ORIGINAL

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 070098-EI
FLORIDA POWER & LIGHT COMPANY

IN RE: FLORIDA POWER & LIGHT COMPANY'S PETITION TO DETERMINE NEED FOR FPL GLADES POWER PARK UNITS 1 AND 2 ELECTRICAL POWER PLANT

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DIRECT TESTIMONY & EXHIBIT OF:

DAVID N. HICKS

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF DAVID N. HICKS

DOCKET NO. 07____-EI

JANUARY 29, 2007

Q. Please state your name and business address.

A. My name is David N. Hicks. My business address is Florida Power & Light, 700 Universe Boulevard, Juno Beach, Florida 33408.

Q. By whom are you employed and what is your position?

A. I am employed by Florida Power & Light Company ("FPL" or the "Company") as a Senior Director of Project Development. In my position at FPL, I have responsibility for the development of power generation projects to meet the needs of FPL's customers.

Q. Please describe your duties and responsibilities with regard to the development of solid fuel generation to meet FPL customer needs.

A. Commencing in the summer of 2003, I was assigned the responsibility for leading the investigation into the potential of adding new solid fuel generation to FPL's system, and the subsequent development of new solid fuel generation additions to FPL's power generation fleet. I was responsible for the development and permitting team for the Southwest St. Lucie Power Park ("SWLPP"). I am currently leading the development and permitting team for the FPL Glades Power Park ("FGPP").

Q. Please describe your education and professional experience.

A. I received a Bachelor of Economics degree from the University of Hawaii-Manoa in 1983 and a Masters of Economics degree from the University of California-Santa Barbara in 1987. I have over 18 years experience in the power generation industry, including power plant asset management, power plant development due diligence, power plant site development and permitting, and utility system modeling.

Q. Are you sponsoring an exhibit in this case?

A. Yes. I am sponsoring an exhibit that consists of the following documents:

Document No. DNH-1	FPL's Report on Clean Coal Generation, March 2005
Document No. DNH-2	Clean Coal Technology Selection Study
Document No. DNH-3	FGPP Development Milestones
Document No. DNH-4	FGPP Vicinity Map
Document No. DNH-5	FGPP Project Boundary Aerial
Document No. DNH-6	FGPP Process Diagram Overview
Document No. DNH-7	FGPP Process Diagram Coal Handling System
Document No. DNH-8	FGPP Process Diagram Limestone Handling System
Document No. DHN-9	FGPP Process Diagram Byproduct Handling System
Document No. DNH-10	FGPP Site Plan Overall

Document No. DNH-11	FGPP Site Plan Power Island
Document No. DNH-12	FGPP Site Plan Typical Elevations
Document No. DNH-13	FGPP Fact Sheet
Document No. DNH-14	FGPP Overall Water Balance

Q. What is the purpose of your testimony in this proceeding?

A. My testimony provides an overview of the technology and site selection processes used by FPL in arriving at its proposed generating plant contained in the Need Application submitted to the Florida Public Service Commission (the "FPSC" or "Commission") in this proceeding. My testimony describes the specific site and unit characteristics for the ultra-supercritical pulverized coal ("advanced technology coal" or "USCPC") plant proposed for the FGPP site, including the size, number and type of units, the heat rate and operating characteristics (i.e., equivalent availability factor, equivalent forced outage rate, capacity factor, and operating costs), emissions control equipment, and the fuel types that will be utilized in the plant.

Q. Please summarize your testimony.

A. Beginning in the summer of 2003, FPL conducted an extensive investigation of the potential of adding solid fuel generation to its resource mix. After a careful and thorough analysis of available technology options and fuel supply issues, and after conducting a comprehensive siting study, FPL concluded that the addition of a USCPC plant, augmented with a complete suite of state-of-the-art emissions control equipment, and plant design that will allow for the recycling of combustion and pollution control byproducts into useful commercial products, will provide FPL's customers reliable, cost-effective fuel diversity employing proven, state-of-the-art generation and pollution control technology.

I. OVERVIEW AND TECHNOLOGY SELECTION

Q. Please summarize FPL's actions since 2003 regarding the potential addition of solid fuel generation to FPL's generation resource portfolio.

A. FPL's actions since the summer of 2003 have been directed towards (1) analyzing the conditions under which the addition of solid fuel generation would be beneficial to FPL's customers, (2) refining the solid fuel addition strategy to enhance the benefits and reduce risks to its customers, and (3) implementing that addition as early as is reasonably possible.

FPL's substantive actions towards bringing solid fuel generation into its system include:

- FPL conducted and disseminated a comprehensive study on current opportunities and issues regarding solid fuel generation (***FPL's Report on Clean Coal Generation, March 2005***). This study was the result of over a year of engineering due diligence, commercial negotiation, and analytical review.
- A dedicated team was staffed to develop all necessary aspects of FPL's future advanced technology coal projects including: local approvals and

public outreach, environmental issues and concerns, and a considerable effort to obtain competitive rail transport and coal terminal agreements.

- FPL contracted with Sargent & Lundy to develop conceptual power plant designs.
- FPL contracted with Worley-Parsons to develop detailed design engineering plans.
- FPL has initiated procurement of major equipment, which includes the boilers, steam turbines and the pollution control equipment. In addition, FPL has secured engineering, procurement and construction pricing for FGPP.

Q. Please summarize FPL's primary conclusion regarding available solid fuel generation technologies.

A. After a careful evaluation of the current state of solid fuel generation technology design and air quality control systems, FPL concluded that significant improvements had been made in solid fuel generation, emissions control technologies, and plant design such that FPL had a number of technology options, all of which would provide fuel diversity while maintaining FPL's leadership position as an environmental steward by being protective of the environment.

Q. What technologies provided FPL options for new solid fuel generation additions?

A. The potential technologies included sub-critical pulverized coal ("SPC"), USCPC, circulating fluidized bed ("CFB"), and integrated gasification combined cycle ("IGCC"). A discussion of each of these technologies is included in ***FPL's Report on Clean Coal Generation, March 2005***, a copy of which is attached as Document No. DNH-1.

Q. Which technology did FPL ultimately select?

A. FPL selected USCPC, an advanced form of the supercritical technology.

Q. Please describe the evaluation process that led to the selection of the USCPC technology.

A. Initially, basic configurations were developed for each of the potential technologies for a target level of 1,200 to 1,700 MW of new solid fuel fossil generation. Each of the technologies was reviewed and the configurations developed in a scaled-up size consistent with commercial availability. For the USCPC steam generator technology, unit sizes selected were 600 and 850 MW, which were unit sizes already commercially available at the time of the initial analysis. In the case of less mature technologies, CFB and IGCC, unit sizes were configured to account for risk due to scale-up. In the case of the CFB technology, each unit was configured as a 2x300 MW boiler providing steam to a single steam turbine. The IGCC configuration was a unit with a 2-on-1 combined cycle configuration with an output of 600 MW.[1] For each of the alternatives, estimates were developed for unit output, heat rate,

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[1] A combined cycle unit is a combination of combustion turbines (CTs), heat recovery steam generators (HRSGs), and a steam-driven turbine generator (STG). Each of the combustion turbines produce electricity. The exhaust gas produced by each turbine, is passed through a HRSG before exiting the stack. The energy extracted by the HRSG produces steam, which is used to drive a STG. Each CT/HRSG combination is called a "train." Therefore, a combined cycle plant with two trains and one steam turbine would be called a "two on one" (2x1) combined cycle plant.

availability, capital cost, fixed and variable O&M costs, capital replacement costs, and emissions rates. This information was provided to FPL's Resource Assessment and Planning Group, which conducted an economic evaluation analyzing each technology option over a multi-decade period. This long-term economic evaluation, combined with the engineering evaluation of the technologies, identified the USCPC technology as the best coal technology option.

Q. Since deciding on the use of USCPC technology, has FPL continued to study alternative coal technologies?

A. Yes. FPL has continued to closely monitor continuing developments across the country and around the world with respect to solid fuel technology. For example, as part of its efforts to test and verify that its analysis of alternative solid fuel technologies was correct and reasonable, in 2006 FPL retained the Black & Veatch engineering firm to work with the Company to prepare a detailed Clean Coal Technology Selection Study. The purpose of the study was to incorporate the most up-to-date information available in the industry concerning each technology into FPL's technology assessment. Accordingly, each technology scenario involved consideration of the advantages and disadvantages with respect to each technology for the addition of a nominal 2,000 MW of capacity. The study compared SPC, USCPC, CFB, and IGCC technologies for consideration to meet FPL's generation needs in the 2012 to 2014 timeframe. The study uses 2012 as the reference year for cost comparisons between the different technologies. I served as FPL's project lead for the study, and am a co-author of the study. A copy is attached as Document No. DNH-2.

In addition, FPL conducted its own economic analysis of these four coal technologies. Dr. Sim addresses this analysis in his testimony.

Q. Please summarize FPL's conclusions based on the study jointly conducted by FPL and Black & Veatch.

A. Based on the assumptions, conditions, and engineering estimates made in this study jointly conducted by FPL and Black & Veatch, FPL concluded that the USCPC option, by a large and significant margin, is the preferred technology selection for the addition of a nominal 2,000 MW net output at the FGPP site.

For example, the busbar cost of the USCPC case is nearly 10 percent less than SPC, which is the second lowest busbar cost case. USCPC will have good environmental performance because of its high efficiency. Emissions of NOx and PM will be very similar across all technologies. Sulfur emissions would be slightly lower for IGCC than the PC and CFB options, although start-up and shutdown flaring will reduce the potential benefit of IGCC. The lower expected reliability of IGCC, particularly in the first years of operation, could compromise FPL's ability to meet baseload generation requirements and require FPL to run existing units at higher capacity factors.

For the 2012 through 2014 planning time period, USCPC will be the best technical and economic choice for the installation of 2,000 MW of capacity at the Glades site.

Q. IGCC technology, in particular, has garnered significant recent interest in the United States. Please describe FPL's efforts to ensure that it has obtained and relied on the most current and accurate industry information concerning this technology.

A. FPL selected Black & Veatch, a global engineering and construction company, as the co-author of the joint study, in part due to its extensive experience with IGCC, in order to help ensure that FPL has access to the most current industry information in considering and supporting its technology choice for FGPP. FPL is aware of and valued that Black & Veatch is currently providing a wide range of IGCC and gasification engineering services to entities investigating its potential use. Black & Veatch is also a joint venture partner with Uhde, who has a technology agreement with Shell. The purpose of this joint venture is to market IGCC solutions to potential customers. The Clean Coal Technology Selection Study leveraged Black & Veatch's considerable knowledge and expertise in IGCC, and its recent experience in developing life cycle IGCC cost estimates for various customers. For similar reasons, FPL retained Stephen D. Jenkins of URS Corporation, who is an expert in and advocate for IGCC technology, to submit testimony in this proceeding in order to provide the Commission, and the public, with the most current and accurate information concerning IGCC technology.

Q. Please describe the IGCC process.

A. IGCC produces power by converting a solid fuel such as coal into a synthetic combustible gas which is burned in a combustion turbine that is part of a combined cycle power plant. The coal is placed in a gasifier vessel (or reactor) where it is partially combusted in a controlled environment. The combustion exhaust from the gasifier vessel is a combustible gas commonly referred to as "syngas." The syngas is then passed through a clean-up process where particulates, sulfur and other impurities are removed and then it is used as the fuel for a combustion turbine.

"Integration" refers to the interconnection of the gasification and combined cycle parts of the IGCC power plant. For example, heat produced in the gasifier is converted to steam which is routed to and mixed with steam produced in the combined cycle heat recovery system and then the combined steam product is used to drive the steam turbine which produces power. "Gasified" refers to the process whereby the coal is broken down into multiple constituent parts, one of which is the syngas that is used as a fuel to generate power. "Combined Cycle" refers to the process of combining a primary heat source with a heat recovery system to more efficiently use a fuel source to generate power.

Q. Why did FPL choose the USCPC technology over IGCC?

A. FPL determined that USCPC technology will materially outperform all available alternative coal electric generation technologies, including IGCC.

At the most basic level, USCPC technology is proven and reliable in large scale utility applications. In contrast, IGCC is not proven and reliable in large scale utility applications. This is demonstrated by the fact that there are only four operating coal-fired IGCC plants in the world, two of which are in the U.S. Unlike existing USCPC units, existing IGCC units are small (less than 300 MW), and are demonstration projects. USCPC units have been built commercially and have satisfied projections of cost, efficiency, reliability, and environmental performance. In contrast, existing IGCC units have not been built commercially, and despite the economic advantage of receiving substantial government funding have not met projections of cost, efficiency, reliability, and environmental performance. The "next generation" IGCC plants expected to be operational in the 2011-2015 period will be in the 600 MW range. None of the next generation IGCC units have been built; therefore such units have not been proven to be cost-effective, reliable, and to deliver acceptable environmental performance. For all of these reasons, both the current and next generation of IGCC plants are insufficient to meet the fuel diversity goals of FPL for its customers. These points are discussed in greater detail by Mr. Jenkins.

FPL specifically chose the USCPC technology over IGCC for an approximately 2,000 MW solid fuel addition at a new site that would be required to produce reliable, cost-effective baseload power for the following reasons:

(1) USCPC is more reliable than IGCC. USCPC technology has a proven performance record of 90% or greater reliability. In comparison, existing IGCC plants fueled by coal have been able to reach approximately 80% reliability, at best, after five to ten years of operation. In addition, the complexity of an IGCC plant, specifically the complex integration involved in an IGCC design, has limited its performance.

(2) The USCPC emissions profile is generally similar to IGCC, and the lower reliability of IGCC creates higher emissions from restarts and replacement power while the IGCC is restarting. The USCPC technology, coupled with an initial extensive array of pollution control equipment, will produce an emissions profile as good as, if not better than, that of the "next generation" IGCC plant. FPL's USCPC plant will achieve a 90% mercury removal rate, which is on par with "next generation" IGCC. USCPC plants can be built with a footprint allowing more advanced emissions control equipment when it becomes commercially viable.

(3) USCPC technology is more efficient than IGCC. USCPC technology is highly efficient, meaning substantially less coal is used to produce the

same amount of electricity with fewer emissions than older, conventional coal plants. USCPC is more efficient than existing and next generation IGCC plants (i.e. USCPC uses less coal to produce the same amount of electricity).

(4) Life cycle costs of the USCPC technology are substantially lower than those of IGCC technology. As demonstrated in the joint study, the lifecycle levelized delivered busbar cost of an IGCC plant is more than 40% higher than that for a similarly sized USCPC plant. Cost differences are even greater when comparing the "next generation" 600 MW IGCC reference plants being developed to the commercially available 980 MW USCPC sizing chosen by FPL.

II. SITE SELECTION

Q. Please describe FPL's work to obtain an acceptable site for its proposed coal-fueled units.

A. FPL performed an independent analysis of the local permitting requirements in the most likely candidate counties for development, conducted meetings with local leadership committees, and performed other information-gathering activities designed to ascertain the level of receptivity of those counties to the economic benefits associated with the construction and operation of an advanced technology coal-fired electric power plant.

The effort also included a comprehensive study of potential sites, based on the following six criteria:

(1) Rail access that would foster coal transportation competition at origin and destination for the delivery of domestic and foreign coal and petroleum coke;

(2) Adequate property to site a large coal-fired power plant, and required support facilities;

(3) Adequate water supplies;

(4) Location of property considering transmission proximity to FPL's major load centers;

(5) Location of property allowing feasible transmission interconnection and integration; and

(6) Site selection considering the goal of minimizing the environmental impediments to permitting (e.g., wetlands, threatened and endangered species, contamination, etc.).

Applying the six key criteria discussed above, FPL chose its proposed site in Glades County. My testimony below provides a detailed description of the proposed FGPP site.

To date, FPL has obtained Glades County site plan approval, and resolutions of support from five different groups including government agencies and economic development. Groups that have passed resolutions include: the

Moore Haven City Council, the Glades County Commission, the Glades County Economic Development Council, the School Board of Glades County and Florida's Heartland Rural Economic Development Initiative.

Q. Was the Glades site the first site proposed by FPL?

A. No. Prior to the selection of the Glades site, FPL selected a site in St. Lucie County. The St. Lucie County Commission did not approve the required rezoning and conditional use application necessary to complete development of this site.

Q. Please provide an overview of the major development milestones for FGPP.

A. It is important to note that FPL must overcome a number of significant challenges before it can proceed to construct a coal-fueled unit. It must obtain local zoning, permits and/or authorizations for the new site. In addition, once the coal-fueled addition is granted a determination of need, approval by Florida's Power Plant Siting Board is required. Obtaining all the numerous governmental approvals in a timely manner is not assured. A schedule of the important development milestones for the FGPP is contained in Document No. DNH-3.

III. OVERVIEW OF PROPOSED FPL GLADES POWER PARK

Q. Please provide an overview of FGPP.

A. The FGPP project involves the proposed construction of FGPP 1 and 2. Each unit will be a solid fuel-fired coal generating unit with a nominal net electrical output of 980 MW. FGPP will be located on an approximately 4,900-acre property located in unincorporated Glades County. The advanced coal technology design selected by FPL is a USCPC steam-electric generating station designed for baseload operation. Bituminous coal, both domestic and foreign supply, will be the primary fuel with the use of up to 20% petroleum coke. The site has direct rail access to the South Central Florida Express, which is connected to two major rail carriers for the delivery of bituminous coal and petroleum coke. The rail access can also be used for delivery of bulk materials such as ammonia and limestone and for the off-site shipment of byproducts such as gypsum and ash. Common associated facilities will include fuel handling and storage facilities for fuel, limestone and ammonia along with handling and storage facilities for byproducts such as gypsum and ash.

Q. Please describe the location of the FGPP site.

A. The site is located approximately four miles Northwest of the town of Moore Haven in an unincorporated area of Glades County. Site access will be from State Road 78, which is approximately one mile to the East of the site.

Document No. DNH-4 is a vicinity map of the area surrounding the site, showing various roads and the town of Moore Haven.

Q. What are some of the surrounding land uses and features of the site?

A. Document No. DNH-5 is an aerial photo of the site, showing the property boundary along with other surrounding features. The general area surrounding the site consists of undeveloped land currently owned by private landowners, generally to the North and West, and agricultural land, generally to the East and South. The town of Moore Haven is to the Southeast. Lake Okeechobee is located East of the site. The site has direct rail access, which abuts the entire Southern boundary of the site.

IV. DESIGN

Q Please describe the proposed electric generation technology for FGPP.

A. Each unit will consist of a supercritical steam generator (boiler), one steam turbine generator ("STG"), a mechanical draft cooling tower and a suite of back-end pollution control equipment. The term "supercritical" in the context of a boiler refers to higher steam operating temperatures and pressures than conventional (sub-critical) boiler designs and results in much greater efficiency of the plant. A boiler which produces steam at pressures less than 3,208 psia is sub-critical in design. Boilers which produce steam at pressures greater than 3,208 psia are classified as supercritical. For FGPP, the operating pressure and temperature will be approximately 3,700 psia and 1,130°F which would classify it as a supercritical boiler. An ultra-supercritical design, as classified by the Department of Energy, is when the pressure is greater than 3,600 psia with temperatures exceeding 1,100°F. Because the proposed FGPP meets the definition of ultra-supercritical, FPL refers to the FGPP technology as ultra-supercritical.

Q. Please describe the facilities that are proposed for FGPP.

A. Document No. DNH-6 shows an overall process diagram of FGPP. As I just discussed, each unit's power island will consist of a supercritical pulverized coal steam generator, a steam turbine generator, a mechanical draft cooling tower, and a suite of pollution control equipment. Coal and petroleum coke will be delivered to the site via rail cars that will be unloaded and transferred to either an active or inactive storage pile. The active storage area will be designed to hold approximately three-days of fuel supply while the inactive storage area will have the ability to store up to 60-days of fuel.

Fuel will be reclaimed from the active storage area and conveyed to a crusher tower were the fuel is processed by crushing it to a specified grain size. The crushed fuel will then be transferred to fuel storage silos that will feed the coal into the boiler for combustion. Document No. DNH-7 shows a more detailed process flow diagram of the coal handling system.

Another significant material delivery and storage feature of the facility will be for limestone, which will be used as part of pollution control equipment, more specifically the Wet Flue Gas Desulphurization ("WFGD") system. The limestone will also be delivered by rail to the site, and will be unloaded and transferred to a covered storage area. The limestone will be reclaimed and transferred to a preparation building prior to use in the WFGD system. Document No. DNH-8 shows a more detailed process flow diagram of the limestone handling system.

Byproduct handling and storage for FGPP would include facilities for fly ash, bottom ash, and gypsum. These are byproducts from either the combustion process (ash) or from the removal of sulfur dioxide from the flue gas. In all three cases, the byproducts are collected and processed for off-site recycling. In addition, a permanent long term byproduct storage area will be provided for off-specification material and for use in the event that recycling opportunities are interrupted or otherwise unavailable. Document No. DNH-9 shows a more detailed process flow diagram for the ash and gypsum byproduct facilities.

Q. How will the site be configured with all the various facilities that you have generally described?

A. As shown in Document No. DNH-10, the power plant has been located essentially in the center of the proposed 4,900 acre site. This will provide FPL with the maximum separation distance from the power plant to the property boundaries, helping minimize impact on off-site land uses and plant visibility. Document No. DNH-11 shows a more detailed plan view of the two power islands.

Other prominent power-island related features of the site are shown in Document No. DNH-10. These include the byproduct and material delivery, handling and storage facilities to the North of the power islands, long term byproduct storage facilities to the Northeast, water storage ponds to the East, electrical interconnection and heat dissipation systems to the South, and temporary construction areas to the West.

Document No. DNH-12 shows typical elevation views of the various facilities that I have described.

Q. What are the expected operating characteristics of FGPP 1 and 2?

A. The units are being designed with state-of-the-art performance features, including an extremely efficient power generation cycle design. The projected output of 980 MW per unit with an average predicted heat rate of 8,800 Btu/kWh over the useful life of FGPP will make it among the most efficient coal-fired electric generating facilities in the United States. The ultra-supercritical technology that FPL will be applying is proven, having been applied at facilities in Japan and Europe. Document No. DNH-13 provides a summary of the projected performance characteristics for FGPP.

Q. Please describe the types of fuel the FGPP units will be able to use, including any fuels for start-up.

A. FGPP will be able to use domestic and foreign bituminous coal, as well as petroleum coke, as fuel during power production operations. Low sulfur fuel oil will be used as the startup fuel.

Q. Please describe how the fuels will be delivered to the site, off-loaded and stored.

A. The fuels will be delivered to the site by train, off-loaded mechanically, and stored in both short-term and long-term coal storage facilities.

Q. What environmental controls will be installed as part of FGPP?

A. Environmental compliance is important to FPL's business, both as an environmental steward and because FPL is required to comply with applicable environmental laws and regulations. Other federal and state agencies will fully review the environmental compliance of FGPP. However, in this filing, FPL has included information with respect to environmental compliance in order to provide assurance to the Commission that these, as well as other legal and regulatory requirements, will be satisfied through FPL's construction of FGPP, and so that the Commission is informed concerning the expected costs of environmental compliance. To this end, FPL will install and operate those environmental controls necessary to comply with all applicable environmental laws and regulations.

For example, from an air emissions compliance perspective, environmental controls will be installed to control emissions of nitrogen oxides (NOx), sulfur oxides (SO_2 and SO_3), mercury and particulate matter. Sources of air emissions consist of FGPP's two supercritical boilers, two mechanical draft-cooling towers, two emergency generators, the auxiliary boiler, and the material handling facilities. FPL's witness Mr. Ken Kosky discusses FGPP's environmental compliance in further detail.

Q. Please describe environmental control processes that will be used to control NOx emissions from FGPP.

A. NOx is a chemical byproduct formed by the combustion of fossil fuels such as oil, natural gas, and coal. NOx formation in the two supercritical boilers will be minimized through application of good combustion controls, particularly by controlling combustion temperatures and by properly staging combustion. The boilers will minimize NOx production by using low-NOx burners ("LNB") and over-fire air ("OFA"). Additional environmental controls for NOx will include a post-combustion environmental control process further reducing NOx emissions. The post-combustion technology being proposed for FGPP is Selective Catalytic Reduction ("SCR"). SCR technology is a proven and widely used post-combustion NOx-control technology that utilizes the selective reaction of ammonia with NOx in the presence of a catalyst. In the process, ammonia is injected into the flue gas upstream of a catalyst. The selective reduction reactions occur on the surface of the catalyst to transform nitrogen oxides into water and nitrogen. Overall, the removal efficiency of the NOx environmental controls will be greater than 90%.

Q. What environmental controls will be installed to control SO_2 and SO_3?

A. The primary source of sulfur compounds from the combustion of fossil fuels comes from the fuel itself, with very minimal contribution from the air being introduced into the boiler. It is for this reason that the application of good combustion controls will not significantly minimize the formation of sulfur dioxides. For pulverized coal-fired utility boilers, SO_2 emission reduction is accomplished by treating the post-combustion flue gas. The technology being proposed for FGPP will involve the use of a WFGD process. The wet scrubbing process involves a reaction in which the SO_2 is transferred to a scrubbing liquid, which, in this case, is a calcium-based wet limestone. The resulting byproduct of the process after further oxidation is a marketable byproduct known as gypsum, which is used in the manufacturing of building materials such as wallboard. Overall, the removal efficiency of the SO_2 environmental controls will be greater than 98.5%.

SO_3 produced through the combustion process is condensed into an aerosol in the flue gas desulfurization system. The technology being proposed for FGPP will involve the use of a Wet Electric Static Precipitator ("WESP"). This technology utilizes an electric field which imparts an electric charge to the aerosol particles in the flue gas. These particles are attracted to collector plates. Water is used to wash the particles from the collector plates and out of the flue gas stream. Overall, the removal efficiency of SO_3 achieved through environmental controls will be greater than 90%.

Q. Please describe the environmental controls that will be installed for the control of particulate matter.

A. The primary sources of particulate matter emissions from the facility will be from the combustion of the fossil fuel in the boiler, emissions from the mechanical draft cooling towers, and fugitive emissions from the handling facilities associated with bulk materials such as fuel, limestone and byproducts.

With respect to the cooling towers, water droplets exhausted into the atmosphere as part of the cooling process contain dissolved solids and chemical impurities which come from the original make-up water supply. In order to minimize the release of these water droplets into the atmosphere, thus minimizing particle matter carry over, drift eliminators will be installed to remove the water droplets from the air stream exhausting from the cooling towers.

Fugitive particulate emissions from bulk material handling and storage facilities will be minimized by equipment design and operating procedures. Materials such as fuel and limestone will be unloaded into bottom dump underground hoppers, which will be protected from wind and which will minimize the generation of fugitive dust. Dust that does get generated from unloading operations will be further controlled using dust collection and suppression systems. Conveyors used for transfer of the bulk materials will be enclosed for minimizing wind-borne fugitive dust. Conveyance points will be designed with either telescoping chutes for stock piling into storage piles, or will be provided with dust collection and suppression systems at the points of on-loading into enclosed hoppers, silos or staging areas for storage. All conveyor transfer points will have a dust collection system.

The major source of particulate matter from FGPP will be from combusting coal in the boiler. Combusting coal and petroleum coke in a pulverized coal-fired boiler produces ash, which is the non-combustible portion of the fuel. Ash is solid and is therefore classified as particulate matter. About 20% of the ash falls to the bottom of the boiler as bottom ash and is removed by the bottom ash system. The remaining 80% of the ash, which does not fall to the bottom of the boiler, is called "fly ash" and is entrained by the flue gases leaving the boiler. The two most commonly used particulate matter environmental controls technologies being used in the industry today are electric static precipitators ("ESP") and fabric filters. ESP technology uses an electric field to impart an electric charge to particles in the flue gas. Particles are magnetically attracted to collector plates. Rapping mechanisms, that are operated intermittently, dislodge the collected particles, which subsequently fall into a hopper for collection and disposal. Fabric filter technology, in contrast, removes particulate matter from the flue gas as it passes through a fabric filter media, such as woven cloths or felts. The filters are arranged as a number of cylinders or tubes (commonly referred to as "bags") through which the flue gas is directed. Cleaning of the bags in the fabric filter usually involves shaking, pulse-jet or reverse-air methods. Dislodged particulates subsequently fall into a hopper for collection and disposal. Both technologies are highly efficient, providing up to 99.9% removal efficiency. The selected technology for FGPP is a fabric filter.

Q. Please describe the environmental controls that will reduce emissions of trace amounts of metals which are released when coal is combusted, such as mercury.

A. Trace amounts of metals are released in the combustion process, which are collected using a combination of pollution controls of the types I have already described in order to achieve compliance with applicable environmental regulations. As an example, the combination of controls is especially important for mercury, one of the trace elements in coal. Mercury removal is enhanced by the SCR where elemental mercury is oxidized into a form that can be readily collected by the particulate and sulfur control systems. Additionally, FGPP will include a sorbent injection system specifically for the control of mercury emissions. The sorbent injection system will oxidize the mercury, further enhancing its collection in the particulate and sulfur removal control systems.

Q. **What are the water requirements for FGPP and how will they be met?**

A. The primary water requirements for FGPP include make-up water to the heat dissipation system, which would consist of mechanical draft cooling towers, water for the WFGD system, process water for cycle make-up into the steam cycle, service water for general maintenance, fire protection water, waste treatment systems, byproduct handling, and fugitive emissions control for material handling operations.

Water for the plant will be from a combination of sources which include Upper Floridan aquifer wells, recycled water from onsite water storage ponds and excess water from adjacent South Florida Water Management District controlled canals. Document No. DNH-14 shows a typical annual water balance with the various sources and usage of the water at FGPP.

Q. **Are the pollution control systems proposed to be installed at FGPP representative of the state-of-the-art in emissions control equipment?**

A. Yes. FPL is proposing to install a complete suite of state-of-the-art, emissions control technology that meets or exceeds the Best Available Control Technology Standard set by the federal Environmental Protection Agency. FPL's witness, Mr. Kosky provides detailed information with respect to these matters in his testimony.

The inclusion of this equipment, along with the plant design to allow for recycling of the byproducts from the combustion and emissions control processes, sets a new standard of excellence for coal-fired electric generating stations in the United States.

Q. Does this conclude your direct testimony?

A. Yes.

FPL's Report on

Clean Coal Generation

Provided to the

Florida Public Service Commission

March 10, 2005

FPL

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List of Figures and Tables

List of Abbreviations

ACI:	Activated Carbon Injection
AFUDC:	Allowance for Funds Used During Construction
BACT:	Best Available Control Technology
B:	Billion
CAIR:	Clean Air Interstate Rule
CC:	Combined Cycle
CFB:	Circulating Fluidized Bed
CFR:	Code of Federal Regulation
CO_2:	Carbon Dioxide
COD:	Commercial Operation Date
DOE:	Department of Energy
DSM:	Demand Side Management
EPA:	Environmental Protection Agency
ESP:	Electrostatic Precipitator
FGD:	Flue Gas De-Sulfurization
FOM:	Fixed Operation & Maintenance Costs
FPSC:	Florida Public Service Commission
Hg:	Mercury
HHV:	Higher Heating Valve
IGCC:	Integrated Gasification Combined Cycle
IRP:	Integrated Resource Planning
LAER:	Lowest Achievable Emissions Rate
LNG:	Liquefied Natural Gas
MACT:	Maximum Achievable Control Technology
MM:	Million
MMBtu:	Million British thermal unit
NAAQS:	National Ambient Air Quality Standards
NG	Natural Gas
NOx:	Nitrogen Oxides

NPDES: National Pollutant Discharge Elimination System

NPGU: Next Planned Generating Unit

NSPS: New Source Performance Standards

OFA: Overfire Air

O&M: Operation & Maintenance Costs

PC: (Subcritical) Pulverized Coal

PSD: Prevention of Significant Deterioration

PVRR: Present Value Revenue Requirements

RFP: Request for Proposal

SCPC: Super Critical Pulverized Coal

SCR: Selective Catalytic Reduction

SIP: State Implementation Plan

SO_2: Sulfur Dioxide

TMDL: Total Maximum Daily Loads

TYSP: Ten Year Site Plan

VOM: Variable Operation & Maintenance Costs

WESP: Wet Electrostatic Precipitator

Executive Summary

Clean Coal Generation Study Report

This Report summarizes the findings of a study FPL performed to ascertain the effect of adding clean coal technology[1] generating units to FPL's generation portfolio, as an alternative to adding only natural gas-fired generation units in the future to meet the needs of FPL's customers.

The Report presents a range of projected net benefits and costs that would be associated with the addition of clean coal generating units and describes the economic analysis performed as part of the study. Key areas of uncertainty related to clean coal generation that could significantly affect the eventual outcome of adding clean coal generation are identified.

The Report explains why FPL concludes that adding clean coal generation is in the best interest of its customers and should be pursued. It also describes what approvals we will seek from the Commission regarding potential outcomes related to the key areas of uncertainty. The types of events and conditions that could cause FPL to defer the effort to add clean coal generation are also discussed.

The Report describes our review of potential clean coal technologies and explains the basis for the selection of supercritical pulverized coal technology as the best clean coal generation choice for FPL's customers, for implementation in 2012 and 2013. It explains the criteria used and the process followed to evaluate candidate sites for clean coal generation additions in this time frame and outlines the steps that will be taken to add clean coal capacity to our generation portfolio beginning in 2012.

In addition, the Report describes coal and petroleum coke sources and characteristics; discusses fuel transportation and delivery issues and costs; explains existing and potential future environmental requirements, compliance alternatives and projected costs; and discusses other government requirements and issues of public interest related to clean coal generation additions.

Reasons for FPL to Add Clean Coal Generation

Maintaining a balanced mix of fuel sources enhances system reliability and helps stabilize the cost of electricity to FPL's customers. By limiting the dependence on any one type of fuel, the effect of a rise in the price of any single fuel on the price of electricity can be mitigated. Similarly, having a diverse fuel mix reduces the effect that an interruption in physical supply or delivery of a specific fuel type could have on our ability to meet our customers' need for electricity. A diverse generation portfolio with a

[1] "Clean coal technology" describes a new generation of energy processes that sharply reduce air emissions and other pollutants compared to older coal burning systems. (excerpt from www.fossil.energy.gov/programs/powersystems/cleancoal/)

variety of technologies also reduces the effect that design or operation problems in one technology could have on system reliability.

Shaping FPL's Diverse Fuel Mix

In the early 1980's FPL was highly dependent on fuel oil-fired generation for serving its customers. As a result, the rise in oil prices that followed the second "oil shock" of 1979 resulted in a significant increase in the price of electricity. Since then, FPL completed St. Lucie Unit 2 which added over 800 MW of nuclear capacity, and added coal-fired generation through its partial ownership interest in, and firm capacity purchase from, St. Johns River Power Park (SJRPP), its partial ownership interest in Scherer Unit 4, its "coal-by-wire" UPS firm coal generation capacity purchase contract with Southern Company, and other firm coal generation capacity contracts with Indiantown Cogeneration L.P., Cedar Bay Generating Co., and Florida Crushed Stone.

During the past ten years FPL has also realized the benefits offered by natural gas fired generation. Combined cycle units offer very low levels of air emissions, as well as low capital costs and high levels of efficiency. These characteristics, combined with the low natural gas prices that existed during the 1990s, made these gas-fired units the most cost-effective choice for our customers. Because of these advantages, FPL added 4,732 MW of gas-fired generation between 1994 and 2004, and will add another 3,038 MW of gas-fired generation by 2007. Moreover, it is anticipated that we will purchase or self-build an additional 2,200 MW of gas-fired capacity between 2009 and 2011 to meet growing customer demand.

Future Generation Capacity Diversity

However, if we continue to add gas-fired generation exclusively through 2013, almost two-thirds of the electricity delivered to our customers in 2013 would be generated using natural gas, while only 12% would be provided by coal. On the other hand, if 1,700 MW of clean coal generation capacity were to be added instead of adding only gas generation, the contribution made by natural gas in 2013 would decrease to 54%, while that of coal would increase to 22%. This latter scenario would provide a more balanced generation portfolio, with a significant hedge against future high gas prices, for the benefit of our customers.

In the last few years, natural gas prices have risen significantly and have become increasingly volatile. By contrast, the price of coal has remained relatively stable. In the future, gas prices are projected to remain significantly higher and more volatile than coal prices. Based on this difference in the projected behavior of natural gas prices and coal prices, adding clean coal generation would provide a very effective hedge against potential future increases in natural gas prices.

In our economic analysis of clean coal generation for 2012 and 2013, we utilized a fuel combination that consists of 40% low sulfur Central Appalachian coal, 40% low sulfur Colombian coal, both of which have plentiful reserves, and 20% petroleum coke. Proven domestic reserves for Central Appalachian coal are estimated to be between 30 and 40 years based on current demand projections, and reserves of Colombian coal are estimated to be between 40 and 50 years. These significant coal reserves support FPL's view that coal prices will remain significantly lower and more stable than gas prices in the future. Our review of petroleum coke capacity indicates that existing and planned coking capacity at domestic and foreign refineries will be adequate to meet market demand.

Even with the addition of 1,700 MW of clean coal generation, FPL will continue to utilize very large quantities of natural gas in its generation portfolio. Because of this, we are also seeking to increase the diversity of our fuel sources and fuel delivery systems by soliciting bids to deliver to our generation system natural gas produced by the re-gasification of Liquefied Natural Gas (LNG). There are abundant natural gas reserves in the Middle East, Latin America, Africa, the former Soviet Union, and Southeast Asia that could be liquefied and transported as LNG to a re-gasification terminal for eventual deliveries of natural gas to the U.S. Having access to these sources would broaden FPL's choices for natural gas in the future.

Our options for significant fuel diversification in the 2012 – 2017 period are limited. Future decisions regarding whether to invest in nuclear generation additions still await resolution of regulatory concerns; there are no geothermal or hydroelectric sources in Florida; and although FPL continues to evaluate wind, solar and microturbine technologies, these technologies cannot contribute significantly to meeting FPL customers' growing capacity needs or our fuel diversity goals due to their higher costs and capacity limitations. Therefore, the most realistic options for diversifying FPL's fuel mix are clean coal generation and LNG. FPL intends to pursue both.

In summary, because adding clean coal generation is one of the two most effective ways to increase the diversity of FPL's generation portfolio by 2013, and because of the significant benefits that a diversified generation portfolio provides, it is important to move ahead to add this technology as part of FPL's generation plan along with new gas generation to meet FPL's customers' future needs.

Technology Selection

FPL conducted an extensive evaluation of the available competitive technologies for the clean generation of electricity from coal and petroleum coke, including subcritical pulverized coal (PC), supercritical pulverized coal (SCPC), circulating fluidized bed (CFB), and integrated gasification combined cycle (IGCC). We concluded from this analysis that pursuing state-of-the-art supercritical pulverized coal technology combined with the best available emissions control technology, would give our customers the best mix of low capital and operating costs, high efficiency, high demonstrated reliability and environmentally responsible conversion of coal to electricity, from among the available clean coal generation alternatives.

The clean coal design selected by FPL in this study is a supercritical, pulverized coal, steam-electric generating station designed for base load operation, with a net power output of 850 MW (summer rating) for each of two units (1,700 MW total). Emissions would be controlled using the best available control technology (BACT). This includes low nitrogen oxide (NOx) burners, overfire air (OFA), and selective catalytic reduction (SCR) for NOx control. A baghouse or electrostatic precipitator (ESP) would be included for particulate control. A wet flue gas de-sulfurization (FGD) system would control sulfur dioxide (SO_2). Finally, a wet-electrostatic precipitator (WESP) would be used for the control of condensable gases. The units would also have design features to facilitate the recycling of generation by-products.

Site Evaluation

As part of its study, FPL performed a comprehensive assessment of potential sites for the addition of clean coal generation capacity to serve its customers. The principal criteria used to evaluate potential sites included: (1) size adequate to accommodate clean coal generation units and the necessary support facilities; (2) cost-effective transmission interconnection and integration; (3) location sufficiently distant from environmentally sensitive areas; (4) adequate access to water supply; (5) access to multiple railroads; and (6) potential for community acceptance to use the site for clean coal generation. FPL evaluated fifteen sites in Florida, Georgia, Alabama, and the Bahamas and has identified a site in St. Lucie County as the best potential site.

Projected Benefits

The results of the study indicate that adding clean coal generation to FPL's generation portfolio would provide significant benefits to FPL's customers:

- Reducing the effect of future gas price spikes on electricity prices by slowing the increase in FPL's use of natural gas and substituting a fuel with low price volatility; and
- Enhancing system reliability by increasing diversity in generation technology, fuel sourcing and delivery.

In addition, adding clean coal generation to our generation portfolio offers the opportunity to lower costs to customers due to the lower cost of coal and petroleum coke. For example, the results of the economic analysis FPL performed utilizing a base set of assumptions depicting our expected or most-likely values for all variables, including FPL's expected gas price forecast, indicate that a clean coal generation plan, which would add 1,700 MW of clean coal generation between 2012 and 2013, would reduce system Present Value Revenue Requirements (PVRR)[2] over 40 years, by $435 million, compared to an all-gas generation plan.

[2] All values in this Report, unless otherwise noted, are provided as present value of revenue requirements in 2004 dollars (PVRR, $2004).

If future natural gas prices were to behave as described in the "high natural gas price sensitivity" then, all else equal, the economic benefit of the clean coal plan to FPL's customers would grow to $1.4 billion.

Areas of Uncertainty

Adding clean coal generation will reduce the effect of natural gas price spikes on the price of electricity. However, the extent to which the addition of clean coal generation as part of FPL's generation plan would also result in lower costs to FPL's customers, compared to an all-gas generation plan, will depend on: (1) the future fuel price differential between natural gas and the combination of coal and petroleum coke; (2) access to diverse sources of coal and petroleum coke, both domestic and foreign; (3) the availability of competitively priced transportation and delivery of coal and petroleum coke to the plant; (4) the cost of complying with currently unknown future environmental requirements; and (5) requirements imposed in the licensing process, and (6) the actual capital cost of the completed clean coal generating plant.

Fuel Price Differential

A sufficiently high price differential between natural gas and coal and petroleum coke is necessary to offset the higher capital and O&M cost of clean coal generation, but the actual fuel price differential could narrow, as well as widen, in the future. If this future fuel price differential is greater than projected, clean coal generation would provide greater savings to the customer. If the differential is smaller than projected it may not be sufficient to offset the greater capital and O&M cost of clean coal generation, although there would still be fuel diversity benefits.

