies have recently announced that they plan to build petcoke IGCC plants in the U.S. For the past 10 years Tampa

Electric has been using petcoke in their 250 MW IGCC plant and have recently announced that they will build an additional 630 MW IGCC plant for operation in 2013. Tampa Electric's President Chuck Black was recently quoted as saying: "it's our least cost-generating resource, so we count on it and use it every day as part of our system" in the November 2006 issue of Time Magazine, Inside Business.

The sources of data for Exhibit RCF-5 - Cost of Electricity Comparison Chart for Florida are:

1. Capital, O&M and all non-fuel costs are based upon: Department of Energy/NETL Presentation, Federal IGCC R&D: Coal's Pathway to the Future, by Juli Klara, presented at GTC, Oct. 4, 2006.

2. Efficiencies and fuel consumption calculations are based upon: EPA Final Report, Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies, July 2006.

3. Fuel costs are based upon: Department of Energy, Energy Information Administration, Average Delivered Cost of Coal and Petroleum Coke to Electric Utilities in Florida, 2005 and 2004.

Q: What are the Additional Costs for Capturing CO_2 from Pulverized Coal and IGCC Plants?

A: IGCC plants are capable of capturing CO_2 at much lower costs than pulverized coal plants. The capture, transporting and sequestering of CO_2 is being done on a commercial scale at the Great Plains Synfuels Plant which will be described in later testimony. Studies performed by the DOE, American Electric Power

(AEP), GE and others all show that IGCC plants will be more cost effective than pulverized coal plants when carbon reductions are required.

Exhibit RCF-6 by GE shows the additional cost that must be added to super-critical pulverized coal (SCPC) plants and IGCC plants for CO_2 capture. The table shows the energy penalty and added capital costs for CO_2 capture. The use of a cost for carbon emissions in planning is reasonable given the high likelihood that carbon will be regulated in the future. This exhibit shows the Cost of Energy (COE) for plants designed with the capability to remove CO_2. The COE with CO_2 capture for PC plants will be an unacceptable 8.29 cents/kwh compared to the COE with CO_2 capture for IGCC plants of 6.90 cents/kwh. This is a 66% increase for PC plants compared to a 25% increase for IGCC plants.

Q. Do the Other Studies Confirm these Results of Significantly Lower Costs for Capturing CO_2 in IGCC Plants?

A. Yes.

Exhibit RCF-7 is from a recent U.S. Dept. Of Energy (DOE) Presentation that shows significantly lower future electric costs for IGCC plants than pulverized coal plants. It is important to note that this study was for a mid-west location and petcoke was not included as a potential fuel for the IGCC plant.

This DOE study shows a 30% increase in COE for IGCC with CO_2 capture versus a 68% increase in COE for PC with CO_2 capture. This confirms the GE results which show a 25% increase in COE for IGCC with CO_2 capture versus a 66% increase in COE for PC with CO_2 capture.

This exhibit shows that the cost of electricity from an IGCC plant using coal and located in the midwest is 5.26 cents per kilowatt-hour compared to 4.97 cents per kilowatt-hour for the Pulverized Coal (PC) plant. Therefore the significant emission reductions by using IGCC will only increase the cost of electricity by 0.29 cent per kilowatt-hour. This chart also shows that with future requirements to reduce carbon dioxide (CO_2) emissions the cost of electricity for PC plants will increase to 8.35 cents per kilowatt-hour while only increasing to 6.84 cents per kilowatt-hour for the IGCC plant. That amounts to an increase in the cost of electricity of 3.38 cents per kilowatt-hour for the PC plant. Therefore the IGCC plants will be less expensive to operate in the future. The net result is much cleaner air now and lower cost electricity in the future.

V. AIR POLLUTANT EMISSIONS FROM PULVERIZED COAL AND IGCC PLANTS

Q: Are the Emissions from Ultra Super-critical Pulverized Coal (USPC) Plants Significantly Higher Than IGCC Plants? If So, Explain.

A: Yes.

Exhibit RCF-8 shows the much lower emissions that are produced from Integrated Gasification Combined Cycle (IGCC) plants than Ultra Super-critical Pulverized Coal (USPC) plants. I prepared this exhibit to show that by using IGCC plants to produce the same amount of electricity as USPC plants will dramatically reduce emissions. The use of IGCC plants will produce:

- 84% less smog forming gases (NO_x)
- 88% less acid rain gases (SO_2)
- 42% less soot or fine particulate (PM10)

- 65% less brain damaging mercury (Hg) and the potential for
- 90% less global warming gases (CO_2)

The potential for future electric cost increases due to future environmental regulations is less for IGCC because IGCC plants can control all emissions more economically than PC plants.

I prepared these emission calculations based upon:

1. The best available control technology as reported in EPA Final Report, Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies, July 2006;
2. DOE Final Report, Major Environmental Aspects of Gasification-Based Power Generation Technologies, Dec. 2002 and
3. Test results from Eastman's gasification process using activated carbon beds for mercury removal.

Q: The EPA Report that you used for your Comparison of Emissions is Based upon a Standard USPC Plant with Emission Levels Slightly Different than the Emission Levels Proposed for the FGPP Plant. How do the Emission Levels of the Proposed FGPP Plant Compare with an IGCC Plant?

A: Exhibit RCF-9 shows the tons per year (or pounds per year) of emissions for the proposed FGPP plant and an IGCC plant producing the same amount of electricity.

This chart shows that an IGCC plant producing the same amount of electricity as the proposed FGPP plant will dramatically reduce emissions. The use of IGCC plants will produce:

- 84% less smog forming gases (NO_x)

- 79% less acid rain gases (SO_2)
- 56% less soot or fine particulate (PM10)
- 67% less brain damaging mercury (Hg) and the potential for
- 90% less global warming gases (CO_2)

I prepared these emission calculations based upon:

1. The emissions data from the Permit Application for FPL Glades Power Park, Dec. 2006;

2. The best available control technology as reported in EPA Final Report, Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies, July 2006;

3. DOE Final Report, Major Environmental Aspects of Gasification-Based Power Generation Technologies, Dec. 2002 and

4. Test results from Eastman's gasification process using activated carbon beds for mercury removal.

Q. Do Recent IGCC Plants' Permit Levels and Proposed Permit Levels Confirm that these Significantly Lower Levels of Emissions Provided in these Studies can be Produced in Actual Plants?

A. Yes.

Exhibit RCF-10 shows a summary of emissions from recent IGCC permits and proposed permit levels. This table summarizes proposed emission levels from IGCC plants that have recently received or applied for air permits. The majority of IGCC plants proposed in the last 12 months have sought to control sulfur using Selexol, a more effective control strategy than MDEA. These plants include, AEP in Ohio and West Virginia, Northwest Energy, Tondu, Duke, ERORA (Illinois and Kentucky). Only one air permit application filed in the last 12 months, Mesaba (filed June 2006) uses the less effective MDEA. Selexol effectively removes sulfur levels to between 0.0117 to 0.019 lb/MMBtu heat input into the gasifier.

As this table shows, a majority of IGCC plants that have filed applications in the last 12 months include SCRs to control NOx. These include, Northwest Energy, Tondu, ERORA in Illinois and Kentucky, and Duke in Indiana (The Duke plant includes and SCR, but bases reductions on diluent injection only). The NO_x emission rates for SCR controlled IGCC plants is 0.012 - 0.025 lb/MMBtu based upon heat into the gasifier.

These trends toward Selexol and SCR adoption are occurring faster than EPA predicted in its July 2006 report, Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies. The July 2006 EPA report assumed that MDEA and diluent injection would be BACT for the near-term. This report was based upon a "snap shot" of IGCC permits that is out of date. As this table shows, the market has responded with technology faster than the EPA report anticipated.

In deciding which emission rates to compare to the FGPP plant's proposed emission rates, the highest weight should be placed on recently proposed IGCC plants because they represent the most current view of IGCC permit levels. The least weight should be placed on existing IGCC plants and IGCC plants with permits issued prior to 2003 because they do not represent the capabilities of current IGCC technology.

Q. What are the Emission Rates from the Proposed FGPP Plant and How do they Compare with Recent IGCC Permit Applications?

A. Exhibit RCF-11 summarizes the range of recently filed air permits for IGCC plants (filed in the last 12 months) and compares them to the proposed emission levels for the FGPP plant. An IGCC plant would have significantly lower emissions of all pollutants than the proposed FGPP plant.

Exhibit RCF-11 shows that:

An IGCC plant with the Selexol process would emit only 29% to 47% of the sulfur dioxide of the proposed FGPP plant.

An IGCC plant with the SCR process would only emit 24% to 50% of the nitrogen oxides of the proposed FGPP plant.

An IGCC plant would only emit 48% of the particulate mater of the proposed FGPP plant.

An IGCC plant would only emit 16% to 46% of the mercury of the proposed FGPP plant.

An IGCC plant would also be expected to emit about three-quarters less CO and significantly less sulfuric acid mist and VOCs than the proposed FGPP plant.

VI. THE CLEAN AIR ACT AND BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

Q. Should IGCC Technology be Evaluated as Part of the BACT Analysis for a New Power Plant?

A. Yes.

Exhibit RCF-12 shows the definition of BACT that is included in the Clean Air Act. Exhibit RCF-12 also shows why Senator Huddleston proposed the amendment that included the words “innovative fuel combustion techniques for control of each pollutant" to The Clean Air Act's definition of BACT. Senator's Huddleston words from the Congressional Record are:

- "And I believe it is likely that the concept of BACT is intended to include such technologies as low Btu gasification and fluidized bed combustion. But, this intention is not explicitly spelled out, and I am concerned that without clarification, the possibility of misinterpretation would remain.
- It is the purpose of this amendment to leave no doubt that in determining best available control technology, all actions taken by the fuel user are to be taken into account – . . [including] gasification, or liquefaction . . . which specifically reduce emissions."

Senator Huddleston's amendment was accepted as part of the definition of BACT in The Clean Air Act. Therefore IGCC technology should by law be evaluated as part of the BACT analysis for a new power plant.

VII. TAMPA ELECTRIC COMPANY (TECO) AND IGCC

Q. How Long have Commercial Size IGCC Plants been in Operation in the U.S.?

A. Commercial IGCC plants have been in operation for more than 10 years in the U.S.

Exhibit RCF-13 shows the Polk Power Plant near Tampa, FL which is a greenfield site and the Wabash Power Plant in Indiana which is a conversion of an existing plant.

Tampa Electric Company's (TECO) Polk Power Station began operation in 1996. It produces 250 MW (net) of electricity. It uses a Texaco (now GE) oxygen-blown gasification system. Power comes from a GE 107FA combined cycle system. During the summer peak power months, availability is greater than 90 percent when using back-up fuel.

The Wabash River Coal Gasification Repowering Project in Indiana began operation in November 1995. It demonstrated the repowering of an existing coal plant to IGCC. The plant uses an "E-Gas" oxygen-blown gasification system which is sold by ConocoPhillips.

For larger size plants, multiple units are being proposed which will improve system availability and reduce costs by making use of standard, modular designs.

Q. Have the Utilities Involved with these IGCC Plants Announced Plans to Build Other IGCC Plant?

A. Yes.

Tampa Electric Company has announced that they will build an additional 630 MW IGCC plant at the Polk Power Plant for operation in 2013. Tampa Electric started operation of its existing 315 MW(gross)/250MW(net) IGCC plant in October, 1996 and has recently celebrated its 10th year anniversary. It is the lowest cost plant to operate on Tampa Electric's System and has won numerous environmental awards.

Cinergy was the utility partner that was part of the Wabash IGCC plant. Cinergy has now merged with Duke Energy. Duke Energy has announced that they will build a 630 MW IGCC plant to be built at their Edwardsport Generating Station in Edwardsport, Indiana.

There are at least twenty-eight (28) IGCC plants being planned in the United States by utilities and independent power producers.

Q. Why are the Stacks of PC Plants So Much Taller Than

the Stacks of IGCC Plants?

A. A tall stack is required on all PC plants because the emissions are so high that a significant amount of dilution is required before the ground level emissions are within acceptable limits for people to breath. The proposed FGPP plant is designed with a 500 foot stack compared to the 120 foot stack at Tampa Electric's IGCC plant. Exhibit RCF-14 is a picture that demonstrates the significantly lower emissions from IGCC plants by the facts that the IGCC stack is clear and that there is no need for a tall stack. The much taller PC stack also decreases property values in a much larger surrounding area. This IGCC plant was designed about 15 years ago. Since then significant improvements have been made in IGCC emissions control which enable much lower emission levels than what was required for this IGCC plant 15 years ago. Therefore any emissions comparison should be based upon the best available control technologies (BACT) for PC and IGCC plants that are currently being built.

VIII. REFERENCES TO CONTACT FOR PC AND IGCC PLANTS

Q. What Government Officials and Power Plant Managers are the Most Informed about the Advantages and Disadvantages of Using PC and IGCC Technologies for New Power Plants?

A. Exhibit RCF-15 shows references that I recommend to be contacted prior to anyone making a decision on which technology to use for a new power plant. Each of them have agreed to be contacted to provide their advise concerning their decision process in evaluating PC and IGCC plants.