Competitive Fuel Transportation from Diverse Sources

The economic benefit of clean coal generation will depend on FPL's future access to diverse and competing sources of coal and petroleum coke, as well as competitively priced transportation and delivery of these fuels from their sources to the plant. This would require that FPL have access to multiple fuel ports for receipt of coal and petroleum coke transported by water from foreign and domestic sources to Florida or the Southeast U.S., as well as competitive choices for rail delivery of these fuels from those ports, and from domestic coal sources, to the plant.

Existing fuel receiving ports would have to be expanded and/or new ports would have to be developed to meet throughput requirements and provide the necessary competition that would contribute to low transportation costs. In addition, having more than one railroad with the capability to transport coal from available ports to the plant would help us obtain the required low fuel transportation rates. FPL will address this challenge in the fuel transportation plan that will be part of future implementation steps.

Our analysis indicates that without competitively priced fuel transportation it is very unlikely that clean coal generation would be a cost-effective choice.

Environmental Compliance Costs

The results of the economic analysis performed as part of this study indicate that the cost of complying with all currently known environmental requirements that would be applicable to clean coal generating units in 2012 and 2013 would not preclude the addition of clean coal generation from contributing savings to FPL's customers.

However, there is significant uncertainty regarding what additional requirements may be imposed by future legislation or regulation, especially regarding emissions of sulfur dioxide (SO_2), nitrogen oxides (NOx), mercury and carbon dioxide (CO_2). Complying with future additional requirements regarding these substances could involve purchasing emission allowances and/or installing and operating additional control equipment. Neither the potential additional requirements, nor the resulting compliance costs may be known until after plant construction has begun, or until after the plant has been placed in service. This means that the economic outcome of adding clean coal generation would not be known until well after the unit has been in operation. Furthermore, the cost of compliance could be very large.

For example, if high CO_2 compliance costs (consistent with what we currently envision as the worst CO_2 case) are imposed on the clean coal facility in our study and all other factors, including natural gas prices, occur as they are assumed in the expected case, our economic analysis indicates that the savings offered by clean coal generation, compared to an all-gas plan, would be reduced to only $29 million (as opposed to the $435 million savings projected under a situation without stringent CO_2 compliance costs). In other words, the cost of complying with future CO_2 controls, as defined in this scenario would be $406 million. To the extent that future additional environmental requirements are imposed on the other substances, the savings due to clean coal generation could disappear. Conversely, if future natural gas prices behave as noted in the high price sensitivity, customer savings would be approximately $1 billion, even with high CO_2 compliance costs.

Licensing Requirements

Because there is very little recent experience regarding the addition of coal plants in Florida, and because of the unique characteristics specific to each permit process, there is uncertainty regarding the issues that may be raised by the various stakeholders and the requirements or conditions that may be imposed on FPL's clean coal facility by government agencies. Such requirements and conditions could affect the cost of compliance.

Capital Costs

Although the capital cost of clean coal generation is significantly greater than that of gas-fired generation, FPL's analysis shows that based on what is currently known and reasonably expected, this capital cost disadvantage would be offset by the price advantage of coal and petroleum coke relative to natural gas. However, the actual capital cost of completing a clean coal unit could change significantly from what has been estimated, depending upon changes in the cost of equipment, labor and materials that could occur during the seven-year period between 2005 and 2012, when the first clean coal unit would be completed. The very long lead times for development, permitting and construction of clean coal units introduce significant uncertainty regarding the actual capital cost of the completed clean coal unit, which could reduce the projected savings of advanced coal generation.

Commission Recognition of Key Areas of Risk

It is essential that the Commission recognize the existence of these key areas of uncertainty, and of the fact that possible future developments in these areas, or other factors, could cause delays, prevent FPL from implementing clean coal capacity additions, or cause the total cost of these additions to be higher than projected. It is also important that the Commission recognize that the adverse effects of future outcomes relative to these areas of uncertainty, or other unforeseen factors, could become known only after FPL has commenced construction of clean coal generation facilities, or after these facilities have been placed in service.

Consequently, as part of the process leading to the addition of clean coal generation it is very important that the Commission express its recognition that FPL's decision to pursue addition of clean coal capacity is prudent, and in the best interest of FPL's customers. FPL will ask for the Commission's concurrence that, if, due to factors related to one or more of the areas of uncertainty discussed above, or other unforeseen factors, FPL were to discontinue its effort to implement clean coal generation, or if FPL does implement clean coal generation and such factors cause FPL's actual costs for clean coal generation to be greater than projected or greater than they would be for an all-gas generation plan, FPL would be authorized to recover, through the normal cost recovery process, all prudently incurred costs.

Next Steps

As part of the process to add clean coal generation, we intend to identify and fully characterize a specific generating facility as our "Next Planned Generating Unit" (NPGU) to meet our customers' June 1, 2012 need, and issue a Request for Proposals consistent with the Commission's Bid Rule not later than July 31, 2006. Because one of the primary objectives of this capacity addition would be to reduce FPL's reliance on natural gas, FPL would only consider proposals to build, own and operate clean coal generation units in response to its 2006 clean coal RFP. FPL may also choose to solicit clean coal generation proposals to meet its June 1, 2013 need in the 2006 RFP.

FPL anticipates that the current RFP process will not readily accommodate the longer lead times, uncertainties and other issues specifically associated with clean coal generation; therefore, it will be necessary to develop an RFP process that will effectively address the unique attributes of clean coal generation. FPL will advise the Commission when it has completed development of its clean coal generation RFP process and will communicate the details of that process to FPSC Staff.

Between March 2005 and July 2006, FPL's clean coal generation implementation process includes the following additional milestones:

- Obtain all local land use and zoning approvals for the selected site
- Complete a detailed engineering and design study and finalize the engineering design
- Develop FPL's coal and petroleum coke transportation plan
- File FPL's Site Certification Application for its clean coal NPGU
- Prepare and issue a Request for Proposals soliciting proposals to build, own and operate clean coal technology units

We expect that between March 2005 and the time when we issue our clean coal RFP in 2006, those entities that are interested in providing clean coal generation capacity will take the steps necessary to ensure that they are financially viable, and that they are able to submit timely, responsive, competitive proposals. These steps include (but are not limited to): obtaining adequate financial backing; selecting and acquiring rights to a plant site and water resources suitable for clean coal technology units; developing robust fuel sourcing, transportation and delivery plans; developing detailed engineering and design for clean coal generation; and developing a clear understanding of environmental requirements and how to comply with those requirements. In order to meet FPL's customers' needs, the bidding entities must be in a position to place in service clean coal generation capacity on the date(s) specified in the RFP.

Conclusions

Based on its evaluation, FPL concludes that adding clean coal generation as one of the components of its generation capacity plan has great potential strategic value for FPL's customers. Adding 1,700 MW of clean coal generation to the generation portfolio by 2013 instead of adding gas-fired generation would raise the contribution of coal to about 22% and would reduce the contribution of natural gas to FPL's energy supply from 63% to 54%.

Natural gas prices are expected to remain significantly higher than coal prices in the future. Natural gas also is expected to exhibit significantly greater price volatility than coal, as it has historically. Consequently, adding clean coal generation would help make FPL's cost of electricity less susceptible to changes in natural gas prices than it would be under an "all-gas" generation capacity plan, and serve as a hedge against future natural gas price spikes. If, on the other hand, future gas prices were to be lower than currently projected, because of FPL's already extensive and growing use of natural gas in its generating fleet, FPL's customers would benefit significantly from the lower gas prices.

The addition of clean coal generation would also broaden the range of energy generation technologies with which we would serve our customers in the future. Consequently, this strategy would help mitigate the effect of natural gas supply shortages or delivery interruptions, as well as the impact of technical problems that may affect combined cycle or oil-fired units, but not affect clean coal technology units.

As has been explained above, not having economic access to port facilities to receive foreign coal and petroleum coke, or not having economically competitive choices for rail delivery of coal and petroleum coke to the plant, could make clean coal generation economically infeasible. In addition, other key areas of uncertainty, which include the future price differential between natural gas and coal, the future cost (capital and O&M) of compliance with currently unknown environmental requirements that may be imposed in the future (possibly after the clean coal generation unit is in operation), requirements imposed in the licensing process, and the actual capital cost of completing a clean coal facility, could have an adverse effect on the cost of clean coal generation.

Nevertheless, primarily because of the perceived portfolio benefits offered by clean coal generation, FPL intends to pursue the addition of 1,700 MW by 2013, with the first clean coal addition currently scheduled for June 1, 2012. However, this plan will be re-evaluated on an ongoing basis. Because of the higher capital cost of clean coal generation compared to gas-fired generation, and the greater uncertainties associated with clean coal generation, FPL will continue to examine all key assumptions and areas of uncertainty to ensure that clean coal will in fact result in a net benefit to its customers.

Part One – Background

In its 2004 Ten Year Site Plan, FPL noted that the diversity of fuels used by the FPL generation system was an issue that impacted our recent planning work. During 2004, we conducted a study of the issues related to the possible addition of coal-fired generation capacity to its portfolio, and of the range of possible economic results of such an addition. The following is a report of the findings and conclusions of that study.

A. Economic and Technological Trends Related to Clean Coal Generation

Recent Resource Decisions Have Favored Gas Generation

Natural gas-fired generation has been the technology of choice for utilities and independent power producers in the past 10 years in the U.S. and Florida. The low capital cost and high efficiency of natural gas combined cycle plants, the short construction lead times, the generally perceived environmental benefits of, and political preference for, gas generation, and the fact that until recently natural gas prices were relatively low (and were projected to increase only moderately in the future), combined to make natural gas generation the most economic and generally preferred alternative among the available technologies. Traditional alternatives to natural gas (e.g., coal and nuclear generation) had higher capital costs and were not as efficient as combined cycle units. Consequently they could not compete with gas generation during this period of low gas prices. Renewable alternatives were (and still are) generally more expensive, and not available in Florida in any significant quantities.

Decision Drivers are Changing

Over this same period of time two things have occurred to offset the cost advantage of natural gas fired generation.

First, as seen in Figure 1.1, the price differential between natural gas and coal[3] has significantly increased. In fact, natural gas prices have more than doubled in real terms between 1995 and 2004, while coal prices have remained relatively stable or declined in real terms. Natural gas prices have also shown significant volatility, which (for a system that relies heavily on natural gas generation) reduces the predictability of fuel costs and therefore electricity prices.

Second, significant advances have been made recently in coal generation technology. These advances have improved the efficiency of new coal plants and reduced air emissions by the application of "back end" emissions cleaning technology. Many of these technological advances were discussed in a December 2004 FPSC Staff report entitled **"Coal Fired Generation: Proven and Developing Technologies".** These advances reduce the cost of operating a clean coal technology facility and thereby offset

[3] Coal, as used in this Report refers to a range of different types and grades of coal and petroleum coke that can be combined for use in clean coal generation technology.

the cost advantage of natural gas technology. In addition, these advances also close the emissions gap between natural gas generation and coal generation by reducing emissions from clean coal generation plants.

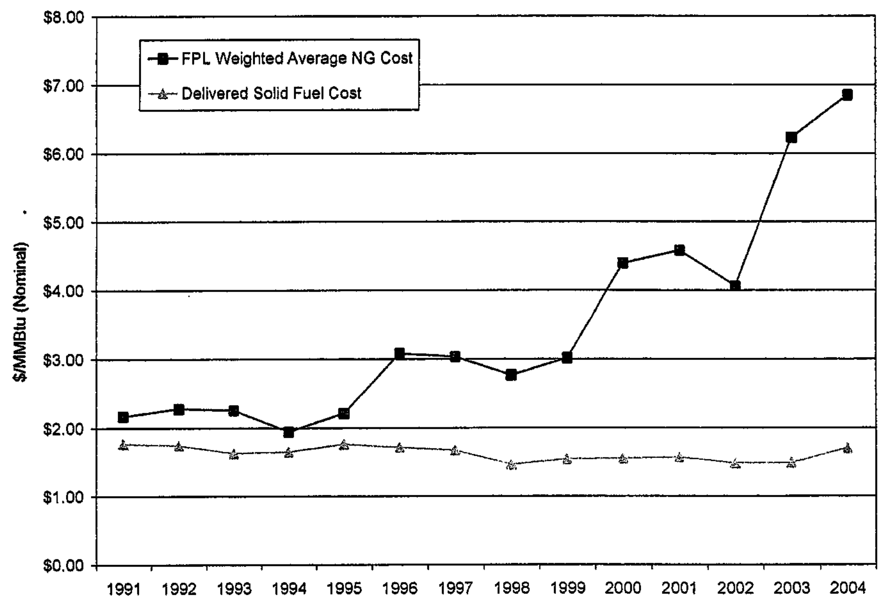

Figure 1.1 History of Annual Average Natural Gas and Coal Costs. Coal costs assume a mix of 80% coal and 20% petroleum coke delivered to Marcy, FL.

As the total cost of electricity generation from clean coal technology becomes comparable with that of natural gas-fired generation, many utilities are reviewing the benefits that can be gained by including clean technology coal units in their generation portfolios. Following more than a decade of generation additions that were largely fueled by natural gas, utilities including FPL are looking for ways to address the issues created by continuing to add generation reliant on a single fuel type. This Report describes the results of our investigation of this important issue.

B. Recent Activity in Clean Coal Development

National and International Activity

The late 1990's through 2003 saw an unprecedented increase in the amount of generation capacity installed in the United States. This increase was driven by growth in demand for electricity and the resulting decline in reserve margins, evolving deregulation in some energy markets, the aging of existing power plants, volatile wholesale electricity prices and abundant sources of debt and equity capital. For the reasons noted above, the overwhelming majority of the generation capital additions during this period were gas-fired. Furthermore, it is anticipated that significant gas generation capacity will be added to meet growing demand, at least during the next six years. However, there is now great interest in clean coal generation to hedge against high gas prices in the future.

Since 2001, there have been approximately 1,000 new coal-fired power projects announced worldwide. 95,000 MW of coal-fired plants are in construction outside the United States. In China alone, between the years 2004-2006, 63,000 MW of new coal-fired plants will enter commercial operation. In the United States, 92 coal-fired power projects have been announced since 2001, representing over 72,000 MW of capacity.

In the US, interest in clean coal generation has increased recently for a number of reasons, including:

- Significant amounts of new base load capacity will be needed in the 2008-2014 time period, much of which can be met with clean coal generation.

- Natural gas markets continue to exhibit severe price volatility[4], and future gas prices, on average, are projected to remain at or above their current levels. This, coupled with continuing increases in gas demand (due to ongoing gas generation additions) and declining domestic gas supply, has induced many electric utilities to consider clean coal generation to meet capacity needs and provide fuel diversity.

- Clean coal generation would provide more stable operating costs (and hence more stable electricity costs) compared to gas-fired projects.

- It is anticipated that under many future fuel market and regulatory scenarios, clean coal generation would provide lower electricity costs than new gas-fired generation.

- There is an increased public awareness of energy issues, and a desire for national energy security. Coal is an abundant domestic fuel source.

- Clean coal generation is much cleaner than existing coal fired plants, and new emission control technologies would result in effective environmental performance.

[4] Volatility is a characteristic measure of commodity price behavior. High volatility commodities can rise or fall sharply in price within short periods of time.

Recent Coal-Related Activity in Florida

A number of municipal utilities have formed a consortium with the goal of constructing a new coal-fired facility in Florida for shared use by the members of the consortium. The consortium appears to have now selected a Perry, Florida location for a pulverized coal facility. As yet no site certification application for this project has been filed with the Florida Department of Environmental Protection (FDEP).

On October 21, 2004 the Orlando Utilities Commission (OUC) and the Southern company released a joint statement announcing a 283 MW integrated gasification combined cycle (IGCC) project in OUC's service territory at the existing Stanton coal plant site. The OUC project, with an estimated cost of $557 million, would be funded in part by a DOE subsidy of $235 million.

C. Clean Coal Generation is Beneficial to Florida

FPL's Projected Growth is Significant and Fuel Diversity Is Decreasing

Both Florida and FPL's service territory are in the midst of unprecedented population growth. This growth has required the addition of 7,770 MW of natural gas fired generation to the FPL system between 1993 and 2007, including the recently approved Turkey Point Unit 5. It is projected that FPL would need to build or purchase almost 4,000 MW of additional generation capacity between 2009 and 2013 to meet future growth in demand. Including clean coal generation as part of those additions would help maintain an economic and diverse balance of fuel sources to provide electricity to our customers.

Without clean coal generation additions, FPL would have to rely on natural gas for about two thirds of its electricity production by 2013.

Resource Options to Increase Fuel Diversity Are Limited

FPL has extensively evaluated and, where warranted, implemented renewable technologies and conservation to meet incremental load growth in its service territory. We continue to be a utility industry leader in the implementation of conservation measures. FPL also continues efforts to fund and evaluate alternative technology demonstration projects. Solar and microturbine technologies are examples of the types of technologies being investigated. Unfortunately, these technologies are not adequate to meet FPL's growing capacity needs or fuel diversity goals due to their extremely high costs and size limitations.

FPL recently conducted a directed site-specific analysis with the goal of evaluating the effectiveness of wind generation in Florida. None of the sites identified and evaluated had gross capacity factors which met or exceeded the threshold for cost-effective implementation of this resource. Nevertheless, we are currently conducting a wind study of the entire State of Florida, and still hope to bring at least a small number of wind turbines into its generating resource portfolio.

Part Two – Substantive Evaluation

A. Portfolio Considerations

Maintaining a Balanced Energy Mix Benefits FPL's Customers

FPL has historically planned its system to provide electric service at reasonable rates, while maintaining a diverse mix of fuel sources. Our fuel mix includes significant quantities of nuclear fuel, coal, fuel oil and natural gas. The generation portfolio has a total of four nuclear units with a total capacity of 2,939 MW at its St. Lucie and Turkey Point sites. These units, which were initially placed into service between 1972 and 1983, have recently been granted a license renewal by the Nuclear Regulatory Commission to continue operation beyond 2032. FPL's portfolio also includes 1,584 MW of owned and purchased coal-fired generation. We also maintain 15 oil-fired units totaling 6,735 MW. These oil-fired units continue to provide reliable service and have helped partially mitigate the effect of recent high gas prices due to the lower cost of fuel oil. FPL also has 16 natural gas-fired units that provide 7,742 MW of generating capacity. Most of this natural gas-fired capacity has been added during the last 10 years.

Maintaining a balanced mix of fuel sources enhances system reliability and helps stabilize the cost of electricity to FPL's customers. By avoiding over dependence on any one type of fuel, the effect of a rise in the price of that fuel on the price of electricity can be effectively mitigated. Similarly, having a diverse fuel mix reduces the effect that an interruption in supply or delivery of a specific fuel type could have on FPL's ability to meet its customers' demand. In addition, having a diverse generation portfolio with various technologies reduces the effect that design or operation problems with one technology could have on system reliability. The increases in reliability and security that would come from a clean coal generation plan are a result of greater independence of the technologies in the portfolio and a higher degree of independence of the fuel delivery infrastructures supplying the system.

In the early 1980's FPL was highly dependent on fuel oil-fired generation for serving its customers. As a result, the rise in oil prices that followed the second "oil shock" of 1979 resulted in a significant increase in FPL's price of electricity. In this time period we completed St. Lucie Unit 2 which added over 800 MW of nuclear capacity to the generation portfolio. In addition, between 1987 and 1995 FPL added coal-fired generation through its partial ownership interest in St. Johns River Power Park (SJRPP) and Scherer Unit 4, as well as a firm capacity purchase from SJRPP. FPL also added coal generation through a "coal-by-wire" UPS firm coal generation capacity purchase contract with Southern Company, and other firm coal generation capacity contracts with Indiantown Cogeneration L.P., Cedar Bay Generating Co., and Florida Crushed Stone.

FPL's generation capacity planning process during the past ten years has recognized the low capital costs and high levels of efficiency offered by natural gas-fired combined cycle units, which made them the most cost-effective choice. FPL also recognized the benefit offered by the very low level of emissions produced by gas-fired units. The advantages of natural gas generation, combined with the fact that ten years ago FPL did not have much gas-fired generating capacity, made gas-fired generation the most beneficial capacity additions for our customers. As a result, FPL has increased its gas-fired generating capability by 4,732 MW between 1993 and 2004. These additions have consisted of both the construction of new gas-fired units (both simple cycle combustion turbines and combined cycle units), and the repowering of existing oil-fired units to very efficient gas-fired combined cycle units. These gas-fired capacity additions include Martin Units 3 and 4, Martin Unit 8 and Ft. Myers Unit 2, and the repowering of Lauderdale Units 4 and 5, Ft. Myers Unit 3, and Sanford Units 4 and 5. The timing and location of these gas-fired additions through 2004 are shown in Figure 2.1.

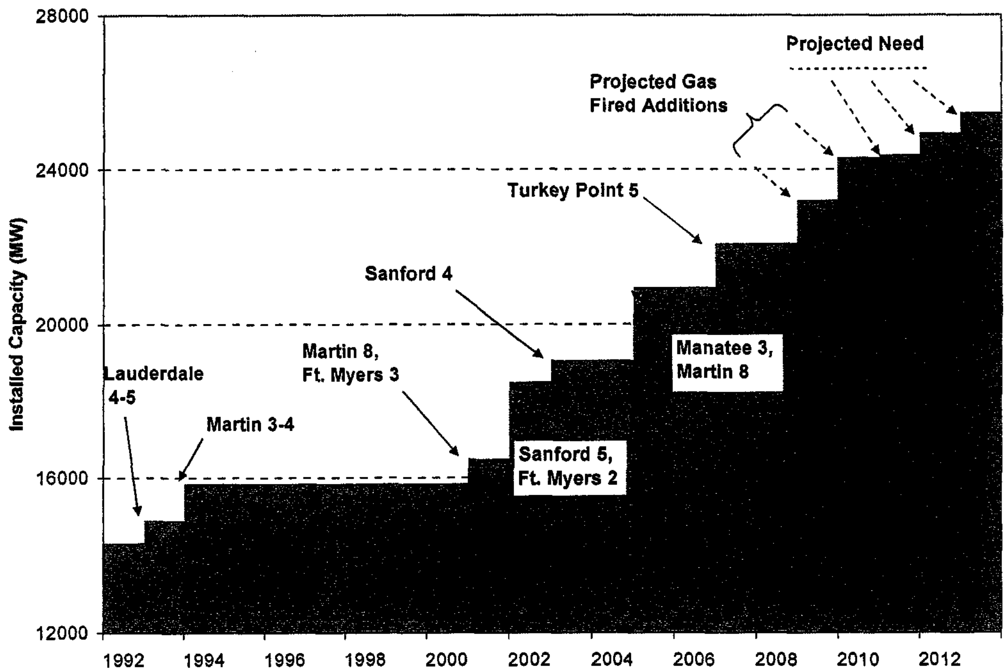

Figure 2.1 Generation Capacity Additions since 1993.

The addition of these very efficient natural gas-fired units has changed the mix of the generation portfolio from one that relied very heavily on fuel oil generation in the 1980's, to the point that in 2004 natural gas was used to provide over one third of the electricity delivered to FPL's customers. Figure 2.2 shows the percentage of overall energy delivered to our customers during calendar 2004, by fuel type.

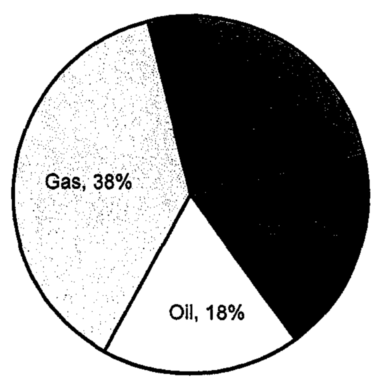

Figure 2.2 Energy produced by Fuel Type for the year 2004.

Figure 2.1 also shows units to be added to the FPL system between 2005 and 2007. FPL plans to complete construction of Manatee Unit 3 and the conversion of Martin Unit 8 in early 2005, and place those units in service by June 1, 2005. In addition, we have received all approvals necessary to proceed with construction of Turkey Point 5 in 2005, and plans to place that unit in service by June 1, 2007. These new units will add 3,038 MW of new gas-fired generating capacity to FPL's portfolio.

Based on the current load forecast (used in the upcoming 2005 Ten Year Site Plan) FPL will need to purchase or build approximately 3,500 MW of new capacity between 2009 and 2013. Due to the long lead time necessary to develop, permit, design and construct clean coal generation, our choices for self-build generation capacity for 2009 through 2011 are limited to natural gas-fired units. These additions are shown on Figure 2.1 as "Projected Gas-Fired Additions." These gas-fired capacity additions, which would consist of more than 2,200 MW, would increase FPL's reliance on natural gas by 2011. However, as this Report indicates, FPL believes that it would be possible to add clean coal generation capacity to the FPL generation system, as early as 2012.

As shown in Figures 2.3 and 2.4, adding clean coal generation in 2012 and 2013 could significantly increase the diversity of FPL's fuel mix. Figure 2.3 shows FPL's projected energy mix in 2013 under an "all gas" generation plan through 2013. In this scenario, almost two thirds of the electricity delivered to our customers would be generated using natural gas, while only 12% would be provided by coal. Figure 2.4 shows the projected energy mix in 2013 under a capacity plan that would add 1,700 MW of clean coal-fired capacity by 2013. In this scenario, the contribution made by natural gas would decrease to 54%, while that of coal would increase to 22%. This latter scenario would provide a more balanced generation portfolio for the benefit of FPL's customers.

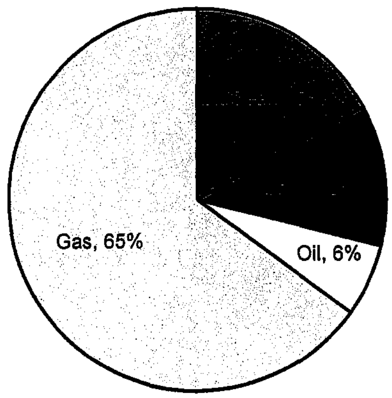

Figure 2.3 Energy Produced by Fuel Type for 2013 assuming an "All Gas" generation plan.

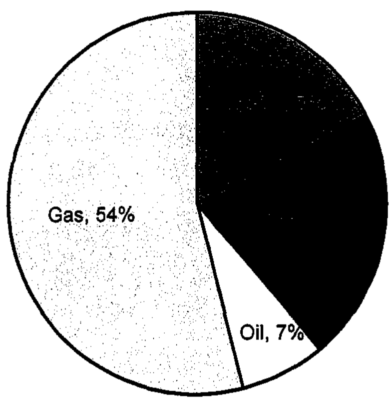

Figure 2.4 Energy Produced by Fuel Type for 2013 assuming 1,700 MW of Clean Coal in the Generation Plan.

Sustainable Fuel Diversity Choices

The alternatives to adding more natural gas-fired generation capacity to meet the growing electricity demand are limited. Because of the magnitude of the need and time frame in which new capacity will be needed, clean coal generation capacity is the only viable generation technology alternative. FPL is also seeking to increase its fuel source and delivery diversity by soliciting bids to deliver to FPL natural gas produced from the re-gasification of Liquefied Natural Gas (LNG).

FPL is committed to meeting the growing capacity needs of its customers in a sustainable manner. Therefore, a decision to add clean coal generation capacity, must meet FPL's three sustainability criteria: economic accountability, environmental stewardship and social responsibility. Part Three of this Report explains why FPL believes that adding clean coal capacity to its portfolio is the economically prudent decision.

Part Two, Section C of this Report presents in detail the process FPL followed to evaluate all environmental aspects of the addition of clean coal generation to FPL's portfolio and explains why FPL believes that the proposed clean coal additions are consistent with FPL's environmental stewardship criterion. FPL has already made a substantial environmental investment with natural gas-fired generation, and that investment has been very successful. The graphs provided in Figures 2.5, 2.6 and 2.7 show how FPL's generation capacity choices have significantly reduced FPL system SO_2, CO_2 and NOx emissions, respectively, on a per megawatt hour basis over the past 10 years.

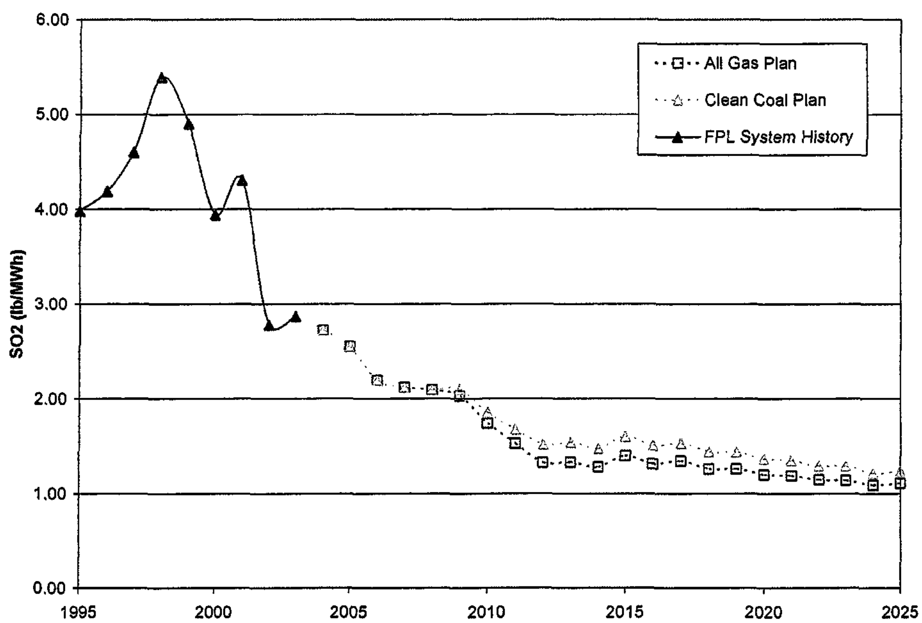

Figure 2.5 Historic and Forecasted SO_2 Emission Profile of FPL System

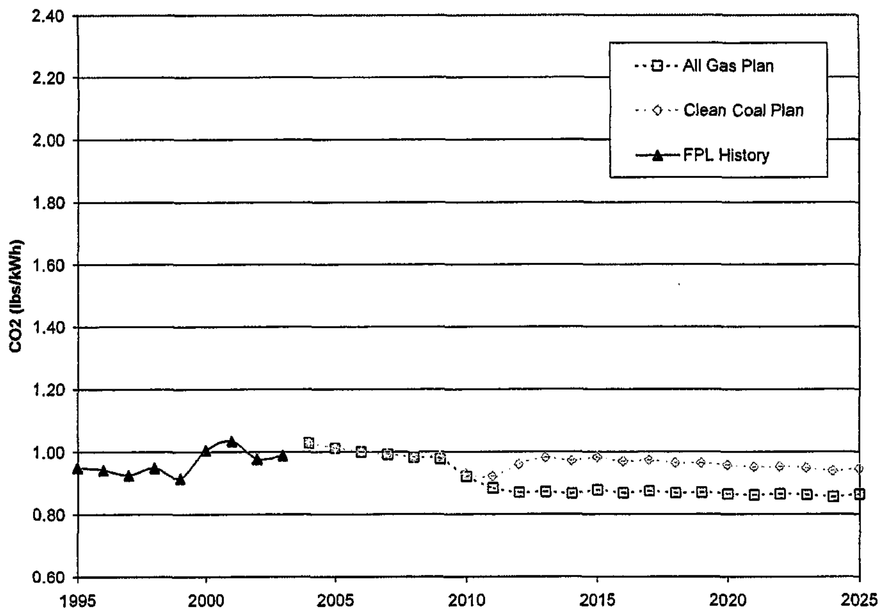

Figure 2.6 Historic and Forecasted CO_2 Emission Profile for FPL System.

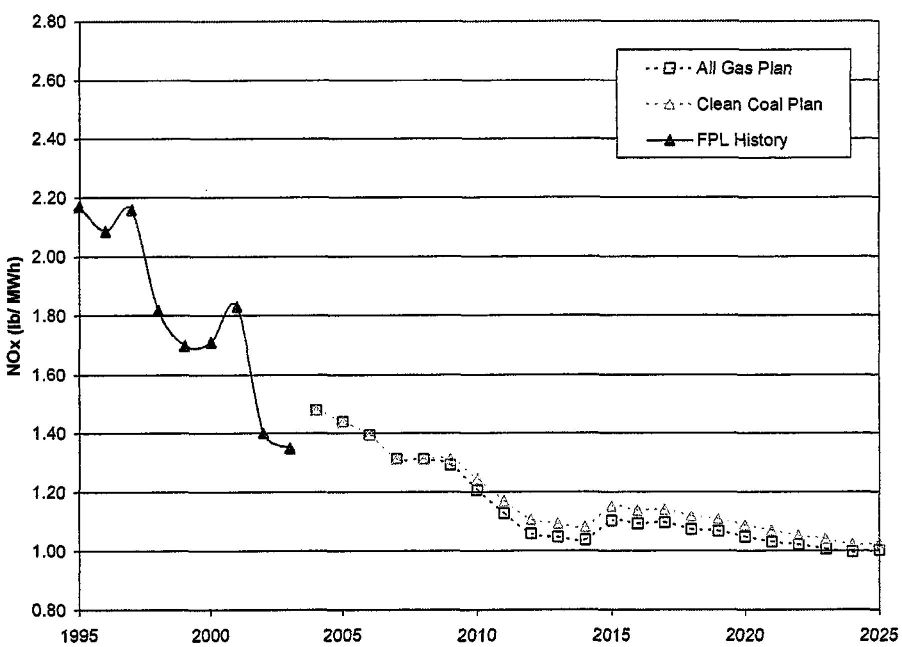

Figure 2.7 Historic and Forecasted NOx Emission Profile for FPL System.

The graphs also show how, with the addition of clean coal generation, FPL can continue to reduce the level of emissions in these substances on a per megawatt hour basis.

Adding clean coal generating capacity to FPL's system is also consistent with FPL's social responsibility criterion in two ways. First, these additions would contribute significantly to increasing the fuel and technology diversity of FPL's portfolio and would thereby serve to mitigate the effect of (a) a rise in the price of a single fuel, such as natural gas, on the cost of electricity; (b) a fuel supply or delivery interruption for a given fuel, or (c) a technology design or operation problem, on FPL's ability to serve its customers.

Second, in developing and implementing its plan to add clean coal generation to its system, FPL will maintain an active dialogue with stakeholders regarding clean coal generation in order to inform the public and learn about the communities' concerns, interests and priorities so we can take these factors in consideration along with the technical requirements we will need to address. By conducting a process that is open to the concerns and interests of the public, FPL is acting in a socially responsible manner.

B. Fuel Supply Related Issues

Selecting the Best Combination of Fuel Sources for the Clean Coal Plant

Clean coal technology can utilize a wide range of individual coal types from different geographic regions, both domestic and foreign, as well as combinations of these individual coal types. Coals differ based on characteristics such as their heat (or energy) content, and their concentration of non-fuel components, such as sulfur and ash. Generally, the geographic region where the coal is produced affects its characteristics, and therefore the "type" of the coal is directly linked to its specific geographic region. As a result, coal types are regularly referred to by their geographical origin. For example, Central Appalachian coal, which comes from the Appalachian producing regions in the US, is generally known to have high heat content and moderate sulfur content. In addition to defining the characteristics of a type of coal, geographic origin also determines, in part, the cost associated with transportation and delivery of that particular type of coal to the generating plant being considered.

Clean coal technology can also utilize petroleum coke, in combination with coal, while maintaining low emissions. Petroleum coke is a solid by-product of the petroleum refinery process that contains useful heat energy. This fuel source is readily and economically available.

The geographic origins and characteristics of the combination of fuel types to be used in a clean coal generating unit have a significant impact on the design requirements of the unit and on the total economics of the project because they affect the capital cost, the fuel efficiency, the operation and maintenance cost, and the costs of fuel transportation and delivery. Therefore, in developing a clean coal generating facility, engineers and fuel specialists work together to select a combination of fuel types (coals and petroleum cokes) that would result in an economic combination of up-front capital costs and long-term operating, maintenance and fuel costs, while complying with all environmental requirements.

The fuel combination selected for the clean coal facility under review includes high heat content coals that have low sulfur content. These are the characteristics FPL considers most important in selecting the preferred fuel types. As explained above, geographic location, as it affects fuel transportation and delivery costs is also very important. Central Appalachian coal would comprise 40% of the selected fuel combination. Another 40% of the selected fuel combination would be foreign-sourced coal (Colombian) with characteristics similar to, and compatible with, those of Central Appalachian coal. Up to 20% of the selected fuel combination would be provided by low cost petroleum coke that can come from domestic or foreign sources. The selected fuel combination described above will be referred to as "coal" in the remainder of this Section B, and throughout the economic analysis discussed in Part Three of this Report.

Price Trends for Natural Gas and Coal

Since the late 1990's, natural gas prices, on average, have risen primarily due to increases in natural gas demand, which has come mainly from the power generation sector. From 1991 through 2004, U. S. natural gas demand has increased, on average, by 0.9% per year compared with a growth rate in gas demand in the electric generation sector, on average, of 3.2% per year. In 2004, gas demand in the electric generation sector represented about 22.9% of total U.S. natural gas demand, compared with 16.8% in 1991. This increase in natural gas demand has primarily been met by two sources; 1) increases in domestic natural gas production (about 0.4% per year on average), and 2) by increases in Canadian imports (about 5.1% per year).

Natural gas prices are expected to decline over the next several years in both nominal and constant dollar terms as the North American supply/demand outlook returns to equilibrium. Figure 2.8 compares the historic and forecasted behavior of natural gas to that of coal prices. Projected trends are shown in nominal and real ($2003) terms.

As is shown in Figure 2.8, the base assumption is that natural gas prices will remain essentially unchanged in constant dollars over the long term. This constant real dollar price level occurs as a result of the expectation that North American natural gas supply and demand will remain in balance, within a normal weather environment, for the remainder of the forecast horizon. More specifically, Canadian imports are expected to remain, on average, at current levels, and the projected slow, but steady decline in domestic production is expected to be more than offset by increasing LNG imports during the balance of this decade and beyond. In other words, the growth in LNG imports is expected to both offset the decline in domestic production, and meet the projected increase in natural gas demand. This means that LNG imports, which currently represent about 2.6% of US supply, have to grow to 11.4% of projected US supply by 2010 and to 18.8% by 2015.

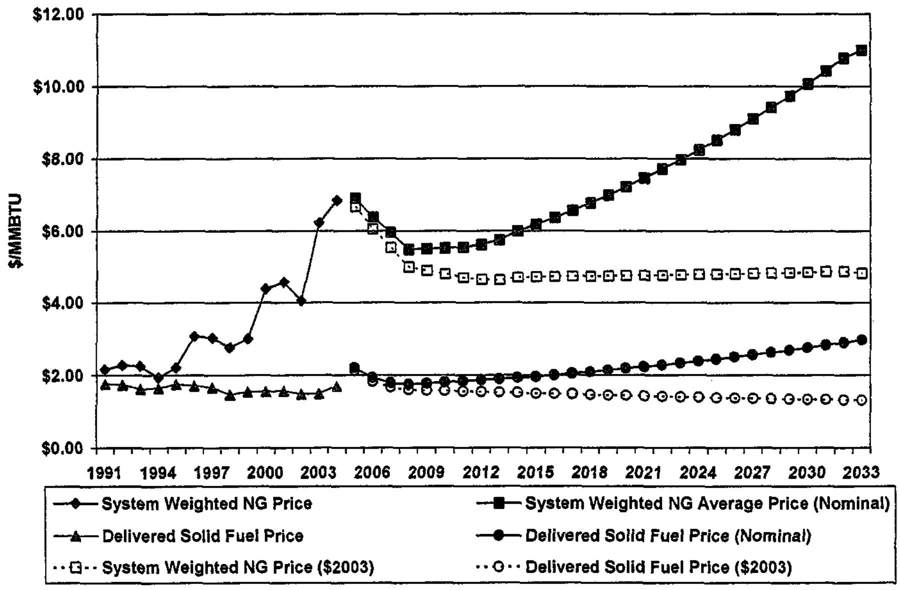

Figure 2.8 Historic and forecasted natural gas and coal mix prices for the mix of coal and petroleum coke used in the FPL study.

During the past decade, the prices of coal, on average, have remained relatively stable in real terms, as increases in productivity have more than offset increases in demand. Coal prices have increased in the past year, primarily due to increases in coal demand in China and other Pacific Rim countries, as well as increases in shipping costs reflecting greater competition for vessels due to the war in the Middle East. However, this recent price increase is not expected to continue due to the abundance of worldwide supply of coal, the continued increases in worldwide productivity, and the anticipated decline in demand for vessels. Over the forecast horizon coal prices are, on average, expected to continue the historical decline in constant dollar terms, although at a slower rate, as increases in productivity are expected to continue offsetting the anticipated slow, but steady growth in demand.

Natural gas price uncertainty is however a key concern and is influential on the results of this Report. The economic analysis in Part Three of this Report uses these general price assumptions and addresses the effect of price sensitivity for natural gas and delivered coal.

Price Volatility and Cost Stability

The price of natural gas has been highly volatile. As a result, increased reliance on natural gas generation makes it is difficult to predict system fuel costs and the resulting cost of electricity to FPL customers. Coal has historically been less volatile due to the dominance of long term contracts for coal and the abundance of domestic supply. For example, during the period between January 1991 and November 2004, natural gas price volatility on a monthly annualized basis was 51%. This means that a month-to-month price swing of $1.47/MMBtu could be expected 90% of the time. The price volatility of coal, on the other hand, was 5% for the same period, which translates into an expected price swing of only to $0.04/MMBtu 90% of the time.

Because the FPL system utilizes the fuels identified in Figures 2.1 through 2.3, the system fuel price is proportionally affected by the volatility of each of these component fuel types. Therefore, increasing the contribution of coal, instead of continuing to add natural gas exclusively, would increase the stability to FPL system fuel costs.

The economic impact of natural gas price volatility is discussed in quantitative terms in Part Three of this Report.