IX. COMMERCIALLY OPERATING AND PLANNED IGCC PLANTS

Q. Please Describe the Types and Number of Commercially Operating Gasification Plants.

A. Exhibit RCF-16 shows the results of the 2004 world survey of operating gasification plants prepared by the Gasification Technologies Council for the Department of Energy.

Gasification dates back to the 18th century, when "town gas" was produced using fairly simple coal-based gasification plants. But what we think of as modern gasification technology dates back to the 1930's when gasification was developed for chemicals and fuels production. Today (2007), there are around 130 gasification plants worldwide that produce fertilizers, fuels, steam, hydrogen and other chemicals, and electricity. Of these 130 plants, fourteen are IGCC plants.

Q. How Many Commercially Operating IGCC Plants Are There?

A. Exhibit RCF-17 from a Department of Energy presentation shows fourteen (14) commercially operating IGCC plants. Together, these plants have a capacity of 3,880 MW(net) and have almost one million hours of operation on syngas.

These plants use a variety of fuels including coal, petroleum coke, biomass, and refinery residues.

Four IGCC plants tend to be the focus of utility interest because they were designed to use coal: 1) Wabash, Indiana, 2) Polk, Florida, 3) Nuon, Netherlands, and 4) Elcogas, Spain. These four commercial IGCC plants have been operating from 10 to 13 years. They have successfully integrated the gasification process with the combined cycle power plant to enable more efficient use of coal while significantly reducing emissions. These plants range in size from 250 to 320 MW per unit.

A second set of plants built after Wabash, Polk, Nuon, and Elcogas are also important in the progression of IGCC. These plants operate at refineries in

Italy. They are: Sarlux 545 MW, Sardinia; ISAB Energy 510 MW, Sicily; Api Energia 280 MW, Falconara; and Eni Power 250 MW, Ferrera. The first two demonstrate that IGCC plants can be built at a scale above 500 MW. Three of the plants were built using non-recourse project financing provided by over 60 banks and other lending institutions. They show that IGCC can be a commercially bankable technology.

Both the Salux and ISAB Energy plants use more than one gasification "train" and operate with more than 90 percent availability without a spare gasifier. The Italian experience with IGCC, while using refinery residues as fuel, is relevant to discussions of coal-fired or petcoke-fired IGCC, because essentially the same equipment is utilized in both instances, differing only in the feed preparation and how solids are removed.

The first commercial-scale demonstration IGCC plant in the United States was Southern California Edison's Cool Water Plant located at Barstow, California. It operated between 1984 and 1989. The plant successfully utilized a variety of coals, both subbituminous and bituminous, and had a feed of about 1,200 tons/day. The project used an oxygen-blown Texaco gasifier with full heat recovery using both radiant and convective syngas coolers.

Q. Can You Describe the Types of IGCC Projects being Developed in the U.S.?

A. Exhibit RCF-18 shows some of the publicly announced IGCC and gasification projects in the U.S.

The range of IGCC projects under development in the United States includes proposals that would be fueled with petroleum coke, bituminous coal, subbituminous coal, and lignite. For example, the Department of Energy announced in August 2006 that it had received tax credit applications under the Energy Policy Act of 2005 from 18 IGCC projects-- 10 using bituminous coal, six using subbituminous coal, and two that would use lignite. The source of this data is from the Department of Energy, Fossil Energy Techline, issued August 14, 2006, Tax Credit Programs Promote Coal-Based Power Generation Technologies.

IGCC technology is commercially available from five major companies: GE, ConocoPhillips, Siemens, Shell and Mitsubishi Heavy Industries (MHI). The gasification industry has undergone many changes in the past few years that have given confidence to industry and lenders that IGCC can obtain sufficient performance warranties to build new IGCC plants. GE, a major company in the power field, has purchased ChevronTexaco's gasification business, and has partnered with Bechtel to offer fully warranted IGCC plants. ConocoPhillips has purchased the E-Gas technology from Global Energy. Siemens has purchased the German gasification technology formerly offered by Future Energy. Shell has partnered with Udhe and Black and Veatch.

Q. Is there a List of the IGCC Projects that are Presently Under Development in the U.S.?

A. Yes.

Exhibit RCF-19 is a recent list presented by DOE that shows some of the gasification projects that are being developed in the U.S.

A recent DOE Report lists 28 IGCC projects that are planned in the U.S. by utilities and independent power producers. This Department of Energy Report is Tracking New Coal-Fired Power Plants, by Scott Klara and Eric Shuster, September 29, 2006.

X. SIZE AND AVAILABILITY OF NEW IGCC PLANTS

Q. Is it Possible to Build the Large Size IGCC Plants that are Needed for the FGPP Plant?

A. Yes.

Large size plants are being built using modular designs that improve system reliability, increase efficiencies and provide fuel flexibility.

The Nuon Utility in the Netherlands, Belgium and Germany has been successfully operating an IGCC plant on coal and biomass for the past 12 years at about 253 MW. Nuon recently announced that they are building a 1200 MW plant which will consist of four 300 MW units. This design shown in Exhibit RCF-20 requires no additional scale-up from the design of their existing plant and makes use of readily available combined-cycle plants that have been used with natural gas. This modular design provides additional system reliability, increased efficiencies, fuel flexibility and any possible size.

The standard IGCC unit is now 300 MW. Most manufacturers are supplying 600 MW plants which consist of two 300 MW units. This is due to the fact that the gasifiers have been sized to produce the amount of synthesis gas needed for the 300 MW combined-cycle plants that are already in-service using natural gas. Therefore the 630 MW unit that Tampa Electric is building for operation in 2013 consists of two units the same size as their existing unit that has been operating for the past 10 years. Therefore there is no additional scale-up required. Any large size plant can be built by using additional 300 MW units. Three manufacturers have 300 MW IGCC units that have been operating successfully for the last 10 to 13 years. GE states that "IGCC technology can satisfy output requirements from 10 MW to more than 1500 MW, and can be applied in almost any new or repowering project where solid and heavy fuels are available." The source of this quote is from: www.gepower.com/prod_serv/products/gas_turbines_cc/en/igcc/index)

Q. Have Recent Coal Gasification Plants and IGCC Plants Demonstrated Reliabilities Above 90% Required by the Utility Industry?

A. Yes.

Now GE offers to take on responsibility for everything "From Coal off the Coal Pile to Electrons on the Grid" by Ed Lowe, GE General Manager of Gasification from Time Magazine, Inside Business, November, 2006.

Exhibit RCF-21 is a chart by GE which shows that their 4 new coal gasification plants that have been operating in China for the past 3 years have been operating at greater than 90 % reliability.

An additional advantage of an IGCC plant is that it can operate on various fuels. If the gasifier is out-of service for maintanence the power plant can still operate on natural gas or diesel fuel. This is not possible with a PC plant which is usually designed for one type of coal. Older IGCC plants built in the early 1990s such as Polk and Wabash that operate without a spare gasifier have demonstrated availabilities above 85%.

A recent Gas Turbine World article reported on the capacity factors of the more recently built IGCC plants in Italy that utilize refinery waste such as asphalt as a fuel. As the report notes, the availability of these plants are between 90% and 94%. The source of this data is from <u>Refinery IGCC plants are exceeding 90% capacity factor after 3 years</u>, by Harry Jaeger, Gas Turbine World, January-February 2006.

Major vendors of IGCC plants such as GE, Shell and ConocoPhillips will warrant that new IGCC plants will achieve greater than 90% availability with a spare gasifier. The economic comparisons conducted for Tampa Electric's IGCC plant indicate that it is more cost effective to operate on natural gas or diesel fuel than to build a spare gasifier to increase plant availability. Tampa Electric's IGCC plant has demonstrated reliability to produce electricity of 95% with their dual fuel capability. This is greater than PC plants that do not have dual fuel capability. The source of this data is from Tampa Electric's Presentation of Operating Results, by Mark Hornick, Plant Manager, presented during plant tours.

Therefore IGCC plants are being built without a spare gasifier. They will be able to operate above 90% availability by using their back-up fuel of either natural gas or diesel.

Reliability and availability are measures of the time a plant is capable of producing electricity. Reliability takes into account the amount of time when a plant is not capable of producing electricity because of unplanned outages. Availability takes into account the time when a plant is not capable of producing electricity because of planned and unplanned outages.

XI. THE GREAT PLAINS SYNFUELS PLANT

Q. Are There Any Commercially Operating Gasification Plants That Are Capturing CO_2?

A. Yes.

Exhibit RCF-22 shows the Great Plains Synfuels Plant in Beulah, North Dakota which is a good example of a commercial gasification plant. It began operating in 1984 and today produces more than 54 billion cubic feet of

Synthetic Natural Gas (SNG) from 6 million tons of coal per year. If the SNG from this one plant were used in combined-cycle power plants there would be enough fuel for more than 1,000MW of generating capacity.

Adjacent to the Great Plains Synfuels Plant is the Antelope Valley Station which consists of two 440 MW lignite coal power plants that also started operation on lignite in the early 1980s.

Both plants are owned by the Basin Electric Power Cooperative. Al Lukes, Senior Vice President and COO of the Dakota Gasification Company, presented a paper at the 2005 Gasification Technologies Conference entitled Experience with Gasifying Low Rank Coals which showed the significantly lower emissions from the coal gasification plant than the coal-fired power plant. I recently asked Al Lukes which technology he would select today for a power plant, and he said "definitely the gasification technology".

Q. Has the Great Plains Synfuels Plant been Able to Commercially Demonstrate that the CO_2 from this Coal Gasification Plant can be Economically Captured and Sequestered?

A. Yes.

Carbon dioxide capture, transportation and sequestration has been operating commercially since 2000 at the Great Plains Synfuels Plant. In 2000, the Great Plains Synfuels Plant added a CO_2 recovery process to capture the CO_2. It transports the CO_2 by pipeline 205 miles, as shown in Exhibit RCF-23, to the Weyburn oil fields where it is used for enhanced oil recovery (EOR). In this way, the CO_2 does not become a global warming emission source but is sold as a useful byproduct to recover additional oil from depleted oil fields and the CO_2 is sequestered underground. This CO_2 recovery process is expected to help extract 130 million extra barrels of oil from this oil field. This demonstrates the ability to efficiently capture and sequester the CO_2 from the gasification process.

XII. ENVIRONMENTAL IMPACT COMPARISONS OF PC AND IGCC PLANTS

Q: What Mercury Control Technology is Used With IGCC Plants that Can Remove So Much More Mercury Than What can be Removed from the Proposed FGPP Plant?

A: The efficient mercury removal process that will be used for IGCC plants has been commercially operating for more than 21 years.

The plant shown in Exhibit RCF-24 uses activated carbon beds for removing more than 94% of the mercury from the synthesis gas of this coal gasification plant. Mercury testing has indicated non-detectable mercury levels in the synthesis gas. However it is not economically possible to use this efficient mercury removal process for conventional Pulverized Coal (PC) plants due to the much larger quantities of stack gas in a PC plant. The stack gas (also called flue gas) from proposed PC plants will be 160 times the volume of the synthesis gas that will be treated in an IGCC plant. It is not economically feasible to treat this much larger volume of stack gas using this much more efficient process. Therefore FPL has proposed the much less expensive and much less efficient technology of activated carbon injection (ACI) that has not underdone long term testing at the commercial scale that should be required for these plants. Therefore a recent Electric Power Research Institute (EPRI) Journal article titled Mercury Control for Coal-Fired Power Plants, Summer 2005, page 19 states:

"No technology designed specifically to control mercury in coal plants is in use anywhere in the world, or has even undergone long term testing."

What this means is that the proposed technology of activated carbon injection (ACI) that FPL has proposed has not underdone long term testing at the commercial scale that should be required for these plants. Therefore there is a significant risk that the proposed mercury control system for the FGPP plant will not meet their proposed emission levels for mercury.

Q. Are there Less Solid Wastes Produced from IGCC Plants?

A. Yes.

Exhibit RCF-25 shows the significantly less solid waste that is produced by IGCC plants. Instead of large quantities of scrubber sludge to dispose from the proposed FGPP plant an IGCC plant produces useful sulfur byproduct. Leachable ash and scrubber sludge from the PC plants can cause ground water contamination. Instead of a leachable fly ash to dispose of IGCC produces a non-leachable slag that can be used in asphalt. The higher temperatures for gasification than combustion has a benefit because coal ash has a softening temperature of about 2250 F. Therefore, the coal ash goes through a molten state when gasified then cools to become an inert, vitrified slag that can be sold as a byproduct or disposed of as a non-leachable material.

Q. Do IGCC Plants Use Less Water than the Proposed PC Plant?

A. Yes.

Exhibit RCF-26 shows that IGCC plants use 30% to 40% less water than a PC plant.

The 30 to 40 % less water usage for an IGCC plant is due mostly to the fact that a combined cycle power plant is being used which requires less cooling tower water. A combined cycle power plant consists of both a gas turbine and a steam turbine for power generation. The gas turbine portion of the power generation cycle does not require the large quantities of water for cooling that are needed for the steam turbine cycle. Since a PC plant generates all of its electricity from the steam turbine cycle it requires larger amounts of water.

Combined cycle plants are more energy efficient but require a clean fuel such as natural gas, diesel, or synthesis gas. The older, less efficient technology uses only a steam turbine, which must be used for PC plants due to the contaminants in the combustion products.

XIII. THE BENEFITS OF FUEL FLEXIBILIY FOR POWER PLANTS

Q: What are the Benefits of a Power Plant being Able to Use Different Fuels?

A: The 1200 MW IGCC Plant to be built by the Nuon Utility in The Netherlands is a good example of a multi-fuel power plant. This plant is shown in Exhibit RCF-20. It will have the capability of using coal, petcoke, biomass and natural gas. This plant will be able to respond to changing fuel prices and availability of these alternative fuels. The coal, petcoke and biomass can all be gasified to produce syngas for the combined-cycle power plants. The biomass capability enables IGCC plants to use various renewable energy sources that will reduce the emissions of CO_2. Biomass is available in Florida as a byproduct of the sugarcane and pulp industries and then renewable energy crops can be developed as a new industry in Florida. The disadvantage of PC plants is that they are only capable of using coal. Therefore PC plants can not respond to changing market conditions or changing emission standards.

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Education:
Massachusetts Institute of Technology, MS CHE 1972.
Worcester Polytechnic Institute, BS CHE 1969.

Experience:

February 2003 to Present

Retired – Volunteer at Camp Sunshine to help children with cancer and volunteer for the Clean Air Task Force (CATF), the Natural Resources Defense Council (NRDC), Environmental Defense, Sierra Club and Public Citizen to advise utilities, government agencies and the public about the environmental benefits, economic potential and energy security of using coal gasification technologies to produce electricity, fuels and chemicals .
Provided expert testimony and information on new energy technologies to Florida's Public Service Commission and Texas Senate Committee on Natural Resources.

September 1989 - February 2003

Consulting Engineer – New Energy Technologies

Consulting engineer to various utility companies, equipment manufacturers, government agencies and environmental organizations on the development and application of new energy technologies.
Consultant in the areas of coal gasification, integrated gasification combined-cycle (IGCC) power plants, alternative fuels, cogeneration and natural gas cooling technologies.
Identify potential applications for these new technologies with electric and gas utilities. Introduce these new technologies to company executives, government officials and potential users. Assist engineers with designs and applications for these new technologies. Create marketing programs with manufacturers for increased use of these technologies.
Direct technical feasibility studies and financial analyses for site specific applications. Assist equipment manufacturers, the Electric Power Research Institute (EPRI), the Gas Research Institute (GRI), and the American Gas Cooling Center (AGCC) with development and demonstration of these new technologies.
Provided expert testimony and information on new energy technologies to Brazil's Center for Gas Technology and Trinidad's National Gas Company.

August 1981 - August 1989

Consulting Engineer – New Fuel Technologies

Consultant to various companies on the technical feasibility and business development for new fuel technologies. Major areas of consulting consist of the development and use of alternative new fuels and the conversion of power plants to these new fuels. Director and project manager for various development programs, feasibility studies, financial analyses, R&D projects, marketing analyses and commercialization of these new fuel technologies.

April 1977 - July 1981

Florida Power & Light Company, Miami, Florida
Senior Project Coordinator – Research and Development
Managed FPL's coal conversion program and fuels R&D program. Developed R&D projects with emphasis on alternative fuels and processes for electric power generation. Assessed the technical and economic feasibility of coal gasification, advanced coal cleaning technologies, coal-oil mixture technologies, coal-water slurry technologies, coal liquefaction processes, fluidized combustion processes and advanced pollution control methods. Established company R&D projects in uranium recovery, coal cleaning, coal-oil mixtures, coal-water slurries and combustion modifications.

September 1975 - March 1977

Center for Energy Policy, Inc., Boston, Massachusetts
Program Manager

Organized multi-disciplinary studies on the technical and economic feasibility of power plant conversions from oil to coal, the pricing policies for fuels and electricity and future methods for energy conservation in space heating. Directed engineering study for the conversion of New England Electric's Brayton Point Plant from oil to coal.

May 1972 - September 1975

Walden Research Division of ABCOR, Inc. Cambridge, Mass.
Senior Engineer

Industrial consultant for air pollution control, energy conservation, and industrial hygiene. Engaged in process modifications to reduce energy consumption. Responsible for engineering evaluations of air pollution control systems.

September 1970 - June 1972

Massachusetts Institute of Technology, Cambridge, Mass.
Graduate Student, Teaching Assistant, Researcher

Researcher – NSF grant to evaluate future energy sources and their environmental impact. Researcher for book entitled "New Energy Technology," by Hottel and Howard, MIT Press.

Graduate Student – Master's thesis: "Technical and Economic Evaluation of Coal Gasification Processes."

Teaching Assistant – "Principles of Combustion and Air Pollution" and "Seminar in Air Pollution."

June 1969 - February 1970

Southern California Edison Company, Los Angeles, California
Chemical Engineer
Engaged in power plant combustion air pollution control. Investigated two-stage combustion to reduce nitrogen oxides emission.

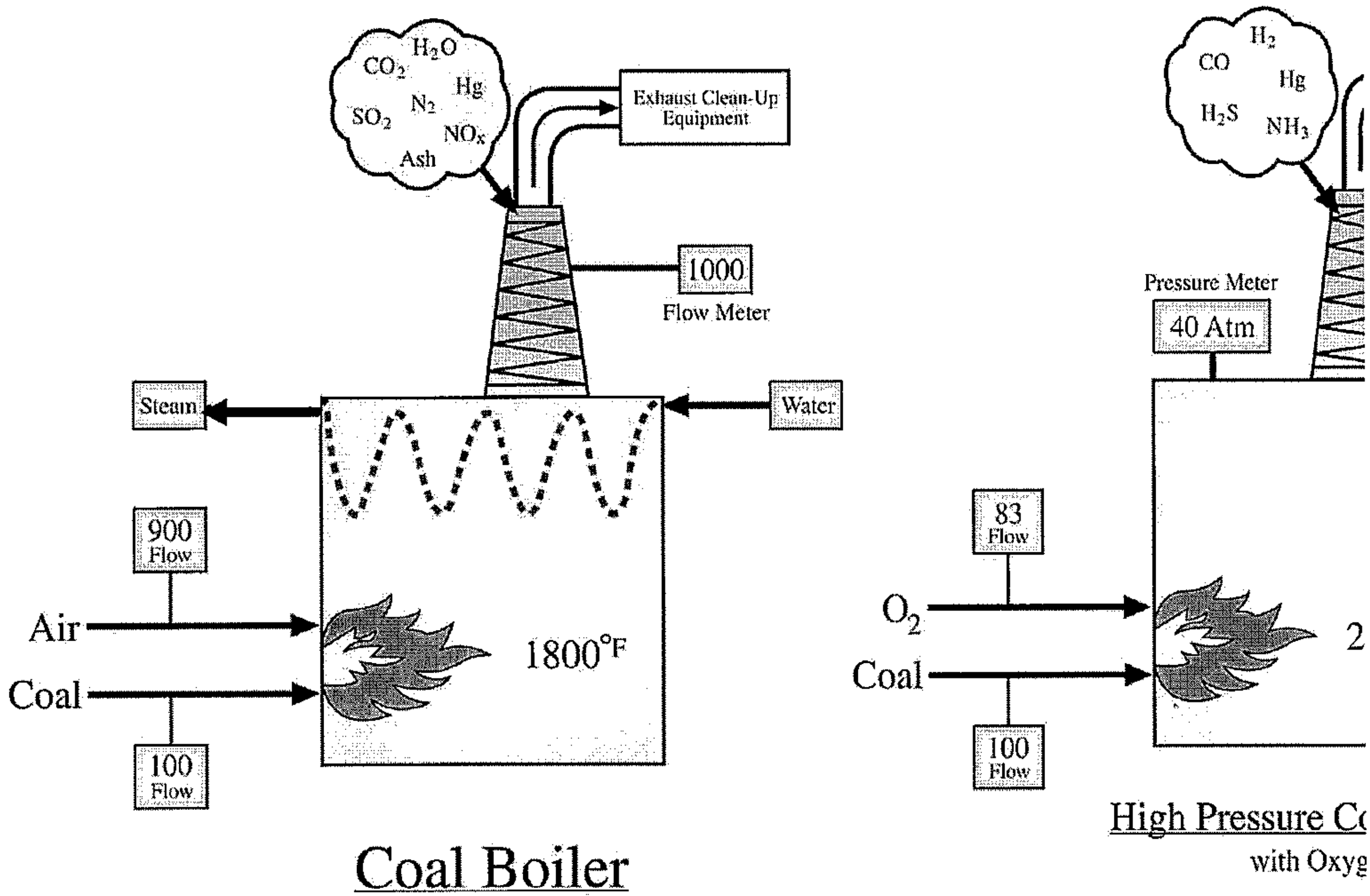
Professional Organizations

Electric Power Research Institute - EPRI
Gas Research Institute - GRI
Association of Energy Engineers - AEE
Cogeneration Institute - CI
American Institute of Chemical Engineers – AIChE
American Gas Cooling Center – AGCC