Fuel Supply Reserves

In general, there are significant coal reserves and production capacity in the US and abroad. More specific to FPL's selected coal types, the proven domestic reserve base for Central Appalachian coal is estimated to be between 30 and 40 years based on current demand projections, and the Colombian coal reserve base is estimated to be between 40 and 50 years. By comparison, proven reserves of domestic natural gas are estimated to be about 8 to 9 years based on current demand forecasts. However, it should be noted that significant additional natural gas reserves exist in North America outside the U.S., as well as elsewhere. There are abundant natural gas reserves in the Middle East, Latin America, Africa, the Former Soviet Union, and Southeast Asia that can be accessed to support the anticipated growth in the worldwide LNG business. Additionally there is the potential for further discoveries on the U.S. Continental Shelf, development of the Canadian MacKenzie Delta region and delivery of the proven reserves in the Alaskan North Slope to the lower 48 states. With the inclusion of these resources, the natural gas resource base is expected to be adequate to supply the projected North American, and worldwide, growth in natural gas demand. However, as identified there are developmental steps necessary to bring many of these resources to the U.S. market. Delays, or higher than anticipated costs, in the delivery of these resources could increase future natural gas prices.

Fuel Supply Delivery

FPL's natural gas generation currently relies on two natural gas pipelines for delivery of fuel to FPL's plants. Most of FPL's natural gas-fired units can either switch between natural gas and fuel oil, or have a fuel oil backup system to allow for limited operation in the event natural gas delivery is disrupted (approximately 72 hours' supply on-site). To date this has been a reliable operational plan.

If FPL continues to exclusively add gas-fired generation to its portfolio, the risk of not being able to fully serve load under all conditions would be greater than if FPL includes clean coal generation among its future capacity additions. For example, consider the unlikely simultaneous failure of both natural gas pipelines in the year 2012 assuming no clean coal generation is added. On a peak day, such a failure would force the use of backup fuel oil in all plants with that capability; require maximum imports via transmission and full exercise of load control. The margin to loss of load would be only about 125 MW. Any additional significant event (i.e., inability to burn fuel oil, unplanned unit outage, inability of a unit out for maintenance to return to service when needed, transmission failure) would precipitate a loss of load.

While the current FPL generation system is highly robust, the inclusion of clean coal in the FPL portfolio would reduce the exposure of the FPL system to this type of event, increasing the margin to loss of load on a MW for MW basis. Moreover, if clean coal technology units are added, coal inventories stored on site would provide these units with the capability to operate from 30 to 60 days without new fuel deliveries.

As stated above, FPL is also exploring opportunities to bring LNG supplies to peninsular Florida which would add a third source of natural gas to the Florida system.

C. Site Evaluation and Environmental Issues

FPL reviewed a number of potential sites in the process of evaluating the potential for clean coal generation in Florida. The review resulted in the selection of a potential site that is suitable for the development of the clean coal facility under consideration. The key environmental concerns that have been considered in FPL's site selection process are addressed below.

Land Use and Solid Waste Management

There are a number of important land issues that are unique to the siting of a coal plant. First, successful siting of a coal plant requires significantly more land than that required by a gas-fired combined cycle facility. Whereas a gas-fired combined cycle plant can be successfully sited on a 50-100 acre tract, the rule of thumb for a coal plant is approximately 1.5 acres of land for each MW of capacity. The 1,700 MW clean coal facility under consideration by FPL would utilize a 3,000 acre site.

The larger site is required due to the fact that a coal plant requires a fuel receiving, handling and storage area, and a byproducts storage area. The fuel handling and receiving area must include room for a rail loop to bring coal-laden trains on to the site, off-load those trains, and store the coal in a short term storage area and a long-term fuel storage area to hedge against transportation dislocations. The long-term storage area typically holds enough coal for 45-60 days of operation. In addition to fuel storage, ample space must be set aside for the storage of byproducts such as fly- and bottom-ash and synthetic gypsum (a byproduct of flue gas de-sulfurization). These byproducts are in demand by the construction industry in that they can be used in the production of concrete and asphalt (ash) and wallboard (synthetic gypsum). FPL would actively pursue identifying customers for those byproducts. It is still important, however to design and permit byproduct storage areas in the event that the demand for these products changes.

Water Consumption and Wastewater

In addition to the land use requirements, water use is an important issue for a coal-fired power plant. This is due to the fact that 100% of the generation from a coal plant is steam turbine driven as opposed to only 40% for a gas fired combined cycle plant. For a typical 1,100 MW gas-fired combined cycle with a 450 MW steam turbine, water use is approximately 12.5 million gallons per day (assuming two cycles of concentration). For a similarly sized coal project, water use would approach 30 million gallons per day. Potential water sources for FPL's proposed project include surface water, groundwater, and water piped in from other reservoir sources.

Project Siting and Environmental Due Diligence

FPL has carefully examined the environmental criteria and potential locations for the siting of a clean coal generating facility. In addition to in-house staff, FPL has utilized several environmental contractors with significant power plant siting experience. Golder Associates of Gainesville, Florida was contracted to perform a *Fatal Flaw Analysis* for site selection of potential clean coal facilities. Environmental Consulting and Technologies of Gainesville, Florida was contracted to perform a *Phase II Environmental Analyses* and potential site rankings for a clean coal project. FPL also hired M. J. Bradley and Associates of Concord, MA to evaluate the potential risk associated with licensing and permitting clean coal projects in Florida. M. J. Bradley developed a report entitled *Assessment of Future Environmental Liabilities Facing a New Coal-Fired Power Plant in Florida.* This report provides a comprehensive analysis of the future environmental requirements that may be faced by a clean coal-fired power plant as a result of potential new environmental regulations for air quality, climate change, water management and waste management. A summary of the findings of each of these reports follows.

Fatal Flaw Analysis (Golder Associates)

The fatal flaw analysis of potential sites was performed utilizing site selection criteria that included air quality evaluation in Prevention of Significant Deterioration (PSD) Class I areas, water supply sources, wastewater discharge options, waste management criteria, noise constraints, floodplain areas, threatened and endangered species habitation, cultural and historical resources and wetlands inventory.

One of the more significant criteria determining site selection proved to be the site proximity to Class I areas and the potential PSD increment consumption in these Class I areas. PSD Class I increment is the maximum allowable increase in concentration from new emissions that is allowed to occur above the baseline concentration for a pollutant. Three PSD Class I areas of concern were identified in the analysis: 1) Chassahowitzka National Wilderness Area; 2) Okeefenokee National Wilderness Area; and 3) the Everglades National Park.

The Class I air impacts analysis was based on, but not limited to, the following criteria:

- The project distance from the PSD Class I Area;
- The presence of multiple PSD Class I areas within 200 km of the project;
- PSD Class I increment consumption of sulfur dioxide, nitrogen dioxide, and particulate matter; and
- Air impact modeling for select areas to estimate impacts for comparison to the PSD Class I significant impact levels and regional haze criteria of 5 and 10 percent.

Results of the fatal flaw analysis clearly indicated that three of the nine potential sites reviewed stood apart as top candidates for the potential project. The three potential project sites are located in a triangular region on Florida's Atlantic coast in St. Lucie, Martin and Okeechobee Counties. Further evaluation of the three potential project sites was conducted in a separate Phase II environmental analysis and site ranking.

Phase II Environmental Analysis (Environmental Consulting Technologies)

The *Phase II Environmental Analysis* provided more detailed analysis of the three highest ranking sites utilizing air quality dispersion modeling and impact analyses to determine compliance with ambient air quality standards and PSD Class II and Class I increments and to assess regional haze impacts at the nearest Class I area. The three sites were rated based on how well each site met seven specific environmental site selection criteria:

- Air quality impacts
- Site contamination
- Land development constraints
- Floodplain issues
- Threatened and endangered species
- Cultural and historical resources
- Wetlands Resources.

The results of the Phase II environmental rankings were combined with the results of other site selection criteria, such as fuel transportation access, real estate related issues, transmission line access, and water supply/discharge, and community issues. The criteria were combined to develop an overall ranking of the sites.

The overall ranking process resulted in the identification of the St. Lucie County site as the best potential location to develop a clean coal generating plant.

Assessment of Future Environmental Liabilities Facing a New Coal-Fired Power Plant in Florida (M. J. Bradley & Associates)

FPL engaged M.J Bradley & Associates of Concord, Massachusetts to evaluate the environmental licensing and permitting risks and liabilities associated with siting a clean coal facility in Florida. M.J. Bradley was tasked with the evaluation of the current and future projected environmental requirements and to report the potential impacts to the project. The M.J. Bradley analysis evaluated current and future federal programs affecting air quality, climate change, water quality, and waste management. A summary of the eight key findings of this review follows:

- Air Quality Standards

  The M. J. Bradley report predicts that the proposed project would meet the requirements of existing or proposed future regulations affecting SO_2, NOx and particulates if the plant installs advanced pollution control systems, such as scrubbers, ESPs and SCRs. This is consistent with FPL's intent and philosophy and the clean coal design under consideration. Further regulatory risks for the siting of a coal-fired facility in Florida are considered to be limited since Florida is currently meeting federal air quality standards for ozone and particulate matter.

- Utility MACT Standards and Residual Risk

  The U.S. EPA is currently developing Maximum Achievable Control Technology (MACT) standards for emissions of mercury from coal-fired facilities. Though these regulations are not final, the M.J. Bradley report anticipates that emissions limits that are more stringent than current limits will be required in the future and new standards will be imposed on new coal plants. Efforts to reduce mercury emissions are focused on two areas: 1) optimizing existing pollution control equipment (e.g. scrubbers, SCRs and ESPs) to increase mercury capture; and 2) the development of mercury-specific control technologies (e.g., activated carbon injection). It is uncertain whether mercury-specific control technologies will be required to meet future MACT standards. Mercury-specific controls are not yet readily available in the marketplace, nor have these technologies proven capable of providing guaranteed mercury removal rates that can meet the most stringent MACT standards under consideration.

- Regional Haze Rule

  The Regional Haze Rule is established under the Clean Air Act to protect air quality related values, particularly visibility, in Class I areas of the U.S., such as national parks and wilderness areas. M.J. Bradley reviewed the design emission levels for the clean coal project under consideration. The M.J. Bradley report concludes that the pollutants implicated in visibility impairment, SO_2, NOx, and PM will be sufficiently controlled at the proposed project to prevent risk of further environmental requirements under this rule.

- Federal Air Legislation

  The M.J. Bradley report indicates that attempts in Congress to pass multi-pollutant emission reduction legislation will continue and may result in passage of a bill that could set stricter standards for SO_2, NOx and mercury emissions. However, it is unlikely that this legislation would be more stringent than currently proposed EPA regulations that achieve similar reductions in SO_2, NOx and mercury. The design for clean coal pollution control equipment that is currently under consideration is expected to meet the requirements of the proposed regulations or possible legislation.

- Greenhouse Gases/Carbon Dioxide

  The cost to comply with potential CO_2 emission regulation is a significant uncertainty when studying the economic viability of a coal-fired power plant. A conventional coal-fired power plant emits roughly 2.0 pounds of CO_2 per kilowatt-hour of electricity production. In contrast, a natural gas-fired facility of equivalent efficiency would produce 44 percent less (1.1 pounds of CO_2 per kilowatt-hour), primarily because the natural gas fuel has a lower carbon content. State of the art natural gas combined-cycle facilities are also more efficient than clean coal facilities, resulting in the natural gas facilities producing CO_2 at a rate that is effectively 60 percent of the clean coal facilities. While both technologies would be affected by CO_2 regulation, coal facilities would bear a proportionally higher cost.

The M.J. Bradley report predicts that Congress will eventually enact legislation regulating CO_2 emissions from power plants. The cost of this regulation will impact the economic return for a coal-fired facility, and this is more fully addressed in Part Three of this Report.

- Revisions to the Clean Water Act National Pollutant Discharge Elimination System (NPDES)

Potential changes to the NPDES program could affect existing and new point sources, including coal plants. Stricter regulations on discharges into impaired water bodies may result in effluent trading guidelines or additional treatment requirements for surface water discharges. At the time of the M.J. Bradley's report submittal there was no indication of planned agency revisions to the effluent limitations guidelines and pre-treatment standards for discharges from the steam electric generating point source category (40CFR Part 423). The steam electric guidelines of this section have been in effect since 1982.

Recent announcement from EPA indicates that the agency will be reviewing the steam electric guidelines in the coming months and will likely initiate rulemaking to revise effluent limits and pre-treatment standards in 2005. This agency action may result in stricter discharge controls or effluent trading requirements for all facilities, including the potential clean coal facility.

- Total Maximum Daily Loads (TMDLs)

The U.S. EPA and the state of Florida are undertaking initiatives to identify impaired water bodies. It is estimated that in Florida alone there are as many as 700 impaired water bodies. Mercury, nutrients and dissolved oxygen are the primary pollutants causing impairment of these water bodies. States have 10 years to develop TMDLs and implement plans for improving the quality of the impaired waters. Florida is currently in the process of determining those waters in the state that are impaired and what contaminants are causing this impairment. TMDLs will be established for the impaired water bodies and point source and non-point source discharges will be regulated to reduce discharges into these water bodies. The M.J. Bradley report states that a potential risk to a coal- fired facility will be potential regulation of non-point source air-related discharges of mercury and nitrogen oxides to surrounding watersheds via atmospheric deposition. However, the report indicates that the potential risk for requirements of further controls of these air deposition-related discharges will not be a major concern, since the proposed project would already include air emissions control equipment to significantly reduce nitrogen oxide and mercury emissions.

- Waste-Bevill Amendment for Coal Ash

  In the year 2000 the EPA published the Final Determination to Congress that the Bevill Exclusion for fossil fuel combustion ash and scrubber byproducts would remain in effect. This determination eliminates the requirement to determine the hazardous waste characteristics of these fossil fuel combustion waste products. The determination allows fossil fuel combustion waste to be managed as non-hazardous waste on-site or in industrial waste landfills. The M. J. Bradley report indicates that there is a small chance that this determination may be overturned in the future due to the presence of mercury in combustion by-products resulting from control of mercury emissions. However, if this were to occur, the most likely requirement would be the regulation of fossil combustion products in double-lined landfills. This level of containment is currently a part of the plan for the management of combustion waste products onsite for the clean coal project under consideration. Therefore, the potential for additional risk to the project is minimal.

Emissions Reduction Requirements - Current Regulations

The Clean Air Act prescribes several technology-based limitations affecting new or modified air pollution sources: 1) New Source Performance Standards (NSPS); 2) Best Available Control Technology (BACT); and 3) Lowest Achievable Emission Rate (LAER). NSPS are uniform national emission standards set by EPA for specific categories of new or modified stationary sources. In addition to meeting NSPS when applicable, major new or modified sources must also install either BACT or LAER, both of which are determined on a case-by-case basis. In all cases, BACT or LAER must be at least as stringent as an applicable NSPS. The BACT requirement, which is part of the Prevention of Significant Air Quality Deterioration program (Sections 165 and 169 of the Clean Air Act), applies to emissions in areas that are in attainment with National Ambient Air Quality Standards (NAAQS). The LAER requirement applies to emissions that affect areas that are not in attainment with the NAAQS. Typically, state and local air pollution control agencies have assumed the primary responsibility for implementing BACT and LAER requirements. In Florida, the Florida Department of Environmental Protection (FDEP) implements the BACT requirements under authority delegated from the Environmental Protection Agency (EPA).

All counties in Florida are in "attainment" for NAAQS, thus the BACT requirements will apply to a potential clean coal facility located in Florida. The design for the clean coal technology plant under consideration would achieve the emissions reduction required by the BACT requirements by using state-of-the-art pollution control equipment to reduce emissions of sulfur dioxide (SO_2), nitrogen dioxides (NOx), mercury and particulates.

Emissions Reduction Requirements - Proposed Regulations/Legislation

The following provides a discussion of proposed legislation or regulation that influence generation planning decisions and how they may impact the clean coal facility under consideration by FPL.

Clean Air Interstate Rule

The EPA has proposed the Clean Air Interstate Rule (CAIR) to reduce emissions contributing to fine particulate and ozone transport into non-attainment areas. Florida is currently included in the 28 states that would be affected by the emissions reduction requirements of CAIR. The proposed CAIR would require reductions of total emissions from electric generating facilities for SO_2 and NOx in two phases with reductions in 2010 and 2015. The rule establishes proposed emissions rate reductions and establishes a cap and trade allowance program to promote emissions reductions.

The proposed clean coal facility under consideration includes state-of-the-art pollution control equipment to meet the proposed requirements of the Clean Air Interstate Rule.

Maximum Achievable Control Technology-Mercury

In addition to the SO_2 and NOx emissions reduction of the CAIR, EPA has also proposed the Maximum Achievable Control Technology Rule to reduce emissions of Hazardous Air Pollutants from electric generating units. Specifically, the MACT Rule requires reductions in the emissions of mercury from coal-fired facilities. EPA has proposed two alternatives for the reduction of mercury:

(1) The MACT method that EPA was required to propose by rule in December 2002 was driven by litigation between EPA and the Natural Resources Defense Council (NRDC). The litigation resulted in a Consent Order requiring EPA to propose the MACT rule and finalize it by December 2004. In this proposal the emissions limit for a new coal unit is set at 6.0 x 10-6 lbs/MWh;

(2) The EPA's alternative to MACT is a cap and trade program that allows mercury reductions using the "co-benefits" of adding other pollution control equipment such as scrubbers and SCRs between 2010 and 2018. In 2018 EPA proposes a nationwide emissions cap of 15 tons of mercury. Under this alternative, mercury emissions could be traded throughout the country. The performance standard limit being proposed for a new unit under this scenario is shown in Table 2.1.

Table 2.1 Emission Limits for Mercury (based on gross energy output)

Bituminous units:	0.00075 ng/J (0.006 lb/GWh)
Sub-bituminous units:	0.0025 ng/J (0.020 lb/GWh)
Lignite units:	0.0078 ng/J (0.062 lb/GWh)
Waste coal units:	0.00087 ng/J (0.0011 lb/GWh)
IGCC units:	0.0025 ng/J (0.020 lb/GWh)

An upper amount of $2,187 per ounce of mercury is proposed as a maximum allowance cost for the trading program.

The proposed rule has been delayed until no earlier than March of 2005. FPL anticipates that the co-benefits of the advanced pollution control equipment being installed as part of the clean coal facility would achieve the mercury emissions limits imposed by the final MACT.

Clean Air Act Legislation

Multi-pollutant emissions reduction legislation has been proposed by several Congressmen in recent years. The intent of these bills is to provide sweeping reductions of the emissions of SO_2, NOx, mercury, and in some cases CO_2. Most prominent of the multi-emissions reduction bills is the Bush Administration's Clear Skies proposal. Clear Skies is a 3-pollutant reduction bill (SO_2, NOx, Hg) that has recently been re-introduced in the 109th Congress by Senator Inhofe. The Clear Skies bill is similar in emissions reduction requirements to the Clean Air Interstate Rule, however Clear Skies also includes reduction requirements for mercury emissions that are an alternative to the MACT rule proposed by EPA.

Climate Change Legislation-CO_2 Reductions

Other multi-emissions reduction proposals include mandatory reductions of greenhouse gas emissions from power plants through the reduction of CO_2 emissions. Mandatory CO_2 reductions have long been a political wildcard in Congress and remain a significant uncertainty in predicting the economic performance of coal-fired generation. Proponents of mandatory CO_2 reductions seek to lower current and future emissions to 1990-2002 levels. However, there are not yet proven, economically available controls for the reduction of CO_2 emissions. The most obvious response to a requirement to reduce CO_2 emissions would be the purchase of CO_2 allowance allocations or the use of more combined cycle gas generation. A coal plant would take on additional operating costs if the requirement for operation includes the purchase of emissions allowances to offset CO_2 through a national cap and trade program. FPL has evaluated the potential impacts of a CO_2 trading program to a new coal plant. Several factors significantly impact the costs of a carbon requirement, including the cost of allowances, timing of the required program and the number of allowances that would be allocated to new facility. These sensitivities are addressed in Part Three of this Report.

D. Technology Issues

FPL conducted an extensive evaluation of the most competitive technologies for the generation of electricity from coal, including subcritical pulverized coal (PC), supercritical pulverized coal (SCPC), circulating fluidized bed (CFB), and integrated gasification combined cycle (IGCC). We concluded from this analysis that by pursuing state-of-the-art, commercially viable supercritical pulverized coal technology our customers would benefit from the best mix of low capital and operating costs, along with the highly efficient, reliable and environmentally responsible conversion of coal to electricity. FPL has developed a specific engineering design, complete with performance characteristics and capital cost estimates to support the analysis described in this Report.

The design proposed for FPL's clean coal facility combines state-of-the-art supercritical generation technology, a full complement of technologically-advanced emissions control equipment and design features that would allow recycling of generation byproducts. The facility would produce synthetic gypsum capable of being used as a primary input into either wallboard or cement. The fly-ash and bottom ash would also be of commercial quality for mixing into cement and cement products. To further reduce emissions to the most cost-effective, best available level possible, the facility would employ the best available backend cleanup equipment, including selective catalytic reduction of NOx, a baghouse or electrostatic precipitator to control particulates, wet flue gas de-sulfurization to remove SO_2 and a wet electrostatic precipitator to remove condensable gases.

In summary, FPL has chosen to proceed with the detailed engineering design and development of a large supercritical pulverized coal design with clean emission control technology. The capacity chosen (1,700 MW in two 850 MW units) allows economies of scale that are available by building a large generation unit. Choosing supercritical technology allows for the most efficient and reliable pulverized coal design commercially available today. Taking advantage of engineering advancements in emission control technology allows FPL to propose a facility with the best available emissions profile.

The following discussion describes the key drivers that resulted in FPL's preference for this specific clean coal design, the alternatives and the rationale for the choices made.

Best Coal Generation Technology

Three major technologies are currently employed to convert coal to electricity. These technologies include (1) Pulverized Coal (PC); (2) Circulating Fluidized Bed (CFB); and (3) integrated gasification combined cycle (IGCC). A brief description of each technology follows:

Pulverized Coal

Pulverized Coal is the most widely used and proven coal-based electric generation technology in the United States, representing over 90% of coal capacity among utilities. A conventional PC steam generating unit receives raw coal that has been pulverized. The pulverized coal is burned in suspension in a waterwall boiler. Waterwalls in the boiler collect the heat of combustion to convert water to steam. Tube banks downstream of the boiler superheat this steam, which then powers the steam turbine generator. PC units can be designed as either supercritical or subcritical plants.

Both supercritical and subcritical coal plants utilize the same basic steam cycle, coal handling and ash removal systems, and balance of plant equipment, and have the same site requirements. Supercritical plants are differentiated from subcritical plants in that supercritical plants operate above the critical point of water (3,203.6 psig and 705.4 degrees Fahrenheit), which is the maximum pressure that liquid and vapor can co-exist in equilibrium. The operation of supercritical units at higher temperatures and pressures require clean materials to handle the stresses associated with those operating conditions.

A typical subcritical unit would operate with heat and reheat temperatures of 1050 degrees Fahrenheit, and a main steam pressure of 2,400 psig. FPL is considering a supercritical unit that would operate at heat and reheat temperatures both greater than 1100 degrees Fahrenheit, and a main steam pressure exceeding 3,700 psig. By operating at higher temperature and pressure, supercritical units are more efficient than subcritical units (i.e., producing more electricity for each unit of fuel consumed).

The first commercial supercritical power plant began commercial operation in 1957 (AEP's Philo Unit 6). Additional supercritical units were installed in the United States throughout the 1960s and 1970s. Installation of supercritical units in the United States slowed down in the 1980s, owing to technical problems that caused low reliability and availability for this first generation of supercritical units installed in the United States.[5] After the mid-1980s, the Japanese and Europeans (particularly the Japanese) continued research and commercial development of the

[5] These early design issues included (1) boiler tube corrosion and failure; (2) premature turbine failure in the rotor blades due to erosion from solid particles; (3) water chemistry problems; and (4) startup complexity due to extremely thick steam lines and valve bodies.

supercritical technology, focusing on correcting early design problems. By the 1990s the supercritical technology supplanted subcritical technology as the coal generating technology of choice outside of the United States. In fact, of the coal-fired plants installed between 1995 and 2000 in the Organization for Economic Cooperation and Development (OECD) countries, over 85% - 20,000 MW – use supercritical technology.

Since the late 1990s, the Japanese and Germans, spearheaded by such firms as Hitachi, Mitsubishi, Toshiba, and Siemens, have aggressively remarketed supercritical technology back into the United States and Canada, with significant success. Supercritical projects currently in construction or approved for construction in North America include the Council Bluffs Project in Iowa, the Genesee project in Canada, the Elm Road project in Wisconsin, and the OPPD project in Nebraska.

Circulating Fluidized Bed

Circulating fluidized bed combustion (CFB) was introduced to the US electric generation industry in the early 1980s. The ability of fluidized bed units to burn a diversity of fuels and satisfy environmental requirements without costly back end control equipment has brought attention to the technology. In a CFB plant, coal and limestone are injected into a highly turbulent fluidized bed combustor where combustion air, feed fuel, limestone sorbent, and recirculating solids are mixed. The velocities are high enough to remove the bed material from the combustor. The reacting gas and solids flow upward and enter a particulate separator, usually a cyclone, where solids are separated and returned to the bottom of the combustor. Flue gas leaves the cyclone and is used to produce steam and generate electricity through a steam turbine.

An environmentally attractive feature of the CFB technology is that sulfur dioxide (SO_2) can be removed in the combustion process by adding limestone to the fluidized bed. The calcium oxide in limestone reacts with SO_2 to form calcium sulfate, which is removed from the flue gas with a conventional particulate removal device. However, recent regulations now require the use of a polishing scrubber on new CFB plants to achieve higher SO_2 removal than that achieved in the combustion process. Technological limitations on CFB boiler size are a primary limiting factor on the commercial viability of the CFB technology, with plant sizes larger than 300 MW requiring multiple boilers with commensurate increases in capital costs.

Integrated Gasification Combined Cycle

Simply stated, an integrated gasification combined cycle plant (IGCC) gasifies coal, producing a synthetic gaseous fuel (syngas) for combustion in a combined cycle power plant. An IGCC plant typically consists of one or more gasifiers that include systems to clean the syngas stream prior to combustion and a combined cycle power block to generate the electricity using the syngas. The design is necessarily capital intensive since the syngas must be produced and cleaned prior to being burned to generate electricity.

Gasification combined cycle plants are "integrated" because they use high pressure steam produced in the gasification process in the steam cycle of the generation plant to increase power from the STG. Additionally a nitrogen byproduct from the gasification process is injected into the combustor in the combustion turbines, providing NOx control in the combustion turbines of the generation plant.

There are currently three joint ventures promoting IGCC, each combining the owners of a proprietary gasification technology with a large engineering and construction organization.

A joint venture of General Electric (GE) and Bechtel uses the Texaco gasification technology, which Texaco sold to GE in the spring of 2004. The Texaco technology was originally designed to gasify oil. Coal must be mixed with water to create a slurry in the current design of this type of gasifier. A second joint venture combines the engineering and construction experience of Fluor Engineering and the Conoco Phillips gasification technology. This gasification technology has been demonstrated in an IGCC project, but is not currently being used in any operating IGCC plants. A third joint venture combines Shell's gasification technology with a design and construction team composed of Uhde and Black & Veatch. Currently, the largest IGCC plant in the world, a 318 MW facility in Spain, uses the Shell technology.

On a net present value of revenue requirements basis, IGCC in its current state does not compete with the state-of-the-art supercritical plant proposed by FPL in this report. The IGCC projects currently in operation are all relatively small demonstration projects which have failed to meet expected cost, construction timelines and/or performance expectations.

After extensive and comprehensive review, analysis, and discussion, FPL's position on the current state of the IGCC "market" and its potential to meet customer need is the following:

(1) IGCC may become a competitive coal generation technology sometime in the future, but not in a time frame necessary to compete as a diversity generation resource to meet the capacity need in 2012-2013.

(2) When and if IGCC becomes a competitive fuel diversity option, FPL will be in a position to bring that technology into the portfolio as a generating resource. This will include the investigation of creative alternatives to plant ownership and construction relationships that may involve joint ventures or third-party supply relationships that may be available before 2012.

Supercritical Technology

As stated above, the first generation of supercritical plants in the US was affected by technical problems. Prior to the start of construction of MidAmerican's Council Bluffs plant, the last unit constructed in the United States was the Zimmer 1 plant in 1991. However, today there are more than 520 supercritical units operating in the world (See Table 2.2). Nearly half of these supercritical units are located in countries that were formerly members of the USSR. There are currently more than 160 supercritical units operating in the US, representing 86,000 MW of capacity and 15% of total US fossil-fuel capacity.

Table 2.2 Worldwide Distribution of Supercritical Power Plants

Region	Number	Size (MW)
United States	164	300-1,100
Europe	60+	200-1,000
Japan	50+	500-1,000
Former USSR	Approx 240	300-1,200
Worldwide	Approx 520	200-1,200

Source: "A Critical Look at Supercritical Power Plants", Power, April 2004

Between 1990 and 1998, Japan showed the greatest growth in installed supercritical capacity. For the period 2000 to 2005, Japan has the largest development program in place for building new supercritical plants. As increasing numbers of supercritical plants are built in Japan, they are also increasing in size. While plants built in the mid-1990s were rated from 400 to 700 MW, plants commissioned in the past few years have been 1,000 MW or larger.

About 60 supercritical units are operating in Western Europe – largely in Germany, Italy (mostly oil-fired) and Denmark. The new unit K at Germany's Niederhaussen complex was recently commissioned near Cologne. This 1,000 MW plant operates under clean steam conditions of 4,000psi/1,075F and is designed to burn lignite.

As their supercritical development programs have accelerated and matured over time, the Germans and especially the Japanese have begun to offer these supercritical technologies in the United States. FPL has had discussions with companies such as Hitachi, Mitsubishi, IHI, and Siemens regarding equipment pricing, emissions and performance to explore investment by FPL in clean coal generation.

Supercritical vs. Subcritical Technology

There are currently in the US a significant number of new coal units either in construction, approved for construction, or in final development. Many of these plants are relying on super-critical coal generation technology, reflecting recognition that this technology (1) is highly reliable; and (2) delivers enhanced efficiency, which results in greater fuel economy and lower emissions. FPL has reviewed several projects to understand the benefits and challenges of key issues impacting plant design and fuel choice.

The decision regarding whether new coal generation should utilize efficient supercritical technology or the more standard subcritical technology is influenced primarily by factors that are specific to each region and/or situation.

For example, large capacity scale is a common feature of units employing the supercritical design. The Council Bluffs Unit 4 (790 MW), Wisconsin Energy's Elm Road (two 650 MW units), Xcel Energy's Comanche Unit 3 (750 MW), Sempra's Granite Fox Facility (two 725 MW units) and Wisconsin Public Service's Weston Unit 4 (520 MW), are all over 500 MW, a feature necessary to capture the economies that make supercritical generation economically favorable. The primary objective of these units is to increase fuel diversity and provide more stable electricity costs into the future for the customers in their service territories.

On the other hand, other plants that are designed to use subcritical technology do so for unique reasons. Santee Cooper is constructing the Cross Units 3 & 4 as subcritical technology in order to maintain the same design as the existing Cross Units 1 & 2. Peabody Coal will use subcritical technology in its Prairie State Plant in order to take advantage of locally available Illinois basin coal, which has a high sulfur and chlorine content and is not appropriate for supercritical technology. Tucson Gas and Electric is constructing Springerville Unit 3, a 400 MW unit that is sized under the 500 MW threshold for supercritical's economic advantage, and which will take advantage of relatively close supplies of Powder River Basin coal, reducing the need for the higher efficiency of supercritical technology.

FPL has selected the supercritical design in order to take advantage of the greater economies of larger units, as well as the lower operating costs and lower emissions offered by the greater efficiency of supercritical coal generation technology.

State-of-the-Art Emissions Control Technology

FPL's analysis of clean coal technologies has determined that a supercritical pulverized coal (SCPC) facility would be the best choice for developing a clean coal generation plant. This facility would include state-of-the-art boiler design to achieve high efficiency when combusting a fuel mix consisting of different grades of domestic and foreign coal and petroleum coke. FPL is proceeding under the assumption that future environmental regulations to reduce air emissions would require significant pollutant control technology on any new clean coal facility. The following describes the equipment related to the pollutants of interest.

Sulfur Dioxide Controls

The clean coal facility under consideration would include a state of the art wet flue gas de-sulfurization (FGD) scrubber process to remove SO_2 emissions. The SO_2 scrubber would be designed to meet the requirements of BACT and the anticipated reduction requirements contained in the proposed CAIR rule. The scrubber would produce calcium sulfate (gypsum) as a by-product. This gypsum would be acceptable for the production of either construction quality wallboard, or commercial grade cement, helping to reduce the solid waste stream from such a facility.

Nitrogen Oxide Controls

To control NOx emissions the clean coal facility under consideration would utilize low NOx burners, over-fire air, and a selective catalytic reduction (SCR) system. The SCR utilizes ammonia or urea in the presence of a catalyst to remove nitrogen oxide gases from the flue gas, much like a catalytic converter in a car. The SCR would be designed to meet BACT and the proposed requirements of the CAIR rules.

Particulate Controls

Clean coal facilities typically include the installation of dry electrostatic precipitators (ESP) or baghouses to reduce the emissions of particulate matter. The clean coal facility under consideration would include state-of-the-art dry ESPs. Ash collected by the ESP would be managed in an on-site landfill or reused in accordance with accepted industry practices and applicable laws for recycling.

In addition to the dry ESPs the clean coal facility under consideration would include a wet electrostatic precipitator (WESP) to further reduce visible opacity from the facility. The WESP is the final cleanup step in the air quality control system. Some of the sulfur in the fuel is converted to SO_3. As the SO_3 passes through the wet scrubber (FGD) system, it is converted to H_2SO_4. Located after the FGD, the WESP collects the H_2SO_4 particles. To preserve the WESP electrodes and collecting plates in the presence of H_2SO_4 (sulfuric acid), water is continuously sprayed over the plates. The water collects the H_2SO_4 which is then collected in the bottom of the vessel for recycle to the FGD system. The WESP would provide added control of fine particulate matter emissions (PM 2.5) and would provide additional control of mercury emissions.

Mercury Controls

Anticipated regulations requiring the reduction of mercury emissions from coal-fired electric generating facilities are expected to establish mercury limits consistent with allowing co-benefits from the use of scrubbers and SCRs as MACT controls for mercury reduction. FPL expects that the SO_2 and NOx control technologies under consideration would yield mercury reductions capable of meeting the new proposed mercury MACT rules. The use of the wet ESP described above is expected to provide additional mercury reduction for the unit.

Other technologies considered for the reduction of mercury include activated carbon injection (ACI) in conjunction with a baghouse. However, there is currently insufficient data to support the use of ACI as a technologically proven method to consistently and reliably remove mercury from all coal types. Because this technology is in an early development stage, FPL understands vendor guarantees for specific mercury removal rates using ACI are not available. Another concern is that the addition of carbon to the fly ash may render the ash non-recyclable, resulting in added solid waste management costs.

Part Three – Economic Analysis

A. Analytical Approach, Assumptions and Results

Analytical Approach

As part of its study of clean coal generation we performed an economic analysis to determine the relative cost of adding clean coal generation to FPL's system by comparing the present value of revenue requirements (PVRR) of two different generation plans. One of the generation plans considered is an "all gas" plan that would meet all future capacity needs by adding gas-fired combined cycle units. The other generation plan, the "clean coal plan," includes 1,700 MW of clean coal generation (i.e., two 850 MW supercritical pulverized coal units) as part of the capacity that would be added to meet FPL's future needs. The only difference between the two plans used in this analysis occurs in 2011 and 2012. The all gas plan would add two 870 MW combined cycle (3x1 CC) units in 2011 and 2012, respectively, while the clean coal plan would add two 850 MW clean coal technology units in 2011 and 2012, respectively, for a total of 1,700 MW of clean coal fired generation. In both plans the 2011 and 2012 capacity additions would be at the same site. In addition, all other capacity additions in the two generation plans, both prior to and subsequent to 2011 and 2012, are identical gas generation additions, added at the same times, sites, and with the same sizes and costs.

This approach allows for a direct comparison of the relative cost of adding 1,700 MW of clean coal generation, as part of FPL's overall generation plan, to the cost of similarly sized and sited gas-fired combined cycle generation, with no significant cost differences attributable to differences in siting, transmission, size, or in other components of the generation plan.

The economic analysis of the clean coal plan relative to the all gas plan assumed that two clean coal technology units would be added in 2011 and 2012, respectively. However, as has been stated in this Report, the ongoing review of the technical and environmental requirements related to adding new clean coal generation indicates that we would not be able to place in service a clean coal technology unit earlier than June, 2012. However, the results of the comparative economic analysis are not dependent on which of these two consecutive years the cost comparison begins, and therefore the results are valid for the purpose of reaching the conclusions presented in this Report.

Organization of Findings

The results obtained in this analysis using a set of base assumptions are provided as the starting point. The results of a number of sensitivity analyses then quantify how different future fuel and environmental compliance cost assumptions would change the results.

The capital and fixed O&M costs of the clean coal plan are higher than those of the all gas plan. In order for the two plans to be economically equivalent, the higher capital costs and O&M costs of the clean coal technology units must be offset by lower fuel and variable operating costs over the life of the clean coal technology units. The analysis assumes an initial set of costs for key variables, such as future fuel prices and emission compliance costs. The analysis shows that the operating cost savings of the clean coal plan effectively more than offset its higher capital and fixed O&M costs. Based on these results alone, one would conclude that the clean coal plan is more cost-effective for our customers.

However, because the useful life of both clean coal technology units and combined cycle units span 40 years, many factors (natural gas price, coal price, emission compliance costs, etc.) could be different than projected, and those differences could significantly impact the relative cost of the two generation plans. This Report describes how these key factors may vary, how the analysis sensitivities address that variability, and how the results of the analysis sensitivities affect our conclusions.

Results Obtained Utilizing Base Assumptions

The capital expense associated with developing, constructing and commissioning a clean coal plant is significantly higher and is expended over a longer time frame than that of a natural gas fired combined cycle plant. Development (and cost outlay) would begin in 2005 for a clean coal technology unit to be operational in 2011, while this process would not begin until 2007 for a combined cycle unit that becomes operational in 2011.

The future variable costs of generating units are strongly influenced by projected fuel prices and emission compliance costs. The expected natural gas price forecast assumes natural gas prices rise at an annual rate of approximately 0.5% greater than that of inflation. Conversely, coal prices are expected to decline in real terms at an annual rate of approximately 0.8%. Under these assumptions, clean coal technology units would incur significant variable emission compliance costs for SO_2. However, CO_2, NO_x and mercury limitations are projected to be satisfied by the emission control equipment built into the capital cost estimates, and therefore would incur no ongoing variable costs.

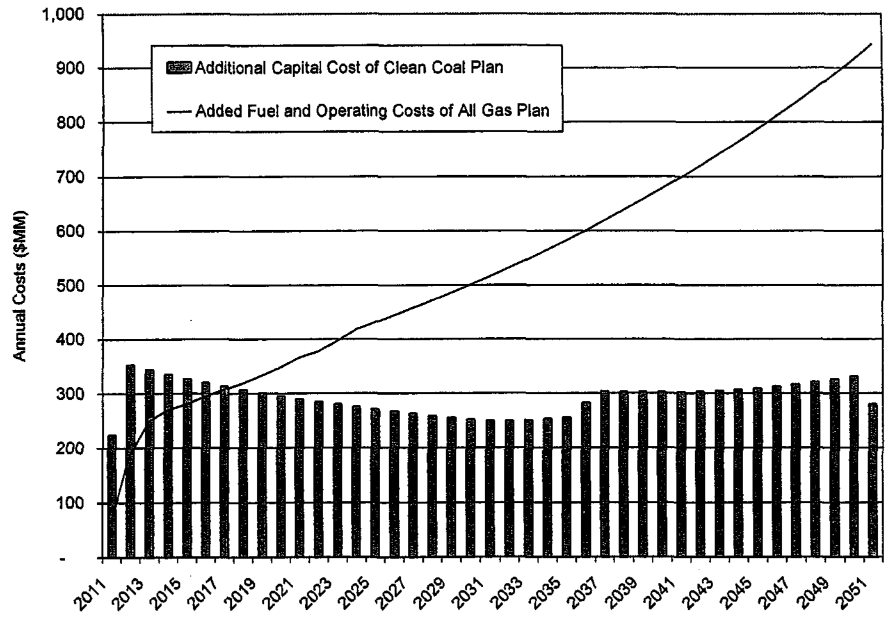

Figure 3.1. Comparison of Annual Cost Differential between a Clean Coal Plan and an All Gas Generation Plan.

The bars in Figure 3.1 show the annual additional capital costs for the clean coal plan, relative to the capital costs of the all gas plan. The line in Figure 3.1 shows the higher fuel and variable operating costs of the all gas plan, relative to those of the advance coal plan. Overall, this figure shows that under these base assumptions, the annual additional capital costs of a clean coal plan are less than the annual additional total variable costs (fuel, emissions and variable O&M) required of an all gas generation plan. Therefore, the savings attributable to the clean coal plan are expected to grow over time as a result of the projected increasing spread between the price of natural gas and that of the selected coal combination. This is true even though the clean coal plan would carry higher emissions compliance costs that are also escalating. In this analysis, the clean coal plan would incur $2.039 B higher capital and fixed O&M costs on a net present value revenue requirements basis[6]. The clean coal plan also would incur $28 MM higher variable emission compliance costs. However these costs disadvantages are offset by the lower fuel and variable O&M cost ($2.502 B) for a net savings of $435 MM.

Figure 3.2 shows the cumulative present value of revenue requirements (CPVRR) of the clean coal plan, relative to the CPVRR of the all gas plan (represented by the "0" line along the x-axis), with costs beginning on a projected commercial operation date in 2011 for the first unit. As can be seen in the graph, the higher capital costs of the clean coal plan result in higher revenue requirements for the clean coal plan in the early years.

[6] Unless otherwise noted, the values provided in this Report will be provided as the net present value of revenue requirements for all future years in 2004 dollars (PVRR, $2004).

However, after 2029 the accumulated fuel savings of the clean coal plan are sufficient to offset its capital cost disadvantage and the clean coal plan reaches the "crossover point" (the CPVRR line crosses the "0" line along the x-axis). At this crossover point the clean coal plan becomes cumulatively less expensive than the all gas plan under the base assumptions.