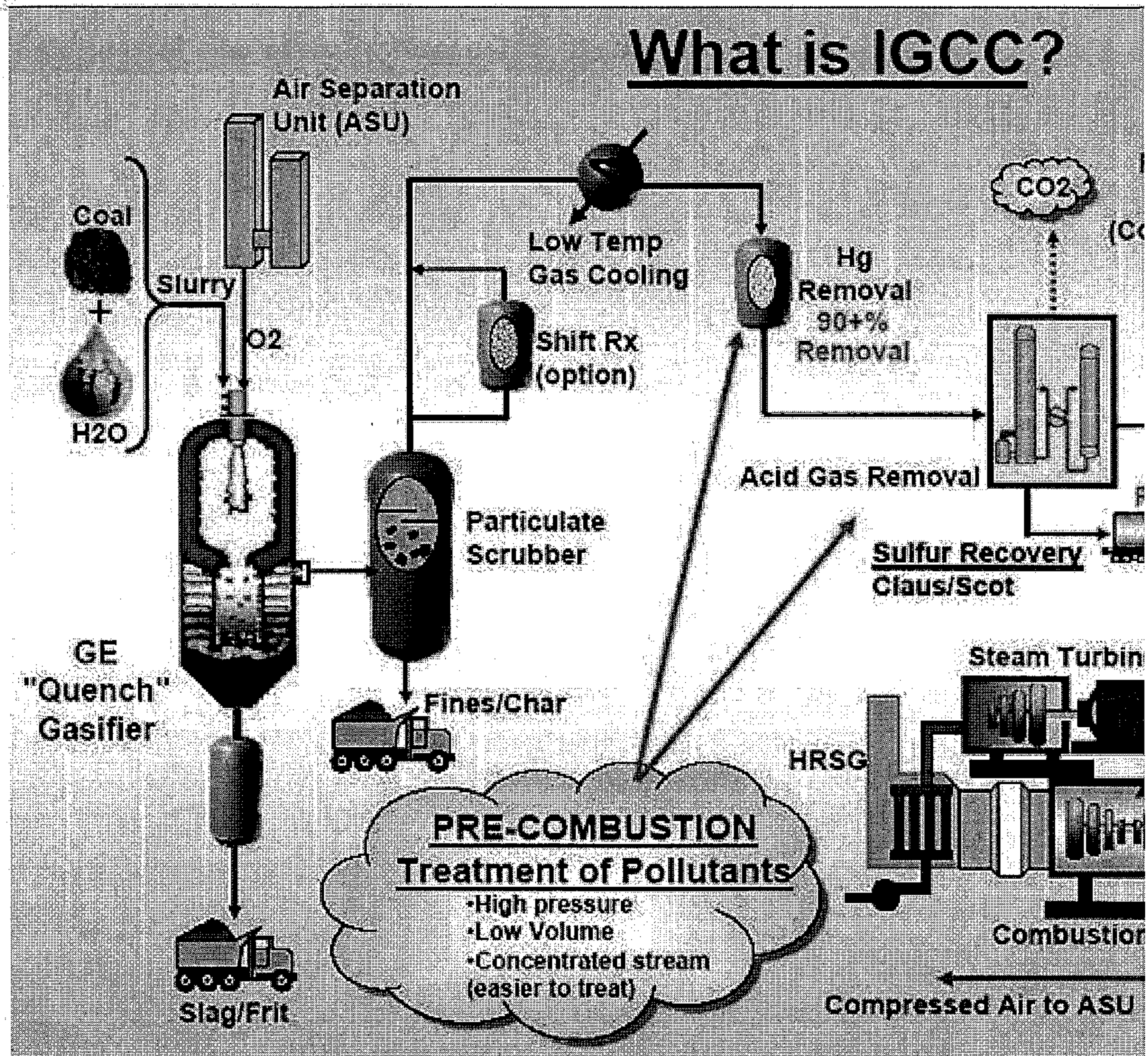
COMBUSTION VERSUS GASIFI(

Volume of Exhaust Gas Clean-Up **Volume of Syn(**

160 X X

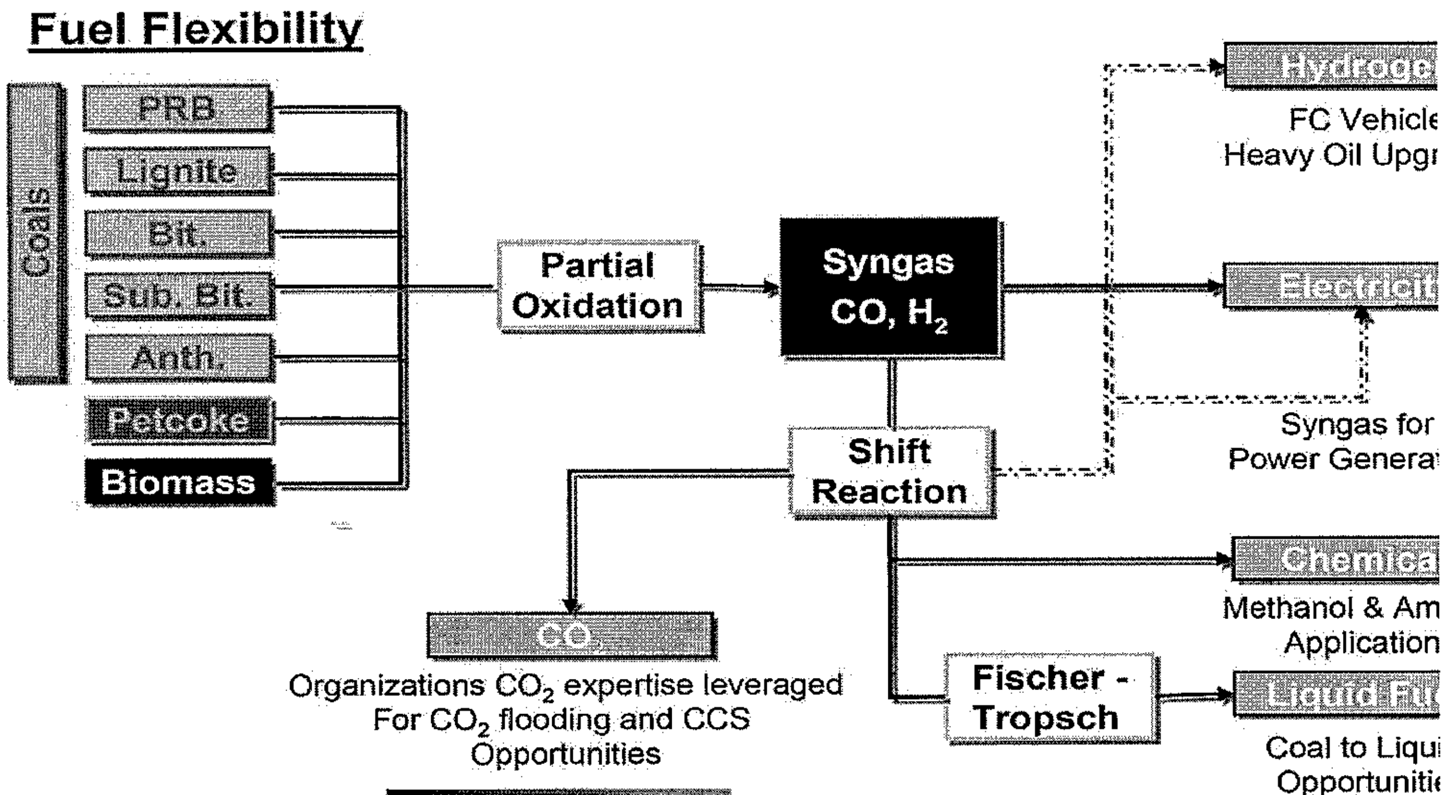
- 

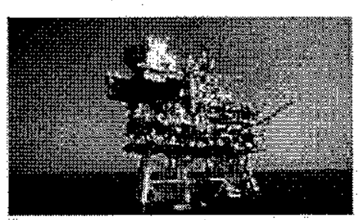
- (Source: EPRI Presentation – "Gasification Combined Cycles 101" by Dr. Jeffrey and 12, presented at the Workshop on Gasification Technologies, Tampa, FL 3/



Source: Eastman Gasification Overview, March 22, 2005, page 15, by Eastman Gasification Services Comp

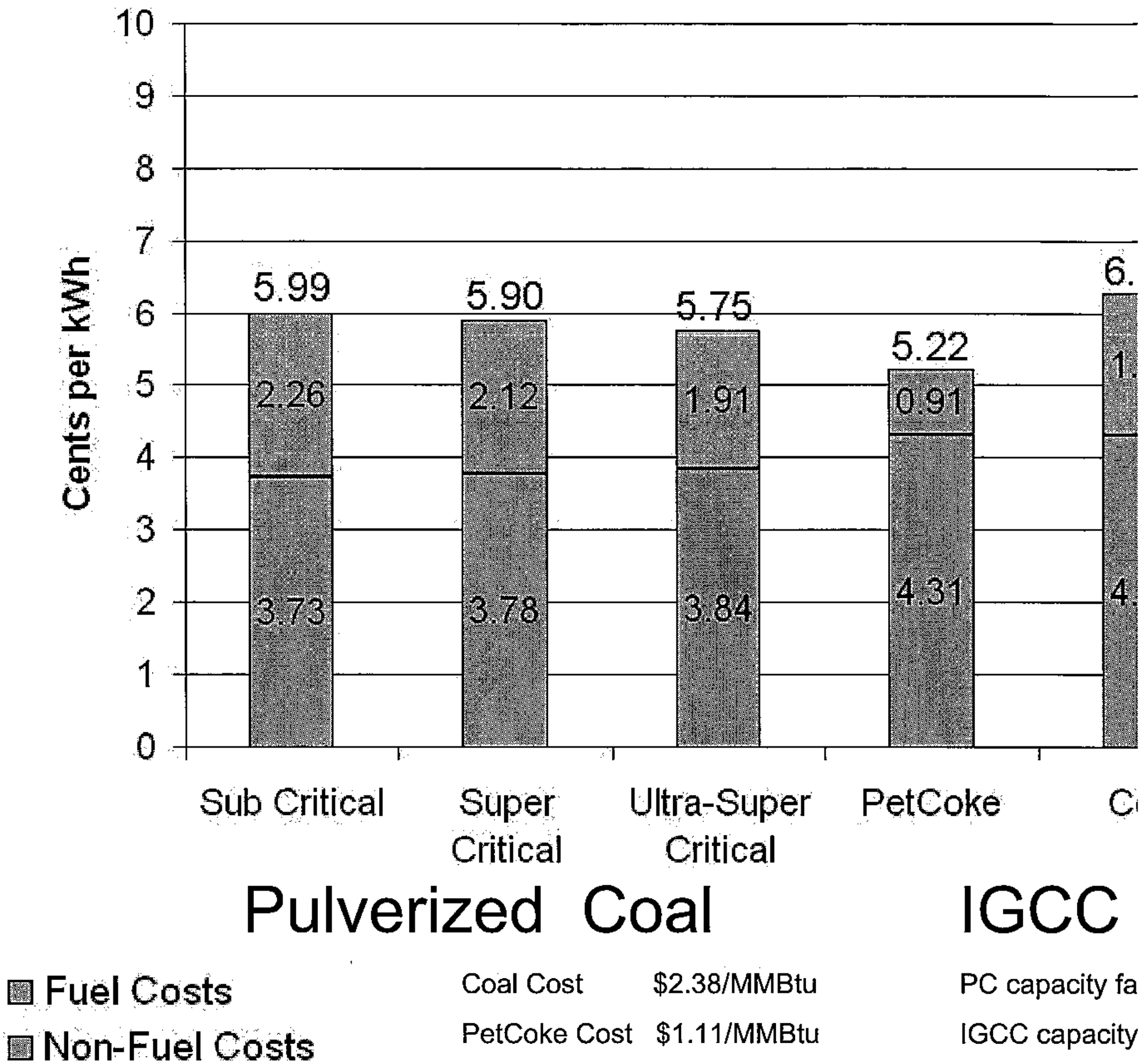
Shell has the enabling clean coal technologies…





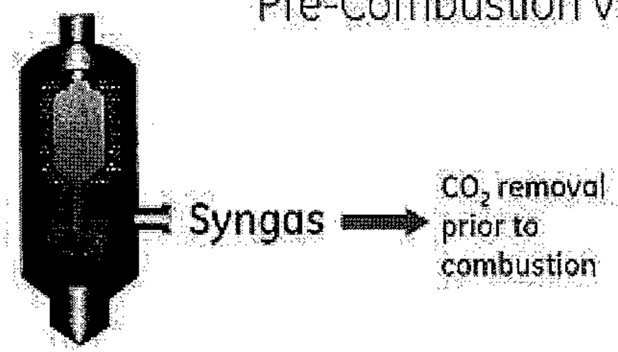
- Source: <u>**Shell Coal Gasification in North America**</u>
  by **Milton Hernandez,** Shell U.S. Gas & Power, Presented at GTC, O

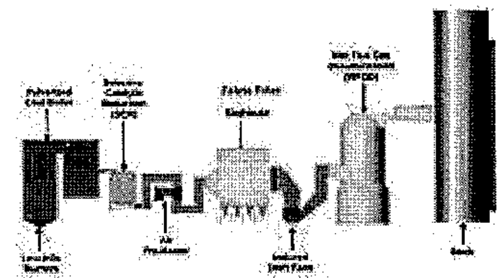
Cost of Electricity Comparison Chart for



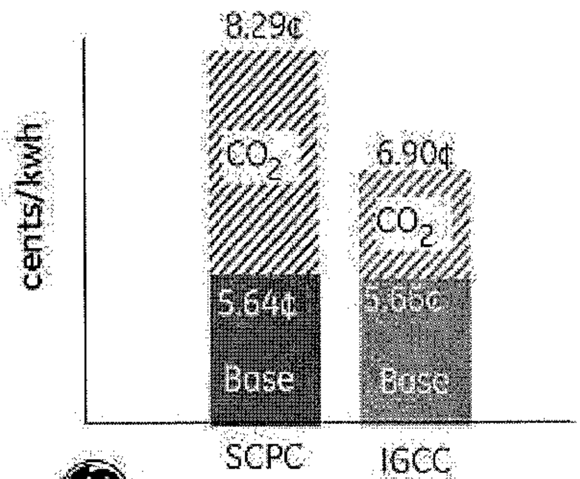
IGCC – CO_2 Capture

Pre-Combustion vs. Post Combustion





IGCC offers CO_2 capture advantages over SCPC

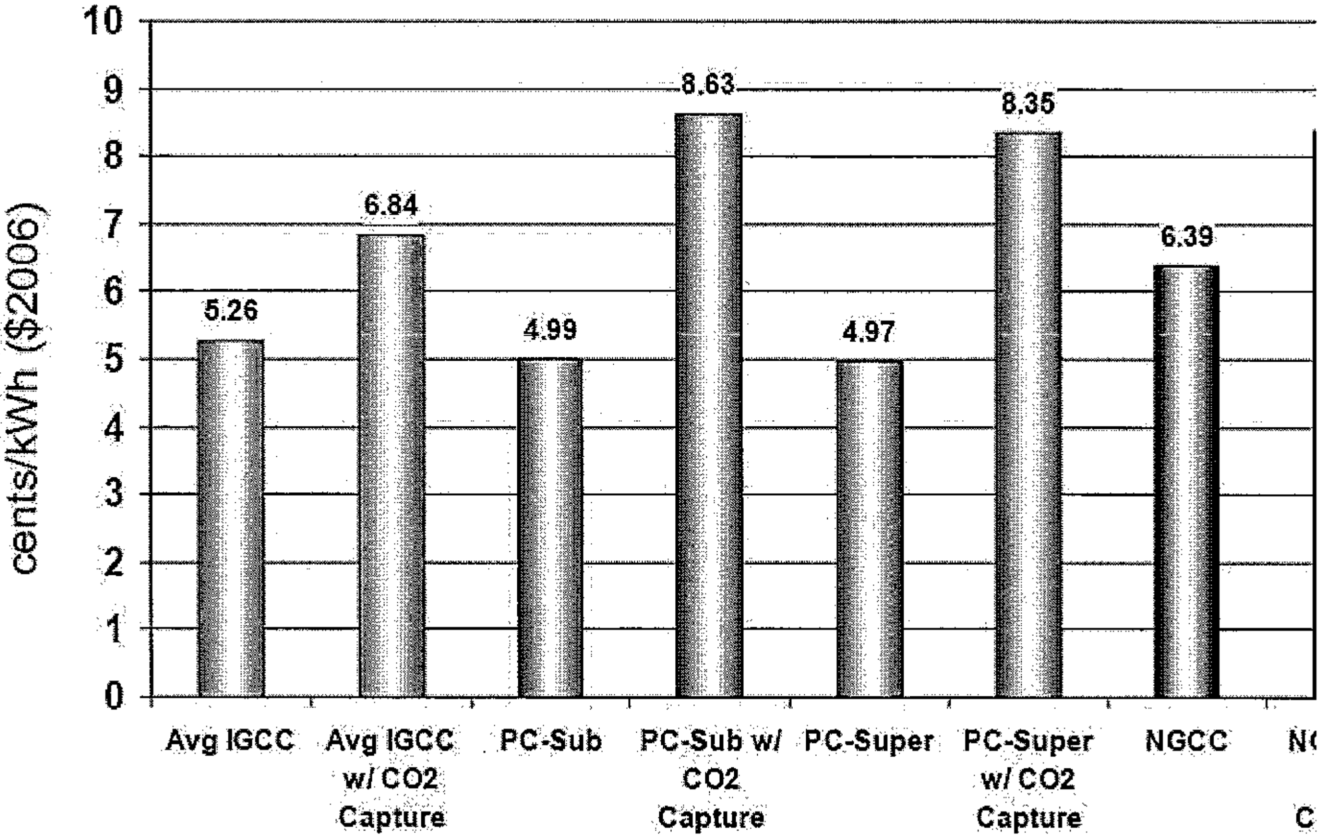


	IGCC	S
kW penalty	-5%	
Capital Cost	+30%	
COE Increase	+25%	

imagination at work

Source: GE Energy, Integrated Gasification Combined Cycle Panel Discussion, by Robert Rig
Commercialization, presented at Power-Gen International, December 8, 2005, page 1

Cost of Electricity Comparison

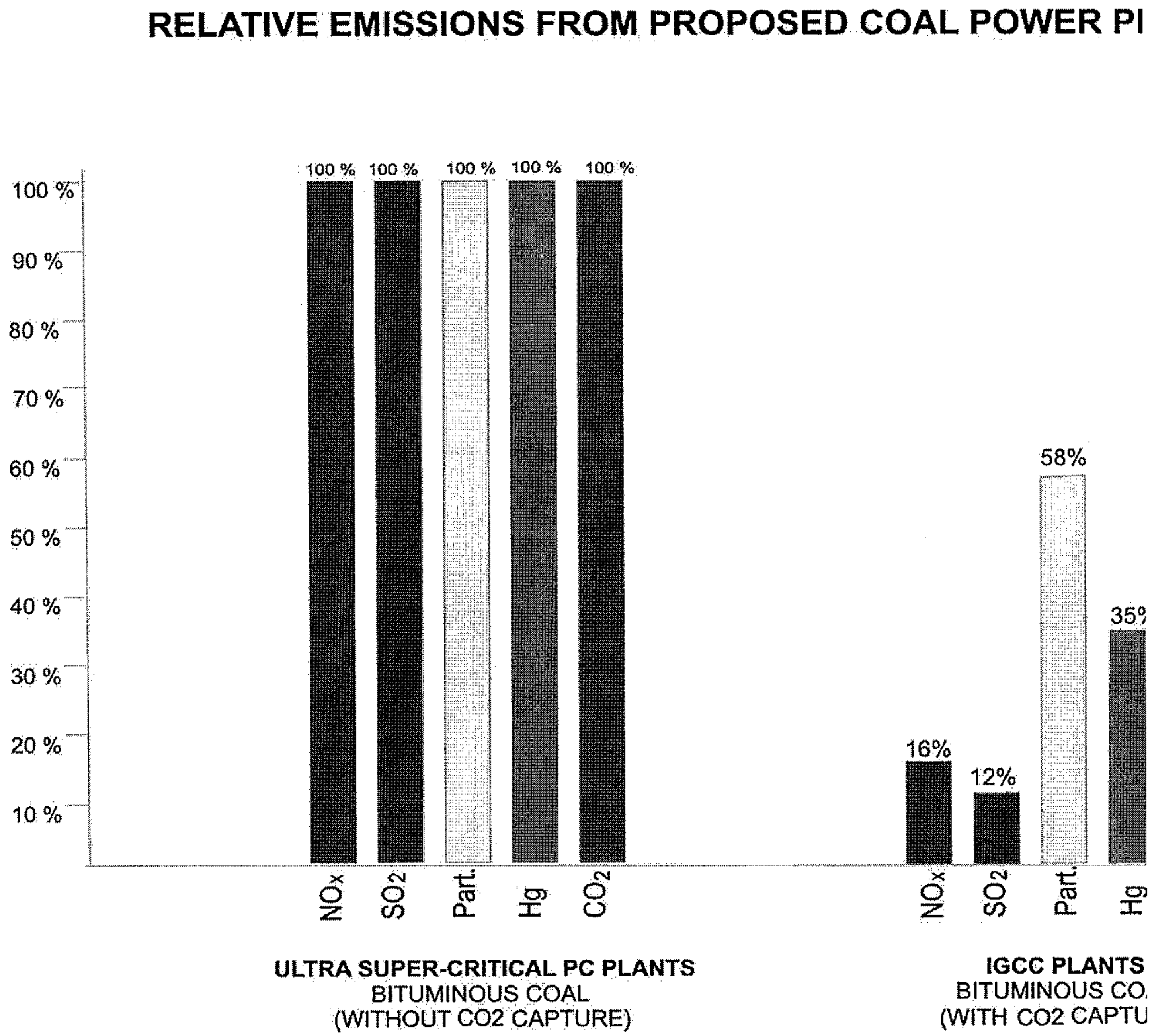


January 2006 Dollars, 85% Capacity Factor, 13.8% Levelization Factor, Coal cost $1.34/10^6Btu, Gas cost $7.46/10^6Btu

Note: Preliminary results as of
report release Date: Janua

NETL Meeting with Wyomi

**Source: Department of Energy/NETL Presentation, Overview of Coal Gasificatio
Gary Stiegel, presented at NSTAR Meeting, Pittsburgh, PA, Oct. 27**



RELATIVE EMISSIONS FROM PROPOSED COAL POWER PI
100 %
90 %
80 %
70 %
60 %
50 %
40 %
30 %
20 %
10 %
100 %
100 %
100 %
100 %
100 %
NOx
SO2
Part.
Hg
CO2
ULTRA SUPER-CRITICAL PC PLANTS
BITUMINOUS COAL
(WITHOUT CO2 CAPTURE)
16%
12%
58%
NOx
SO2
Part.
Hg
IGCC PLANTS
BITUMINOUS CO.
(WITH CO2 CAPTU

TOTAL EMISSIONS FROM FPL GLADES POWER PAI
AND
AN IGCC PLANT OF THE SAME SIZE (1960 M

	NOX (Tons per Year)	SO2 (Tons per Year)	Particulates (Tons per Year)	Mercury (Pounds per Year)
PC	3,811	3,048	991	180
IGCC	601	631	438	60
% REDUCTION	84%	79%	56%	67%

less smog forming gases / acid rain gases / fine particulate / brain damage /

SUMMARY OF RECENT IGCC PERMITS AND PROPOSED PERI

	Approved Permit			Application Filed, Draft Permit Not Issue					
Pollutant	Global Energ Lima, Oh, 59 MW	Kentucky Pionee Energy, KY	Wisconsin Electric Elm R 600 MW	ERORA Cash Cre KY, 630 MW	Southern Illinoi Clean Energy Complex, IL, 64 MW & 110 MMS methane	ERORA, Taylorville, IL MW	Nueces, T 600 MW	Energy Northwest WA, 600 MW	AEP, 629 M
	(in lb/MMB	(in lb/MMBtu)	(in lb/MMBtu)	(in lb/MMBtu)	(in lb/MMBtu)	(in lb/MMBtu)	(lb/MMBtu	lb/MMBtu	lb/M
SO2	0.021	0.032 -3 hr ave	0.03 -24 hr ave	0.0117 -3 hr ave	0.033 -30 day ave	0.0117 -3 hr ave	0.019	0.016 -3 hr ave	
NOx	0.097	0.0735 -3 hr ave	0.07 (15 ppmdv) -30 day ave	0.0246-24 hr ave	0.059 -30 day ave	0.0246 -24 hr ave	0.019	0.012 -3 hr ave	
Mercury			.56 x 10-6	.197 x10-6 (1)	.547 X10-6	.19 x 10-6 (1)	1.825 x10-6	1.1 x10-5	
PM	0.01	.0.011	0.011 (backhalf)				0.015	0.001	
PM10			0.011 (backhalf)	0.0063 -3 hr ave (filterable)	0.00924 (filterable)	0.0063 -3 hr ave (filterable)	0.014		.006 (filtera
VOCs	0.0082	0.0044	0.0017 -24 hr ave (LAER) (3)	0.006 -24 hr ave	0.0029	0.006 -24 hr ave	0.004	0.003	0.001
Sulfuric Acid Mist			0.0005 -3 hr ave	0.0026 -3 hr ave	0.0042 -30 day ave	0.0026 -3hr ave	0.0001		98 ton
Fluorides (2)									
CO	0.137	0.032 -3 hr ave	.030 -24 hr ave	0.036 -24 hr ave	0.04 -30 day ave	0.036 -24 hr ave	0.04	0.036	
Lead			0.0000257						
Sulfur Control Techn	MDEA	MDEA	MDEA	Selexol	MDEA	Selexol	Selexol	Selexol	Selexo
Nox Control Technology	Diluent injection	Diluent injection	Diluent injection	Diluent/SCR	Diluent injection	Diluent/SCR	Diluent/SCR	Diluent/SCR	Diluen injecti

(1) Application estimates this emission limit but does not proposed an emission limit
(2) No limit established. Fluorides from IGCC plants are below PSD significance
(3) Polk IGCC also has this emission rate effective July 2003 as set by BACT.

Source: Declaration of John Thompson, Director of the Clean Air Transition Project for the Clean Air Task Force, subr Rock air permit, dated November 10, 2006, page 13.

EMISSIONS FROM FPL GLADES POWER PAR
VERSUS
RECENT IGCC PERMIT APPLICATIONS

	FGPP	IGCC			
	Proposed Emission Rates	Sulfur control using MDEA	Sulfur control using Selexol	Nitrogen control using diluent injection	Nit dil
	(lb/MMBtu)	(lb/MMBtu)	(lb/MMBtu)	(lb/MMBtu)	(
SO2	0.04	0.025 - 0.033 (62% - 82%)	0.0117 - 0.019 (29% - 47%)		
NOx	0.05			0.057 - 0.07 (114% - 140%)	0 (
PM	0.013	0.0063 (48%)			
CO	0.15	0.03 - 0.04 (20% - 27%)			
Hg	0.0000012	0.00000019 - 0.00000056 (16% - 46%)			

Sources: 1. IGCC Data from Declaration of John Thompson, Director of the Clean Air Transition Project for th
submitted to EPA for the Desert Rock air permit, dated November 10, 2006, page 15.
2. Air Permit Application for FPL Glades Power Park, by Golder Associates, December 2006.

The Clean Air Act specifies that Gasification must be Evaluated to Determine the Best Available Control Technolog

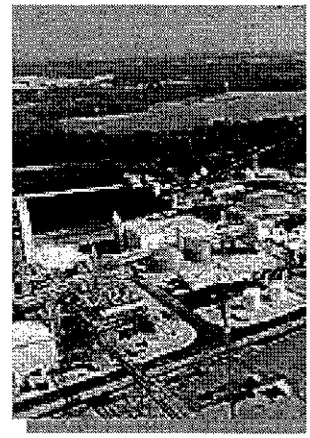
- The Clean Air Act defines BACT as follows:
- The term "best available control technology" means an emission limitation based on th reduction of each pollutant subject to regulation… emitted or which results from any m which the permitting authority, on a case-by-case basis, taking into account energy, er economic impacts and other costs, determines is achievable for such facility through tl production processes and available methods, systems, and techniques, including fuel treatment or innovative fuel combustion techniques for control of each pollutant.
- Indeed, the Act itself is clear – BACT emission limitations must consider "application o and available methods, systems, and techniques, *including . . . innovative fuel combu* control of each pollutant." (42 U.S.C. § 7479(3)).