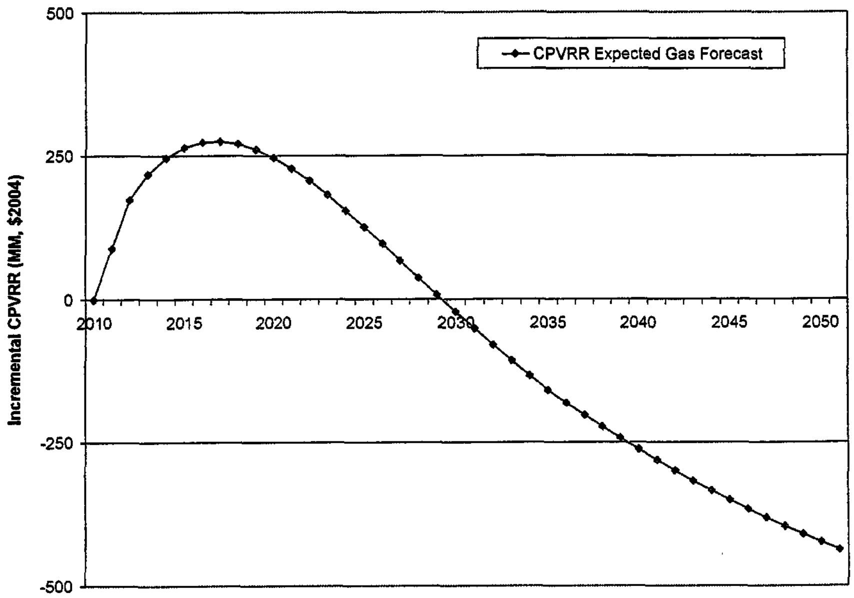

Figure 3.2 Crossover of CPVRR difference between plans (Base Assumptions).

This information can also be used to show the relative impact on rates that would result from the selection of a clean coal plan compared to the selection of an all gas plan, and is shown in Figure 3.3. As seen in the revenue requirements chart, rates would initially be higher because the annual capital cost of the clean coal plan, reduced somewhat by the fuel savings, exceeds that of the all gas plan during the early years. However, the annual cost of the clean coal plan becomes less than the annual costs of the all gas plan after the 6th year (2017) and therefore the rates become less than that estimated for an all gas plan.

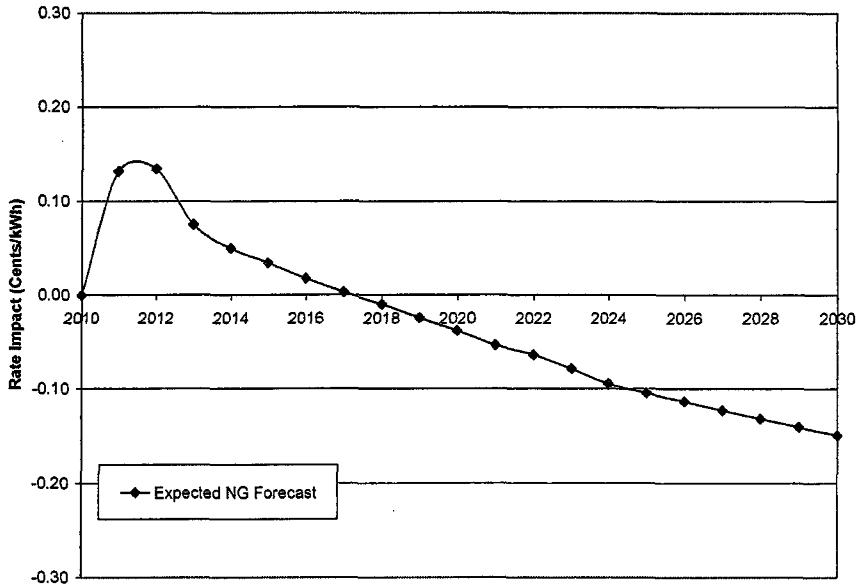

Figure 3.3 Relative annual impact to rates (in Cents/kWh) of selecting a clean coal plan compared to selection of an all gas plan (base assumptions).

B. Fuel Price Sensitivities

Need for Sensitivities

The differential between the delivered price of coal and the delivered price of natural gas is the primary cost advantage of clean coal generation. Consequently, the results of an economic comparison between clean coal generation and gas generation depend primarily on the magnitude of this fuel price differential in the future. As discussed in Part Two, Section B, there are many factors that can influence the future behavior of these fuel prices, and in particular, the price of natural gas. The assumptions that underlie FPL's gas price forecast, such as significant growth in gas demand, growth in LNG imports, and stable Canadian gas imports, may or may not occur as anticipated. Consequently, actual natural gas prices in the future could be higher or lower than those in the base assumptions. In order to address this uncertainty in future natural gas prices and in the fuel price differential between natural gas and coal, and determine how significantly that uncertainty could affect the relative economic value of clean coal generation, we expanded the economic analysis to consider a high natural gas projected price sensitivity and a low natural gas projected price sensitivity.

Natural gas prices have experienced significant volatility in recent years, and this high degree of volatility in natural gas prices is expected to continue in the future. Because coal prices are expected to remain stable, it is anticipated that adding clean coal generation to FPL's system would reduce the system fuel cost risk in the future, compared to what it would be under an "all gas" generation plan. In order to quantify the reduction in system fuel cost risk offered by the lower fuel price volatility of a generation plan that includes clean coal generation compared to the higher fuel price volatility of an all gas plan, we performed a probabilistic analysis of natural gas prices.

Although the price of coal has been, and is projected to remain, stable at a level well below than that of natural gas, the cost of transporting coal to Florida and delivering it to a clean coal technology plant would be substantial. In order to achieve a sufficiently large differential between delivered coal and delivered natural gas to make clean coal generation competitive with gas-fired combined cycle units, it is necessary to be able to deliver coal to Florida from both domestic and foreign sources through ports that allow access to multiple railroads which can deliver to the potential site. We performed a sensitivity to determine the economic effect of not having competitive delivery of coal.

The following sections discuss these four fuel price-related sensitivities; a high natural gas projected price sensitivity, a low natural gas projected price sensitivity, a probabilistic analysis sensitivity to quantify the benefit of reducing our fuel price risk by adding clean coal generation, and a sensitivity to determine the economic effect of non-competitive coal delivery.

Establishing the High and Low Projected Natural Gas Price Sensitivities

The forecasted commodity price used in the study is developed following FPL's standard forecasting process, which utilizes input from a range of industry consultants and then applies our own fuel management knowledge and fuel availability and price forecasting expertise. The high natural gas price sensitivity utilizes a projected price of gas that is sufficiently high, such that the forecaster estimates that there is only a 25% probability that the actual future price of natural gas would be higher than this high projected price, while there is a 75 % probability that the actual future price of natural gas will be lower than this high projected price. Conversely, the low natural gas price sensitivity utilizes a projected price of gas that is sufficiently low, such that the forecaster estimates that there is only a 25% probability that the actual future price of natural gas would be lower than this low projected price, while there is a 75 % probability that the actual future price of natural gas will be higher than this low projected price. By comparison, the forecasted price of natural gas in expected case is such that the forecaster estimates that there is an equal probability (50%) that the actual future price of natural gas would be higher, or lower than that forecasted price. Figure 3.4 displays the forecasted price of natural gas in the base assumptions, as well as the high projected price used in the high natural gas price sensitivity, and the low projected price used in the low natural gas price sensitivity.

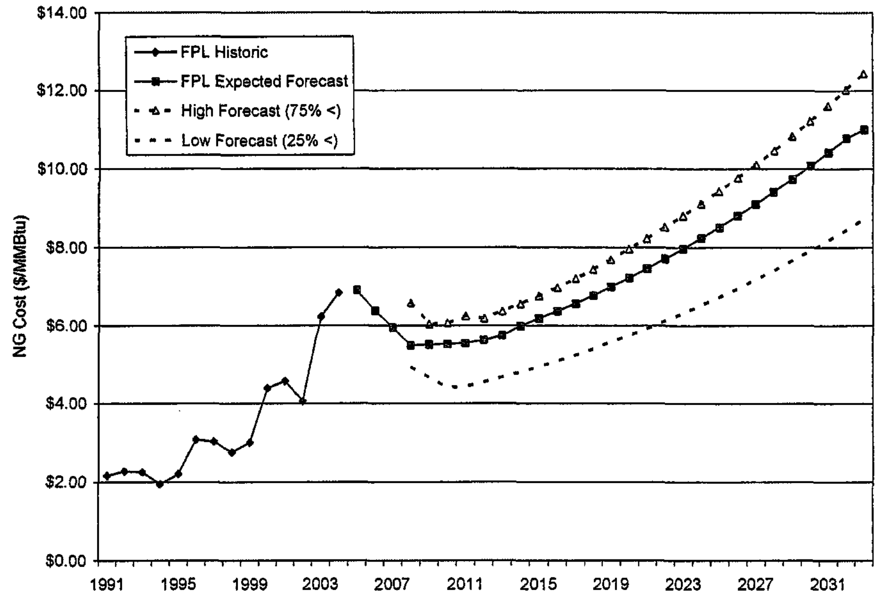

Figure 3.4 Historic Natural Gas Prices (nominal $/MMBtu) with High, Low and Expected Forecasts.

The range of possible natural gas prices shown on Figure 3.4 was also used in the probabilistic sensitivity. The probabilistic analysis sensitivity is discussed below.

Natural Gas Price Sensitivity Results

The projected price of natural gas used in the high gas price sensitivity results in total system costs, for both study generation plans, that are significantly higher than the results obtained using the base forecast. This is a result of the natural gas consumed by FPL's existing gas-fired generation and the future gas-fired filler units that are added to the generation portfolio after 2012. Conversely, the projected price of natural gas price used in the low gas price sensitivity results in total system costs, for both study generation plans, that are significantly lower than the results obtained using the base forecast because all of FPL's gas-fired generation would benefit from the lower gas price.

As expected, the comparison of the two generation plans shows that the system costs of the clean coal plan increases less in the high gas price sensitivity because FPL's system does not consume as much higher priced natural gas with the addition of clean coal generation. The clean coal generation plan has a $1.4 B advantage over the all gas plan in the high gas forecast sensitivity.

Conversely, the system costs of the clean coal plan are higher than those of the all gas plan in the low gas price sensitivity, resulting in a $466 MM advantage for the all gas plan in this sensitivity. However, it is important to note that in the clean coal plan the low natural gas price sensitivity results in system costs that are about $7.0 B (present value) lower than the results obtained using the base assumptions. In other words, while it is true that if we were to adopt the all gas plan, and gas prices were to be at the low gas price sensitivity level, the total system costs would be about $7.0 B lower than under the base assumptions with an all gas plan, about 94% of this system cost reduction would still be achieved with the clean coal plan, which would save about $6.44 B.

In summary, under the high gas price sensitivity the clean coal plan would reduce costs by $1.4 B, while under the low natural gas price sensitivity the clean coal plan would still produce more than 94% of the savings the system would have experienced with an all gas plan. By reducing our exposure to high natural gas prices, the clean coal plan provides a cost hedge for the FPL system that cannot be provided by the all gas plan.

Figure 3.5 shows the cumulative present value of revenue requirements for the clean coal plan relative to the all gas plan, from the commercial operation date of the 2011 unit for the base assumptions and both natural gas price sensitivities. The crossover point occurs much earlier (2016) under the high natural gas sensitivity. Figure 3.6 shows the relative rate impact for the three natural gas forecasts considered.

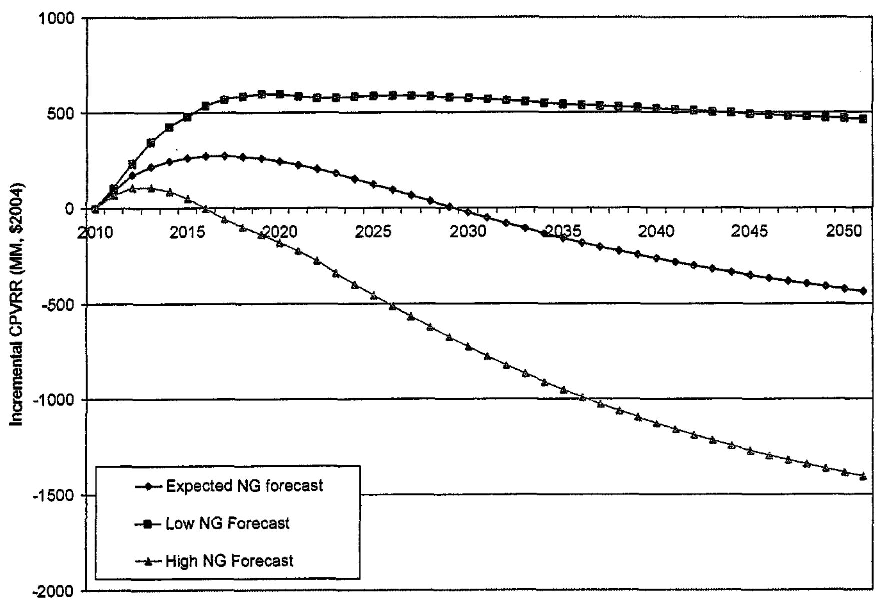

Figure 3.5 Crossover of CPVRR difference between plans for three gas forecasts.

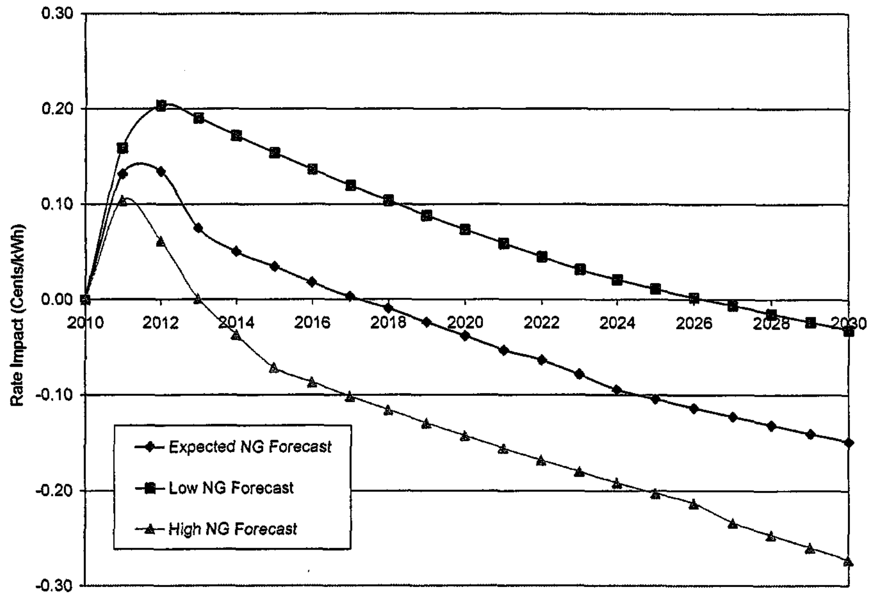

Figure 3.6 Relative annual impact to rates (in Cents/kWh) under three natural gas forecasts.

Impact of Natural Gas Volatility

There is a wide range (or distribution) of potential natural gas price outcomes that could occur in the future. Each of these potential outcomes has an associated probability of occurrence. The width (or standard deviation) of this distribution of potential outcomes is a function of the volatility of natural gas prices, and the width of this distribution expands with time. Figure 3.7 provides an example distribution for the year 2015. In this sensitivity, the distribution is truncated at the extremes to exclude unreasonably high and low values. The base analysis and the two gas price sensitivity analyses described above address three of these potential outcomes – the base price outcome, the high gas price sensitivity outcome, and the low gas price sensitivity outcome.

We performed a sensitivity analysis that varied natural gas price across the range of potential outcomes, while all other inputs remain unchanged. The result of this sensitivity analysis, using the distribution of natural gas price outcomes, is a distribution of potential system costs for each of the two generation plans under consideration. However, the standard deviation of the system cost distribution is not only dependent on the shape of the gas price distribution, but also on the amount of natural gas consumed under each of the generation plans. Because the clean coal plan uses less natural gas than the all gas plan, the standard deviation of its distribution of potential future system fuel costs is narrower than that of the all gas plan.

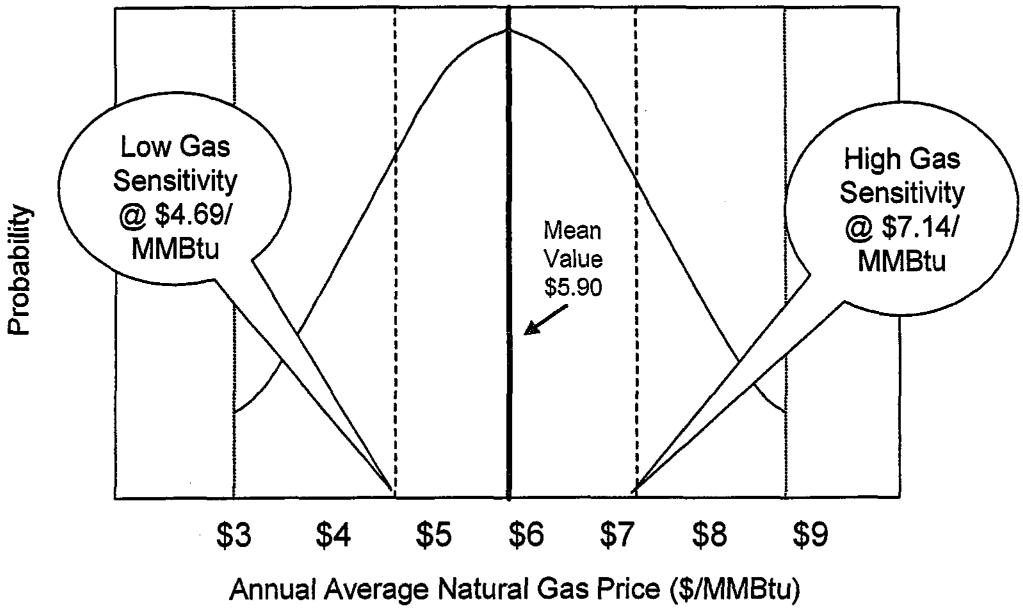

Figure 3.7 Example truncated probability distribution of annual average delivered natural gas prices ($/MMBtu, 2003$) for the year 2015.

The difference between the standard deviations of system fuel costs under the two plans is a measure of the reduction in system fuel cost risk offered by the clean coal plan, or alternately a measure of the increased certainty with which the fuel cost of the clean coal plan can be projected into the future.

The result of this sensitivity analysis indicates that the standard deviation (or expected variability) of the distribution of potential future system fuel costs under the clean coal plan would be $1.22 B or 11% less than that of the all gas plan, on a PVRR basis. This means that on an annual average basis, system fuel cost variability would be reduced by $100 MM (nominal $'s) if the clean coal plan is implemented. Because this reduction in the variability of system costs applies to both higher and lower than forecasted system fuel costs, only half of this reduction in variability – about $50 MM (nominal $'s) per year, on average – applies to reducing the higher-than-forecast system fuel cost risk. In other words, all other inputs being equal, adding 1,700 MW of clean coal generation to the generation portfolio would reduce our customers' exposure to higher than forecasted system fuel costs by about $50 MM (nominal $'s) per year, compared to an all gas plan.

Delivered Coal Price

As indicated in Part Two, Section B of this Report, for the purpose of this analysis FPL has selected a combination of "solid fuels" that consists of 40% low sulfur Central Appalachian coal, 40% low sulfur foreign coal and 20% petroleum coke. Based on the stable price history of these fuels, and our review of future expectations regarding this fuel combination, there is no need to consider price volatility for this coal combination in the analysis. However, the delivered price of coal and petroleum coke includes not only their commodity prices, but also the costs of transporting and delivering each via ship, barge, and/or rail to the plant, and there is significant uncertainty regarding the magnitude of those transportation and delivery costs. This uncertainty relates to the feasibility of obtaining competitive fuel delivery through multiple port facilities and competing railroads. If the necessary infrastructure and corresponding agreements that would support competitive fuel delivery cannot be developed, fuel transportation and delivery costs would be significantly higher, and would result in much higher delivered coal prices than those assumed in the base assumptions. This uncertainty regarding the feasibility of competitive fuel delivery required us to also develop a non-competitive fuel delivery cost forecast to determine the impact of this outcome on the economics of clean coal generation. The results of the analysis performed using this non-competitive fuel delivery forecast is discussed below. Both fuel transportation and delivery cost estimates used in these analyses were developed based on input from industry consultants, as well as our own experience derived from involvement in fuel management for its current coal-fired generation plants and FPL's commodity price and transportation forecasting expertise.

The costs of providing the necessary coal delivery infrastructure to achieve competitive delivery of coal, including those related to port terminal facilities are reflected in the coal transportation rates used in the economic analysis. The capital cost of rail spurs into the plant site, rail cars and coal handling equipment at the plant are included in the construction capital cost estimates. Costs to maintain this equipment are included in the fixed O&M costs estimated for the entire facility.

Non-Competitive Delivery Situation

The use of foreign coal, domestic coal and petroleum coke in the coal combination requires that at least 60% of the fuel for the clean coal technology plant be delivered via a major shipping port with bulk material handling capabilities. This waterborne fuel must then be delivered via rail to the plant site. The remaining fuel needs of the plant would be delivered directly from Central Appalachia to the plant via rail. One way to maintain low coal transportation costs is to contract with multiple ports and carriers to provide delivery of the required fuel quantities. In the event that only one delivery method (e.g., having access to only one port, or having access to only one railroad) is available, the transportation costs would be expected to be significantly higher due to lack of competition. This increase in delivered price would add an estimated $383 MM of cost to the clean coal plan. This added cost would reduce the advantage seen in the results obtained using the base assumptions from a $435 MM net savings to only $52 MM net savings for the clean coal generation plan as compared to the all gas plan.

Under some combined outcomes the uncertainty regarding future gas prices discussed above, and that of environmental compliance costs discussed below, could together eliminate the economic benefits of a clean coal plan compared to an all gas plan. It is therefore very important that a robust competitive coal transportation plan be established prior to making a final decision to implement clean coal generation.

C. Emission Compliance Sensitivities

We considered four types of air emissions in its study of clean coal generation. They are sulfur dioxide (SO_2), nitrogen oxides (NO_x), carbon dioxide (CO_2) and mercury (Hg). The base assumptions used in the economic analysis reflect current environmental regulations. However, this section examines how potential future environmental legislation or regulation would affect the differential cost between a clean coal generation plan and an all gas plan. FPL consulted with industry experts and national organizations concerned with future air emissions regulations to develop an understanding of how future regulation may affect the cost of compliance for each of these four substances.

Modeling Emission Compliance Costs

FPL's analysis includes three types of emission compliance costs. They are the capital cost of emission control equipment that must be installed in conjunction with the generating unit, the O&M costs to operate and maintain the equipment, and the cost of purchasing emission allowances necessary to allow a generating unit to emit above a specified limit. The capital costs of the emission control equipment required for clean coal generation are reflected in the total capital cost estimates used in the analysis.

O&M costs related to emission control may be fixed O&M or variable O&M. Fixed O&M costs include the annual long term maintenance costs necessary to keep the emission control equipment in working order throughout the life of the facility. The fixed costs attributed to emission control equipment for clean coal technology units are integrated into the total fixed O&M cost estimate for those units. The variable O&M costs related to emission control include consumable materials needed to operate the emission control equipment. An example of such a variable O&M cost would be the cost of limestone used in a scrubber to reduce SO_2 emissions. Those variable O&M costs related to emission controls required by current environmental regulation, such as the cost of limestone, were considered in the analysis.

Emission allowance costs are considered in the analysis for sulfur dioxide (SO_2). The economic analysis has also considered the economic impact of allowance costs related to possible future allowance requirements for nitrogen oxides (NO_x) and carbon dioxide (CO_2). This study anticipates that Mercury (Hg) would be effectively managed, to the extent required, by emission control equipment, and therefore no allowance cost has been considered for Hg. Projected emission rates (lbs/kwh) for each substance are developed as part of the engineering design. The production cost model is then used to determine how much energy the clean coal technology unit is expected to produce each year, and how many allowances would be required. FPL then uses its knowledge of allowance markets, as well as input from industry experts to develop a forecast of the future cost of each allowance. The annual cost of allowances is the product of these components. Table 3.1 summarizes the cost types that are relevant to each pollutant.

Any future increase in emission compliance costs contribute to the variable costs of both clean coal generation and gas generation. However, the variable costs of the clean coal plan are more strongly affected by such an increase because of the greater need for emission control of clean coal technology. This effect is reflected in the results of the emission sensitivities conducted as part of the analysis.

Table 3.1 Cost Areas Associated with Certain Pollutants

	Capital Cost	**Fixed O&M**	**Variable O&M**	**Allowances**
SO_2	Yes	Yes	Yes	Yes
NOx	Yes	Yes	Yes	Yes*
CO_2	Yes	Yes	No	Yes*
Hg	Yes	Yes	Yes*	No

* Indicates this cost is considered in certain sensitivities.

Sulfur Dioxide

The SO_2 allowance price forecast of the general assumptions are consistent with those projected assuming the passage of the Clean Air Interstate Rule. SO_2 allowances at this level would add $28.2 MM to the cost of operation of a clean coal plan over that of an all gas plan. There is a possibility that regulation could develop that would increase SO_2 allowance prices even higher. This would add an additional $54.1 MM in allowance costs for a total incremental of $82.3 MM to the operational cost of a clean coal facility when compared to an all gas plan.

Nitrogen Oxides

Currently, there is no requirement to acquire NOx allowances. However, the proposed clean coal plant design would utilize Best Available Control Technology (BACT) to maintain NOx levels below required emission limits. Even with BACT, there is the potential for future regulation or legislation that would require the purchase of NOx allowances. It is estimated that such a requirement would add as much as $37 MM to the operational cost of a clean coal facility above that of an all gas plan.

Carbon Dioxide

There is significant uncertainty regarding whether, and to what extent, CO_2 emissions would be controlled in the future. However, with the help of industry experts FPL has developed two possible scenarios that would, if implemented, add additional operational costs to the clean coal plan. A moderate CO_2 control program would add as much as \$193 MM to the operational cost of a clean coal facility, while a more stringent program could add as much as \$406 MM to the operational cost of a clean coal plan above that of an all gas plan.

Mercury

There are currently proposed regulations and legislation that would set a standard (not yet identified) for mercury emissions. The proposed clean coal technology plant design would significantly reduce the levels of mercury emitted by utilizing the air-stream cleaning equipment that is required to control SO_2 emissions. If future regulation and legislation sets a mercury standard that cannot be met using existing equipment, additional equipment can be added. The installation and operation of this additional control equipment could add as much as \$170 MM to the operational cost of a clean coal facility above that of an all gas plan.

D. Potential Scenarios Combining Sensitivities

The individual effects of uncertainty regarding future natural gas prices, the viability of competitive delivery of coal, and the magnitude of emissions compliance costs have been provided above as independent sensitivities. In actuality, these individual factors will occur simultaneously and have a combined effect on the economic results of the clean coal plan. When considering how these factors would combine, it is helpful to recognize general relationships between these variables that make some combinations of future behavior more likely than others. The primary relationship of note is the expected correlation between natural gas prices and CO_2 emission allowance prices. High CO_2 allowance costs would tend to raise natural gas prices because greater use of natural gas (with its lower CO_2 emissions rate) would help a generator avoid paying the high CO_2 allowance costs. Conversely, if no significant CO_2 allowance costs are expected, natural gas demand would not rise, resulting in relatively lower natural gas prices. Therefore, it is expected that there would be a positive correlation between future CO_2 emission allowance costs and future natural gas prices.

In effect, the likely positive correlation between CO_2 emissions costs and higher natural gas prices would dampen the net adverse effect of high CO_2 emissions costs on the relative savings offered by a clean coal plan. Figure 3.8 provides three possible emission scenarios, drawing on the sensitivities discussed in the previous section. The three scenarios are 1) the base assumptions (SO_2 costs only), 2) a scenario which adds the moderate CO_2 control program costs to the base assumptions, and 3) a scenario which reflects all of the most stringent emission sensitivities, including high CO_2 compliance cost.

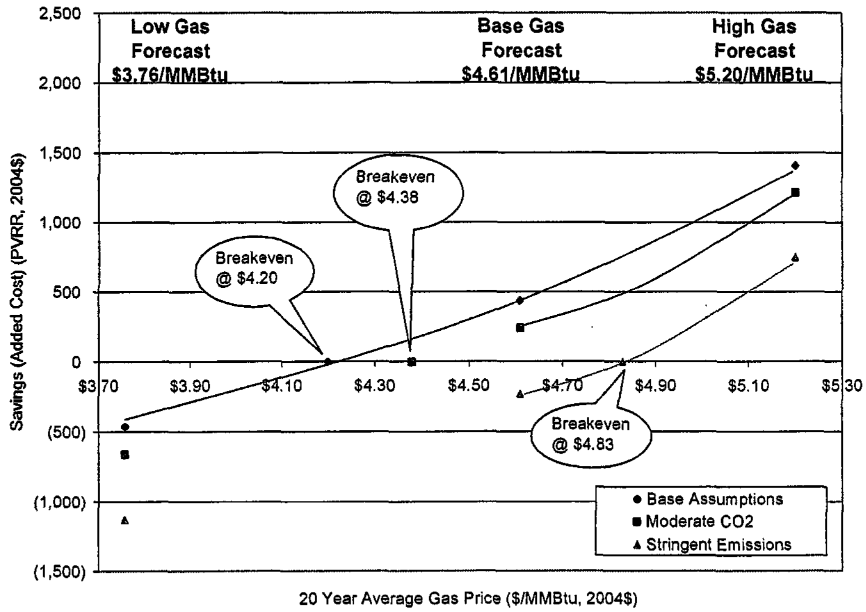

Figure 3.8 Relative Savings (Added Costs) for Potential Scenarios.

The blue, red and green lines show the savings results for the future natural gas price and environmental compliance (CO_2) cost combinations that are likely to occur. This illustrates how the expected correlation of CO_2 emission costs and high natural gas prices is expected to limit the likely range of savings/added costs that would result from the implementation of the clean coal plan over the all gas plan. As shown on the graph, as the cost of environmental compliance increases, the range of likely future gas prices is focused on the natural gas price region that is higher than the expected natural gas price forecast. This anticipated correlation between CO_2 compliance costs and natural gas prices increases the likelihood that the clean coal plan would provide savings, compared to the all gas plan.

E. Economic Analysis Summary

The results of the economic analysis indicate that the higher capital and operating costs of a clean coal plan can be more than offset by the lower cost of coal, to the point that a clean coal generation plan would result in total system costs that are $435 MM lower that an all gas generation plan. The sensitivities explored as part of the study highlight the effect of uncertainty regarding both the future price differential between natural gas and coal and the future cost of environmental compliance on the economic benefits of implementing the clean coal generation plan. However, as is discussed above, the clean coal plan is the most cost-effective plan, even in the face of this uncertainty.

The future price of natural gas has a strong effect on the magnitude of the savings that could result from the clean coal plan compared to the all gas plan. These savings could be as great as $1.4 B under the high gas price sensitivity. This is the primary reason for implementing the clean coal plan. Moreover, as was pointed out above, even under the low natural gas price sensitivity the clean coal plan would still produce more than 94% of the savings our customers would have experienced with an all gas plan. At the same time, by reducing our exposure to high natural gas prices, this clean coal plan provides a cost hedge for our customers that cannot be provided by the all gas plan.

The clean coal plan also reduces fuel cost volatility. The analysis shows that the clean coal plan would reduce our customers' exposure to higher than forecasted system fuel costs by about $50 MM (nominal $'s) per year, compared to an all gas plan.

Compliance with future environmental regulations could also increase the cost of a clean coal plan and thereby affect its economic performance relative to an all gas plan. The most extreme environmental compliance scenario considered in the analysis would add $667 MM to the cost of the clean coal plan, potentially making it $232 MM more costly than the all gas plan. However, as has been discussed above, any outcome that imposes high costs for compliance with CO_2 emission requirements would likely be accompanied by higher than forecasted natural gas prices, which would likely offset, at least in part, the effect of environmental compliance on the economics of the clean coal plan.

A key requirement to support the economic benefits and reliability of the clean coal plan is to have effective, competitively priced coal transportation and delivery to the plant. FPL intends to develop a robust competitive coal transportation plan prior to making a final decision to implement the clean coal generation plan.

Part Four – Issues that Must Be Addressed

This section of the Report discusses four topics that are very important to the successful implementation of clean coal generation. The topics are: (1) the need for competitively priced transportation and delivery of coal and petroleum coke to the generation plant; (2) the importance of recognition by the Commission of key areas of uncertainty related to clean coal generation; (3) the importance of public participation in the clean coal generation implementation process; and (4) the need for an RFP process that can effectively address issues related to clean coal generation. This section of the Report also provides a preliminary list of steps FPL will take towards implementation of clean coal generation.

A. Need for Competitive Fuel Delivery

The ability to deliver foreign coal and petroleum coke to FPL's proposed clean coal plant is necessary to achieve sufficiently low delivered fuel costs to offset the higher capital and O&M costs of clean coal generation. To achieve this goal, FPL must have access to one or more coal receiving port terminals with efficient rail transport routes from the terminal facilities to the plant site. Additionally, in order to obtain economic rail transportation and delivery rates it is necessary that there be at least two competing railroads that can load fuel at the selected fuel origins (receiving port terminals for foreign coal and petroleum coke, and producing mines for domestic coal) and deliver it to the plant site. FPL believes that effective rail competition at both origin and destination is necessary if a clean coal plant is to provide value to our customers. Conversely, being captive to one railroad would result in unacceptably high fuel transportation and delivery costs over the long term and, as the economic analysis in Part Three of this Report indicates, would erode the fuel cost advantage of coal over natural gas.

FPL's study of clean coal generation included a review of existing and potential future fuel receiving port terminal facilities in Florida and elsewhere along the southeast U.S. Atlantic and Gulf Coasts, and of the railroads that serve those facilities. The results of that review indicate that the necessary fuel receiving terminal port facilities that would allow for delivery of foreign coal and petroleum coke, and provide effective rail competition at both origin and destination are not currently available. We will continue our effort to have the necessary fuel receiving port terminal facilities developed and/or expanded to help us achieve the key fuel transportation objectives. Without economic coal transportation and delivery, it would not be possible to achieve the fuel cost savings required to make the addition of clean coal generation technology economically acceptable.

B. Commission Recognition of Key Areas of Uncertainty

As explained in this Report, FPL has estimated that the benefits to its customers of adding clean coal generation could be very significant based on current expectations regarding future fuel prices, future environmental requirements, and other future operations and maintenance requirements, and therefore FPL believes that adding clean coal generation is the preferred strategy for FPL's customers.

However, it is important to note that the higher capital cost of adding clean coal generation would be incurred at the outset, while the anticipated benefits of the clean coal plan (primarily lower and more stable fuel costs), would be experienced gradually over the operating life of the clean coal facility. In addition there are a number of unpredictable factors, which have been referred to in this Report as key areas of uncertainty, that could affect the realization of these anticipated benefits.

Uncertainty regarding these factors creates a situation where FPL would commit to a high capital cost facility, either through a long-term purchase of clean coal capacity via a power purchase agreement or ownership of a self-build clean coal generation facility, without certainty that that over time that commitment would actually result in reduced costs to our customers.

One key uncertainty factor is the possibility that the fuel price differential between coal and natural gas may narrow in the future. That factor, combined with the possibility that we may not be able to obtain competitively priced delivery of coal and petroleum coke to the clean coal generation facility, would reduce the fuel cost savings provided by clean coal generation.

Another key uncertainty factor that could affect the benefit that customers actually receive relates to currently unknown future changes in environmental regulations that could be implemented after the design of the clean coal plant is finalized, or during plant construction, or even after the plant has been placed in service. Complying with future environmental regulations could significantly increase the capital and O&M costs of clean coal generation, depending on the form, extent and timing of those new regulations, and the market's response to those regulations.

It is also important to note that because the clean coal facility contemplated by FPL will include steam generation greater than 75 MW, a Site Certification from the Governor's Siting Board will be required prior to construction, pursuant to the Power Plant Siting Act PPSA), in addition to local rezoning, conditional use and site plan approvals. Also, because there is very little recent experience regarding the addition of coal plants in Florida, and because of the dynamics specific to each permit process, there is uncertainty regarding the issues that may be raised by the various stakeholders and the requirements or conditions that may be imposed on FPL's clean coal facility by government agencies. Such requirements and conditions could affect the cost of compliance.

Yet another factor that affects the cost of clean coal generation more than it does gas-fueled generation is the longer lead time required to develop, permit, and construct a clean coal facility and place it in service. This longer lead time creates a greater potential for the costs of equipment, materials and labor to change significantly. Any increase in these costs would (all other things held equal) reduce the benefit of the clean coal unit to our customers.

It is essential that the Commission recognize the existence of these key areas of uncertainty, and the fact that possible future developments in these areas, or other factors, could cause delays or prevent the addition of clean coal capacity, or cause the total cost of these additions to be higher than projected. It is also important that the Commission recognize that the adverse effects of future outcomes relative to these areas of uncertainty, or other unforeseen factors, could become known only after construction of clean coal generation facilities has begun, or even after these facilities have been placed in service.

The addition of clean coal generation can only be achieved through the combined participation of many stakeholders, including the Florida Public Service Commission, for the benefit of our customers. Consequently, and in light of the key areas of uncertainty discussed above, it will be very important that, as part of the process leading to the addition of clean coal generation the Commission express its recognition that FPL's decision to pursue the addition of clean coal capacity is prudent, and in the best interest of its customers. FPL would ask for the Commission's concurrence that if, due to factors related to one or more of the areas of uncertainty discussed above or other unforeseen factors, the effort to implement clean coal generation were to be discontinued, or if during the time of construction or after clean coal generation has been placed in service such factors cause actual costs for clean coal generation to be greater than projected, or greater than they would be for an all-gas generation plan, FPL would be authorized to recover, through the normal cost recovery process, all prudently incurred costs.

As part of the process of adding clean coal generation to its portfolio, we will continue to examine all key areas of uncertainty to assess whether clean coal additions are reasonably likely to result in a net benefit to our customers.

C. Public Participation in Clean Coal Generation

A state-of-the-art clean coal facility would provide clean, economically stable generation to our customers for years to come. Any clean coal generation technology proposed by FPL would be designed to operate in a manner consistent with our environmental stewardship objectives. That means that such a facility would, at a minimum, fully meet the stringent requirements of the U.S. Environmental Protection Agency and the Florida Department of Environmental Protection, including all health-based air emission requirements. Twenty-first century emission control technologies and other design features ensure that today's clean coal generation facilities emit significantly less pollution and consume less water and fuel than any coal facilities that have come before.

However, FPL recognizes that its plans for new capacity to meet the growing needs of its customers are important to the communities it serves. Therefore, we will promote and maintain an active dialogue with communities and other stakeholders regarding clean coal generation in order to inform the public and learn about the communities' concerns, interests and priorities. FPL will take these concerns, interests and priorities in consideration along with the technical requirements FPL would need to address. In this manner we can develop a plan that addresses technical, economic, environmental and community considerations.

Recent plans for new clean coal facilities in Florida and around the country have been met with a variety of responses and support. While many recognize the compelling economic and strategic benefits that can be offered through the efficient use of a plentiful fuel resource in today's clean coal generating plants, others maintain strong reservations regarding the impact that these facilities may have on surrounding environments, or generally question any energy policy that continues to rely on fossil fuels.

Any clean coal generation facility proposed by FPL would undoubtedly have supporters and opponents. In addition to the opportunities for public input afforded by the formal licensing process, as we proceed to bring the benefits of clean coal generation to our customers, we will continue to encourage and facilitate an open, positive dialogue with all stakeholders in order to provide information about the proposed facility and seek common ground on all areas. However, it is important to recognize that despite FPL's best efforts to facilitate an open dialogue with all stakeholders, some parties may pursue other avenues to block the development of a clean coal facility. Responding to such actions would require additional resources and may impact our ability to add clean coal generation within the time frame identified in this Report.

D. Request for Proposal Process for Clean Coal Generation

FPL intends to pursue a generation plan that includes clean coal generation in addition to gas-fired generation to meet our customer future needs. One step in that plan would be to define, by the first half of 2006 consistent with the Commissions Bid Rule, a specific clean coal facility that would be FPL's self-build alternative, or "Next Planned Generating Unit," to meet our capacity need in 2012, or in 2012 and 2013. Another step in the plan would be to issue, not later than July 2006, a Request for Proposals (RFP) to meet this need in 2012, or possibly for 2012 and 2013. Because one of the primary objectives of the capacity addition would be to reduce our reliance on natural gas, FPL will only consider those proposals submitted in response to this RFP that would provide clean coal generating capacity by the date(s) specified in the RFP.

Moreover, because there are significant differences between clean coal generation and gas-fired generation in areas such as fuel transportation and delivery systems, longer lead time for development, permitting and construction, greater uncertainty regarding future environmental requirements, plant-specific fuel procurement, transportation and delivery requirements, greater variability in the design, engineering and construction, etc., it will be necessary to develop an RFP process that will effectively address all clean coal generation-related issues and, therefore, would be somewhat different from the RFP process previously utilized for gas-fired generation.

For example, the longer lead time necessary for development, permitting and construction of clean coal facilities requires that cost estimates be developed well in advance. Because changes in economic factors that could occur during this long lead time could affect the cost for equipment, material and labor, the actual capital cost of a completed clean coal facility could be much different from estimates prepared by bidders and FPL six or seven years earlier. If this concern is not addressed in the RFP process, bidders would likely submit conservatively high-priced proposals that reflect a risk premium related to the long lead time.

Another key difference related to an RFP for clean coal generation relates to fuel transportation and delivery. We currently do not have a coal purchasing, transportation and delivery infrastructure in place. Moreover, the fuel procurement, transportation and delivery requirements of each proposal would be specific to that proposal. Therefore it would not be feasible, nor practical for FPL to offer a tolling agreement to prospective suppliers of clean coal generation capacity and energy. We anticipate that the clean coal generation RFP would consider only those proposals that include, and reflect in the proposal pricing, the fuel procurement, transportation and delivery plans required by and consistent with those proposals, and that indicate that the bidding entity accepts responsibility for purchasing, transporting and delivering fuel to its clean coal generating plant.

Another important difference related to an RFP for clean coal generation is that there are more significant differences in design, engineering and construction among clean coal plants than among gas-fired combined cycle plants. Because of these differences, we would not be in a position to assume ownership of a generating facility designed, engineered and constructed by other entities. Therefore, we anticipate that a clean coal RFP would not consider "turnkey" proposals because accepting such a proposal would create an unacceptable operation and maintenance risk that would adversely affect our customers.

FPL will advise the Commission when it has completed development of its clean coal generation RFP process, and will communicate the details of that process to FPSC Staff.