- Next the analysis of Congressional Intent:
- The legislative history of the CAA makes this point just as clearly. Consider the follow Senator Huddleston of Kentucky who proposed the amendment to add the words, "or i techniques" to the definition of BACT:
- The definition in the committee bill . . . indicates a consideration for various control stra phrase "through application of production processes and available methods, systems, including fuel cleaning or treatment." And I believe it is likely that the concept of BACT such technologies as low Btu gasification and fluidized bed combustion. But, this inter spelled out, and I am concerned that without clarification, the possibility of misinterpret
- It is the purpose of this amendment to leave no doubt that in determining best availabl actions taken by the fuel user are to be taken into account – . . . [including] gasificatio which specifically reduce emissions.
- [CITE: 123 Cong. Rec. S9434-35 (June 10, 1977) (debate on P.L. 95-95) (emphasis a

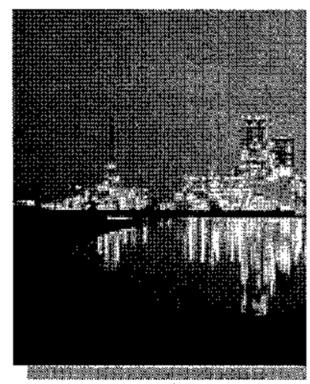
IGCC Technology in Early Commerciali

U.S. Coal-Fueled Plants

- **Wabash River**
  - 1996 Powerplant of the Year Award*
  - Achieved 77% availability **
- **Tampa Electric**
  - 1997 Powerplant of the Year Award*
  - First dispatch power generator
  - Achieved 90% availability **



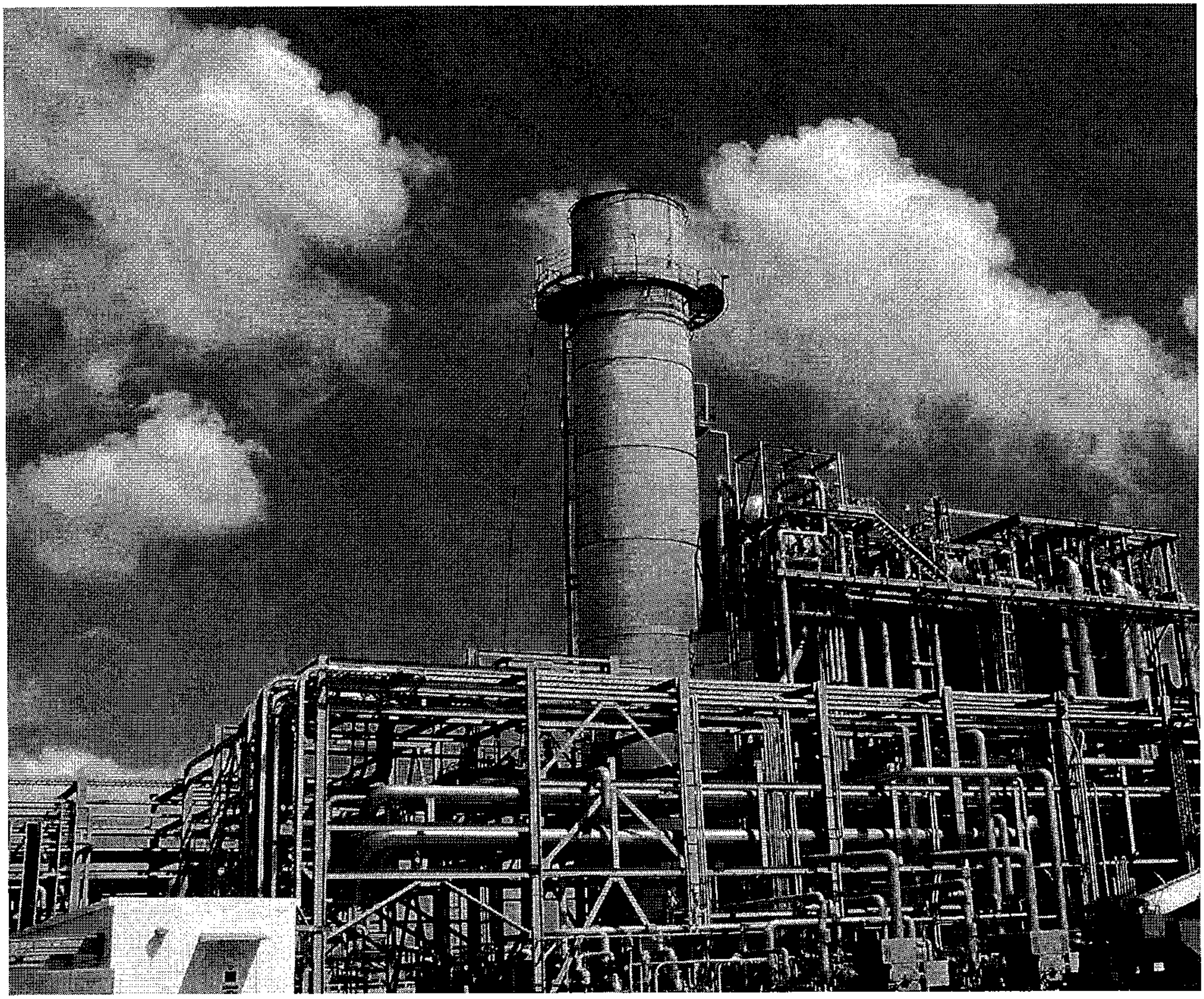
Nation's first commercial-scale IGCC plants, each achieving
> 97% sulfur removal
$\geq$ 90% NO_x reduction



NETL

Power Magazine* * Gasification Power Block*

Source: Department of Energy/NETL Presentation, <u>Overview of Coal Gasificatic</u>
Gary Stiegel, presented at NSTAR Meeting, Pittsburgh, PA, Oct. 2



IGCC PLANT STACK AT POLK POWER PLANT
TAMPA ELECTRIC COMPANY

References to Conta

Pulverized Coal vs. IGCC Pla

City of Gainesville

Pegeen Hanrahan
Mayor

City Hall
200 E. University Avenue
Gainesville, FL 32602-0490

Station 19, PO Box 490
Gainesville, FL 32602-0490
Telephone: (352) 334-5015
Facsimile: (352) 334-2036
mayor@ci.gainesville.fl.us

City of Gainesville hired ICF Consultants directly. ICF evaluation selected IGCC as best choice. Gainesville issued RFI for partners in IGCC plant.

TECO
TAMPA ELECTRIC

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GENERAL MANAGER
POLK POWER STATION
PHILLIPS POWER STATION

TAMPA ELECTRIC COMPANY
P.O. BOX 111
TAMPA, FL 33601-0111
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CELL 813-376-6643
FAX 863-428-5927
MJHORNICK@TECOENERGY.COM

Tampa Electric has operated an IGCC plant for over 10 years. Tampa Electric has announced an additional 630MW IGCC plant to be operating in 2013. The plant manager can answer any questions. Tours of the plant are available.

LAURA MILLER
MAYOR

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Laura.Miller@dallascityhall.com

The Mayor of Dallas has toured the Tampa Electric IGCC plant and is knowledgeable about power plants and pollution control equipment. She has formed a coalition of 22 mayors in Texas to encourage the use of IGCC plants.

ST. LUCIE COUNTY FLORIDA

Chris Craft
County Commissioner
District 5

ST. LUCIE COUNTY

2300 Virginia Avenue
Ft. Pierce, FL 34982-5652
www.co.st-lucie.fl.us

Ph. (772) 462-1408
Fax (772) 462-2131
Suncom 259-1408
e-mail: Chris_Craft@co.st-lucie.fl.us

The St. Lucie County Commission voted 6 to 0 against a 1700MW PC plant proposed by FPL. Commissioner Chris Craft traveled to the Taylor County Commission hearing to advise them on St. Lucie's experience.

World Gasification Survey: Summary Operating Plant Statisti 2004

117 Operating Plants

385 Gasifiers

Capacity~**45,000** MWth

Feeds

Coal **49%**, Pet. Resid. **36%**

Products

Chemicals **37%**, F-T **36%**, Power **19%**

Growth Forecast **5% annual**

Operating IGCC Projects

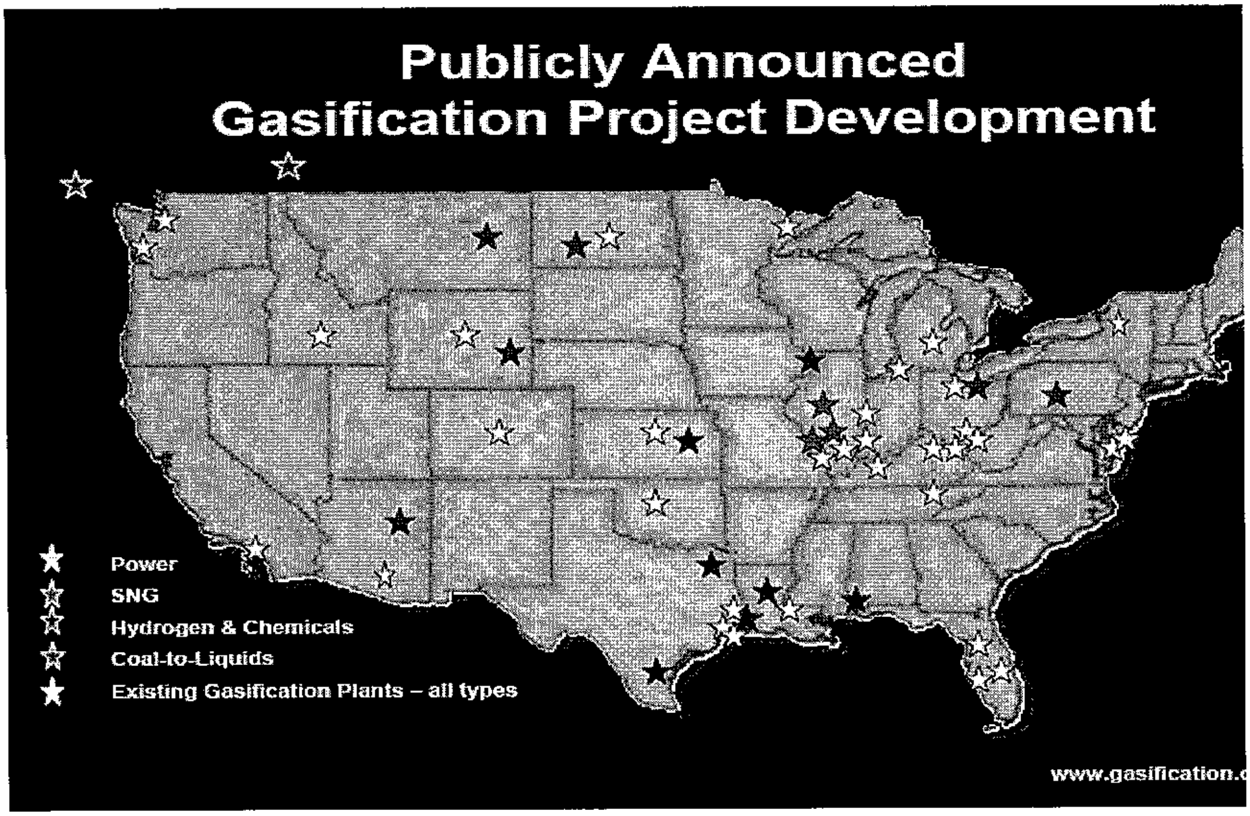
Project – Location	COD	Megawatts	Feedstock - Products
Nuon (Demkolec) – Netherlands	1994	250	Coal - Power / Coal
Wabash (Global/Cinergy) – USA	1995	260	Coal/Petroleum Coke – R
Tampa Electric Company – USA	1996	250	Coal/Pet. Coke – Power
Frontier Oil, Kansas – USA	1996	45	Coke – Cogeneration
SUV – Czech Republic	1996	350	Coal – Cogeneration
Schwarze Pumpe – Germany	1996	40	Lignite - Power & Methan
Shell Pernis – Netherlands	1997	120	Visbreaker Tar - Cogen &
Puertollano – Spain	1998	320	Coal/Coke – Power
ISAB: ERG/Mission – Italy	2000	510	Asphalt – Power
Sarlux: Saras/Enron – Italy	2001	545	Visbreaker Tar - Power, S
Exxon Chemical – Singapore	2001	160	Ethylene Tar – Cogenera
API Energia – Italy	2001	280	Visbreaker Tar - Power &
Valero Refining – Delaware, USA	2002	160	Coke – Repowering
Nippon Refining – Japan	2003	340	Asphalt - Power
EniPower – Italy (in start-up)	2006	250	Asphalt - Power

NETL

Total IGCC Megawatts – 3,880 MW
Total Experience, Operating Hours on Syngas = Almost 1,000,000 hours

NETL Meeting with Wyo

Source: Department of Energy/NETL Presentation, <u>Overview of Coal Gasification</u>
Gary Stiegel, presented at NSTAR Meeting, Pittsburgh, PA, Oct. 27,2006.



Source: Phil Amick, "Experience with Gasification of Low-Rank Coals," presented at Workshop on Gasification Technologies, Bismark North Da

- In the United States, there are 40 to 50 IGCC and gasification projects that are under development. Examples include the following IGCC projects:
- **Two 629 MWe IGCC plants** to be built by the nation's largest utility, American Electric Power Company (AEP), in Ohio and West Virginia scheduled to be operational in 2010;
- **600 MWe IGCC plant** proposed by the nation's fourth largest utility, Cinergy (now part of Duke), near Edwardsport, Indiana;
- **550 MW IGCC plant** planned by Mississippi Power Company in Kemper County, MS
- **630 MW IGCC** plant proposed by Tondu Corp. in Corpus Cristi, Texas
- **630 MW IGCC plant** planned b in Polk County, FL to operate ir
- **630 MW IGCC plant** proposed Washington
- **366 MW IGCC plant** proposed
- **Three repowering projects** to convert them to IGCC by NRG **would be 630 MW**
- **500 MW IGCC plant** to be buil CO2 capture for enhanced oil r
- **Two 630 MW IGCC plants** pro Group (one in Illinois and one i
- **Two 606 MWe IGCC units** in I Excelsior Energy

Source: John Thompson, Desert Rock testimony, page 7, November 6, 2006 and DOE press release Nov. 3

US Gasification Development
Coast to Coast, and North to South

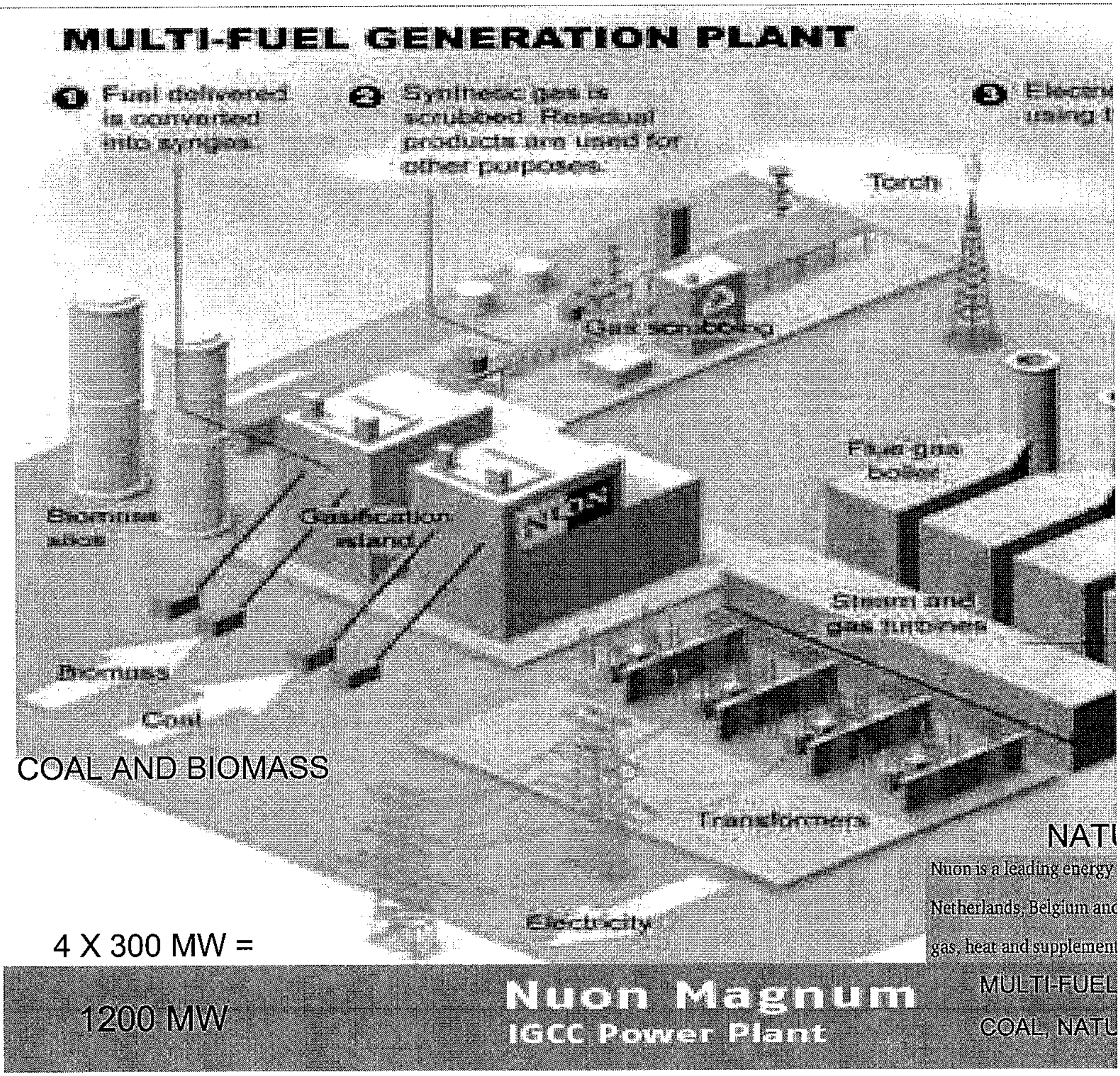
- American Electric Power OH, WV
- Agrium/Blue Sky AK
- Baard Generation OH
- BP/Edison Mission CA
- Cash Creek Generation KY
- Clean Coal Power IL
- DKRW WY
- Duke/Cinergy IN
- Energy Northwest WA
- Erora Group IL
- Excelsior Energy MN
- First Energy/Consol OH
- Leucadia National LA
- Madison Power IL
- Mountain Energy ID
- NRG Energy DL
- Orlando Util/Southe
- Otter Creek MT
- Power Holdings IL
- Rentech MS
- Royster Clark/Rente
- Southeast Idaho ID
- Steelhead Energy Il
- Synfuel OK
- WMPI PA
- Xcel Energy CO

Most large projects are for power, but also substitute natural gas and

NETL Meeting with

Courtesy of Burns

**Source: Department of Energy/NETL Presentation, <u>Overview of Coal Gasification Techn</u>
Stiegel, presented at NSTAR Meeting, Pittsburgh, PA, Oct. 27,2006.**


MULTI-FUEL GENERATION PLANT
1 Fuel delivered is converted into syngas.
2 Synthetic gas is scrubbed. Residual products are used for other purposes.
Torch
Gas scrubbing
Flue-gas boiler
Biomass silos
Gasification island
NUON
Steam and gas turbines
Biomass
Coal
COAL AND BIOMASS
Transformers
Electricity
4 X 300 MW =
1200 MW
Nuon is a leading energy
Nuon Magnum
IGCC Power Plant
MULTI-FUEL

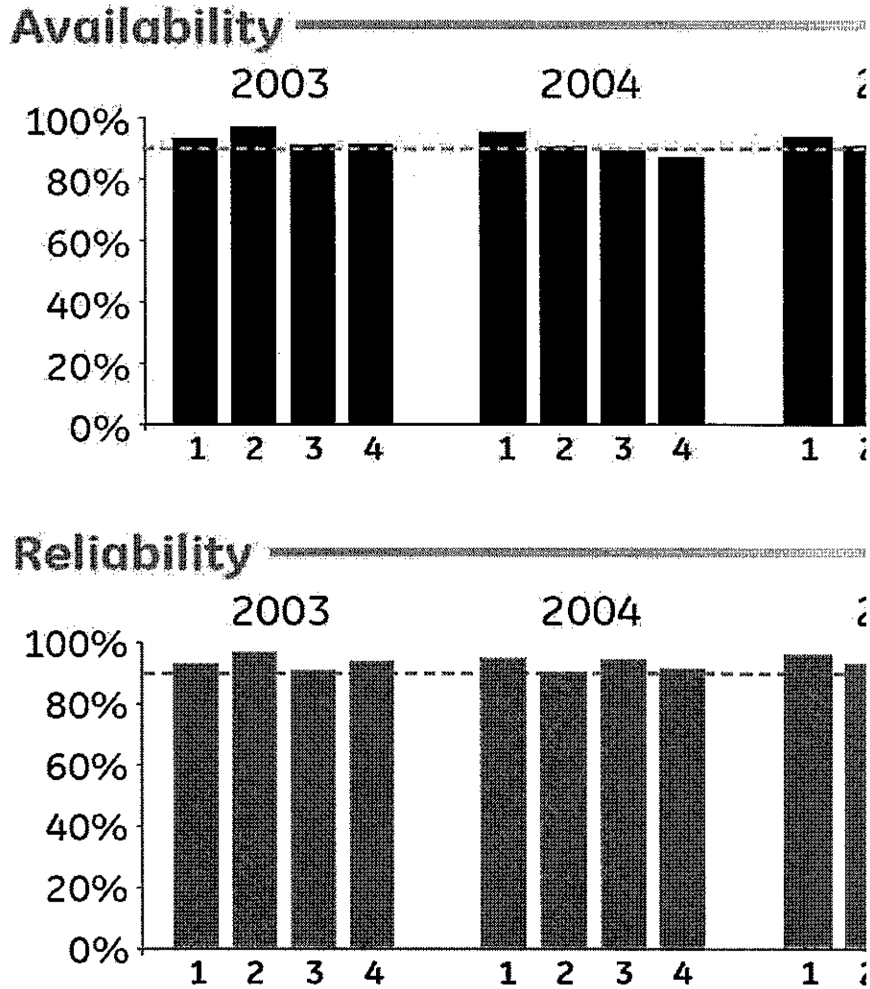
Availability & Reliability – Solids Gasif in China