It should be noted that there will also be generation capacity needs in FPL's system that must be met in 2009 through 2011. Because the lead times required to develop, permit and construct a clean coal generating plant are so long, it would not be feasible to place a clean coal technology unit in service before June 2012. Therefore, FPL's self-build alternative(s), or "Next Planned Generating Unit(s)" to meet these capacity needs in 2009 through 2011 are expected to utilize natural gas. An RFP that will solicit proposals to meet FPL's need in 2009, and perhaps 2010 and 2011 as well, will be issued in 2005. This RFP will not restrict the type of generation technology or fuel in the proposals.

Clean Coal Technology Selection Study

Final Report

January 2007

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Acronyms

AFBC	Atmospheric Fluidized Bed Combustion
AGR	Acid Gas Removal
AQCS	Air Quality Control Systems
ASML	Above Mean Sea Level
ASU	Air Separation Unit
BACT	Best Available Control Technology
BFP	Boiler Feed Pump
Ca/S	Calcium to Sulfur
CaO	Calcium Oxide
CaS	Calcium Sulfide
$CaSO_4$	Calcium Sulfate
CCPI	Clean Coal Power Initiative
CCRB	Clean Coal Review Board
CFB	Circulating Fluidized Bed
CO	Carbon Monoxide
CO_2	Carbon Dioxide
COD	Commercial Operation Date
COP	ConocoPhillips
COS	Carbonyl Sulfide
CTG	Combustion Turbine Generator
DA	Deaerator
DCS	Distributed Control System
DLN	Dry Low NO_x
DOE	Department of Energy
EIS	Environmental Impact Statement
EPC	Engineering, Procurement, and Construction
EPRI	Electric Power Research Institute
ESP	Electrostatic Precipitator
FBC	Fluidized Bed Combustion
FEED	Front End Engineering Design
FGR	Flue Gas Recirculation
FPL	Florida Power & Light
FWH	Feedwater Heater
FGPP	FPL Glades Power Park

GE	General Electric
GEC	Gasification Engineering Corporation
H_2S	Hydrogen Sulfide
H_2SO_4	Sulfuric Acid
HCl	Hydrogen Chloride
HCN	Hydrogen Cyanide
HHV	Higher Heating Value
HP	High-Pressure
HRSG	Heat Recovery Steam Generator
IDC	Interest During Construction
IGCC	Integrated Gasification Combined Cycle
IP	Intermediate-Pressure
ISO	International Organization for Standardization
KBR	Kellogg Brown and Root
LHV	Lower Heating Value
LP	Low-Pressure
MDEA	Methyl Diethanol Amine
MHI	Mitsubishi Heavy Industries
NEPA	National Environmental Policy Act
NGCC	Natural Gas Combined Cycle
NH_3	Ammonia
NO_x	Oxides of Nitrogen
NSPS	New Source Performance Standards
O&M	Operations and Maintenance
OFA	Overfire Air
OP	Over Pressure
OUC	Orlando Utilities Commission
PC	Pulverized Coal
Petcoke	Petroleum Coke
PJFF	Pulse Jet Fabric Filter
PM_{10}	Particulate Matter (filterable 10 microns and less)
PRB	Powder River Basin
PSDF	Power Systems Development Facility
PUCO	Public Utilities Commission of Ohio
SCR	Selective Catalytic Reduction
SDA	Spray Dryer Absorber

SNCR	Selective Noncatalytic Reduction
SO_2	Sulfur Dioxide
SPC	Subcritical Pulverized Coal
SCPC	Supercritical Pulverized Coal
SPG	Siemens Power Generation
STG	Steam Turbine Generator
SWEPCO	Southwestern Electric Power Company
TC4F	Tandem-Compound Four Flow
TRIG	Transport Reactor Integrated Gasification
US	United States
USCPC	Ultra Supercritical Pulverized Coal
VWO	Valves Wide Open

Units of Measure

¢	Cents
$	Dollar
%	Percent
% wt	Percent weight
° F	Degrees Fahrenheit
Btu	British thermal unit
ft	foot
ft^3	cubic feet
h	hour
in. HgA	inches of mercury, absolute
kW	kilowatt
lb	pound
ltpd	long tons per day (2,240 lb/day)
m^3	cubic meters
MBtu	million British thermal unit
mg	milligram
MW	megawatt
MWh	megawatt-hour
N	Newton
ppb	parts per billion
ppm	parts per million
ppmvd	parts per million, volumetric dry
psia	pounds per square inch, absolute
scf	standard cubic feet
sec	second
stpd	short tons per day (2,000 lb/day)
tpd	tons per day
yr	year

1.0 Executive Summary

1.1 Introduction

This study is in connection with Florida Power & Light's (FPL) generation expansion project investigations for the addition of a nominal 2,000 MW of capacity. FPL has previously identified a need to diversify its fuel consumption. Therefore, this study investigates only coal-fueled technologies. The study compared subcritical pulverized coal (SPC), ultrasupercritical pulverized coal (USCPC), circulating fluidized bed (CFB), and integrated gasification combined cycle (IGCC). These baseload pulverized coal (PC), CFB, and IGCC technologies comprise the clean coal options available for consideration to meet FPL's generation expansion project needs in the 2012 to 2014 time period.

This study provides technology descriptions, plant descriptions, and screening level estimates of performance, capital costs, and operations and maintenance (O&M) costs for the various power generation technologies considered. Performance and cost estimates were based on assumptions made by Black & Veatch, in conjunction with FPL, for site and ambient conditions, cycle arrangements, air quality control systems (AQCS), and analysis of the proposed fuel. A busbar economic analysis was also performed to compare the technologies.

1.2 Plant Descriptions

Black & Veatch developed screening level performance and cost estimates for each of the technologies: SPC, USCPC, CFB, and IGCC. The required capacity would be met by installing blocks of power at the site to obtain a nominal 2,000 MW net. The fuels used for the performance and cost estimates consisted of blends of Central Appalachian coal, Colombian coal, and petroleum coke (petcoke). The PC and CFB cases utilized a blend of 40 percent Central Appalachian coal, 40 percent Colombian coal, and 20 percent petcoke – referred to as the AQCS Blend. The IGCC case utilized a blend of 25 percent Central Appalachian coal, 25 percent Colombian coal, and 50 percent petcoke – referred to as the IGCC Blend. All blend percentages are by weight. The technologies, plant sizes, and arrangements that were considered for this study are shown in Table 1-1.

Table 1-1. Summary of Power Generation Technologies

Case	Technology Type	Single Unit Output, MW	Net Plant Output, MW	Configuration	Fuel Supply
1	SPC	500	2,000	4 Boilers 4 STGs	AQCS Blend
2	USCPC	980	1,960	2 Boilers 2 STGs	AQCS Blend
3	CFB	497	1,988	8 Boilers 4 STGs	AQCS Blend
4	IGCC	940	1,880	6 GE Radiant Gasifiers 6 CTGs 6 HRSGs 2 STGs	IGCC Blend

STG–Steam Turbine Generator
CTG–Combustion Turbine Generator
HRSG–Heat Recovery Steam Generator

1.3 Overall Assumptions

For the basis of the performance estimates, the site conditions of the proposed greenfield FPL Glades Power Park (FGPP) in Glades County, Moore Haven, Florida were used. The site conditions were provided to Black & Veatch by FPL. Performance estimates were developed for both the hot day and the average day ambient conditions. Following are the overall assumptions, which were consistent among all of the technologies:

- Elevation–20 feet above mean sea level (ASML).
- Ambient barometric pressure–14.67 psia.
- Hot day ambient conditions:

  Dry-bulb temperature–95° F.

  Relative humidity–50 percent.
- Average day ambient conditions:

  Dry-bulb temperature–75° F.

  Relative humidity–60 percent.
- The assumed fuel is a blend of three different fuels. The ultimate analysis of the AQCS and IGCC Blend fuels (which were used to determine performance and cost estimates) is provided in Table 1-2.

- AQCS equipment was selected to develop performance and cost estimates, based on Black & Veatch experience. Actual AQCS equipment would be selected to comply with federal New Source Performance Standards (NSPS), be subject to a Best Available Control Technology (BACT) review, and achieve the emission levels shown in Table 5-4.
- Condenser performance was based on Black & Veatch experience. The expected condenser back pressures were supplied for hot and average day ambient conditions.

Table 1-2. Ultimate Fuel Analysis

Fuel	AQCS Blend	IGCC Blend
Carbon, % wt	69.85	73.28
Sulfur, % wt	1.98	3.77
Oxygen, % wt	5.51	3.74
Hydrogen, % wt	4.35	3.96
Nitrogen, % wt	1.37	1.46
Chlorine, % wt	0.07	0.05
Ash, % wt	7.68	4.99
Water, % wt	9.18	8.74
HHV, Btu/lbm	12,300	12,800
HHV–Higher Heating Value.		

1.4 Performance Estimates

1.4.1 PC and CFB Cases

The cases were evaluated on a consistent basis to show the effects of technology selection on project performance. The performance estimates were generated for single units that would be installed at a multiple unit greenfield site. Full-load performance estimates for each of the PC and CFB cases are presented in Table 1-3.

Table 1-3. PC and CFB Coal Performance Estimates, per Unit

Technology	SPC	USCPC	CFB
Fuel	AQCS Blend	AQCS Blend	AQCS Blend
Performance on Average Ambient Day at 20 ft ASML, Clean and New Equipment			
Steam Conditions, psia/° F/° F	2,415/1,050/1,050	3,715/1,112/1,130	2,415/1,050/1,050
Fuel Input, Mbtu/h	4,600	8,480	4,730
Boiler Efficiency (HHV), percent	88.9	88.9	87.0
Heat to Steam (HHV), Mbtu/h	4,090	7,545	4,200
Gross Single Unit Output, MW	550	1,054	556
Total Auxiliary Load, MW	50	74	59
Net Single Unit Output, MW	500	980	497
Gross Turbine Heat Rate, Btu/kWh	7,450	7,140	7,540
Condenser Pressure, in. HgA	2.2	2.1/1.7	2.2
NPHR (HHV), Btu/kWh	9,210	8,660	9,510
Net Plant Efficiency (HHV), percent	37.0	39.4	35.9
Performance on Hot Day at 20 ft ASML, Clean and New Equipment			
Net Single Unit Output, MW	494	976	491
NPHR (HHV), Btu/kWh	9,340	8,690	9,640
Performance On Average Ambient Day at 20 ft ASML, Maximum Degradation (1.0% heat rate and 1.0% net plant output)			
Net Single Unit Output, MW	495	970	492
NPHR (HHV), Btu/kWh	9,300	8,750	9,610

Note:
USCPC option has dual condensers, therefore both pressures are listed.
No margins were applied to performance estimates.

1.4.2 IGCC Cases

Full-load performance estimates were developed for the IGCC case. The IGCC case was evaluated on a consistent basis with the PC and CFB cases with respect to site and ambient conditions to show the effects of technology selection on project performance. Performance estimates for the IGCC case using GE Radiant gasifiers are presented in Table 1-4. IGCC performance is presented in a separate table from the PC and CFB cases because the performance parameters are slightly different.

Table 1-4. GE Radiant IGCC Performance Estimates, per Unit

Fuel	IGCC Blend
Combined Cycle Configuration	3 x 1 GE 7FB
Performance on Average Day at 20 ft ASML, Clean and New Equipment	
Coal to Gasifiers, MBtu/h	8,400
Gasifier Cold Gas Efficiency, % (Clean Syngas HHV/Coal HHVx100)	74
CTG Heat Rate (LHV), Btu/kWh	8,370
CTG(s) Gross Power, MW	687
Steam Turbine Gross Power, MW	451
Syngas Expander Power, MW	5
Total Gross Power, MW	1,143
Aux. Power Consumption, MW	203
Net Power, MW	940
Net Plant Heat Rate (HHV), Btu/kWh	8,990
Net Plant Efficiency (HHV), Btu/kWh	38.0
Performance on Hot Day at 20 ft ASML, Clean and New Equipment	
Net Power, MW	902
Net Plant Heat Rate (HHV), Btu/kWh	9,360
Performance on Average Day at 20 ft ASML, Maximum Degradation (2.5% heat rate and 2.5% net power output)	
Net Power, MW	917
Net Plant Heat Rate (HHV), Btu/kWh	9,215

Note:
Based on publicly available data from technology vendor.
No margins were applied to performance estimates.

1.5 Cost Estimates

1.5.1 Capital Costs

Screening level overnight capital cost estimates for the four technologies were estimated on an engineering, procurement, and construction (EPC) basis, exclusive of Owner's costs. The estimates are expressed in 2006 United States (US) dollars and are included in Table 1-5. The cost estimate includes estimated costs for equipment and materials, construction labor, engineering services, construction management, indirects, and other costs on an overnight basis. The estimates were based on Black & Veatch proprietary estimating templates and experience. These estimates are screening-level estimates prepared for the purposes of project screening, resource planning, comparison of alternative technologies, etc. Cost estimates are made using consistent methodology between technologies, so while the absolute cost estimates are expected to vary within a band of accuracy, the relative accuracy between technologies is better.

Capital cost estimates for all power generation technologies are exhibiting considerable upward trends. Market pricing of technology components, coupled with commodity and labor demand worldwide, is rapidly escalating capital costs. These costs increases are not confined to any particular generation technology; they apply across the industry.

Table 1-5. EPC Capital Cost Estimates

Technology	SPC	USCPC	CFB	IGCC
Net Single Unit Output, MW	500	980	497	940
Net Multiple Unit Output, MW	2,000	1,960	1,988	1,880
EPC Cost, 2006$MM	3,078	2,646	3,240	3,541
Unit EPC Cost, 2006$/kW	**1,540**	**1,350**	**1,630**	**1,880**
Escalation to 2012$	490	421	516	564
Subtotal - EPC Cost 2012$	*3,568*	*3,067*	*3,756*	*4,105*
Owner's Costs, 2012$	1,218	1,153	1,236	1,411
IDC, 2012$	1,063	914	1,119	1,223
Project Cost, 2012$	*5,849*	*5,134*	*6,111*	*6,739*
Unit EPC Cost, 2012$/kW	**2,925**	**2,619**	**3,074**	**3,585**

1.5.2 Nonfuel O&M Costs

Preliminary screening level estimates of O&M expenses for the technologies were developed. The O&M estimates were derived from other detailed estimates developed by

Black & Veatch, based on vendor estimates and recommendations; actual performance information gathered from in-service units; and representative costs for staffing, materials, and supplies. The nonfuel O&M cost estimates, including fixed and variable costs, are shown in Table 1-6.

Table 1-6. O&M Cost Estimates

Technology	SPC	USCPC	CFB	IGCC
Net Single Unit Output, MW	500	980	497	940
Net Multiple Unit Output, MW	2,000	1,960	1,988	1,880
Capacity Factor, percent	92.0	92.0	88.0	80.0
Annual Generation, GWh	16,100	15,800	15,300	13,200
Fixed Costs, 2006$, (1,000s)	35,780	27,500	38,800	47,810
Fixed Costs, 2006$/kW	17.89	14.03	19.54	25.43
Variable Costs, 2006$ (1,000s)	45,130	47,500	68,000	80,120
Variable Costs, 2006$/MWh	2.94	2.86	4.44	6.07
Fixed Costs, 2012$, (1,000s)	41,480	31,870	45,050	55,420
Fixed Costs, 2012$/kW	20.74	16.26	22.66	29.48
Variable Costs, 2012$ (1,000s)	54,900	52,300	78,600	92,930
Variable Costs, 2012$/MWh	3.41	3.31	5.14	7.04

1.6 Busbar Cost Analysis

A levelized busbar cost analysis was performed using several sets of data. These include:

- Economic criteria provided by FPL
- Fuel forecasts provided by FPL
- Performance estimates for the PC, CFB, and IGCC cases listed in Table 1-3 and Table 1-4.
- EPC capital cost estimates listed in Table 1-5,
- O&M cost estimates listed in Table 1-6.

The PC and CFB cases were run with 40 year book and 20 year tax lives. The IGCC case was run with 25 year book and 20 tax lives.

Performance was based on the annual average day conditions. The capacity factors for the PC, CFB, and IGCC units were assumed to be 92, 88, and 80 percent, respectively.

The results of the busbar analysis are provided in Table 1-7. Results are provided in 2012$. Several cases were run:

- Degraded performance at average ambient conditions with no emissions allowance cost included.
- New and clean performance at average ambient conditions with no emissions allowance cost included.
- Degraded performance at average ambient conditions with emissions allowance cost included for oxides of nitrogen (NO_x), sulfur dioxide (SO_2), and mercury (Hg). Emission allowance costs were estimated by multiplying a forecasted allowance cost by the total annual emissions of each pollutant based on the assumed control limits minus annual emission allocations for FGPP.
- New and clean performance at average ambient conditions with emissions allowance cost included for NO_x, SO_2, and Hg.
- Degraded performance at average ambient conditions with emissions allowance cost included for NO_x, SO_2, Hg, and carbon dioxide (CO_2) using the 2005 Bingaman carbon tax proposal. No carbon capture was included.

From the analysis, the USCPC unit is the most cost effective technology.

Table 1-7. Busbar Cost Analysis Results, ¢/kWh

Case	SPC	USCPC	CFB	IGCC
Degraded performance, w/o emissions	9.56	8.63	10.54	12.69
New and clean performance, w/o emissions	9.47	8.54	10.43	12.38
Degraded performance, w/ emissions	9.68	8.74	10.66	12.81
New and clean performance, w/ emissions	9.58	8.65	10.56	12.50
Degraded performance, w/ emissions including CO_2	10.96	9.94	11.99	14.00

Note: Results were based on economic criteria from Table 7-1, fuel forecasts from Table 7-2, and the inputs from Table 7-3. These results are based on the maximum assumed capacity factors at average ambient conditions. Results are based on 2012 cost estimates.

Three charts are provided to illustrate sensitivities of the busbar cost analysis. Figure 1-1 shows a breakdown of the components of the base case busbar cost without emissions allowances. Fuel and capital requirements make up the majority of the total busbar costs. Variations in these two cost categories will have the largest effect on the estimated busbar cost for any technology. Figures 1-2 and 1-3 are similar to Figure 1-1, but show the effect of adding the cost of emissions allowances. Figure 1-2 shows the incremental cost of adding allowance costs for NO_x, SO_2 and Hg. It can be seen that variations in emissions translate to minimal cost variations between the technologies. Figure 1-3 shows that the effect of adding CO_2 allowances (using the Bingaman case with no carbon capture). The carbon tax causes a noticeable increase to the absolute busbar costs, but because CO_2 emissions are relatively equal between technologies there is no effect on the rank order of busbar costs. All of the cases illustrated are based on degraded performance.

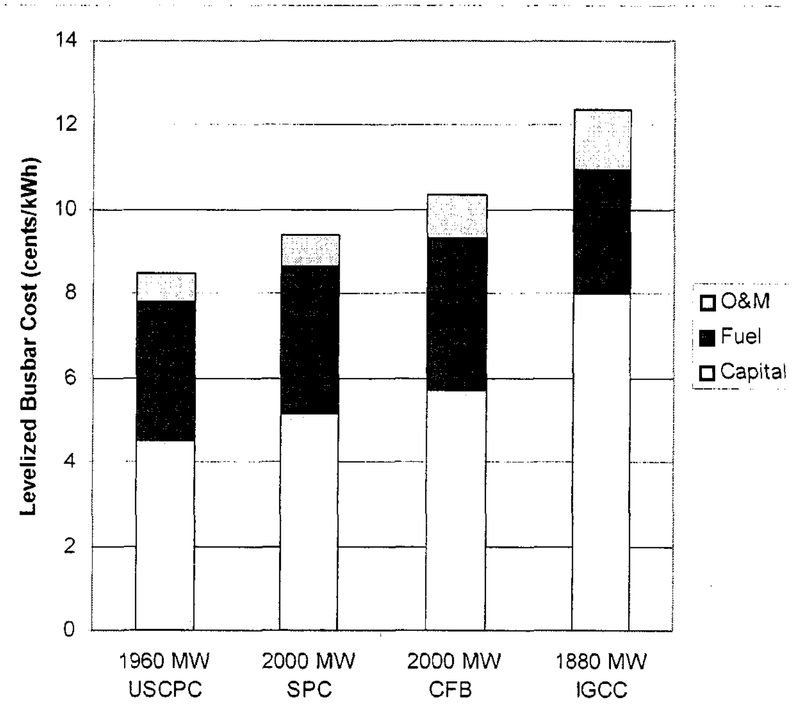

Figure 1-1. Busbar Cost Component Analysis without Emissions

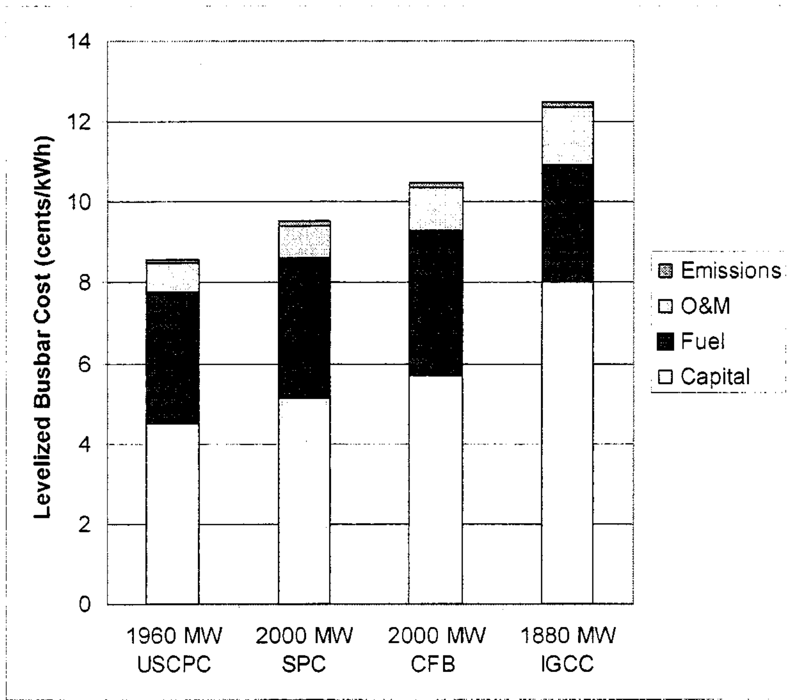

Figure 1-2. Busbar Cost Component Analysis with Emissions

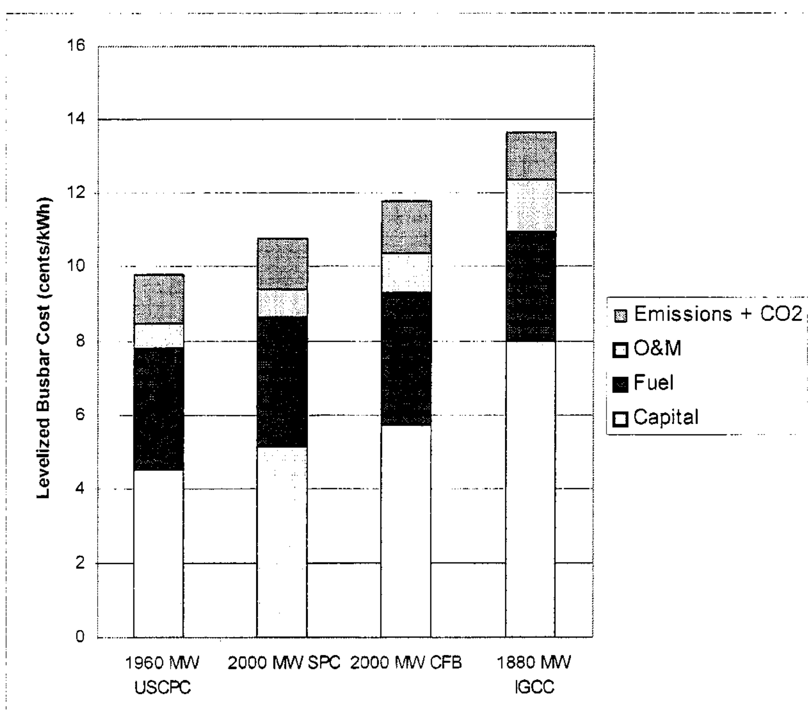

Figure 1-3. Busbar Cost Component Analysis with CO_2

A sensitivity case was run that included potential costs of carbon capture. There have been many studies performed by other parties to quantify the cost of capturing carbon. Because study of the potential cost of carbon capture was not a focus of this effort, high level assessments have been made to provide a representation of the cost of carbon capture and show the relative effect of this added cost on the economic comparison between technologies.

A review of recent literature, including the US EPA "Environmental Footprints and Cost of Coal-Based Integrated Gasification and Pulverized Coal Technologies", the Alstom chilled ammonia position paper, and Black & Veatch work indicates a probable range of carbon capture as shown in Table 1-8.

Table 1-8. Probable Carbon Capture Costs, \$/Avoided Ton CO_2.

Case	Low Cost	High Cost
Post-Combustion, 2006\$	20	40
Pre-Combustion, 2006\$	20	30

The cost range for pre-combustion is representative of current literature values published by technology neutral sources. The cost range for post-combustion uses Alstom's cost projection for their technology to establish the low value and then makes an assumption that the commercial cost could be 100 percent more for the high value. Estimated costs for other post combustion carbon capture systems published in other studies are higher than those published for this unique Alstom technology.

When these costs are added to the busbar cost analysis, with adjustments for output and net plant heat rate made as needed, the percentage increase of busbar cost over the base case analysis for new & clean conditions are as shown in Table 1-9.

Table 1-9. Probable Busbar Percentage Cost Increase with Carbon Capture and Emissions Allowances.

Case	Low Cost	High Cost
SPC	20	30
USCPC	20	30
CFB	20	30
IGCC	20	25

Note:

Assumes 90 percent carbon capture for conditions at average ambient temperatures compared to case with no emissions allowance costs. Includes emissions allowances for NO_x, SO_2, Hg, and emitted CO_2 using the 2005 McCain cost proposal.

A sensitivity analysis was run to show the effect variations in capacity factor have on economic analysis outputs. Figures 1-4 and 1-5 show the variations in busbar cost in cents per unit of generation (¢/kWh) and net levelized annual cost in dollars per unit of net plant output ($/kW) versus annual capacity factor. The sensitivity analysis was run over a range of capacity factors, from 40 percent to the maximum for each technology. The net plant heat rate was kept constant for all capacity factors, assuming full load operation. While all of the technologies have dramatic changes in busbar and net levelized annual cost across the range of capacity factors, the rank order of costs does not vary with capacity factor.

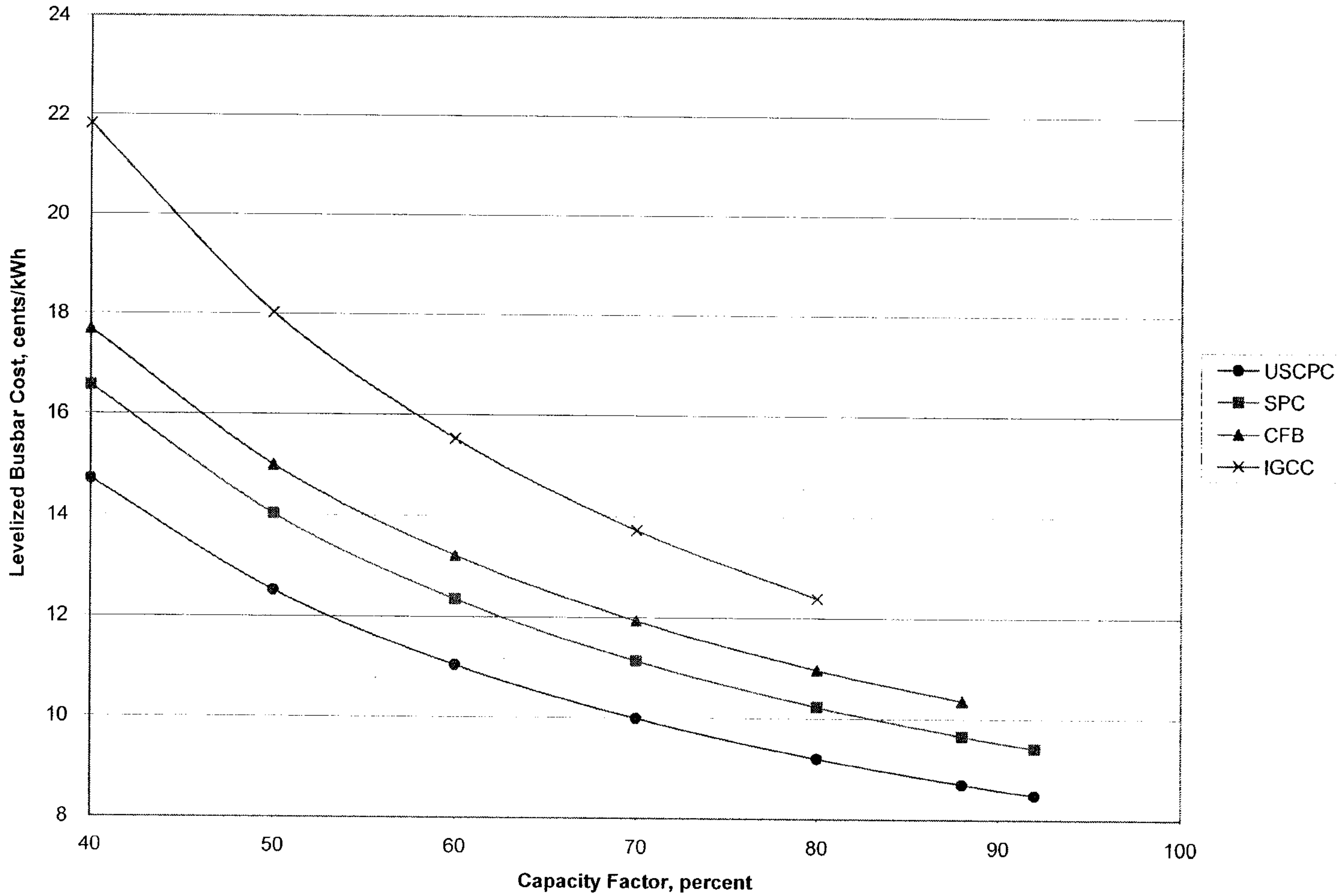

Figure 1-4. Busbar Cost Variation with Capacity Factor

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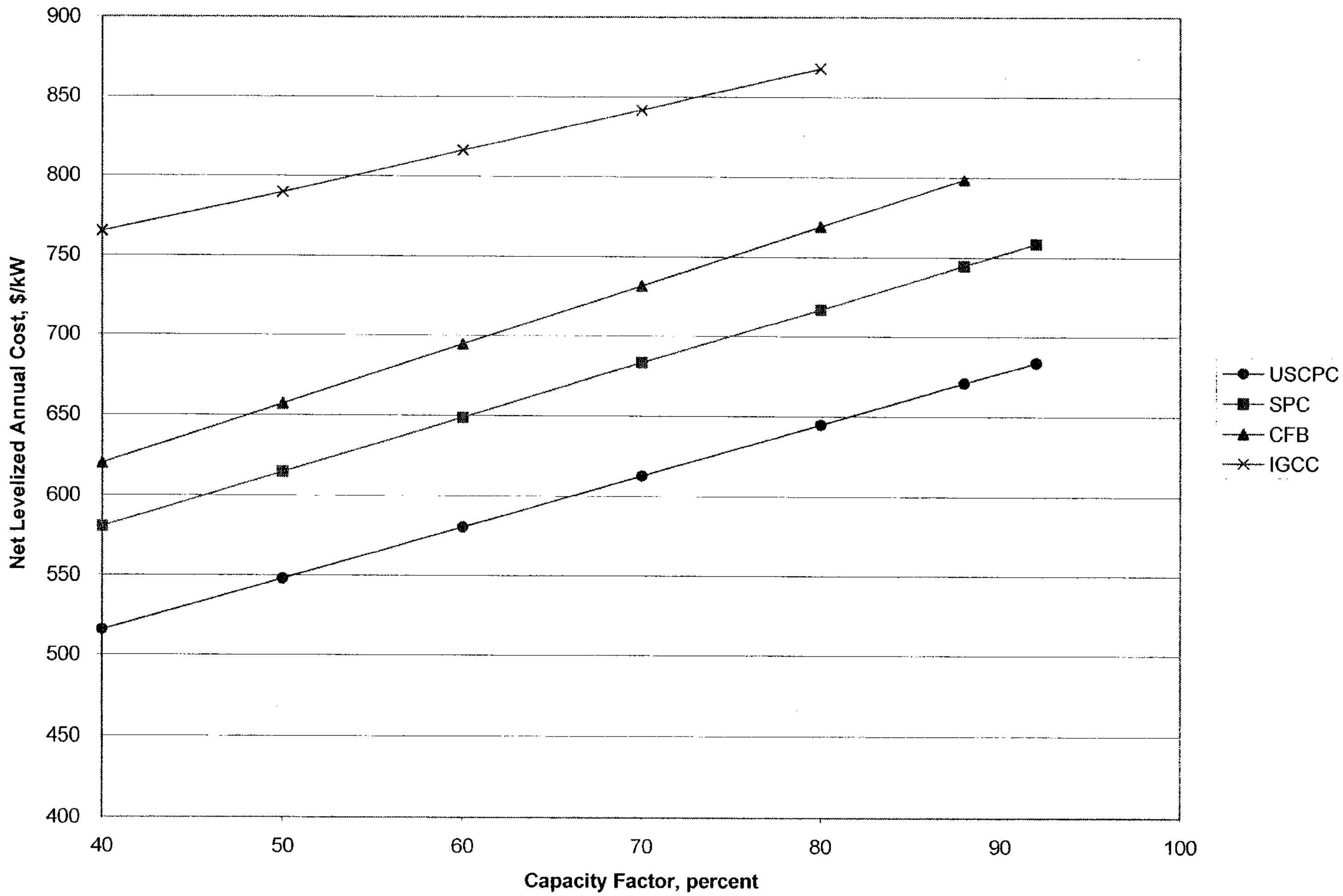

Figure 1-5. Net Levelized Annual Cost Variation with Capacity Factor

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1.7 Conclusions

This study made a comparison of performance and cost of four commercially available coal-fired power generation technologies. These were USCPC, SPC, CFB and IGCC. The estimates for performance were made using publicly available data and engineering data that has been collected by Black & Veatch and FPL. The results of the study are not intended to be absolute for any given technology but rather are intended to be accurate relative from one technology to another.

This study addresses technology risks known or assumed for each type of plant. Clearly PC plants are commercial and have been a dependable generation technology for years. The advancement of operation at ultrasupercritical steam conditions is somewhat new, but has been commercially demonstrated and proven around the world. CFB has also proven its dependability over the past two decades and is considered a mature technology. IGCC has been demonstrated on a commercial scale for over ten years. A second round of commercial scale IGCC plants is being planned currently. Many utilities will reserve decisions on making future IGCC installations until they have observed the installation and operation of these new plants.

Capital cost estimates for all power generation technologies are exhibiting considerable upward trends. Market pricing of technology components, coupled with commodity and labor demand worldwide, is rapidly escalating capital costs. These costs increases are not confined to any particular generation technology; they apply across the industry.

Based on the assumptions, conditions, and engineering estimates made in this study, the USCPC option is the preferred technology selection for the addition of a nominal 2,000 MW net output at the Glades site. The busbar cost of the SPC case, which is the second lowest busbar cost case, is nearly 10 percent more than USCPC. USCPC will have good environmental performance because of its high efficiency. Emissions of NO_x and PM will be very similar across all technologies. Sulfur emissions would be slightly lower for IGCC than the PC and CFB options, although start-up and shutdown flaring will reduce the potential benefit of IGCC. The lower expected reliability of IGCC, particularly in the first years of operation, could compromise FPL's ability to meet the baseload generation requirement and require FPL to run existing units at higher capacity factors.

For the 2012 to 2014 planning time period, USCPC will be the best technical and economic choice for installation of 2,000 MW of capacity at the Glades site.

2.0 Introduction

This study is in connection with Florida Power & Light's (FPL) generation expansion project investigations for the addition of a nominal 2,000 MW of capacity. The objective of this technology assessment is to characterize the commercially available coal fired electric power generation technologies. The baseload coal technologies considered were SPC, USCPC, CFB, and IGCC. These options were selected as representative of the options that could meet FPL's clean coal capacity planning needs.

This study provides technology descriptions, plant descriptions and assumptions, and screening level estimates of performance, capital costs, and O&M costs for four coal power generation technologies. Full-load performance estimates were developed at both the hot day and average day ambient conditions.

Each of the cases considered would be located on a greenfield site at the proposed Florida Glades Power Park (FGPP) in Moore Haven, Florida. The required net capacity would be met by installing blocks of power to obtain a nominal 2,000 MW net at the plant boundary. The SPC unit would have a net capacity of 500 MW. The SPC units would be arranged in a four boiler-by-four steam turbine (4x4) configuration. This configuration would produce the required net capacity of 2,000 MW. Each SPC unit would have a net capacity of 980 MW; a 2x2 configuration would be used. Each CFB unit would have a 500 MW net capacity and would comprise two 250 MW CFB boilers and one 500 MW steam turbine. An 8x4 configuration would be required for the CFB case.

For the IGCC case, the nominal 2,000 MW project net capacity could be met by two 940 MW IGCC units. To obtain the 1,880 MW net capacity at the site boundary, six GE Radiant gasifiers would be used in two 3x3x3x1 configurations. The combined cycle configuration of the FGPP plant would consist of six combustion turbine generators (CTGs) whose exhaust heat would generate steam in six heat recovery steam generators (HRSGs). Steam produced in the HRSGs would then be expanded through two steam turbine generators (STGs).

Each of the technologies considered would be fired by a blended fuel consisting of Central Appalachian coal, Colombian coal, and petcoke. A summarized list of the cases that were considered is shown in Table 2-1.

Table 2-1. Summary of Power Generation Technologies

Case	Technology Type	Single Unit Output, MW	Net Plant Output, MW	Configuration	Fuel Supply
1	SPC	500	2,000	4 Boilers 4 STGs	AQCS Blend
2	USCPC	980	1,960	2 Boilers 2 STGs	AQCS Blend
3	CFB	500	2,000	8 Boilers 4 STGs	AQCS Blend
4	IGCC	940	1,880	6 GE Gasifiers 6 CTGs 6 HRSGs 2 STGs	IGCC Blend

Assumptions were made for each technology, which addressed their configuration and AQCS. The AQCS for each technology were selected to comply with NSPS and recent BACT levels for criteria pollutants, including oxides of nitrogen (NO_x), sulfur dioxide (SO_2), filterable particulate matter of 10 microns or less (PM_{10}), and sulfuric acid mist (SAM). AQCS assumptions were made by FPL and are expected to be appropriate to control air emissions to the levels specified in Table 5-4.

3.0 PC and CFB Technologies

This section contains a summary-level comparison of PC and CFB technologies, including review of technology experience in the United States and discussions of advanced PC steam conditions and issues related to scaling-up CFB unit sizes.

The function of a steam generator is to provide controlled release of heat from the fuel and efficient transfer of heat to the feedwater and steam. The transfer of heat produces main steam at the pressure and temperature required by the high-pressure (HP) turbine. Coal fired steam generator design has evolved into two basic combustion and heat transfer technologies. Suspension firing of coal in a PC unit and the combustion of crushed coal in a CFB unit are the predominant coal fired technologies in operation today.

3.1 Pulverized Coal

Coal is the most widely used fuel for the production of power, and most coal-burning power plants use PC boilers. PC units utilize a proven technology with a very high reliability level. These units have the advantage of being able to accommodate up to 1,300 MW, and the economies of scale can result in low busbar costs. PC units are relatively easy to operate and maintain.

New-generation PC boilers can be designed for supercritical steam pressures of 3,500 to 4,500 psia, compared to the steam pressure of 2,400 psia for conventional subcritical boilers. The increase in pressure from subcritical (2,400 psia) to supercritical (3,500 psia) generally improves the net plant heat rate by about 200 Btu/kWh (HHV), assuming the same main and reheat steam temperatures and the same cycle configuration. This increase in efficiency comes at a cost, however, and the economics of the decision between subcritical and supercritical design depend on the cost of fuel, expected capacity factor of the unit, environmental factors, and the cost of capital.

Newly constructed supercritical PC boilers are currently being designed to provide main and reheat steam at 1,050° F or higher. Advancements in metal alloys now allow main steam temperatures of 1,112° F and reheat temperatures of 1,148° F. The US DOE has defined ultra-supercritical steam cycles as operating pressures exceeding 3,600 psia and main superheat steam temperatures approaching 1,100° F[1].

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[1] "Materials Development for Ultra-supercritical Boilers", US Department of Energy, Clean Coal Today, Fall 2005

To date, several ultrasupercritical projects in the US, Europe and Japan have been completed or are soon to be completed. Table 3-1 lists some of the more notable projects that have pushed supercritical PC technology to higher throttle pressures and temperatures.

For this study, FPL is investigating USCPC as a potential candidate for electric power generation capacity at FGPP. Although use of USCPC will be a technology advancement in the US, based on documented success of this technology in Europe and Japan shows that USCPC is not a significant technology risk for FPL.

Beyond what is feasible with current technology, future advancements in the use of high-nickel alloys could allow main steam temperatures to reach 1,292° F with a reheat temperature of 1,328° F; however this technology has not yet been fully developed or tested. The THERMIE 700 project in Europe is the first attempt at these higher steam temperatures. Construction of this plant was originally planned for 2008 with a commercial operation being achieved in 2012; however the progress of this project has appeared to stall. The newer alloyed materials necessary to build a plant of this type would not be commercially available until sometime after the successful operation of the THERMIE 700 or a similar demonstration project. In addition to the boiler improvements that would be necessary to increase steam temperatures, advancements in the steam turbine sector would have to be made in order to reliably sustain higher temperatures. The International Energy Agency's Clean Coal Centre published the history and the possible future of steam temperatures and pressures as shown on Figure 3-1.

Similar to increasing the steam temperature, an increase in steam pressure will also increase efficiency and capital cost. However, the efficiency gain for increased steam pressure is not as great as that for increased temperature. The economics of each situation would have to be examined to optimize the design temperatures and pressure.

With PC technology, coal that is sized to roughly ¾-in. top size is fed to the pulverizers which finely grind the coal to a size of no less than 70 percent (of the coal) through a 200 mesh screen (70 microns). This pulverized coal, suspended in the primary air stream, is conveyed to coal burners. At the burner, this mixture of primary air and coal is further mixed with secondary air and, with the presence of sufficient heat for ignition, the coal burns in suspension with the expectation that combustion will be complete before the burner flame contacts the back wall or sidewalls of the furnace. Current pulverized fuel combustion technology also includes features to minimize unwanted products of combustion. Low NO_x burners or air and fuel staging can be used to reduce NO_x and carefully controlling air-fuel ratios can reduce CO emissions.

Table 3-1. Notable Worldwide Ultrasupercritical Projects

Power Plant Name (Owner)	Country	MW	Steam Conditions: Steam Pressure, psia	Main Steam, ° F	Reheat Steam, ° F	COD
Big Stone 2 (Multiple)	USA	600	3,600	1,080	1,080	2012
Comanche 3 (Xcel)	USA	750	3,800	1,055	1,055	2009
Council Bluffs 4(Mid American)	USA	790	3,690	1,050	1,075	2007
Elm Road 1 & 2 (WE Energies)	USA	2x600	3,800	1,055	1,055	2009
Genesee 3 (EPCOR)	Canada	495	3,626	1058	1054	2005
Holcomb 2 (Sunflower)	USA	700	3,600	1,080	1,080	2011
Holcomb 3 (Sunflower)	USA	700	3,600	1,080	1,080	2012
Holcomb 4 (Sunflower)	USA	700	3,600	1,080	1,080	2013
Iatan 2 (KCP&L)	USA	850	3,686	1,085	1,085	2010
North Rhine-Westphalia Reference Power Plant – 60 Hz	USA	800	4,134	1,112	1,030	2010
Trimble County (LG&E)	USA	750	3,750	1,088	1,088	2010
Red Rock (AEP)	USA	900	4,000	1,100	1,100	2012
Hempstead (AEP)	USA	650	4,000	1,100	1,100	2011
Weston 4 (WPSC)	USA	500	3,800	1,076	1,076	2007
Boa 2 Neurath	Germany	2x1,000	3,771	1,103	1,103	2010
Boxberg 1	Germany	907	3,860	1,013	1,078	2000
Lippendorf	Germany	934	3,873	1,029	1,081	1999
Niederaussem	Germany	1,027	3,989	1,076	1,112	2003
North Rhine-Westphalia Reference Power Plant – 50 Hz	Germany	600	4,134	1,112	1,148	2008
Hemweg 8	Netherlands	680	3,844	1,004	1,054	1994
Avedoere 2	Denmark	450	4,351	1,076	1,112	2002
Nordjylland 3	Denmark	411	4,206	1,080	1,076	1998
Isogo 1	Japan	600	4,061	1,121	1,135	2002
Hitachi Naka, Tokyo Electric Power	Japan	1,000	3,675	1,112	1,112	2003

Table 3-1. Notable Worldwide Ultrasupercritical Projects

Power Plant Name (Owner)	Country	MW	Steam Conditions			COD
			Steam Pressure, psia	Main Steam, °F	Reheat Steam, °F	
Hranomachi 2, Tohoku Electric Power	Japan	1,000	3,675	1,112	1,112	1998
Tachibanawan 1	Japan	1,050	3,750	1,121	1,135	2000
Changshu	China	3x600	3,684	1,009	1,060	2006
Chugoku EPCO Misumi 1	China	1,000	3,556	1,112	1,112	1998
Huaneng	China	4 x 1,000	3,844	1,112	1,112	2008
Waigaoqiao	China	2 x 900	4,047	1,008	1,044	2004
Wangqu	China	2 x 600	3,989	1,060	1,056	2007
Zouxian IV	China	2 x 1,000	3,916	1,112	1,112	2008

COD--Commercial Operation Date

Note:

Data reported from various sources, not all data can be verified.

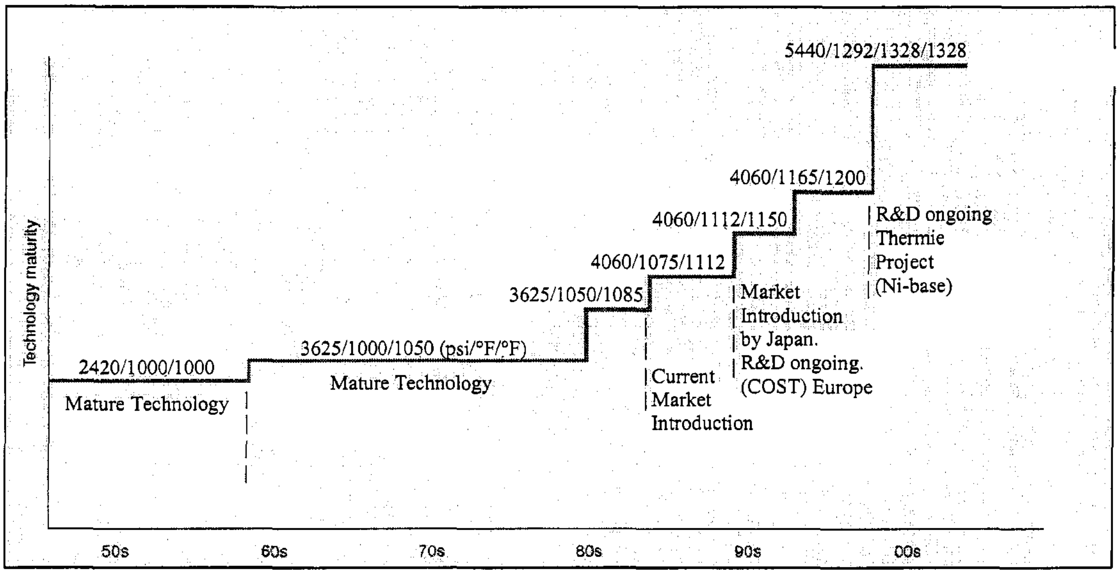

Figure 3-1. Trends in Steam Conditions of Coal-Fired Power Plants[1]

Because of the high combustion temperature of PC at the burners, the furnace enclosure is constructed of membrane waterwalls to absorb the radiant heat of combustion. This heat absorption in the furnace is used to evaporate the preheated boiler feedwater that is circulated through the membrane furnace walls. The steam from the evaporated feedwater is separated from the liquid feedwater and routed to additional heat transfer surfaces in the steam generator. Once the products of coal combustion (ash and flue gas) have been cooled sufficiently by the waterwall surfaces so that the ash is no longer molten but in solid form, heat transfer surfaces, predominantly of the convective type, absorb the remaining heat of combustion. These convective heat transfer surfaces include the superheaters, reheaters, and economizers located within the steam generator enclosure downstream of the furnace. The final section of boiler heat recovery is in the air preheater, where the flue gas leaving the economizer surface is further cooled by regenerative or recuperative heat transfer to the incoming combustion air.

Though the steam generating surfaces are designed to preclude the deposition of molten or sticky ash products, on-line cleaning systems are provided to enable removal of ash deposits as they occur. These on-line cleaners are typically soot blowers that utilize either high-pressure steam or air to dislodge ash deposits from heat transfer surfaces or,

[1] "Profiles", IEA Clean Coal Centre, November 2002. Available at:
http://www.iea-coal.org.uk/publishor/system/component_view.asp?PhyDocId=5385&LogDocId=81049

in cases with extreme ash deposition, utilize high-pressure water cannons to remove molten ash deposits from evaporative steam generator surfaces. The characteristics of the coal, such as ash content and ash chemical composition, dictate the type, quantity, and frequency of use of these on-line ash cleaning systems. Ash characteristics also dictate steam generator design regarding the maximum flue gas temperatures that can be tolerated entering convective heat transfer surfaces. The design must ensure that ash in the flue gas stream has been sufficiently cooled so it will not rapidly agglomerate or bond to convective heat transfer surfaces. In the case of very hard and erosive ash components, the flue gas velocities must be sufficiently slow so that the ash will not rapidly erode heat transfer surfaces.

With PC combustion technology, the majority of the solid ash components in the coal will be carried in the flue gas stream all the way through the furnace and convective heat transfer components to enable collection with particulate removal equipment downstream of the air preheaters. Typically, no less than 80 percent of the total ash will be carried out of the steam generator for collection downstream. Roughly 15 percent of the total fuel ash is collected wet from the furnace as bottom ash, and 5 percent is collected dry in hoppers located below the steam generator economizer and regenerative air heaters.

3.2 PC Vendors

There are currently eight major manufacturers of PC steam generators. These manufacturers are listed in Table 3-2.

Table 3-2. PC Boiler Vendors

• Alstom	• Foster Wheeler (FW)
• Babcock Power (BP)	• Ishikawajima Harima Heavy Industries (IHI)
• Babcock & Wilcox (B&W)	• Mitsubishi Heavy Industries (MHI)
• Babcock-Hitachi (B-H)	• Mitsui Babcock (MB)

The current utility steam generator technology offered by the major vendors is similar, with the exception of boiler tube construction, commercially available alloys, and burner arrangement and technology.

3.2.1 Boiler Tube Construction

All subcritical boilers use vertical tubes; nearly all of the vendors use smooth tubes except Babcock & Wilcox which uses a slightly rifled tube. There are two main design philosophies for supercritical boiler tube design. Either a vertical rifled or spiral wound tube is used. The two designs are shown on Figure 3-2.

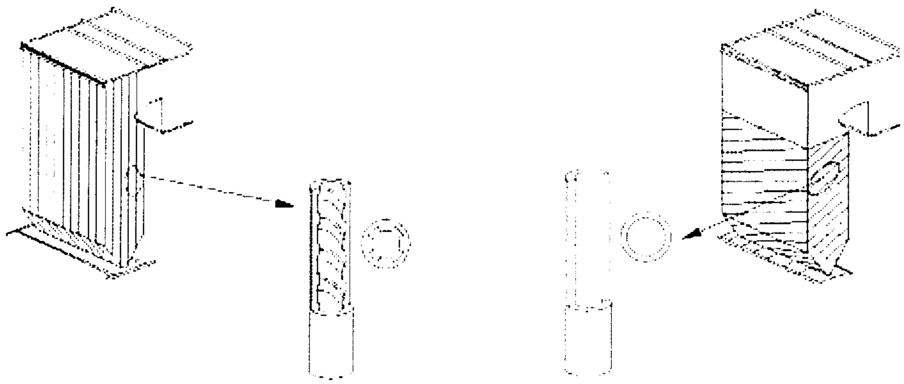

Figure 3-2. Vertical Rifled and Smooth Spiral Wound Tube Design (MHI).

There are numerous advantages and disadvantages to both the vertical and spiral tube designs. The vertical tube from a design standpoint is considered to be more ideal, however in practice the spiral tube design is the accepted technology. By nature in a rectangular boiler different sections of the furnace wall will see different temperatures. This can cause problems in a vertical tube arrangement where the feedwater cannot travel vertically. Certain sections of the wall will receive excess heating which can cause failure while others will be exposed to less heat. In a spiral wound design where the tube wraps around the furnace wall each tube will be exposed to the same amount of heat and this problem is avoided.

Thus current boiler designs implement the spiral tube design in the lower furnace and then switch to the vertical tube design in the upper furnace where the heat flux is lower. The disadvantage of the spiral tube design is that there is a much larger pressure drop through the tube compared to the vertical tube design. This pressure drop increases the work the feedwater pump must perform, thus lowering the overall efficiency of the plant. The capital costs associated with a vertical tube furnace are also lower, because the design requires a much simpler construction with less supporting structures. Because of the savings that could be experienced by using a vertical tube design, work is being performed to try and overcome the challenges faced by the vertical tube design.

The most prominent challenge of implementing a vertical tube design is its inability to handle the high heat flux in the lower furnace. As shown on Figure 3-2, one of the recent developments to aid with this issue is to use ribs within the tube instead of a smooth wall. This increases heat transfer area and creates turbulence within the tube, which increases overall heat transfer rates to the water and keeps the tubes cooler.

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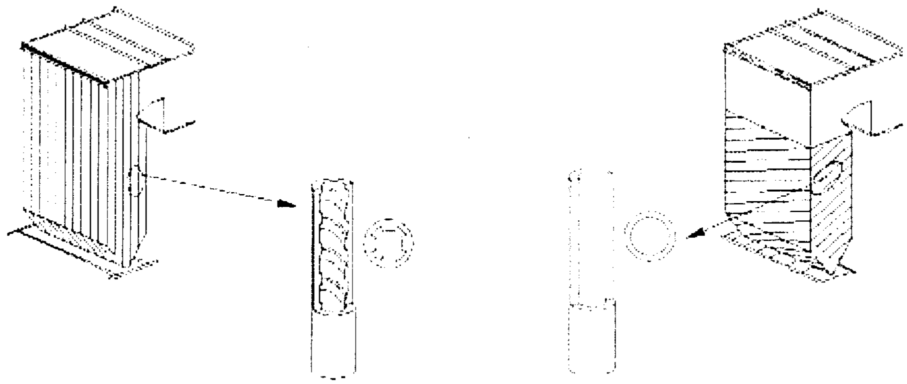

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A possible advantage of a vertical tube design is its ability to operate in natural circulation. Current supercritical boiler tube designs rely on forced circulation systems. New vertical tube designs are currently being developed to operate in natural circulation. A characteristic of natural circulation subcritical boilers is that when the water within the tube heats up the mass flow rate will also increase, thus drawing in more cooler water to maintain a safe tube temperature. In a supercritical application this characteristic would automatically control problems associated with boiler tubes overheating. However this characteristic has only been shown to occur in laboratory tests and there is no actual experience with a supercritical power plant using this technology.

Table 3-3 highlights the advantages and disadvantages of vertical rifled tubes versus spiral wound tubes.

Table 3-3. Vertical Rifled Tubes vs. Spiral Wound Tubes

Vertical Rifled Tubes	Spiral Wound Tubes
Lower Capital Costs • Simpler Construction • Self Supporting Tubes	Higher Capital Costs • More Complex Construction
Lower Operating Costs • Lower Pressure Drop • Less Feedwater Pumping Required	Higher Operating Costs • Higher Pressure Drop • More Feedwater Pumping Required
Can Operate in Natural Circulation	Forced Circulation Operation Only
Less Operating History	Proven Technology

3.2.2 Commercially Available Alloys

In addition to the type of boiler tube, selecting the tube material is a major design decision. There are currently a number of steel alloys available for use in boiler tube construction. Table 3-4 displays some of the more common alloying elements and the properties they exhibit. While Table 3-4 describes the general characteristics of alloying elements, metallurgy is a complicated science, and small variations in the combination of elements at different heating temperatures can produce varying results.

Table 3-4. Common Alloying Elements

Alloying Element	Properties
Chromium	Increases high temperature strength, adds resistance to corrosion and oxidation
Nickel	Increases hardenability and impact strength
Chromium – Nickel	Tends to add the positive properties of each element without the negative aspects
Molybdenum	Increases hardenability and creep strength
Vanadium	Increases yield and tensile strength

The common steel alloys are primarily differentiated by their cost, strength, and temperature properties. Capital costs associated with the alloy increase with increased temperature resistance and increased strength. Using an alloy that can withstand higher temperatures allows for higher steam temperatures. Higher steam temperatures directly correlate to increased boiler efficiencies. The higher capital cost of the alloy can be offset by this increase in boiler efficiency. Table 3-5 lists some of the common alloys and their associated pressure/temperature operating limits for boiler applications.

Another benefit is the increased strength properties of the alloyed steels. By using a stronger alloy, a smaller pipe diameter and thickness can be used. This results in significant weight savings in the boiler. A lighter boiler requires less structural support and this lowers the material cost during construction of pipe supports, structural steel, and equipment connection loads. Smaller component thickness allows for more operating flexibility as well. A plant with large thick sections will be limited to the ramp rates it can safely achieve. Replacing thick sections with thin sections allows for quicker heat transfer from inside the furnace to the feedwater or steam, this allows for larger ramp rates and better load matching capability.

The following is a discussion of the current commercially available alloys and their respective applications.

3.2.2.1 Boiler Tubes

P22, P91, and P92 are some of the most commonly used steel alloys. These steels are primarily alloyed with chromium (P22 - 2.25 percent chromium, P91 and P92 – 9 percent chromium) and also contain smaller amounts of molybdenum. P91 is now used in favor of P22, because of the higher temperatures and pressures it can handle. P92 is similar to P91, but it contains up to 2 percent tungsten in addition the chromium and molybdenum present in P91. P92 is used in installations where it will be exposed to temperatures higher than what P91 can withstand.

Table 3-5. Coal-Fired Power Generation Boiler Temperature and Material Development

Live Steam		Application Date	Alloy	Equivalent Material
Pressure, psi	Temperature, ° F			
<2,900	<968	Since the early 1960s	X20	Cr Mo V 11 1
<3,626	<1,004	Since the early 1980s	P22	2 ¼ Cr Mo
<4,351	<1,040	Since the late 1980s	P91	9Cr - 1Mo
<4,786	<1,148	Since 2004	P92	X10CrWMoVNb9-1, Europe STBA29-STPA29, Japan
<5,076	<1,292	Expected in 2010	Super Alloys	CCA 617 - IN 740 Haynes 230 - Save 12

Source: M.R. Susta and K. George, "Ultra-Supercritical Pulverized Coal Fired Power Plants," CoalGen 2006, Cincinnati, OH, August 16-18, 2006

3.2.2.2 Superheater Tubes

Superheater tubes have been previously constructed out of materials such as T20 or X20, but due to poor corrosion resistance austenitic steels are now more commonly used. Suitable materials for applications up to 1,050° F are the austenitic steels T316 and T346[1]. NF709 and HRC3 are considered suitable for applications of up to 1,112° F main steam temperature.

[1] "Supercritical Steam Cycles for Power Generation Applications," Department of Trade and Industry, January 1999.

3.2.2.3 Headers, Manifolds, Piping

For lower steam temperatures of 1,050° F carbon steel X20CrMoV121 can be used. To achieve higher steam temperatures P91/T91/F91 should be used[1]. For 1,112° F main steam temperature applications ferritic steels P92, P122 and the austenitic steel X3CrNiMoM1713 are considered to be the suitable commercially available options.

In the future advancements in nickel alloys could allow for main steam temperatures of 1,292° F.

Figure 3-3 is a chart presented by Alstom, a major boiler manufacturer, showing their recommended boiler alloys for particular steam conditions. Alstom has included a timeline showing expected availabilities of nickel alloy materials.

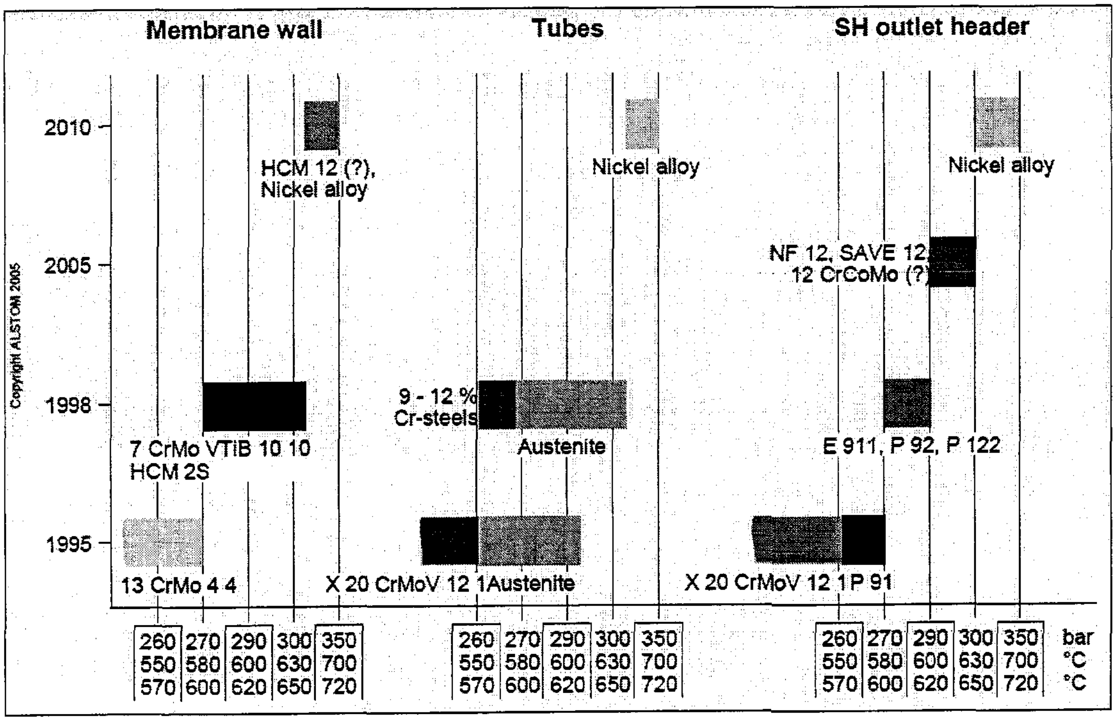

Figure 3-3. Alstom Boiler Alloys and Steam Conditions

Determining which alloy to use depends on the particular application. In some cases the increased capital cost can be offset by increased boiler efficiency, lower emissions, and lower structural cost. The most common practice for alloy selection is to first determine the surface temperature of the boiler tubes from the boiler design and then select an alloy that can withstand that temperature.

3.2.3 Burner Arrangement

PC boiler burners can be arranged in either a wall-fired or a corner or tangentially fired set-up. The wall-fired burners are either rear or front wall firing or they can be set up as front and rear-wall opposed. Corner or tangential fired set-ups typically have the burners firing from each of the four corners of the furnace.

3.3 Fluidized Bed

During the 1980s, fluidized bed combustion (FBC) rapidly emerged as a viable alternative to PC-fueled units for the combustion of solid fuels. Initially used in the chemical and process industries, FBC was applied to the electric utility industry because of its perceived advantages over competing combustion technologies. SO_2 emissions could be controlled from FBC units without the use of external scrubbers, and NO_x emissions from FBC units are inherently low. Furthermore, FBC units are "fuel flexible," with the capability to fire a wide range of solid fuels with varying heating values, ash contents, and moisture contents. Additionally, slagging and fouling tendencies were minimized in FBC units because of the low combustion temperatures.

There are several types of fluidized bed technologies, as illustrated on Figure 3-4. Pressurized FBC is currently a demonstration technology and will not be discussed here. Atmospheric FBC (AFBC) is generally divided into two categories: bubbling and circulating. A typical AFBC is composed of fuel and bed material contained within a refractory-lined, heat absorbing vessel. The composition of the bed during full-load operation is typically in the range of 98 percent bed material and only 2 percent fuel. The bed becomes fluidized when air or other gas flows upward at a velocity sufficient to expand the bed. At low fluidizing velocities (3 to 10 ft/sec), relatively high solid densities are maintained in the bed and only a small fraction of the solids are entrained from the bed. A fluid bed that is operated in this velocity range is referred to as a bubbling fluidized bed (BFB).

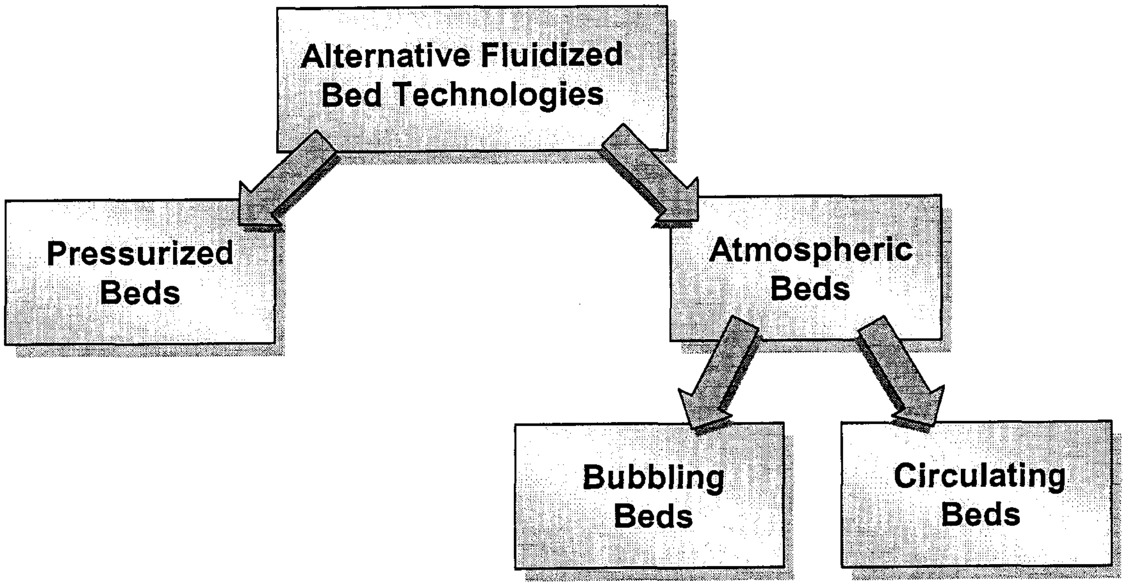

Figure 3-4. Fluidized Bed Technologies

If the fluidizing velocity is increased, smaller particles are entrained in the gas stream and transported out of the bed. The bed surface, well defined for a BFB combustor, becomes more diffuse; solids densities are reduced in the bed. A fluid bed that is operated at velocities in the range of 13 to 22 ft/sec is referred to as a circulating fluidized bed, or CFB. The CFB has better environmental characteristics and higher efficiency than BFB and is generally the AFBC technology of choice for fossil fuel applications greater than 50 MW.

The primary coal fired boiler alternative to a PC boiler is a CFB boiler. In a CFB unit, a portion of the combustion air is introduced through the bottom of the bed. The bed material normally consists of fuel, limestone (for sulfur capture), and ash. The bottom of the bed is supported by water-cooled membrane walls with specially designed air nozzles that uniformly distribute the air. The fuel and limestone are fed into the lower bed. In the presence of fluidizing air, the fuel and limestone quickly and uniformly mix under the turbulent environment and behave like a fluid. Carbon particles in the fuel are exposed to the combustion air. The balance of combustion air is introduced at the top of the lower, dense bed. Staged combustion and the low combustion temperature limit the formation of thermal NO_x.

The bed fluidizing air velocity is greater than the terminal velocity of most of the particles in the bed and, thus, fluidizing air carries the particles through the combustion chamber to the particulate separators at the furnace exit. The captured solids, including any unburned carbon and unused calcium oxide (CaO), are re-injected directly back into the combustion chamber without passing through an external recirculation. This internal solids circulation provides longer residence time for the fuel and limestone, resulting in good combustion and improved sulfur capture.

Commercial CFB units offer greater fuel diversity than PC units, operate at competitive efficiencies, and, when coupled with a polishing SO_2 scrubber, operate with emissions below the current levels mandated by federal standards. Compared to conventional PC technology, which was first utilized in the 1920s, CFB is a commercially proven technology that has been in reliable electric utility service in the United States for only the past 20 years.

By the late 1980s, the transition had been made from small industrial-sized CFB boilers to several operating electrical utility reheat boilers, ranging in size from 75 to 165 MW. Several reheat boilers of over 300 MW are currently in service, and boiler suppliers are offering boiler designs to provide steam generation sufficient to support up to 600 MW, but none has been built larger than 340 MW. Fuels for these applications range from petcoke and bituminous coal to high ash refuse from bituminous coal preparation and cleaning plants, and high moisture fuels such as lignite.

An environmentally attractive feature of CFB is that SO_2 can be removed during the combustion process by adding limestone to the fluid bed. The CaO formed from the calcination of limestone reacts with SO_2 to form calcium sulfate, which is removed from the flue gas with a conventional particulate removal device. The CFB combustion temperature is controlled at approximately 1,600° F, compared to approximately 2,500 to 3,000° F for conventional PC boilers. Combustion at the lower temperature has several benefits. First, the lower temperature minimizes the sorbent (typically limestone) requirement, because the required calcium to sulfur (Ca/S) molar ratio for a given SO_2 removal efficiency is minimized in this temperature range. Second, 1,550 to 1,600° F is well below the ash fusion temperatures of most fuels, so the fuel ash never reaches its softening or melting points. The slagging and fouling problems that are characteristic of PC units are significantly reduced, if not eliminated. Finally, the lower temperature reduces NO_x emissions by nearly eliminating thermal NO_x. Figure 3-5 illustrates the benefits of the lower combustion temperature for CFBs.

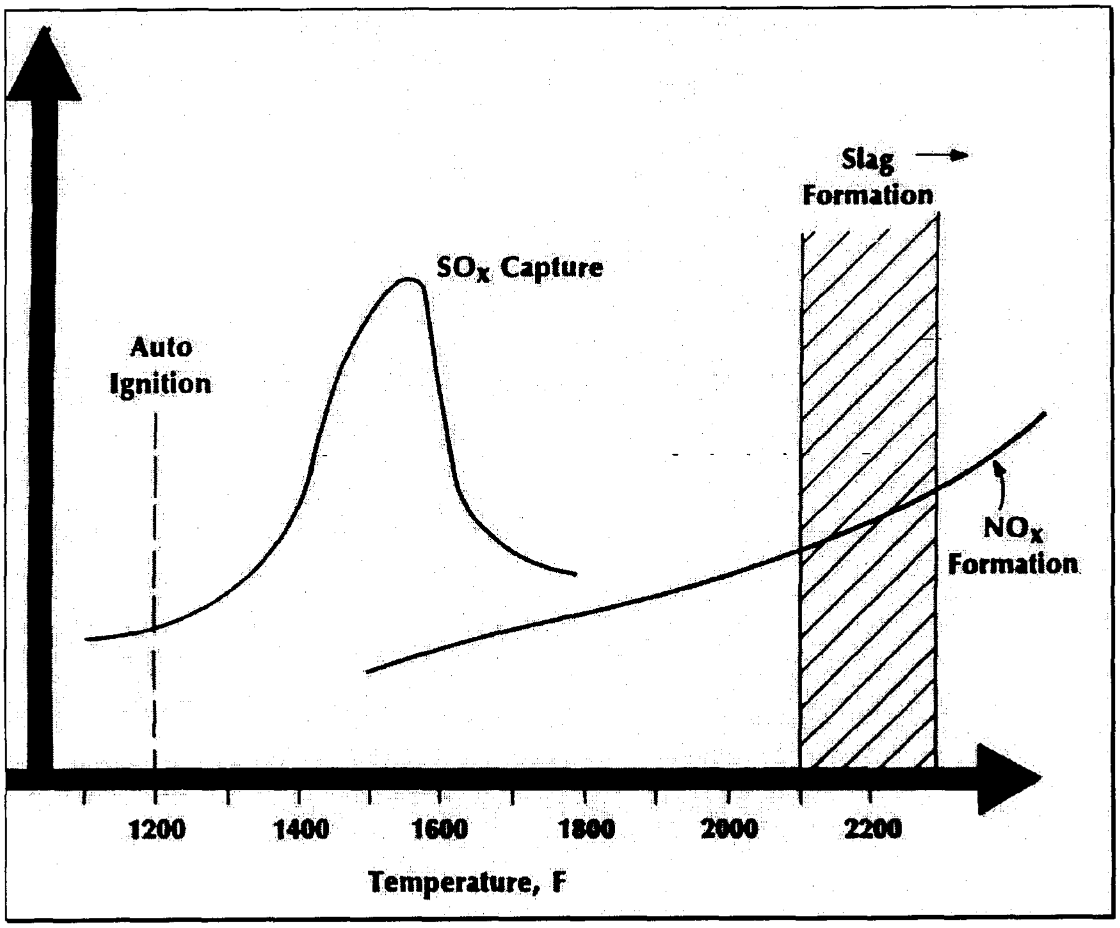

Figure 3-5. Environmental Benefits of CFB Technology

Since combustion temperatures are below ash fusion temperatures, the design of a CFB boiler is not as dependent on ash properties as is a conventional PC boiler. With proper design considerations, a CFB boiler can fire a wider range of fuels with less operating difficulty.

A typical CFB arrangement is illustrated schematically on Figure 3-6. In a CFB, primary air is introduced into the lower portion of the combustion chamber, where the heavy bed material is fluidized and retained. The upper portion of the combustor contains the less dense material that is entrained with the flue gas from the bed. Typically, secondary air is introduced at higher levels in the combustor to ensure complete combustion and to reduce NO_X emissions. The combustion gas generated in the combustor flows upward, with a considerable portion of the solids inventory entrained. These entrained solids are separated from the combustion gas in hot cyclone-type dust collectors or in mechanical particulate separators and are continuously returned to the combustion chamber by a recycle loop. The cyclone separator and recycle loop may include additional heat recovery surface to control the bed temperature and steam temperature and to minimize refractory requirements.

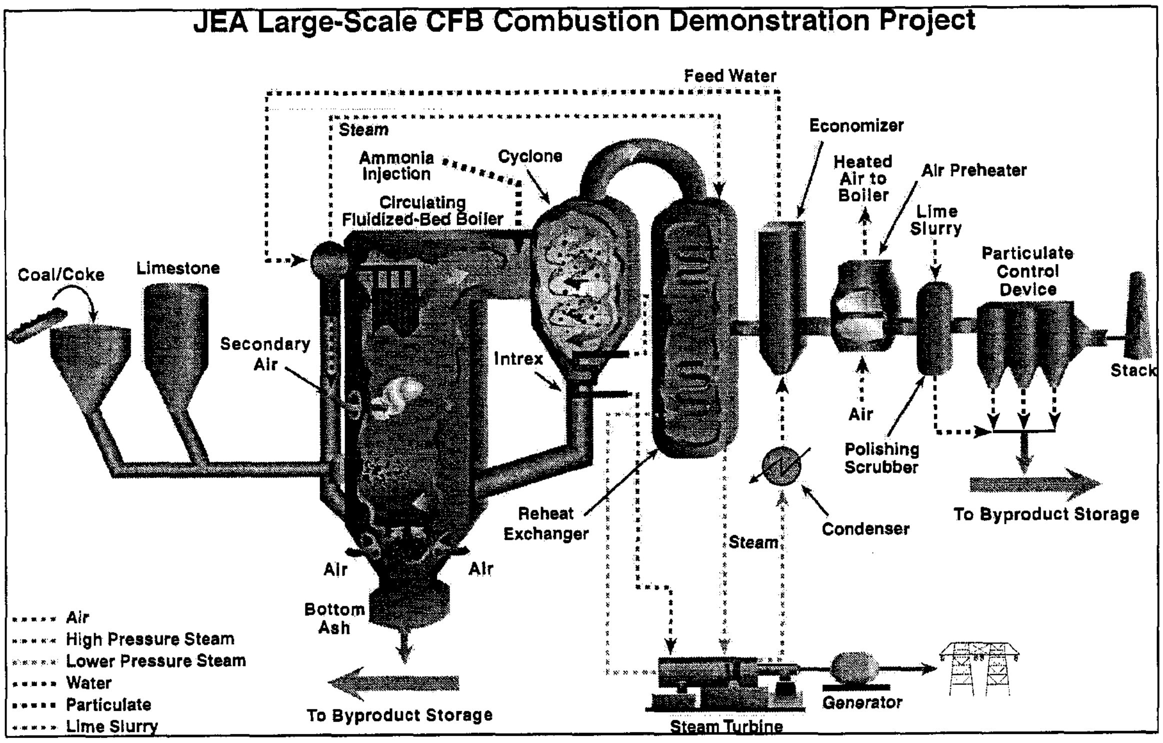

Figure 3-6. Typical CFB Unit

The combustion chamber of a CFB unit generally consists of membrane-type welded waterwalls that provide most of the evaporative boiler surface. Heat transfer to evaporative surfaces is primarily through convection and conduction from the bed material that contacts the evaporative wall surfaces or division panel surfaces located in the upper combustor. The lower third of the combustor is refractory lined to protect the waterwalls from erosion in the high-velocity dense bed region.

The fuel size for a CFB boiler is much coarser than the pulverized fuel needed for suspension firing in a PC boiler. Compared to the typical 70 micron particle size for a PC unit, the typical fuel size for a CFB is approximately 5,000 microns. Especially for high ash fuels, the use of larger fuel sizing reduces auxiliary power and pulverizer maintenance requirements and eliminates the high cost of pulverizer installation.

Ash removal from the CFB boiler is from the bottom of the combustor and also from fly ash that is entrained in the flue gas stream, similar to PC boilers. With a CFB boiler, the ash split between bottom ash and fly ash is roughly 50 percent bed ash and 50 percent fly ash. All of the ash drains from CFB boilers are typically retained in a dry condition without the need for water impounded hoppers or water submerged conveyors, typically utilized for PC boiler bottom ash collection and conveying.

3.4 Technical Characteristics of PC Versus CFB

The technical characteristics of the two competing boiler technologies were addressed in the previous section. Table 3-6 compares PC and CFB across several different parameters; these are summarized in the following subsections.

3.4.1 Environmental

Environmental impacts are categorized as flue gas emissions, solid waste production, and water consumption:

- **Flue Gas Emissions**--In the US, PC and CFB technologies will be required to meet similar emissions levels.
- **Solid Waste Production**--Solid waste production for the two technologies would be similar, except that the bottom ash from the PC boiler would be transported in a wetted condition because of the bottom ash collection technology, which includes either water impounded bottom ash hoppers or submerged conveyors below the furnace bottom. Bed ash extraction from a CFB is a dry process, where the ash is collected in a granular form and cooled with a combination of fluidizing cooling air and water jacketed screw coolers. The quantity of sorbent required for sulfur removal will affect the relative volume of solid waste.
- **Water Consumption**--Water consumption for the two technologies would be essentially identical for the boiler drum blowdown to maintain boiler water quality; however, when steam is used for soot blowing, the boiler water makeup requirements may be slightly higher because of the higher soot blowing steam demand of PC boiler technology.

Table 3-6. PC Versus CFB Boiler Comparison

Evaluation Parameter	PC Boiler	CFB Boiler
Environmental		
NO_x	SCR	SNCR
SO_2	FGD	Limestone injection and polishing FGD
Particulate	Fabric filter	Fabric filter
Operational		
Auxiliary Power	Base	Slightly higher
Maintenance	Base	Slightly higher
Fuel Flexibility	Within design coals	Better
Startup and Load Ramping	Base, 5 percent per minute	4 hours additional startup time, 2 to 3 percent per minute
Availability and Reliability	Base	Same
Technology Maturity	Well established	Recently constructed in 300 MW size
Capital Costs	Base	Slightly higher
Fixed O&M Costs	Base	Slightly higher
Variable O&M (Nonfuel) Costs	Base	Typically, slightly higher
Net Plant Heat Rate	Base	Higher

SCR--Selective Catalytic Reduction

FGD--Flue Gas Desulfurization

SNCR--Selective Non-catalytic Reduction

3.4.2 Operational

Operational impacts are categorized as auxiliary power, maintenance, fuel flexibility, startup, and load ramping:

- **Auxiliary Power**--The power requirements of the primary air fans for the CFB boiler provide the motive power to fluidize and circulate the bed material. This is a higher power requirement than that of the primary air fans for a PC boiler application. Since CFB boilers do not need pulverizers, the power savings from this normally results in the auxiliary power requirements for the two boiler technologies being relatively similar, with CFB requirements being slightly higher.
- **Maintenance**--The major maintenance requirements of CFB boilers involve the refractory repairs caused by the erosive effects of the bed materials circulating through the boiler components. Initial CFB boiler applications experienced significant refractory maintenance requirements. Subsequent refractory system improvements, materials, and installation techniques have provided significant reductions in these maintenance requirements. The major maintenance requirements of PC boilers and their auxiliaries are often associated with pulverizers, soot blowers, and associated heat transfer surface damage caused by soot blower erosion in areas where excessive soot blowing is needed to prevent the accumulation of agglomerating ash deposits. Unlike PC boilers, CFB boilers do not require pulverizers. In addition, CFB boilers require fewer soot blowers because the coal ash temperature is not elevated to the point where it becomes molten or agglomerating. The O&M cost of PC is slightly less than that of CFB.
- **Fuel Flexibility**--CFB boilers have the capability of superior fuel flexibility compared to PC boilers. Since the combustion temperature of CFB boilers is below the ash initial deformation temperature, the slagging and fouling characteristics of alternative fuels are not of concern. As long as the CFB boiler auxiliaries, such as fuel feed equipment and ash removal equipment, are provided with sufficient capacity, a wide range of fuel heating values and ash content can be utilized. The capacity of the sorbent feed equipment also needs to be designed for the range of fuel sulfur content that is expected to occur. Because of the long fuel residence time in the CFB boiler combustion loop, a very wide range of fuel volatile matter content can also be utilized. A CFB boiler can efficiently burn fuels in ranges of volatility well below those required in a PC boiler.

- **Startup**--Because of the large mass of bed material and larger quantity of refractory in a CFB boiler compared to a PC boiler, CFB boilers are somewhat less suited for numerous startups and cycling service than are PC boilers. The large mass of bed material results in significantly higher thermal inertia for a CFB boiler compared to a PC boiler. Startup from cold conditions can be extended for several hours. This higher thermal inertia can also result in unstable bed performance during periods of rapid load changes. Optimal sorbent feed for FGD is achieved during baseload operation, which enables consistent bed inventory, desulfurization, and sorbent utilization. CFB boilers have some advantages during hot and warm restarts, because the refractory and bed hold a significant amount of heat.
- **Load Ramping**--CFB boilers are generally capable of ramp rates of 2 to 3 percent per minute, but may be restricted to 1 to 2 percent per minute to control steam conditions, SO_2 emissions, and limestone stoichiometry fluctuations. PC boilers are generally capable of ramp rates of 5 percent per minute.

3.4.3 Availability and Reliability

Over the past 20 years that CFB boilers have been utilized for steam production for electric power generation, the availability and reliability have improved and are considered to be generally equivalent to PC boilers. Several improvements in refractory system designs, fuel and sorbent feed system designs, and ash extraction equipment design have been made that adequately address the initial problems encountered with these system components. These systems are high maintenance and can cause lower overall availability of CFB compared to PC. Since CFB boiler systems do not have pulverizers, do not have multiple burner systems with a large number of moving or controlled components, and have significantly fewer soot blowers, many of the high maintenance components of PC boilers are avoided.

3.4.4 Technology Maturity

Though CFB boilers have been used to provide steam for reheat turbine electric power generation for more than 20 years, the steaming capacities have been limited to less than 150 MW in most cases. In recent years, manufacturers have increased unit size to the point where there are more reheat boilers in service supporting electrical generation up to 300 MW gross output, with the largest being 320 MW net. These units are currently in service or under construction and are designed to burn the full range of solid fuels including low volatile anthracite, petcoke, subbituminous coal, high volatile bituminous coal, and high moisture lignite. CFB boiler manufacturers are currently proposing to supply units with capacities in excess of 400 MW electrical output. PC boilers have been installed and are operating with steaming capacities sufficient to support up to 1,300 MW of electrical generation. Because of the economies of scale for PC boiler and their auxiliaries, recent PC boiler installations have been predominantly larger than 250 MW. Many of the newer units have been designed to operate with supercritical steam pressure conditions.