GE Technology in China Four Coal Plants

Availability = (1-(unplanned outage +planned outage) /8760)*100%

Reliability = (1-(unplanned outage) /8760)*100%

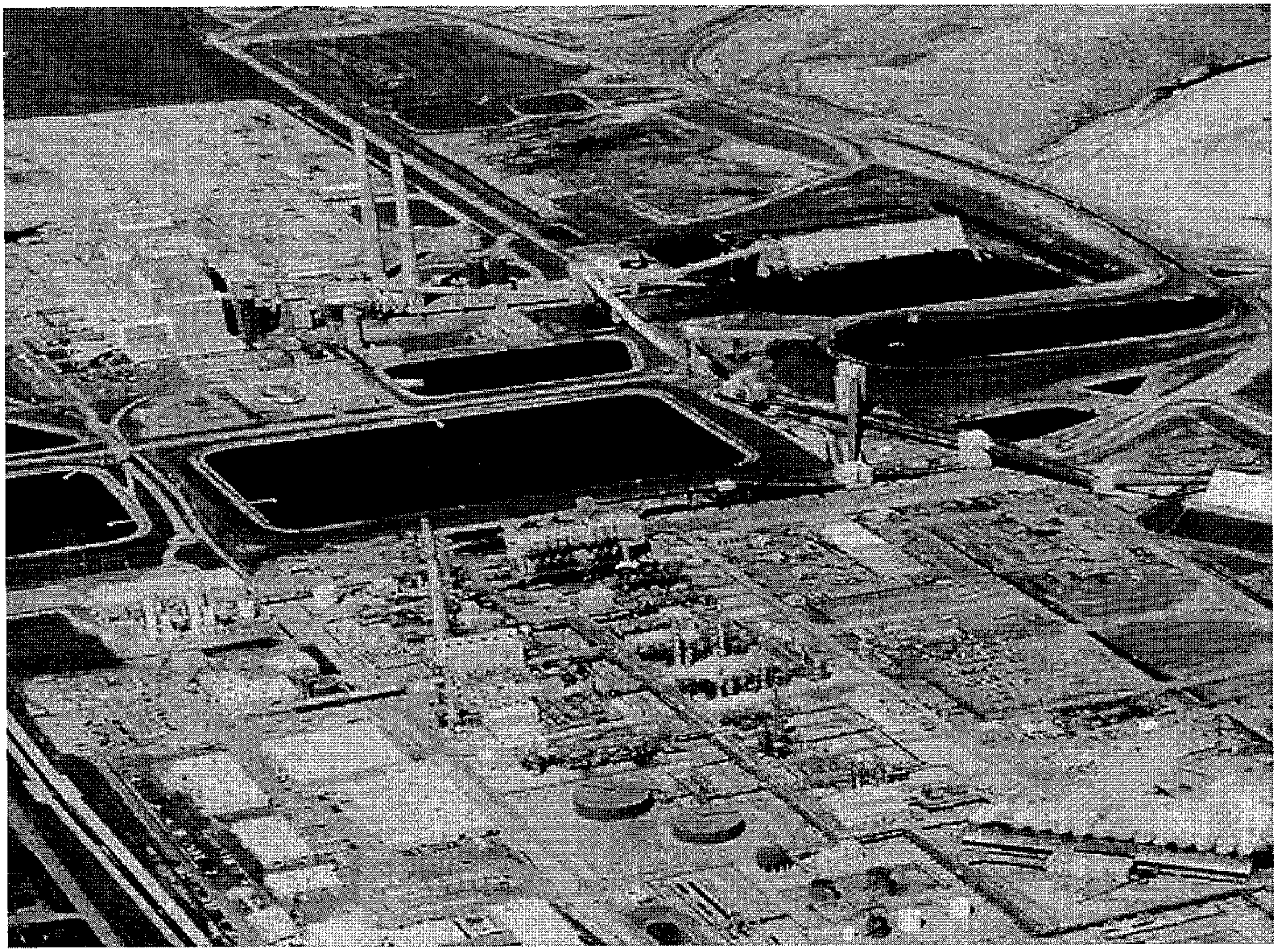
imagination at work



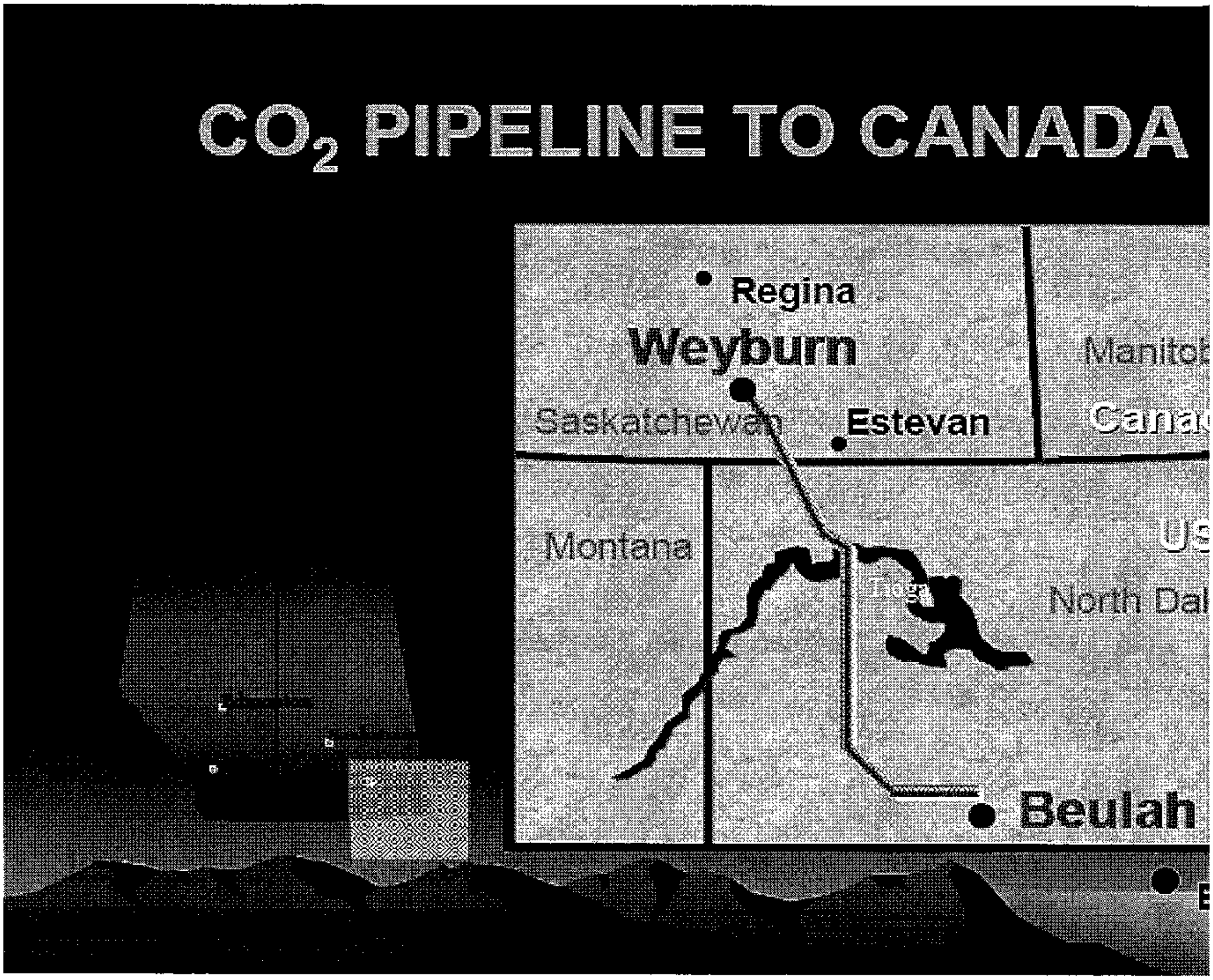
- **Source: Commercial Experience of GE's Gasification Tech by Qianlin Zhuang, GE Energy, Presented at GTC, Oct 3,**

THE GREAT PLAINS SYNFUELS PLANT

The Gasification Plant shown in the foreground began Operating in 1984 in North Dakota & uses 6 million
to Produce 54 Billion cubic feet of Synthetic Natural Gas (SNG) and 4 million tons per year of Carbon
The Antelope Valley Power Plant shown in the background uses 5 million tons of Lignite Coal for tl

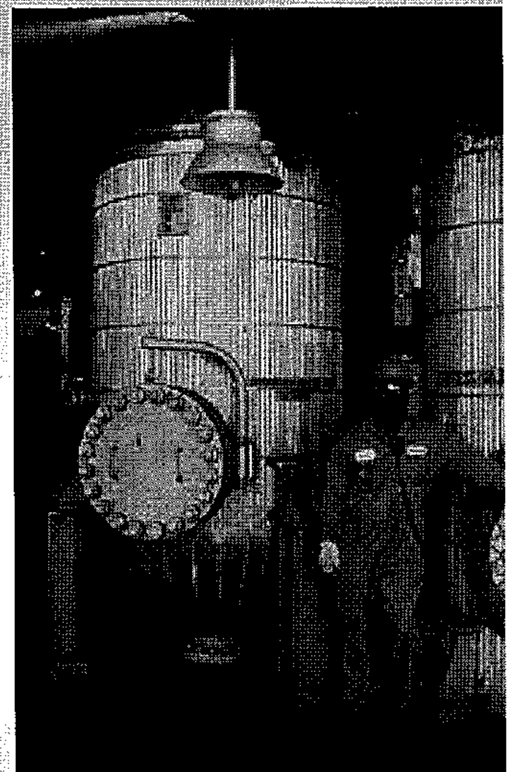


(Source: "The New Synfuels Energy Pioneers" by Stan Stelter, Introduction by Former President
published by Dakota Gasification Co.- 2001, A subsidiary of Basin Electric Power Coopera



(Source: Experience Gasifying ND Lignite by Al Lukes, Dakota Gasificatioı
The Great Plains Synfuels Plant presented at the Montana Energy Future

EASTMAN GASIFICATION SERVICES COMPANY



Vapor-Phase Mercury Removal

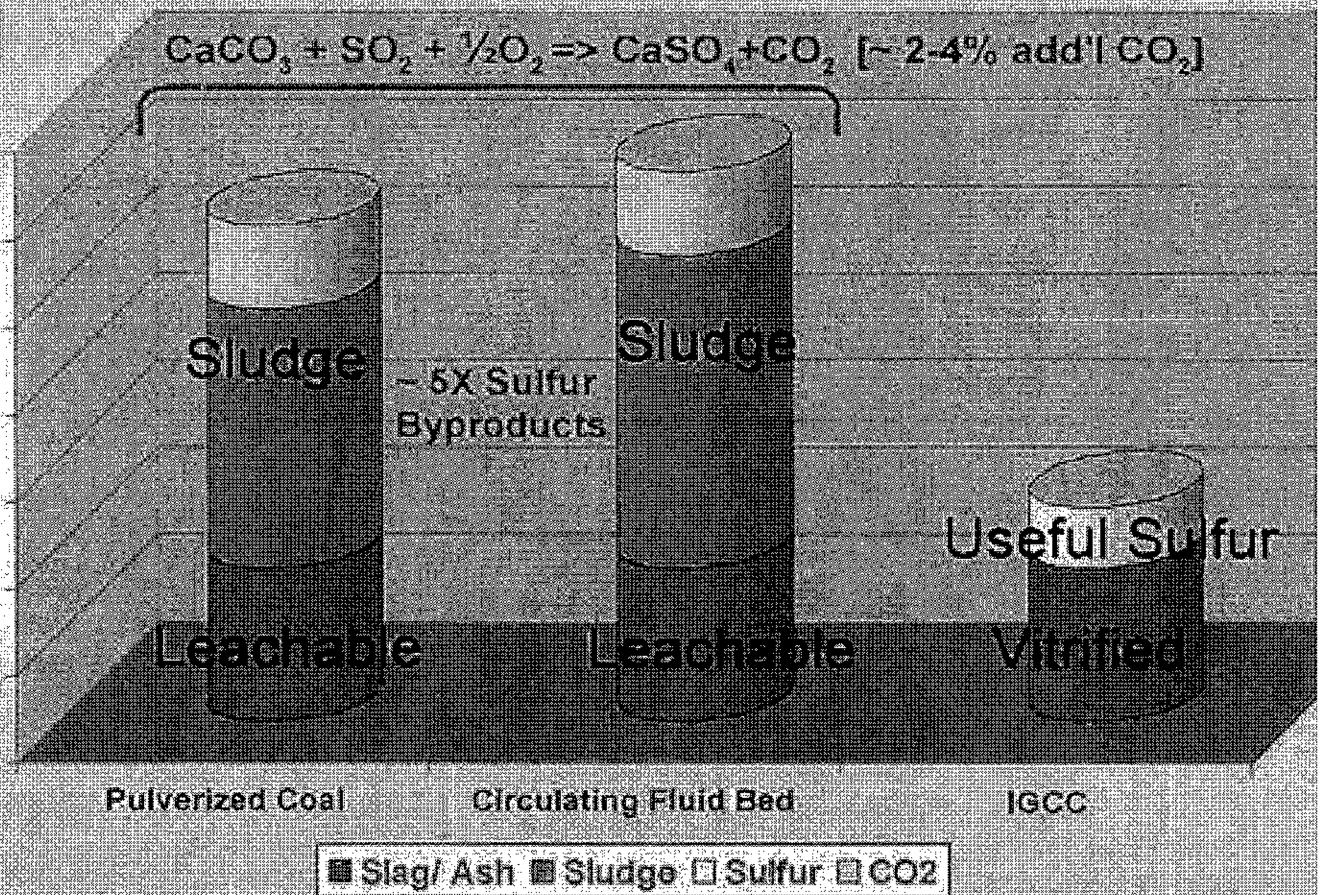
>94% Removal

Demonstrated for 21 years at East

The cost of volatile mercury removal by IGCC is estimated to be < $0.25/MWh, alm magnitude lower than for PC technologies using activated carbon, according to a 20 by Parsons (DOE Report, "The Cost of Mercury Removal in an IGCC Plant", Sept

EAS

IGCC: Lowest Collateral Wa

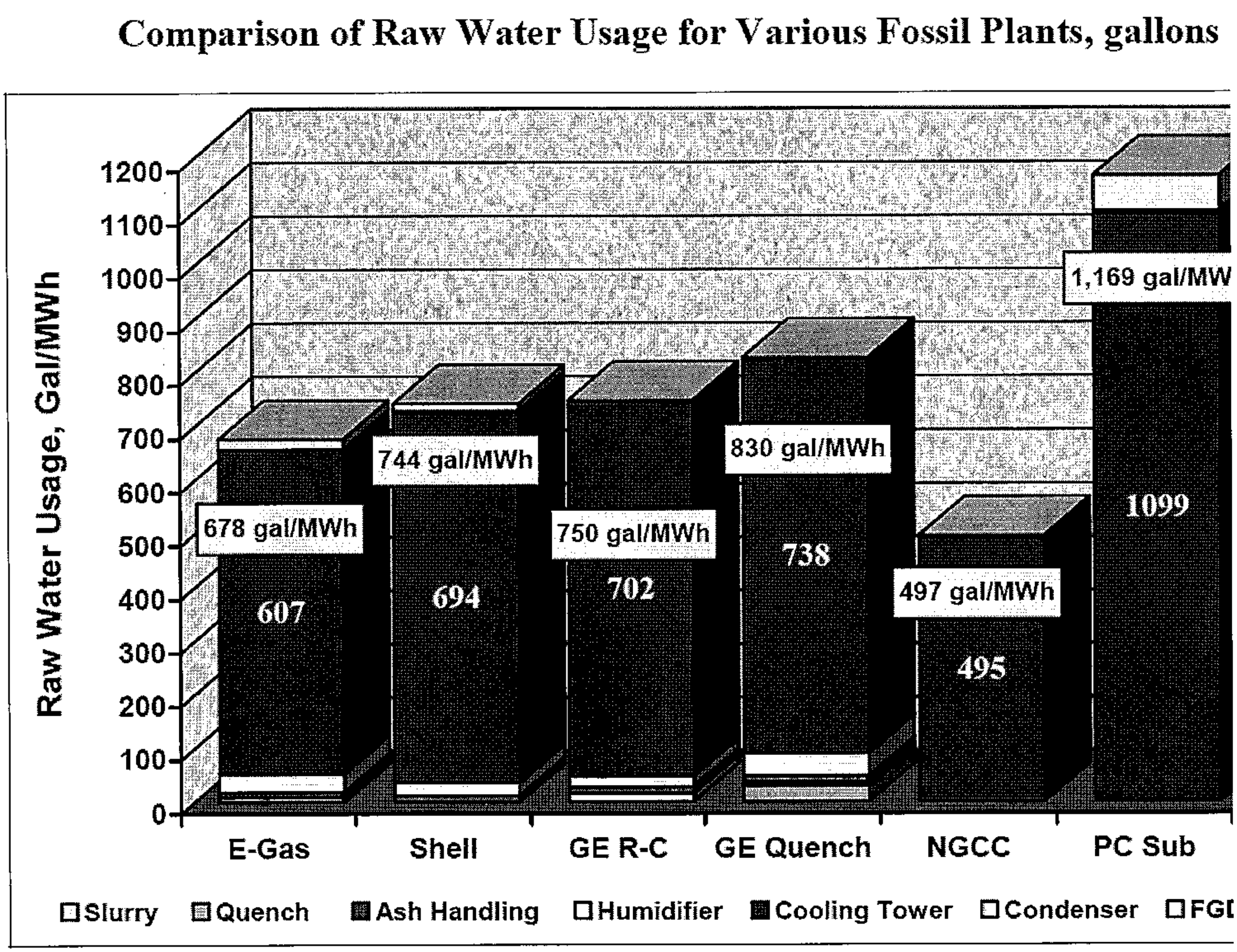


No Add'l CO_2 Associated with Sulfur Removal f

Slide provided by G.E. Power Systems

EASTM

30% to 40% Less Water Usage With IG(



Source: Power Plant Water Usage and Loss Study, DOE/NETL Report, August 2005, b