3.5 FBC Experience in the United States

The first utility-grade AFBC unit was constructed in Rivesville, West Virginia, in 1976, a 30 MW (electric) Foster Wheeler BFB unit. One of the first utility-grade CFB units was the Tri-State Nucla project, completed in 1987. This 110 MW unit from Foster Wheeler was a Department of Energy (DOE) Clean Coal Demonstration Project. In the late 1980s and early to mid-1990s, a significant number of CFB units came online. In the early 1990s, the industry began to view CFB as a mature technology. The initial US CFB units were predominantly fired on bituminous coals. Around 1995, the trend reversed and almost all CFB units since that time have fired waste coals, lignites, or opportunity fuels such as petcoke and biomass. The field of international CFB vendors has consolidated to four dominating players: Alstom, Foster Wheeler, Lurgi, and Kvaerner Pulping. Alstom and Foster Wheeler have dominated the US and international markets for units above 150 MW. Lurgi does not actively market in the US.

CFB units have been increasing in size over the last 15 years, with the largest US operating CFB units at 300 MW (JEA Northside). The largest unit in operation is the ENEL Sulcis Unit in Sardinia, Italy. This Alstom unit is the equivalent of 340 MW, comprised of a 220 MW repowering unit along with additional process steam requirements.

Alstom, Foster Wheeler, and Lurgi have developed designs for single units in the 500 to 600 MW range. Alstom and Foster Wheeler have 600 MW designs, while Lurgi's largest design is 500 MW.

3.6 Current PC and CFB Project Development

There are numerous PC and CFB project currently being developed in the United States. Most of these will employ subcritical and supercritical steam conditions. These projects have been identified by the National Energy Technology Laboratory and are also tracked by Black & Veatch as the projects currently in development that may to move forward to construction.[1] These projects are listed in Table 3-7.

Table 3-7. Currently Announced PC and CFB Project Developments.

Project/Company	Size (MW)	Fuel	Technology	Location	Expected COD
MDU / Hardin	116	PRB	Subcritical	MT	2006
Manitowoc / Unit 9	63	Unknown	CFB	WI	2006
Tri-State / Springerville 3	418	PRB	Subcritical	AZ	2006
Santee Cooper / Cross Unit 3	600	Cent. App	Subcritical	SC	2007
XCEL / King	600	PRB	Supercritical	MN	2007
MidAmerican / CB4	790	PRB	Supercritical	IA	2007
Newmont / TS Ranch Plant	203	PRB	Subcritical	NV	2008
Black Hills / Wyg2 Unit 4	90	PRB	Subcritical	WY	2008
WPSC / Weston 4	530	PRB	Supercritical	WI	2008
TXU / Sandow	564	Lignite	CFB	TX	2009
TXU / Oakgrove U1	800	Lignite	Supercritical	TX	2009
TXU / Oakgrove U2	800	Lignite	Supercritical	TX	2009
CWLP / Dallman 34	201	Illinois	Subcritical	IL	2009
EKPC / Spurlock 4	278	Bituminous	CFB	KY	2009
CLECO / Rodemacher	600	Petcoke	CFB	LA	2009
Santee Cooper / Cross Unit 4	600	Cent.App.	Subcritical	SC	2009
WE Energies / Elm Road 1	615	Illinois	Supercritical	WI	2009
OPPD / Nebraska City 2	663	PRB	Subcritical	NE	2009
Salt River / Springerville 4	400	PRB	Subcritical	AZ	2010
NRG / Big Cajn. II, 4	675	PRB	Supercritical	LA	2010
CUS / Southwest U2	300	PRB	Subcritical	MO	2010
KCP&L / Iatan Unit 2	850	PRB	Supercritical	MO	2010
TXU / Texas Sites	8 x 800	PRB	Supercritical	TX	2010
NAPG / Two Elk	325	PRB	Subcritical	WY	2010

[1] "Tracking New Coal-fired Power Plants," NETL, S. Klara, E Shuster, September 29, 2006

Table 3-7. Currently Announced PC and CFB Project Developments.

Project/Company	Size (MW)	Fuel	Technology	Location	Expected COD
LG&E / Trimble Cty 2	732	Illinois Basin	Supercritical	KY	2010
LSP / Plum Point 1	665	PRB	Supercritical	AR	2010
CPS / Spruce 2	758	PRB	Subcritical	TX	2010
WE Energies / Elm Road 2	615	Illinois	Supercritical	WI	2010
XCEL / Comanche 3	750	PRB	Supercritical	CO	2010
Sierra Pacific / Ely Energy Ctr	750	Unknown	Supercritical	NV	2011
Sithe / Desert Rock 1	750	Unknown	Supercritical	NV	2011
LSP / White Pine	2 x 800	PRB	Supercritical	NV	2011
LSP / Elk Run	750	PRB	Supercritical	IA	2011
Peabody CMS / Prairie Stste 1	750	Illinois	Supercritical	IL	2011
Sunflower / Holcomb 2	600	PRB	Supercritical	KS	2011
LSP / Sandy Creek,	800	PRB	Subcritical	TX	2011
WF&Brazos / Hugo 2	750	PRB	Supercritical	OK	2011
Duke / Cliffside Unit 5	800	Bituminous	Supercritical	NC	2011
EKPC / J.K. Smith 1	278	Bituminous	CFB	KY	2011
S Mont.-SME / Highwood	250	Montana	CFB	MT	2011
Basin Elec. / Dry Fork-	385	PRB	Subcritical	WY	2011
AEP / Hempstead	650	PRB	Ultra-Supercritical	AR	2011
AECI / Norborne 1	660	PRB	Supercritical	MO	2011
Big Stone II Owners / Big Stone II	600	PRB	Supercritical	SD	2012
Santee Cooper / Great Pee Dee River 1	600	East KY Bituminous	Supercritical	SC	2012
NRG / Limestone U3	800	PRB	Supercritical	TX	2012
Sithe / Desert Rock 2	750	Unknown	Supercritical	NV	2012
Sithe / Toquop	750	Unknown	Supercritical	NV	2012
Alliant-WP&L	300	PRB & Bit	CFB	WI	2012
AMP Ohio	500	Bituminous & PRB	Unknown	OH	2012
FPL / FGPP Unit 1	1000	Bituminous	Ultra-Supercritical	FL	2012
UAMPs/Pacificorp / IPP 3	900	UT/CO	Unknown	UT	2012
AEP / Red Rock	900	PRB	Ultra-Supercritical	OK	2012
Sunflower / Holcomb 3	700	PRB	Supercritical	KS	2012
LSP / Longleaf	2 x 600	PRB/Bit.	Unknown	GA	2012

Table 3-7. Currently Announced PC and CFB Project Developments.

Project/Company	Size (MW)	Fuel	Technology	Location	Expected COD
Peabody-CMS / Prairie Stats 2	750	Illinois	Supercritical	IL	2012
Dominion / Wise Co. VA	600	Bit, Waste Coal/Bio	CFB	VA	2012
BPU / Nearman Cr 2	235	PRB	Subcritical	MO	2012
Duke / Cliffside 7	800	Bituminous	Supercritical	NC	2012
Seminole / Palatka 3	750	Bituminous /Illinois 6 /Petcoke	Supercritical	FL	2012
PPGA / Hastings 2	220	PRB	Subcritical	NE	2012
PacificCorp / Hunter Unit 4	400	Unknown	Supercritical	UT	2013
Santee Cooper / Great Pee Dee River U2	600	East KY Bituminous	Supercritical	SC	2013
Alliant-IP&L	600	PRB	Supercritical	IA	2013
AMP Ohio	500	Ohio & PRB	Unknown	OH	2013
Sunflower / Holcomb 4	600	PRB	Supercritical	KS	2013
JEA/FMPA / Taylor	800	Bituminous	Supercritical	FL	2013
PacificCorp / J. Bridger 4	750	PRB	Supercritical	WY	2014
FPL / FGPP Unit 2	1000	Bituminous	Ultra-Supercritical	FL	2013
Sierra Pacific / Ely Energy Ctr 2	750	Unknown	Supercritical	NV	2014
Tri-State / CO Coal Unit	656	PRB	Supercritical	KS	2020

Note:
This list is a compilation of known projects as published by NETL and Black & Veatch, independently. Not all data can be verified.

3.7 Post Combustion Carbon Capture

For PC and CFB technologies, the likely approach for CO_2 capture would be a post-combustion CO_2 capture process. In CO_2 capture, the CO_2 concentration and the CO_2 partial pressure in the gas stream are important variables. Higher concentrations and higher partial pressures of CO_2 facilitate its capture. The relatively low concentration of CO_2 in the flue gas makes the CO_2 capture process difficult.

Because the carbon capture technology is implemented as "post-combustion" for PC and CFB technologies, the steam generation equipment is constructed and operated the same as it would be for a plant without carbon capture. The resulting flue gas would be treated by removing the CO_2, which would then be dehydrated, compressed, and transported.

The addition of a carbon capture process would have a significant impact on the output and heat rate of a PC or CFB facility. Significantly higher auxiliary loads are required for additional pumps, fans, and miscellaneous loads in the capture process, and thermal energy in the form of process steam is required to separate the CO_2 from the absorption solvent. Energy would also be required for captured CO_2 compression. These energy requirements would have an impact on the net plant output and net plant heat rate of the facility. In order to maintain project required net plant output, additional generation capacity would need to be installed to compensate for the increased auxiliary loads of the carbon capture process. The increase in gross plant generation would meet the carbon capture process energy requirements.

Typically, CO_2 capture from the flue gas of a post-combustion process for a conventional coal technology plant has been thought to employ absorption using mono-ethanol amine (MEA), a chemical solvent that is commercially available and widely used. The CO_2 capture plant would consist of flue gas preparation, CO_2 absorption, CO_2 stripping, and CO_2 compression.

For an MEA CO_2 capture process, an auxiliary load in the range of 20 to 30 percent of gross plant output can be expected which would require additional capacity of 30 to 40 of gross plant output in order to maintain project required net capacity. The capital requirements for CO_2 capture addition would need to include both the CO_2 capture equipment and the capital required for additional capacity.

A new and developing alternative to the MEA CO_2 capture process is a chilled ammonia CO_2 absorption process, currently under development by Alstom. Compared to the MEA absorption process, the chilled ammonia absorption process appears to have the potential to significantly reduce the energy and capital requirements to achieve post-combustion CO_2 capture. A schematic of this process is shown in Figure 3-7. The description provided here is based on data presented in a position paper published by Alstom.[1]

For a CO_2 capture process employing Alstom's chilled ammonia absorption, the flow would begin at the flue gas discharge from the plant FGD. First, the flue gas would be cooled from a typical FGD exit temperature of 120 to 140° F to approximately 35° F. Flue gas cooling can be achieved by cooling towers and mechanical chillers. The power consumed by the cooling process is estimated by Alstom to consume one to two percent of the gross plant output. Reducing the temperature of the flue gas would have the effect of condensing out saturated water in the flue gas introduced by the FGD and any residual contaminants remaining in the flue gas. In addition, cooling the flue gas to a lower

[1] "Chilled Ammonia Process for CO2 Capture," Alstom, November 2006.

temperature will reduce the volume of the flue gas (a volume reduction of approximately 33 percent will occur when cooled from 140° F to 32° F). The reductions in mass flow rate resulting from moisture removal and volumetric flow rate of the flue gas may reduce the size, energy requirements and capital costs of downstream capture equipment.

Once the flue gas is cooled, the CO_2 absorption takes place in an absorption module similar to an FGD absorption module. A slurry containing a mixture of dissolved and suspended ammonium carbonate and ammonium bisulfate is discharged in the module against an upward flow of flue gas. More than 90 percent of the CO_2 contained in the flue gas is absorbed in the slurry. Any ammonia transferred to the flue gas by the absorption process would be captured by a cold-water wash process and returned to the slurry. After CO_2 absorption, the slurry is regenerated in a high pressure regenerator. Regenerating the slurry at a high pressure reduces the energy requirements for CO_2 compression once it is stripped from the slurry. CO_2 is stripped from the slurry by thermal energy addition which is obtained from a heat exchanger prior to injection in to the regenerator and heat addition by a reboiler in the regenerator. Any ammonia or water vapor contained in the CO_2 gas stream stripped from the slurry is removed in a cold-water wash at the top of the absorber.

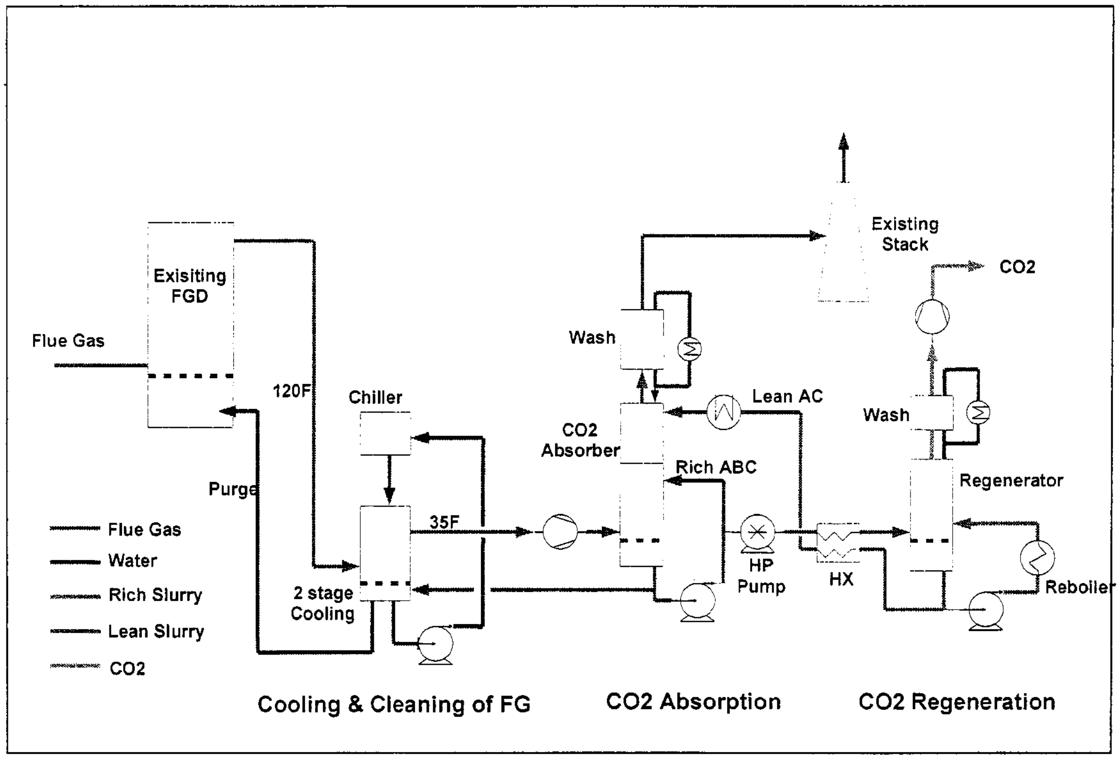

Figure 3-7. Schematic of Ammonia-Based CO_2 Capture System.

The primary advantage of the Alstom chilled ammonia CO_2 absorption process compared to MEA is the reduced operating energy requirements and capture costs. In a reference study prepared by Alstom comparing their ammonia absorption process to an MEA absorption process, the ammonia absorption process had a significantly reduced affect on net plant output and net plant heat rate. In addition, the cost of capture in dollar per avoided ton of CO_2 was less than half that expected with MEA.

Alstom's chilled ammonia CO_2 absorption process is still in development. Alstom projects the offering of a commercial product before the end of 2011. An Alstom press release dated October 2, 2006, announced a collaborative project between Alstom, the Electric Power Research Institute (EPRI) and We Energies to build a 5 MW pilot plant that will demonstrate the CO_2 capture process. The facility will be constructed at a power plant owned by We Energies in Pleasant Prairie, Wisconsin and is expected to be commissioned in mid-2007. The demonstration facility will give Alstom and EPRI the opportunity to evaluate the process on a larger commercial scale moving from bench scale testing.

4.0 IGCC Technologies and Industry Activity

This section contains a summary-level description of IGCC technologies, including a review of IGCC experience and a discussion of the issues related to commercializing the technology.

Reliability is expected to be lower for an IGCC plant than for a PC or CFB plant with respect to producing electricity from coal. IGCC plants without spare gasifiers are expected to achieve long-term annual availabilities in the 80 to 85 percent range on coal versus approximately 90 percent for PC and CFB. IGCC availability on coal during initial startup and the first several years of operation is expected to be significantly lower. A generation plant that uses IGCC technology could increase the availability by firing the combined cycle portion of the plant on a backup fuel such as natural gas when syngas is not available from coal gasification. The cost, availability, and air emissions of backup fuel firing may limit or prevent its use. Currently, natural gas is not available at FGPP. The installation of a relatively long natural gas pipeline would be required if natural gas were to be used as a backup fuel. Large capital cost would be required for the installation of a natural gas pipeline to FGPP. Additional capital would also be required for the installation all associated equipment required to operate the combined cycle on natural gas. These large capital requirements would not be justified by the incremental benefit of increased plant availability with higher cost natural gas as a backup fuel. Because of this, the use of natural gas as a backup fuel for an IGCC plant at FGPP would not be economically feasible. Likewise, using fuel oil as a backup fuel to enhance syngas production reliability would also be prohibitively expensive and logistically cumbersome.

Cost, schedule, and plant availability issues cause IGCC projects to have higher financial risk than conventional PC or CFB power generation projects. Details regarding the guarantee levels for cost, schedule, and performance; the associated liquidated damages clauses and risk premium; and availability assurances are not well defined at this time. It is expected that the standards for contractual arrangements between owners and constructors will evolve based on the experiences of the next generation of IGCC project development.

4.1 Gasification Technologies and Suppliers

Gasification is a mature technology with a history that dates back to the 1800s. The first patent was granted to Lurgi GmbH in Germany in 1887. By 1930, coal gasification had become widespread and in the 1940s, commercial coal gasification was used to provide "town" gas for streetlights in both Europe and the United States.

Currently, there are four main types of gasifiers:

- Entrained flow
- Fixed bed
- Fluidized bed
- Transport bed

The following listing includes the most notable technology suppliers by type:

- Entrained Flow Gasifiers:
  - ConocoPhillips (COP) (E-Gas, formerly Global Energy, originally Dow-Destec).
  - General Electric (GE) (formerly ChevronTexaco, originally Texaco).
  - Mitsubishi Heavy Industries (MHI).
  - Shell.
  - Siemens GSP (formerly Noell).
- Fixed Bed (or Moving Bed) Gasifiers:
  - BGL (slagging, Global Energy, formerly British Gas Lurgi).
  - Lurgi (dry bottom).
- Fluidized Bed Gasifiers:
  - Carbona (formerly Tampella).
  - HTW (formerly High Temperature Winkler).
  - KRW.
  - Lurgi.
- Transport Bed Gasifiers:
  - KBR.

Entrained flow gasifiers have been operating on oil feedstock since the 1950s and on coal and petcoke feedstock since the 1980s. Entrained flow gasifiers operate at high pressure and temperature, have very low fuel residence times, and have high feedstock capacity throughputs. Fixed bed gasifiers have operated on coal feedstock since the 1940s. Compared to entrained flow gasifiers, fixed bed gasifiers operate at lower pressure and temperature, have much longer fuel residence times, and have lower capacity throughputs. Fluidized bed gasifiers have operated on coal since the 1920s. Compared to entrained flow gasifiers, fluidized bed gasifiers operate at lower pressure and temperature, use air instead of oxygen, have longer fuel residence times, and have lower capacity throughput. Transport bed gasifiers have only recently been tested on a small scale. Compared to entrained flow gasifiers, transport gasifiers operate at lower pressure and temperature, use air instead of oxygen, have longer fuel residence times, and have lower capacity throughput.

Limestone is fed with coal to fluidized bed and transport bed gasifiers for capturing sulfur as calcium sulfide (CaS), which is typically oxidized to $CaSO_4$ for landfill disposal. Entrained flow and fixed bed gasifiers treat the syngas from gasification to remove the sulfur-containing constituents as elemental sulfur or sulfuric acid (H_2SO_4), which can be sold. The ash from fluidized bed, transport bed, and dry bottom fixed bed gasifiers is leachable and is typically landfilled. Entrained flow and slagging fixed bed gasifiers operate above the ash fusion temperature and produce a nonleachable slag that can be sold.

Entrained flow and fixed bed gasifiers generally use high purity oxygen as the oxidant. Fluidized bed and transport gasifiers use air instead of oxygen. Since high purity oxygen does not contain the large concentration of nitrogen present in air, equipment size can be reduced commensurately. Higher gasifier operating pressures are also more economical for the smaller gas flow rates and equipment size associated with high purity oxygen use. Entrained flow gasifiers have higher operating temperatures and lower residence times than fluidized and transport bed gasifiers. These conditions typically require the use of high purity oxygen for entrained flow gasifiers. An oxygen purity of 95 percent by volume is the optimum for entrained flow gasifiers producing syngas for combustion turbine fuel. Oxygen purities of 98 percent or higher are required when the syngas is used to produce chemicals and liquid fuels.

Entrained flow gasifiers are relatively new technologies compared to fluidized bed and fixed bed gasifiers. Entrained flow gasifiers have been operating successfully on solid fuels since the mid-1980s to produce chemicals and since the mid-1990s to produce electricity in four commercial-scale IGCC demonstration plants, located in Europe (two units) and the US (two units).

Transport bed gasification technology is a recent development that has not yet been demonstrated on a commercial scale. The Southern Company and KBR have been testing a 30 tpd air-blown transport reactor integrated gasification (TRIG) system at the US DOE-funded Power Systems Development Facility (PSDF) at Wilsonville, Alabama. TRIG employs KBR catalytic cracking technology, which has been used successfully for more than 50 years in the petroleum refining industry. In 2004, the US DOE awarded $235 million to the Southern Company and the Orlando Utilities Commission (OUC) to build a 285 MW IGCC Plant at the Stanton Energy Center in Florida to demonstrate TRIG combined cycle technology under the Clean Coal Power Initiative (CCPI) program. The total cost of this plant is estimated to be $792 million. The proposed plant will gasify subbituminous coal. Southern Company estimates that the plant heat rate will be approximately 8,400 Btu/kWh (HHV coal).[1] The demonstration plant is scheduled to start up in or after 2010. Results from this commercial-scale demonstration plant should determine whether TRIG technology will be competitive with entrained flow gasifier technology.

At this time, based on their characteristics and level of development, oxygen-blown entrained flow gasifiers are the best choice for high capacity gasification for power generation.

4.2 Entrained Flow Gasification Process Description

A typical IGCC process flow diagram is shown on Figure 4-1.

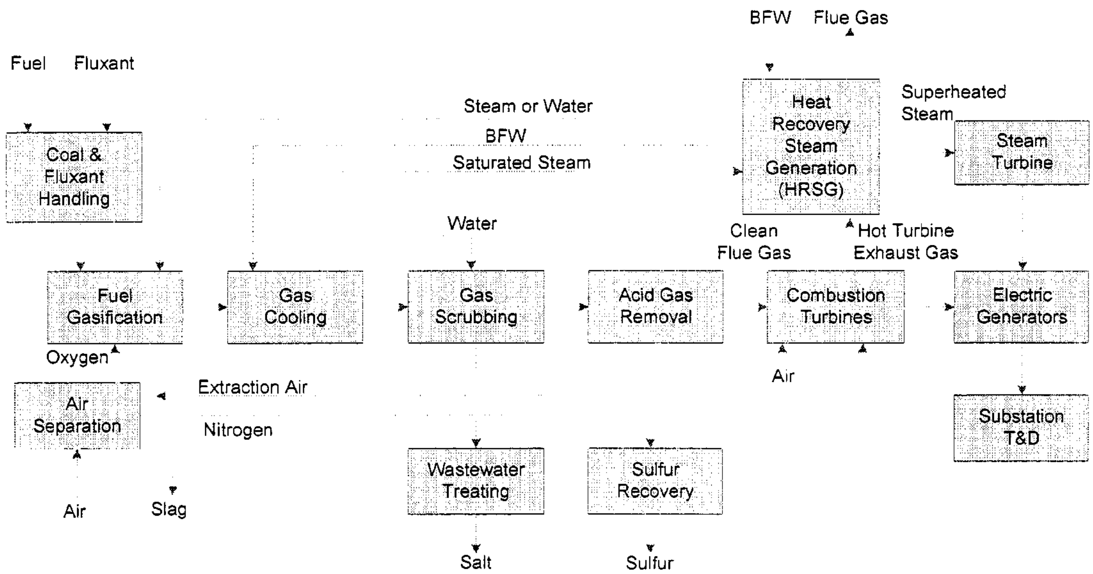

Figure 4-1. IGCC Process Flow Diagram

Gasification consists of partially oxidizing a carbon-containing feedstock (solid or liquid) at a high temperature (2,500 to 3,000° F) to produce a syngas consisting primarily of CO and hydrogen. A portion of the carbon is completely oxidized to carbon dioxide (CO_2) to generate sufficient heat required for the endothermic gasification reactions. (The CO_2 proportion in the syngas from the gasifier ranges from 1 percent for the dry feed Shell gasifier to more than 15 percent for the slurry feed COP and GE gasifiers.) The gasifier operates in a reducing environment that converts most of the sulfur in the feed to hydrogen sulfide (H_2S). A small amount of sulfur is converted to carbonyl sulfide

[1] At average ambient conditions, and assumed new and clean.

(COS). Some sulfur remains in the ash, which is melted and then quenched to produce slag. Other minor syngas constituents include ammonia (NH_3), hydrogen cyanide (HCN), hydrogen chloride (HCl), and entrained ash, which contains unconverted carbon. In IGCC applications, the minimum gasifier pressure is typically 450 to 550 psia. This pressure is determined by the combustion turbine syngas supply pressure requirements. GE gasifiers operate at higher pressures, up to 1,000 psia, and the excess syngas pressure is let down in an expander to produce additional power.

A fluxant may need to be fed with the coal to control the slag viscosity so that it will flow out of the gasifier. Fluxant addition is less than 2 percent of the coal feed. The fluxant can be limestone, PC boiler ash, or, in some cases, dirt. The required fluxant composition and proportion will vary with the coal feed composition. The gasification process operators must know the feed coal composition and make fluxant adjustments when the coal composition changes. Too little fluxant can allow excessive slag to accumulate in the gasifier, which could damage the refractory and eventually choke the gasifier. Too much fluxant can produce long cylindrical slag particles instead of small slag granules when the slag is quenched in the lockhopper. These long thin slag particles will plug up the slag lockhopper.

Solid fuel feeds to the gasifier can be dry or slurried. Solid fuels slurried in water do not require the addition of steam for temperature moderation. While slurries typically use water, oil can also be used. Steam is added to the oxygen as a temperature moderator for dry solid feed gasifiers, solid feeds slurried in oil, and oil feed gasifiers.

Entrained flow gasifiers use oxygen to produce syngas heating values in the range of 250 to 300 Btu/scf on an HHV basis[1]. Oxygen is produced cryogenically by compressing air, cooling and drying the air, removing CO_2 from the air, chilling the feed air with product oxygen and nitrogen, reducing the air pressure to provide autorefrigeration and liquefy the air at -300° F, and separating the liquid oxygen and liquid nitrogen by distillation. Air compression consumes a significant amount of power, between 13 and 17 percent of the IGCC gross power output.

Hydrogen in syngas prevents the use of dry low NO_x (DLN) combustors in the combustion turbines. The dilution of the syngas to reduce flame temperature is required for NO_x control. Syngas is typically diluted by adding water vapor and/or nitrogen. Water vapor can be added to the syngas by evaporating water using low level heat. Nitrogen can be added by compressing excess nitrogen from the air separation unit (ASU) and adding it to the syngas either upstream of the combustion turbine or by injection into the combustion turbine. Syngas dilution for NO_x control increases the mass

[1] Comparatively, pipeline quality natural gas has a heating content of about 950 to 1,000 Btu/scf (HHV).

flow through the combustion turbine, which also increases power output. GE combustion turbines inject this diluent nitrogen separately from the syngas into the same ports used for steam or water injection. For MHI and Siemens Power Generation (SPG – formerly known as Siemens Westinghouse or SW) combustion turbines, diluent nitrogen is premixed with the syngas. The nitrogen supply pressure required for injection into a GE 7FB is 405 psia versus 450 to 500 psia for mixing with the syngas for the MHI 501F and the SPG SGT6-5000F (previously referred to as the SW 501FD). The diluted syngas has a heat content of 140 to 150 Btu/scf. However, the mass flow of the diluted syngas is eight times that of natural gas, which increases the combustion turbine power output by up to 16 percent, when no air is extracted for the ASU. A portion of the combustion turbine compressed air may be extracted for feed to the ASU. The ASU and combined cycle are integrated by the nitrogen and air exchanges. Extracting compressed air from the combustion turbine improves overall efficiency, but it adds complexity to the process, including longer startup periods, if there is no separate source of startup compressed air. The prevailing thought is to minimize or avoid compressed air integration.

The raw hot syngas is cooled by the boiler feedwater from the HRSG to a temperature suitable for cleaning. The syngas cooling process generates steam. The steam quantities and pressures vary with the gasification process design. Gasification steam is subsequently integrated into the steam cycle.

Before the raw syngas enters the combustion turbine combustor, the H_2S, COS, NH_3, HCN, and particulates must be removed. Cooled syngas is scrubbed to remove NH_3, water soluble salts, and particulates. Syngas may also be filtered to remove additional particulates. COS in the syngas is hydrolyzed by a catalyst to H_2S, which is removed from the syngas by absorption in a solvent. This absorption process is called acid gas removal (AGR).

Syngas is filtered in ceramic candle filters at the Buggenum and Puertollano IGCC plants. At the Wabash IGCC plant, syngas was initially filtered in ceramic candle filters; later, the filter elements (candles) were changed to sintered metal. The syngas filters at the Buggenum, Puertollano, and Wabash plants are located upstream of the AGR. At the Polk County IGCC plant, syngas is filtered in cartridge filters downstream from the AGR.

The H_2S that is removed from the syngas by absorption in a solvent is desorbed as a concentrated acid gas when the solvent is regenerated, by lowering its pressure and increasing its temperature. Descriptions of commercial AGR systems are provided in Section 4.9. The acid gas stream is typically converted to elemental sulfur in the Claus sulfur recovery process, although it is also possible to produce sulfuric acid.. The primary chemical reaction in the Claus process is the reaction of H_2S and SO_2 to produce elemental sulfur and water. This reaction requires a catalyst and is performed in two stages. The SO_2 is produced by oxidizing (burning) one third of the H_2S in the feed gas. External fuel is only needed to initially heat up the Claus thermal reactor and initiate combustion of the acid gas. Under normal operation, the oxidation of H_2S provides sufficient heat to maintain the reaction. The sulfur is formed as a vapor; the S_2 form of sulfur reacts with itself to produce S_6 and S_8, which are subsequently condensed. This condensed liquid sulfur is separated from the residual gas and stored in a pit at 275° to 300° F. As required, the liquid sulfur is pumped from the pit to railcars for shipment. Solid sulfur can be produced in blocks or pellets by cooling the liquid sulfur to ambient temperature. The residual (tail gas) is primarily CO_2 and nitrogen, which are compressed and reinjected into the syngas upstream of the AGR.

4.3 Gasification Technology Suppliers

Today, there are three major entrained flow coal gasification technology suppliers:

- COP, which licenses E-Gas technology that was developed by Dow. COP purchased this technology from Global Energy in August 2003.
- GE, which purchased Texaco gasification technology from ChevronTexaco in June 2004. GE offers both Quench and Radiant (high temperature heat recovery [HTHR]) cooler gasifiers.
- Shell, which developed its gasification technology in conjunction with Prenflo. Prenflo technology is no longer licensed.

The other entrained flow gasifiers listed in Section 4.1 are not currently strong competitors in the utility-scale IGCC market because of the relative maturity of the technology. MHI is developing an air-blown, two-stage entrained flow gasifier with dry feed. MHI intends to demonstrate this technology at a 250 MW project in Japan. Siemens (formerly Sustec GSP, FutureEnergy, and Noell) has one small gasification plant (Schwarze Pumpe, 200 MW_{th} methanol and power cogeneration). Its technology has been geared toward biomass and industrial processing on a smaller scale, but it seems to be making an entry into the utility-scale power generation market. According to a May 2006 press release, Siemens plans to build a 1,000 MW coal IGCC in Germany as a first step to commercializing its newly acquired IGCC technology. Multiple other GSP coal gasification projects are currently being implemented, including three in China that wil produce ammonia and methanol.

The COP and GE gasifiers are refractory lined with coal-water slurry feed. In the late 1970s, Shell and Krupp-Koppers jointly developed a waterwall type gasifier with dry, pulverized coal feed specifically for IGCC power generation for a 150 ltpd demonstration plant near Hamburg, West Germany. During the 1990s, Shell and Krupp-Koppers licensed their gasification technology separately. The Puertollano, Spain IGCC plant, which was built in the mid-1990s, uses Krupp-Kopper's Prenflo gasification technology. In the late 1990s, Krupp-Koppers merged with Uhde, and Uhde reached an agreement with Shell to license Shell gasification technology and no longer market the Prenflo gasification process. Uhde has incorporated its Prenflo experience into Shell's coal gasification process technology.

Each of the three commercial, entrained flow coal gasification technologies generates similar syngas products. All three gasifiers react the coal with oxygen at high pressure and temperature to produce a syngas consisting primarily of hydrogen and CO. The raw syngas from the gasifier also contains CO_2, water, H_2S, COS, NH_3, HCN, and other trace impurities. The syngas exits the gasifier reactor at approximately 2,500 to 2,900° F.

Each of the COP, GE, and Shell gasification processes cools the hot syngas from the gasifier reactor differently. In the COP process, the hot syngas is partially quenched with coal slurry, resulting in a second stage of coal gasification. The raw syngas from the COP gasifier may also contain methane and products of coal devolatilization and pyrolysis because of its two-stage gasification process. The partially quenched syngas is cooled with recycled syngas to solidify the molten fly slag and then further cooled to produce HP steam in a vertical shell and tube heat exchanger. (Syngas flow is down through the tubes. Boiler water and steam flow is up through the shell side.) Unconverted coal is filtered from the cooled syngas and recycled to the gasifier first stage. GE has two methods for cooling the hot syngas from the gasifier: radiant cooling to produce HP steam via HTHR and water quench with low-pressure (LP) steam generation. In the Shell process, hot syngas is cooled with recycled syngas to solidify the molten fly slag and then further cooled in a convective cooler to produce high-temperature steam.

The cooled, raw syngas is cleaned by various treatments, including filtration, scrubbing with water, catalytic conversion, and scrubbing with solvents, as discussed in Section 4.9. The clean syngas that is used as combustion turbine fuel contains hydrogen, CO, CO_2, water, and parts per million (ppm) concentrations of H_2S and COS.

4.4 Gasifier Technology Selection

Table 4-1 provides process design characteristic data for the COP, GE, and Shell gasification technologies for systems that would generally be considered for a facility of this size and type. The Shell gasification technology has the highest cold gas efficiency, because the gasifier feed coal is injected into the gasifier dry, whereas with the COP and GE gasifiers, the feed is a slurry of coal in water. However, the Shell dry feed coal gasification process has a higher capital cost. Cooling the hot syngas to produce HP steam also contributes to higher IGCC efficiency, but with a higher capital cost. Shell and COP generate HP steam from syngas cooling. GE offers both HP steam generation using Radiant syngas coolers and LP steam generation using its Quench process, which has a significantly lower capital cost than the Radiant. The COP and GE gasifiers are refractory lined, while the Shell gasifier has an inner water tube wall (membrane). The refractory-lined gasifiers have a lower capital cost, but the refractory requires frequent repair and replacement. The COP and GE gasifier burners typically require more frequent replacement than the Shell gasifier burners.

Table 4-1. Comparison of Key Gasifier Design Parameters

Technology	COP	GE Quench	GE HTHR	Shell
Gasifier Feed Type	Slurry	Slurry	Slurry	Dry N_2 Carrier
Gasifier Burners	Two Stage: First Stage--Two horizontal burners Second Stage--One horizontal feed injector w/o O_2	Single Stage--One vertical burner	Single Stage--One vertical burner	Single Stage--Four to eight horizontal burners
Gasifier Vessel	Refractory lined	Refractory lined	Refractory lined	Waterwall membrane
Syngas Quench	Coal Slurry and Recycle Gas	Water	None	Recycle Gas
Syngas Heat Recovery	Firetube HP WHB	Quench LP WHB	Radiant HP WHB	Watertube HP WHB
Coal Cold Gas Efficiency, HHV	71 to 80 percent	69 to 77 percent	69 to 77 percent	78 to 83 percent
Coal Flexibility	Middle	Low	Low	High
Capacity, stpd	3,000 to 3,500	2,000 to 2,500	2,500 to 3,000	4,000 to 5,000

WHB--Waste Heat Boiler

It is worth mentioning gasifier sizing issues with respect to the Shell and GE Quench technologies. Shell has stated that its maximum gasifier capacity is 5,000 stpd of dried coal, which is large enough to supply syngas to two GE 7FB or Siemens SGT6-5000F combustion turbines. GE offers gasifiers in three standard sizes: 750, 900, and 1,800 ft^3. The largest Quench gasifier that GE currently offers is 900 ft^3. The maximum capacity of this gasifier is approximately 2,500 tpd of as-received coal and does not produce enough syngas for a GE 7FB or Siemens SGT6-5000F combustion turbine. The largest Radiant gasifier that GE currently offers is 1,800 ft^3, which will supply sufficient syngas for a GE 7FB or Siemens SGT6-5000F combustion turbine. COP currently offers a gasifier that will supply sufficient syngas for a GE 7FB or Siemens SGT6-5000F combustion turbine.

Overall, energy conversion efficiencies for IGCC plants vary with the gasification technology type, system design, level of integration, and coal composition. The gasifier efficiency of converting the coal fuel value to the syngas fuel value (after sulfur removal) is known as the cold gas efficiency, which is generally expressed in HHV. The values for cold gas efficiency in Table 4-1 are indicative of the range of achievable performance for coal and petcoke. Cold gas efficiency for the Shell dry coal feed process is about 3 percent higher than the coal-water slurry feed gasification processes for low moisture coal. This difference increases with coal moisture content. HP steam generation from syngas cooling increases IGCC efficiency by about 2 percent over that of water quench.

4.5 Commercial IGCC Experience

There have been approximately 18 IGCC projects throughout the world, as listed in Table 4-2. Of these, fifteen were based on entrained flow gasification technology. Nine of the projects were coal based, two are petcoke based, one is sludge based, and the other six are oil based. Two of the coal-based IGCC plants, Cool Water in California and the Dow Chemical Plaquemine Plant in Louisiana, were small demonstration projects and have been decommissioned. Another small coal IGCC demonstration project was Sierra Pacific's Piñon Pine Project in Nevada. This project, based on KRW fluidized bed technology, was not successful.

Of the six operating coal IGCC plants, one is a 40 MW plant that coproduces methanol using a Noell gasifier, one is a 350 MW lignite cogeneration plant that has 26 Lurgi fixed bed gasifiers, and four are commercial-scale, entrained flow gasification demonstration projects (ranging in capacity from 250 to 300 MW) that are located in Florida, Indiana, The Netherlands, and Spain. The Wabash Indiana IGCC plant did not operate for an extended period in 2004 and 2005 because of contractual problems, but is currently back in operation. Design data for these four demonstration plants are listed in Table 4-3. None of these demonstration units is of the same capacity scale as that required for the FGPP units.

Table 4-2. IGCC Projects – All Fuels

Owner - Location	Year(1)	MW	Application	Fuel	Gasifier
SCE Cool Water(2) – USA (CA)	1984	120	Power	Coal	Texaco (GE)
Dow LGTI Plaquemine – Plaquemine(2) - USA (LA)	1987	160	Cogen	Coal	COP (Destec)
Nuon Power – Netherlands	1994	250	Power	Coal	Shell
PSI/Global Wabash – USA (IN)	1995	260	Repower	Coal	E-Gas (COP)
TECO Polk County – USA (FL)	1996	250	Power	Coal	Texaco (GE)
Texaco El Dorado(3) – USA (KS)	1996	40	Cogen	Petcoke	Texaco (GE)
SUV - Czech Republic	1996	350	Cogen	Coal	Lurgi(5)
Schwarze Pumpe - Germany	1996	40	Power/ Methanol	Lignite	Noell
Shell Pernis Refinery - Netherlands	1997	120	Cogen/Hydrogen	Oil	Shell
Elcogas - Spain	1998	300	Power	Coal/ Petcoke	Prenflo
Sierra Pacific(4) – USA (NV)	1998	100	Power	Coal	KRW(6) - Air
ISAB Energy - Italy	1999	500	Power/Hydrogen	Oil	Texaco (GE)
API - Italy	2000	250	Power/Hydrogen	Oil	Texaco (GE)
Delaware City Refinery - USA (DE)	2000	180	Repower	Petcoke	Texaco (GE)
Sarlux/Sara Refinery - Italy	2000	550	Cogen/Hydrogen	Oil	Texaco (GE)
ExxonMobil - Singapore	2000	180	Cogen/Hydrogen	Oil	Texaco (GE)
FIFE - Scotland	2001	120	Power	Sludge	BGL(5)
NPRC Negishi Refinery - Japan	2003	342	Power	Oil	Texaco (GE)

(1)First year of operation on syngas.
(2)Retired.
(3)The El Dorado Refinery is now owned by Frontier Refining.
(4)Not successful.
(5)Fixed bed.
(6)Fluidized bed.

Table 4-3. Coal-Based IGCC Demonstration Plants [1]				
Project	**Nuon Power**	**Wabash [3]**	**TECO Polk County [4]**	**Elcogas**
Location	Buggenum, Netherlands	Indiana	Florida	Puertollano, Spain
Technology	Shell	E-Gas (COP)	Texaco (GE)	Prenflo (Krupp)
Startup Year	1994	1995	1996	1998
Net Output, design, MW	252	262	250	300[5]
HHV Efficiency, net design, percent	41.4	37.8	39.7	41.5
Height, ft	246	180	295	262
Fuel, design	Coal	Coal	Coal	50% coal/50% petcoke
Fuel Consumption, tpd	2,000	2,200	2,200	2,600
Fuel Feed	Dry N_2 lockhopper	Wet slurry	Wet slurry	Dry N_2 lockhopper
Syngas HHV, Btu/scf	300	276	266	281
CTG Model	Siemens V94.2	GE 7FA	GE 7FA	Siemens V94.3
Firing temperature, °F	2,012	2,300	2,300	2,300
Combustors	Twin vertical silos	Multiple cans	Multiple cans	Twin horizontal silos
CTG Output, design, MW	155	192	192	200
STG Output, design, MW	128	105	121	135
Auxiliary Power, design, MW	31	35.4	63	35
Net Output, design, MW	252	262	250	300
Net Output, achieved, MW	252	252	250	300
NPHR, design, Btu/kWh HHV	8,240	9,030	8,600	8,230
NPHR, achieved, Btu/kWh HHV [2]	8,240	8,600 - Adjusted for HRSG feedwater heaters	9,100 - Adjusted for gas/gas heat exchanger	8,230
ASU Pressure, psi	145	72.5	145	145
Nitrogen Usage	Syngas Saturator	Vented	CTG NO_x Control	Syngas Saturator

Table 4-3. Coal-Based IGCC Demonstration Plants [1]

Project	Nuon Power	Wabash [3]	TECO Polk County [4]	Elcogas
NO_x Control	Saturation and N_2 dilution	Saturation + steam injection	N_2 dilution to combustors	Saturation and N_2 dilution
NO_x, 6% O_2, mg/Nm^3	25	100 to 125	100 to 125	150
Slag Removal	Lockhopper	Continuous	Lockhopper	Lockhopper
Recycle Gas Quench	50% of gas, to 1,650° F	Some in second stage	None	67% of gas, to 1,475° F
Integration				
Water/steam	Yes	Yes	Yes	Yes
N_2 Side ASU/CTG	Yes	No	Yes	Yes
Air Side ASU/CTG	Yes	No	No	Yes
Add Air Compressor	Yes	Yes	Yes	No
Gas Cleanup				
Particulate Removal	Cyclone/Ceramic candle filter	Sintered metal candle filter	Water wash	Ceramic candle filter
Chloride Removal	Water scrubbing	Water scrubbing	Water scrubbing	Water scrubbing
COS Hydrolysis	Yes	Yes	Retrofit in 1999	Yes
AGR Process	Sulfinol	MDEA	MDEA	MDEA
Sulfur Recovery	Claus + SCOT TGR	Claus + Tail Gas Recycle	H_2SO_4 Plant	Claus + Tail Gas Recycle
SO_2, 6% O_2, mg/Nm^3	35	40	40	25

[1] Information taken from "Operating Experience and Improvement Opportunities for Coal-Based IGCC Plants," Holt, Neville from *Science Reviews – Materials at High Temperatures*, Spring 2003. Additional footnotes are by Black & Veatch.

[2] Achieved NPHR are instantaneous values from performance testing. Long term annual average heat rates vary with degradation and dispatch profile.

[3] Wabash NPO and NPHR reported as 261 MW and 8,600 Btu/kWh in "The Wabash River Coal Gasification Repowering Project, an Update", USDOE, September 2000.

[4] TECO NPO and NPHR reported as 250 MW and 9,650 Btu/kWh in "Tampa Electric Integrated Gasification Combined Cycle Project", USDOE, June 2004.

[5] Based on ISO conditions. Site specific design NPO was 283 MW, with probable further derate due to higher ASU auxiliary load.

Each of the four projects was a government-subsidized IGCC demonstration, two in the United States and two in Europe. Each of these IGCC plants consists of a single train (one ASU, one gasifier, one gas treating train, and one combined cycle consisting of one CTG, one HRSG, and one STG). Wabash has a spare gasifier.

Table 4-3 also summarizes the integration in each plant. Basically, there are three major areas for potential integration:

- Water and steam between the power generation area and the gasification island. High- and low-level heat rejection from the gasification process is utilized to produce combined cycle power.
- The nitrogen side of the ASU and CTG--Waste nitrogen is mixed with the syngas to reduce NO_x formation and to increase power output.
- The air side of the ASU and the CTG--Air is extracted from the CTG compressor to reduce the auxiliary power and increase efficiency.

Figure 4-2 depicts potential areas of integration. The European plants have been highly integrated, partly in response to higher fuel prices, while the US plants have been less integrated. Both the Nuon Power Buggenum, Netherlands plant and the Elcogas Puertollano, Spain plant experienced operating difficulties as a result of the highly integrated design. EPRI has suggested that such high integration should be avoided in future designs.

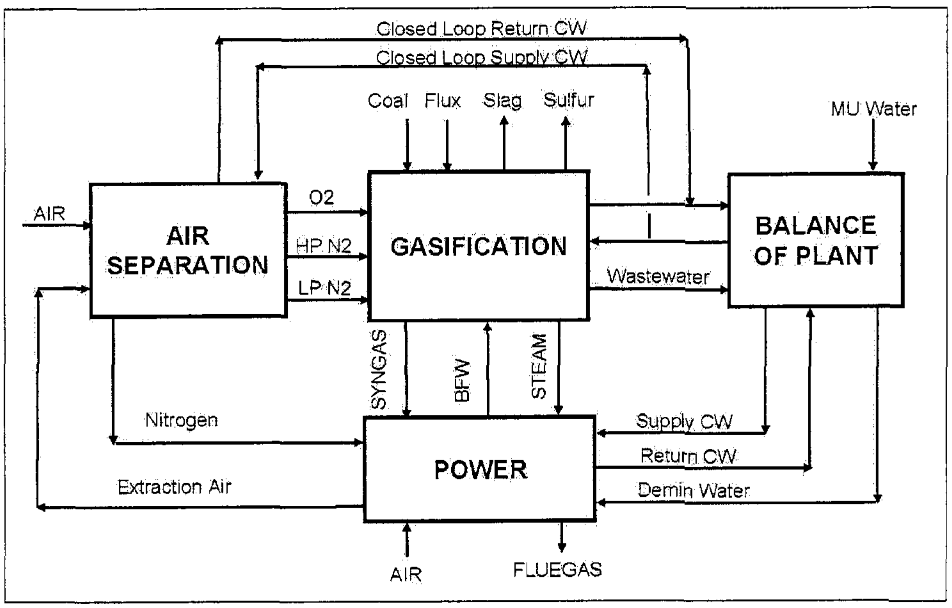

Figure 4-2. Potential Areas for Integration

The operation of these four commercial coal-fueled IGCC plants has adequately demonstrated capacity, efficiency, and environmental performance, but uncertainty remains regarding availability, reliability, and cost. The complexity and the relative immaturity of the IGCC process increase opportunities for deficiencies in design, vendor-supplied equipment, construction, operation, and maintenance. The high risks of cost overruns and low availability have presented obstacles to the development of nonsubsidized coal-fueled IGCC projects. At present, there are several coal-based IGCC projects being developed in the United States that have or expect to receive subsidies.

4.6 Fuel Characteristics Impact on Gasifier Selection

There are three general coal feedstocks typically considered for IGCC projects: Appalachian, Illinois, and Powder River Basin (PRB). Petcoke is a fourth solid fuel feedstock that is frequently considered for IGCC applications. Petcoke may be a lower cost fuel, but it is not as readily obtainable as coal. Historically, anthracite and lignite coals have not been seriously evaluated for IGCC projects, nor have waste coals such as gob (coal mine waste) and culm (waste produced when anthracite is mined and prepared for market, primarily rock and some coal).

Coal-based operating experience has been focused almost exclusively on bituminous coals (e.g., Pittsburgh No. 8 and Illinois No. 6), and there is also extensive experience with petcoke. Subbituminous (i.e., PRB) coals have been tested only in a limited fashion, but because of the nature of the US coal market and the abundance of PRB coal, there is strong interest in using it for IGCC applications. Typical design values for the coals generally considered for IGCC are listed in Table 4-4.

Table 4-4. As-Received Coal Properties of Typical IGCC Coals

Fuel	Pittsburgh No. 8	Illinois No. 6	PRB
Heat Content, Btu/lb (HHV)	12,300	10,200	8,400
Moisture, percent	8.0	14.1	29.4
Ash, percent	12.0	15.7	6.0
Sulfur, percent	4.0	4.3	0.34

In the GE gasification process, all of the inherent water in the coal and the liquid water in the slurry must be evaporated in the gasifier by combusting more CO to CO_2, which results in a lower cold gas efficiency than the COP and Shell gasification processes. For low moisture fuels, such as the one in this study, the GE process can be very cost competitive. COP is able to attain a higher cold gas efficiency than GE through use of a full slurry quench

4.7 IGCC Performance and Emissions Considerations

IGCC net power output decreases with increasing ambient temperature, but this reduction is less than that of a natural gas combined cycle (NGCC) plant. The IGCC plant auxiliary power consumption also increases slightly with the ambient temperature for ASU air compression and cooling tower fans, but this is offset by higher combustion turbine output.

The CO and NO_x emissions estimates were based on CTGs firing syngas with nitrogen dilution, but without an SCR or CO oxidation catalyst in the HRSG:

- 25 ppmvd CO in the CTG exhaust gas.
- 15 ppmvd NO_x (at 15 percent by volume O_2) in the CTG exhaust gas.

The SO_2 emissions estimate was based on a 25 ppm molar concentration of sulfur as H_2S and COS in the syngas. Sulfur removal efficiencies of greater than 99 percent are achievable for an IGCC plant processing high sulfur coal or petcoke, depending on the solvent selected. Flaring during startups, shutdowns, and upsets can result in significant SO_2 emissions. Sour gas flaring during upsets cannot be eliminated, but can be minimized by appropriate process design and operating procedures.

Syngas will flow through sulfur impregnated carbon, which is estimated to lower the syngas mercury concentration below 5 ppb by weight. Up to 40 percent of the mercury in the coal may be removed upstream of the sulfur impregnated carbon by scrubbing, which would reduce the mercury concentration at the inlet of the sulfur impregnated carbon to 30 to 42 ppb by weight. Eastman Chemical Company's coal gasification plant has used sulfur impregnated carbon beds for mercury removal since its startup in 1993. Eastman reports 90 to 95 percent mercury removal with a bed life of 18 to 24 months.

4.8 Gasification Wastewater Treatment

There are two general categories of plant wastewater:

- Streams that contain metals from the as-received coal, referred to as gasification wastewater streams.
- Streams that do not contain these metals, referred to as balance-of-plant wastewater streams.

The gasification wastewater streams will be combined and treated separately from the balance-of-plant wastewater streams. Accurate specification of the process wastewater composition has been a problem on other operating gasification plants because of the wide variation in coal composition. The wastewater treatment design should accommodate variations in wastewater composition.

There are three basic options for treating gasification wastewater streams:

1. Open Discharge Concept, which consists of metals precipitation, followed by biological treatment to produce an effluent suitable for discharge.
2. Zero Liquid Discharge (ZLD) Concept, which consists of lime softening, followed by evaporation and crystallization to produce a solid salt for landfill disposal.
3. Discharge to a municipal sewage treatment facility or other receiving stream. This option is generally considered impractical, because the coal gasification wastewater exceeds typical pretreatment limitations.

Biological treatment of the gasification wastewater can be problematic, because the diverse contaminants are believed to be sufficiently variable so that the operation would be unreliable, which could result in violations of expected permit requirements. The open discharge system would cost approximately the same as the ZLD option and is not a proven technology in this application. The operating costs are equivalent between ZLD and open discharge systems. However, ZLD requires additional LP steam, which could otherwise be used to generate an additional 2 to 5 MW of electricity.

4.9 Acid Gas Removal Technology

Sulfur in coal is converted to H_2S and COS during gasification. The molar ratio of H_2S to COS in the raw syngas from the gasifier varies according to the gasifier type, from approximately 13 to 1 for the Shell gasifier to approximately 26 to 1 for the COP and GE gasifiers. The resulting syngas is treated to meet combustion turbine fuel and air emissions permit requirements. The requirement is for total sulfur in the clean syngas to be less than 25 ppm by weight, which is equivalent to 15 ppm by mole of COS and H_2S.

The two primary solvents considered for IGCC AGR are Selexol and methyl diethanol amine (MDEA). Selexol solvent is a mixture of dimethyl ethers of polyethylene glycol, $CH_3(CH_2CH_2O)_{(3 \text{ to } 9)}CH_3$. UOP licenses Selexol technology for treating syngas from gasification. Selexol is a physical solvent. Its capacity to absorb sulfur compounds (including H_2S) and to absorb CO_2 increases with increasing pressure and decreasing temperature.

MDEA, $(HOC_2H_4)2NCH_3$, is a chemical solvent, specifically a selective amine used to remove H_2S, while leaving most of the CO_2 in the syngas. MDEA forms a chemical bond with H_2S and CO_2. MDEA's performance is nearly independent of operating pressure. Typical absorber operating temperatures with amines are between 80 and 120° F. Lower absorber operating temperatures increase both H_2S solubility and selectivity over CO_2.

The higher absorber operating pressures and higher syngas CO_2 concentrations for the COP and GE gasification processes favor the use of Selexol, while MDEA is generally favored for the Shell gasification process.

4.10 Pre-combustion Carbon Capture

In the conventional IGCC case, the gasification process produces a synthetic gas (syngas) composed primarily of a homogeneous mixture of CO and hydrogen. This fuel is provided to a combined cycle power plant, and the combustion process produces comparably the same amount of CO_2 as does a conventional coal plant.

However, by adding water-gas shift and CO_2 absorption steps, the gasification process can yield a gaseous fuel stream that is nearly carbon-free, and a CO_2-rich solvent from which CO_2 can be removed for separate sequestration or other industrial uses. The fuel stream, composed mostly of hydrogen, would be used directly as a fuel in an appropriately designed combined cycle plant.[8] The outcome is the generation of "low carbon" electric power from a low-cost fuel source.

An IGCC facility with carbon capture capability would consist of a gasification process that is closely integrated with a conventional combined cycle power plant. The base facility would consist of five major components:

- ASU
- Gasification plant
- Gas cleanup
- Water shift process
- Combined cycle power plant

[8] Hydrogen fueled CTGs are not currently commercially available.

After particulate and acid gas removal, clean syngas is water shifted prior to combustion in the power block. The result is a gas stream composed almost entirely of hydrogen and CO_2. From that stream, up to 90 percent of the CO_2 is then removed through a stripping process by passing the gas through an absorption tower using a physical CO_2 solvent. Hydrogen can then be provided as a nearly carbon-free fuel to the CTGs. The CO_2 removed by the solvent is recovered, cooled, compressed, dried, and transported to a sequestration location.

The addition of a carbon capture process would have a significant impact on the output and heat rate of an IGCC facility. Significantly higher auxiliary loads are required for compression loads in the capture process, and thermal energy in the form of process steam is required to separate the CO_2 from the absorption solvent. Energy would also be required for captured CO_2 compression. These energy requirements would have an impact on the net plant output and net plant heat rate of the facility. In order to maintain project required net plant output, additional generation capacity would need to be installed to compensate for the increased auxiliary loads of the carbon capture process. The increase in gross plant generation would meet the carbon capture process energy requirements.

Figure 4-3 shows a pre-combustion CO_2 removal process for a typical IGCC plant.

The inclusion of carbon capture in IGCC has several significant advantages over other carbon capture options:

- The process takes place at relatively high pressures and prior to the dilution of CO_2-containing gas. With CTGs, the combustion process occurs in a very large mass of compressed air, which adds excess oxygen and large amounts of nitrogen to the flue gas. In contrast, the volume of high-pressure pre-combustion syngas flow from which CO_2 must be removed is less by two orders of magnitude than that required in the post-combustion treatment of CTG flue gas streams, significantly reducing equipment dimensions, capacities, and costs.
- CO_2 capture takes place at temperatures and pressures in which a "physical" solvent can be used, instead of the chemical solvent required in most post-combustion processes. CO_2 can be separated from physical solvents through a pressure reduction process that requires much less thermal energy than the post-combustion alternative.
- There are additional cycle efficiency benefits that may occur as more advanced CTGs are developed. At the present time, F Class technologies

are expected to be the CTG technology developed for high hydrogen, carbon-free applications in the near term. G and H Class technologies, along with other alternative CTG cycles, offer opportunities for efficiency improvements. While none of these technologies is currently capable of burning high hydrogen fuels, industry requirements, driven by the need for carbon capture, may stimulate the required research and development to enable this application.

Pertinent technology considerations include the following:

- While IGCC plants are in operation using F Class technologies, CO_2 capture applications where the CTGs are burning virtually pure hydrogen do not exist. CTG combustion system development is required to burn hydrogen to fully support the IGCC-based carbon capture.
- There is currently a large-scale coal gasification plant with carbon capture in North Dakota in commercial operation. The Great Plains Synfuel Plant has been operating since 1983 and gasifies 16,000 tons per day of lignite to produce synthetic natural gas. CO_2 is captured as a required precursor to methanation and used for EOR. While this scale is comparable to an electric power plant, the Great Plains plant is not directly comparable to a power plant because of the additional processes that are carried out at Great Plains. This example is the most relevant commercial operating experience for this carbon capture process.

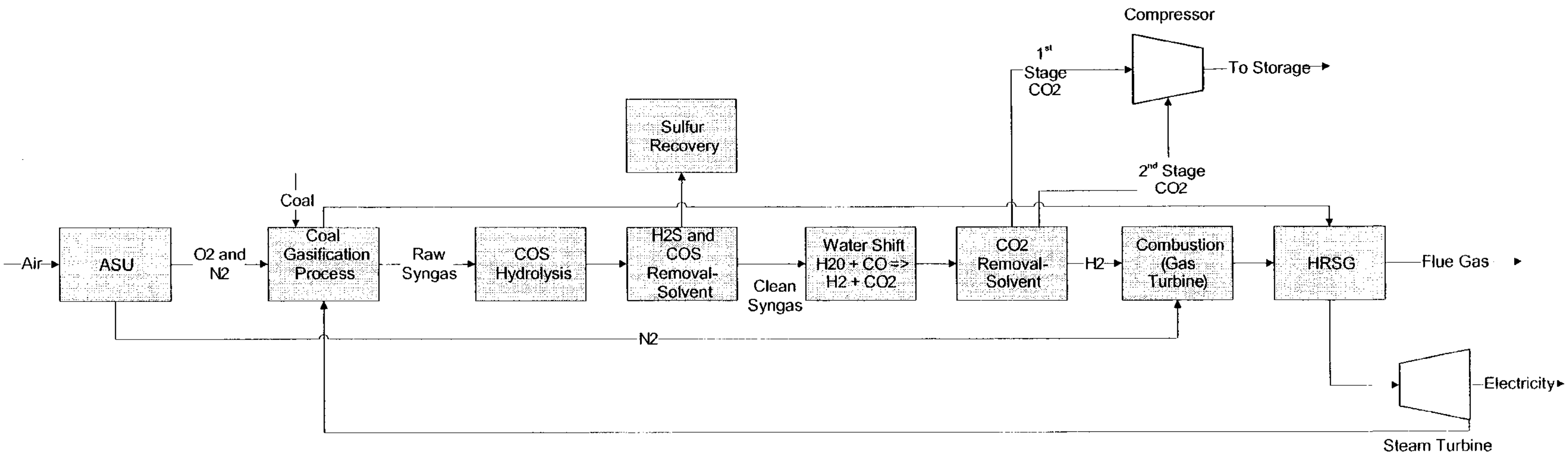

Figure 4-3. IGCC with Pre-Combustion CO_2 Capture.

4.11 Equivalent Availability

An IGCC plant is not expected to be as reliable as a PC or CFB plant with respect to producing electricity from coal. IGCC plants without spare gasifiers are expected to achieve long-term annual equivalent availabilities in the 80 to 85 percent range versus approximately 90 percent for PC and CFB plants. Based on past experience, IGCC availability during initial startup and the first several years of operation is expected to be significantly lower than the long-term targets. This can be mitigated by firing the CTGs with backup fuel (such as natural gas or low sulfur fuel oil) however, this would reduce the fuel diversity benefit of adding coal fired generation. The equivalent availability of the combined cycle portion of an IGCC plant is expected to be above 90 percent. The equivalent availability of an IGCC plant can be increased by providing a spare gasifier. Spare gasifier economics depend on the gasifier technology, cost of backup fuel, and plant dispatch economics. The next generation of coal-fueled IGCC plants may take advantage of the lessons learned from existing operating plants, but significant startup problems should be expected.

4.11.1 First Generation IGCC Plants

Solids-related problems (erosion, pluggage, unstable flows, and syngas cooler tube leaks) caused significant gasification downtime for all four of the coal-based IGCC plants. Gasifier burner and refractory maintenance also resulted in significant downtime for the COP and GE gasifiers. For the Buggenum and Puertollano plants, CTG problems related to syngas combustion and startup air extraction were significant. Since the problems were identified, plant modifications and O&M improvements have greatly improved performance; these two plants now produce electricity at design rates and close to design efficiencies.

Estimated annual equivalent availabilities for producing electricity from coal (syngas operation) are listed in Table 4-5 for all four of the coal-based IGCC plants discussed in Section 4.5. These equivalent availabilities are for electricity production from coal or petcoke; power generation from firing the CTG on backup fuel is excluded. Gasification process availability for each of these plants was poor during the first several years of operation and continues to be a problem. The complexity and relative technological immaturity of large-scale commercial gasification processes increase opportunities for deficiencies in design, vendor-supplied equipment, construction, operation, and maintenance. During the first several years of plant operation, a number of these deficiencies were corrected, and the plant staff has optimized the plant O&M as they "move up the gasification learning curve." Design improvements are expected to be introduced on future IGCC plants, which should improve equivalent availability.

4.11.2 Next (Second) Generation IGCC Plants

If the equivalent availability of the facility is critical to the project, the GE Quench technology with a spare gasifier is expected to provide high availability (from 85 to 90 percent), in the long term. However, as with all of the gasification technologies, in the first year, availability is expected to be around 50 percent. This would be expected to increase to the mature availability over four to five years.

Gasifiers with the water quench process have lower capital costs than gasifiers with HTHR. However, the GE Quench gasifiers have a lower efficiency power cycle because they produce LP steam instead of HP steam. Also, it is not practical to operate with a hot spare for gasifiers that use HTHR, because the HTHR requires a shutdown to switch gasifiers.

In the long-term IGCC unit forced outage rates are expected to range from 10 to 15 percent without a spare gasifier and from 5 to 10 percent with a hot spare gasifier. However, in the first year, the forced outage rate is expected to be around 45 percent. The CTG(s) can operate on backup fuel, if available, when syngas is not available. The combined cycle availability is expected to exceed 90 percent. Despite the comparatively low capital cost to add a spare Quench gasifier (roughly 60 percent of a HTHR gasifier), it appears that the prevailing sentiment in the gasification community is that the economics of a spare gasifier will be difficult to justify in most power generation applications, because of the reduced efficiency.

For many utilities, there is reduced power demand in the spring and/or fall of the year that would allow for annual planned outages. Because there are three gasifier/CTG trains, these would not typically be full plant outages, but would reduce the available output from the plant by one third for an extended time. Full plant planned outages would be required approximately every 6 years for steam turbine maintenance, similar to that required for a PC or CFB plant. The annual planned outages are a contributing factor to the lower expected equivalent availability of an IGCC plant as compared to a PC or CFB plant.

4.12 Other Commercial Entrained Bed Gasification Experience

GE Quench type gasifiers have been in commercial operation on coal or petcoke since 1983, producing syngas for chemical production. Two plants of note are the Eastman Chemical Plant in Kingsport, Tennessee, and the Ube Ammonia Plant in Japan. The syngas from these two plants is used to produce acetyl chemicals and ammonia, respectively. Kingsport has two gasifiers; one is normally operated and the other is a spare. Ube has four gasifiers; three are normally operated and one is a spare. Ube originally gasified crude oil, then switched to refinery residuals, then to coal, and has been gasifying a total of 1,650 tpd of petcoke since 1996. At Kingsport and Ube, an average syngas availability of 98 percent is achieved by rapid switchover to the spare gasifier, which is on hot standby, and the high level of resources (e.g., O&M) applied to the gasification process.

The Eastman Kingsport plant has occasionally been referred to as an IGCC plant. This is incorrect because it produces no power; the Eastman plant produces syngas for chemical production, with no power generation. The economics of chemical production at the Eastman facility are different from the economics of the power market. As such, a fully redundant gasifier is warranted at the Eastman facility. Eastman has made gasification one of its focus areas, as evidenced by its formation of the Eastman Gasification Services Company.

Table 4-5. Coal/Coke-Fueled IGCC Plant Equivalent Availabilities

IGCC Plant Location	**Nuon** Buggenum Netherlands	**Global Energy** Wabash Indiana	**TECO** Polk County Florida	**Elcogas** Puertollano Spain
Gasifier	Shell	COP E-Gas	GE HTHR	Prenflo
Net Output	252 MW	262 MW	250 MW	300 MW
Startup Year	1994	1995	1996	1998
Year after Startup	**IGCC Equivalent Availability (percent)**			
1	23	20	35	16
2	29	43	67	38
3	50	60	60	59
4	60	40	75	62
5	61	70	69	66
6	60	69	74	58
7	57	75	68	NA
8	67	78	81	
9	73	--	82	
10	78	--		
11	NA			

Note:

1. Data is based upon available information. Data reporting methodology varies somewhat between the plants.
2. Wabash Years 5 to 8 IGCC equivalent availability estimated as 95 percent of reported syngas availability.
3. Wabash availability excludes periods when the plant was shut down because of no product demand (24 percent in Year 7 - 2002 and 16 percent in Year 8 – 2003, shutdown in Year 9 - 2004 and Year 10 - 2005).

4.13 Current Announced Electric Generation Industry Activity

Major industry participants, such as AEP and Duke Energy (formerly Cinergy), are considering implementing IGCC projects. In addition, numerous smaller companies are pursuing gasification projects using state and federal grants. The more advanced, publicly discussed IGCC projects of which Black & Veatch is aware are shown in the table below.[9]

Table 4-6. Announced IGCC Projects Currently In Development.

Owner	Size, MW	Fuel	Technology	Location
AEP	600	Bituminous	GE	OH
AEP	600	Bituminous	GE	WV
Duke/Cinergy	600	Bituminous	GE	IN
Excelsior	600	Bituminous/ PRB	COP	MN
Southern & OUC	285	PRB	KBR	FL
Global Energy	540	Petcoke	COP	IN
Global Energy	600	Petcoke	COP	OH
ERORA	557	Bituminous	GE	IL
Energy Northwest	600	PRB/Petcoke	NA	WA
NRG Northeast	630	PRB/Petcoke	Shell	CT
NRG Northeast	630	PRB/Petcoke	Shell	NY
TECO	789	Bituminous	GE	FL
Mississippi Power CO	700	Lignite	KBR	MS

4.13.1 Summary of Proposed Projects

The development activities of the eight companies discussed in the previous subsections represent advances in the development of new IGCC plants within the United States.

Entrained flow gasification technology has been selected by six of the companies. Southern Company and OUC are moving forward with the commercial demonstration of a transport bed gasifier. Energy Northwest has not selected a vendor at this stage, but all indications are that it will be a COP, GE, or Shell entrained flow gasification technology.

All of the projects are in coastal or Midwestern locations, with elevations generally at 1,000 feet or less.

The AEP, Duke, and ERORA projects are all based upon bituminous coal. The Global Energy Lima project is based upon petcoke. Excelsior Energy and Energy Northwest anticipate a blend of fuels that would include PRB coal with petcoke. The Southern Company/OUC project is based upon 100 percent PRB coal, but is a

[9] According to December 28, 2006, press release, AEP will delay its IGCC plant development to try to reduce the estimated capital cost to be within 20 percent of market pricing of "conventional coal fired power plant."

commercial demonstration project for a new gasification technology and the demonstration will not be complete until 2015. The fuel supply for the NRG sites is primarily coal, but could include up to 20 percent petcoke and 5 percent biomass.

4.13.2 Gasification Market Opportunities

The gasification market appears to have strong opportunities in non-electric power generation sectors. Primarily, these are production of synthetic natural gas (SNG) and coal-to liquids (CTL). Gasification is also used worldwide for ammonia production from coal.

High natural gas prices have spurred interest in SNG production. Several such projects are currently in advanced stages of development. SNG has been proven commercially by the Great Plains facility in North Dakota which has been gasifying lignite for SNG production since 1983.

For the past several years, the continuous cost increase of petroleum based transportations fuels has created a market for alternative transportation fuels. This recently emerged market, coupled with the vast coal reserves of the US, provides potential near term gasification opportunities with CTL technologies. The US Departments of Defense and Energy both have technology development initiatives that are helping drive technology deployment in the US. CTL technologies are commercially available and proven.

5.0 Performance and Emissions Estimates

Black & Veatch developed estimates of performance for four coal-fueled generation technology options. Both performance and emissions limits were developed for single units that would be installed at a multiple unit greenfield site. Project capacity has been specified as a nominal 2,000 MW net at the FGPP plant boundary. The project required net capacity would be met by installing blocks of power to obtain the nominal 2,000 MW.

The fuel used for the performance and cost estimates consisted of a blend of Central Appalachian coal, Colombian coal, and petcoke. The PC and CFB cases utilized a blend of 40 percent Central Appalachian coal, 40 percent Colombian coal, and 20 percent petcoke, referred to as the AQCS Blend.

Technical limitations exist that restrict the amount of petcoke that can be fired in PC units. These limitations are related to the fuel characteristics of petcoke. The low volatile matter of petcoke compared to its high fixed carbon content leads to flame instability in PC furnaces. In addition, the high sulfur content of petcoke, typically in the range of 3 to 8 percent, can lead to fireside corrosion of heat transfer equipment, flue gas path ductwork, and flue gas handling equipment. The high sulfur content also adds complications in meeting SO_2 emission requirements. Because of this, petcoke is typically co-fired with coal in PC units.

The IGCC case utilized a blend of 25 percent Central Appalachian coal, 25 percent Colombian coal, and 50 percent petcoke, referred to as the IGCC Blend.

For the purposes of this evaluation, the technologies were evaluated on a consistent basis relative to one another. The technologies, plant sizes, and arrangements that were considered for this study are shown in Table 2-1.

5.1 Assumptions

Black & Veatch and FPL developed assumptions for each of the technologies. The assumptions are provided in the following subsections.

5.1.1 Overall Assumptions

For the basis of the performance estimates, the site conditions of the proposed greenfield FGPP in Glades County, Moore Haven, Florida were used. The site conditions were provided to Black & Veatch by FPL. Performance estimates were developed for both the hot day and the average day ambient conditions. Following are the overall assumptions, which were consistent among all of the technologies:

- Elevation--20 feet.

- Ambient barometric pressure--14.67 psia.
- Hot day ambient conditions:
  Dry-bulb temperature--95° F.
  Relative humidity--50 percent.
- Average day ambient conditions:
  Dry-bulb temperature--75° F.
  Relative Humidity--60 percent.
- The assumed fuel is a blend of three different fuel supplies. The ultimate analysis of these fuels, along with the analysis of the 40/40/20 and 25/25/50 blended fuels (which were used to determine performance and cost estimates for the PC, CFB, and advanced coal technologies, respectively) is provided in Table 5-1.
- AQCS were selected to develop performance and cost estimates, based on Black & Veatch experience. Actual AQCS would be selected to comply with federal NSPS and would be subject to a BACT review.

Table 5-1. Ultimate Fuel Analysis

Fuel	Appalachian Coal	Colombian Coal	Petcoke	AQCS Blend[(1)]	IGCC Blend[(1)]
Carbon, %	70.73	64.4	79	69.85	73.28
Sulfur, %	0.91	0.67	6.75	1.98	3.77
Oxygen, %	5.65	7.73	0.78	5.51	3.74
Hydrogen, %	4.62	4.6	3.3	4.35	3.96
Nitrogen, %	1.46	1.17	1.6	1.37	1.46
Chlorine, %	0.13	0.03	0.02	0.07	0.05
Ash, %	10.05	8.9	0.5	7.68	4.99
Water, %	6.45	12.5	8	9.18	8.74
HHV, Btu/lbm	12,510	11,300	13,676	12,300	12,800

[(1)]Developed from a blend of Appalachian coal, Colombian coal, and petcoke. Blended on the basis of percent weight.

5.1.2 Degradation of Performance

Net power plant output and heat rate performance for PC, CFB and IGCC plants can be expected to decline or "degrade" with hours of operation due to factors such as blade wear, erosion, corrosion, and increased tube leakage. The magnitude of performance degradation is dependent upon the specific characteristics of each facility such as mode of operation, fuel characteristics, water washing and maintenance practices as well as site specific ambient conditions. A portion of this degradation is recoverable and a portion is non-recoverable.

Periodic maintenance and overhauls can recover much, but not all, of the degraded performance compared to the unit's new and clean performance. The degradation which cannot be recovered is referred to as non-recoverable degradation. Performance that is recovered by scheduled maintenance is referred to as recoverable degradation. Performance degradation can also be reported as maximum degradation, which is the reduction in performance from clean and new equipment that is expected prior to a major overhaul.

Based on Black & Veatch experience, quantifying degradation in performance is difficult because actual data is not easily documented by the users and not easily obtained from the users or from the manufacturers. Many papers contain information regarding degradation in performance but the information is heavily qualified and vaguely presented thereby limiting analysis. For this study, a maximum degradation factor, a factor used to estimate the decline in a performance parameter, was assumed for each of the technologies. A maximum degradation of 1.0 percent for both the heat rate and net power output has been assumed for the PC and CFB cases. For the IGCC case, the maximum degradation was assumed to be 2.5 percent for both the heat rate and net power output.

5.1.3 PC and CFB Coal Cycle Arrangement Assumptions

The following assumptions were common to the SPC, USCPC, and CFB cases:

- All cases would utilize a wet mechanical draft cooling tower.
- A 40/40/20 fuel blend would be used for boiler efficiency in accordance with Table 5-1.
- Condenser performance was estimated on Black & Veatch experience. The expected condenser back pressures were supplied for hot and average day ambient conditions.
- The facilities would be designed for a nominal 2,000 MW net at the FGPP plant boundary by installing multiple units. Performance estimates were developed for multiple units generating a nominal 2,000 MW net of power at the average day ambient conditions.

The following subsections provide the specific assumptions used for each of the PC and CFB cases.

5.1.3.1 Subcritical PC.

- Single unit capacity--500 MW net.
- Subcritical STG and subcritical PC boiler.
- Tandem-compound, four-flow, 33.5 inch last-stage blade (LSB) (TC4F-33.5) STG.
- Assumed capacity factor of 92.0 percent.
- AQCS:
    - LNB, overfire air (OFA), flue gas recirculation (FGR), and SCR for NOx control.
    - Wet limestone FGD for SO_2 control.
    - Activated Carbon Injection (ACI) for further Hg control
    - Pulse jet fabric filter (PJFF) for particulate control.
    - Wet electrostatic precipitator (ESP) for control of sulfuric acid mist (SAM.)
- Auxiliary power assumed to be 9.0 percent of gross plant output.
- The auxiliary load estimate was based on using motor driven boiler feed pumps (BFPs). This estimate would decrease by 2 to 3 percent if BFPs were turbine driven.
- Throttle conditions--2,415 psia, 1,050/1,050° F.
- Seven feedwater heaters (FWHs)--Three HP, three LP, and one deaerator (DA).
- Condenser pressure for hot and average day ambient conditions assumed to be 2.9 and 2.2 in. HgA, respectively.

5.1.3.2 Ultrasupercritical PC.

- Single unit capacity--1,000 MW net.
- Supercritical STG and supercritical PC boiler.
- TC4F-40.0 STG.
- Assumed capacity factor of 92.0 percent.
- AQCS:
    - LNB, OFA, FGR, and SCR for NOx control.
    - Wet limestone FGD for SO_2 control.
    - ACI for further Hg control
    - PJFF for particulate control.
    - Wet ESP for control of SAM.
- Auxiliary power assumed to be 7.0 percent of gross plant output.

- The auxiliary load estimate was based on using turbine driven BFPs. This estimate would increase by 2 to 3 percent if BFPs were motor driven.
- Throttle conditions--3,715 psia, 1,112/1,130° F.
- Seven FWHs--Two HP, four LP, and one DA.
- Dual condenser used. For average ambient conditions, the HP condenser pressure was assumed to be 2.1 in. HgA; LP condenser pressure was assumed to be 1.7 in. HgA.

5.1.3.3 CFB.

- Single unit capacity--2x250 MW net boilers and 1x500 MW STG.
- Subcritical STG and subcritical CFB boiler.
- TC4F-33.5 STG.
- Assumed capacity factor of 88.0 percent.
- AQCS:
  - SNCR for NOx control.
  - Boiler limestone injection and wet limestone FGD for SO_2 control.[10]
  - ACI for further Hg control
  - PJFF for particulate control.
- Auxiliary power assumed to be 10.0 percent of gross plant output.
- The auxiliary load estimate was based on using motor driven boiler feed pumps (BFPs). This estimate would decrease by 2 to 3 percent if BFPs were turbine driven.
- Throttle conditions--2,415 psia, 1,050/1,050° F.
- Seven FWHs--Two HP, four LP, and one DA.
- Condenser pressure for hot and average day ambient conditions assumed to be 2.9 and 2.2 in. HgA, respectively.

5.1.4 IGCC Cycle Arrangement Assumptions

IGCC application has different issues that need to be considered. Unlike PC and CFB units, an IGCC cannot be sized to match a selected net plant output. The constraints are similar to that of a conventional natural gas fired simple or combined cycle unit. CTGs come in discrete sizes and are much more sensitive to changes in elevation and ambient temperature than thermal plants.

Currently, the most economic IGCC configurations are based upon state-of-the-art conventional "F" class CTGs modified to fire syngas. The GE 7FB and the Siemens SPG

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[10] Wet FGD was applied to the CFB case to attain a comparable SO_2 emission to allow comparison with the PC options.

SGT6-5000F CTGs are the most likely models to be incorporated in an IGCC plant. At International Organization for Standardization (ISO) conditions (sea level, 59° F, 60 percent relative humidity), these CTGS are rated at 232 MW when firing syngas. A single 7FB or SGT6-5000F in an IGCC configuration produces a nominal 300 MW net at ISO conditions. Therefore, a 3-on-1 IGCC configuration would produce a nominal 900 MW net at ISO conditions. The net output will vary somewhat depending upon the gasification technology employed, as well as the degree of integration.

The intent of the study was not to compare all of the gasification technologies against the PC and CFB options. To perform this study a gasifier technology choice needed to be made by Black & Veatch. Because of the fuel and location of the project, Black & Veatch selected GE Radiant as being representative of the commercial gasification technologies available. Based on experience, it was Black & Veatch's opinion that there would be not sufficient difference in cost and performance of one technology over another that would cause IGCC to be positively or negatively affected in the overall technology comparison. Black & Veatch did not select the GE Quench technology because GE currently prefers the Radiant in IGCC applications.

The following were assumed:

- Fuel supply used for gasifier feedstock in accordance with Table 5-1.
- Capacity factor of 80.0 percent.
- Six GE Radiant gasifiers.
- Six GE 7321(FB) CTGs with syngas combustors.
- TC2F-33.5 STG.
- Three-pressure reheat HRSG with duct firing.
- AQCS:
    - Selexol AGR.
    - Nitrogen diluent and syngas saturation for NO_x control.
    - Candle filter.
    - Sulfided carbon bed for Hg adsorption.
- 100 percent syngas fuel -- no backup fuel will be provided.
- Inlet air evaporative cooling above 59° F.
- Wet deaerating condenser.
- Throttle conditions--1,565 psia/1,000° F/1,000° F.
- For this evaluation, the STG was designed for normal pressure at average day conditions during syngas operation.

5.2 Performance Estimates

Full-load performance estimates for each of the PC and CFB cases are presented in Table 5-2. Full-load performance estimates for the IGCC cases are presented in Table 5-3. The IGCC case is presented in a separate table from the PC and CFB cases because IGCC has some unique performance parameters.

5.2.1 PC and CFB Cases

Full-load performance estimates were developed for each of the specific PC and CFB cases. A total of six performances cases were run (two for each technology), consisting of performance estimates for the hot day and average day ambient conditions. Each of the cases was evaluated on a consistent basis to show the effects of technology selection on project performance. The performance estimates were generated for single units that would be installed at a multiple unit greenfield site.

5.2.2 IGCC Cases

Full-load performance estimates were developed for the IGCC cases. A total of two performance cases were run, one at hot day and one at average day ambient conditions. The IGCC case was evaluated on a consistent basis with the PC and CFB cases with respect to site and ambient conditions to show the effects of technology selection on project performance.

5.3 Emissions Estimates

For the purpose of estimating capital and O&M costs for AQCS, probable full-load emission limits were provided to Black & Veatch by FPL. These limits will be subject to later BACT review and are not intended to define performance requirements. Emissions estimates for the PC, CFB, and IGCC cases are summarized in Table 5-4. The emissions rates in the tables are expressed in lb/MBtu of heat input from the fuel. Emissions estimates should only be used for the screening-level evaluation. Final permit levels may vary on a case-by-case basis. Estimates of CO_2 emissions are shown in Table 5-5.

Table 5-2. PC and CFB Coal Performance Estimates, per Unit

Technology Fuel	SPC AQCS Blend	USCPC AQCS Blend	CFB AQCS Blend
Performance on Average Ambient Day at 20 ft ASML, Clean and New Equipment			
Steam Conditions, psia/° F/° F	2,415/1,050/1,050	3,715/1,112/1,130	2,415/1,050/1,050
Fuel Input, MBtu/h	4,600	8,480	4,730
Boiler Efficiency (HHV), percent	88.9	88.9	87.0
Heat to Steam (HHV), MBtu/h	4,090	7,545	4,200
Gross Single Unit Output, MW	550	1,054	556
Total Auxiliary Load, MW	50	74	59
Net Single Unit Output, MW	500	980	497
Gross Turbine Heat Rate, Btu/kWh	7,450	7,140	7,540
Condenser Pressure, in. HgA	2.2	2.1/1.7	2.2
NPHR (HHV), Btu/kWh	9,210	8,660	9,510
Net Plant Efficiency (HHV), percent	37.0	39.4	35.9
Performance on Hot Day at 20 ft ASML, Clean and New Equipment			
Net Single Unit Output, MW	494	976	491
NPHR (HHV), Btu/kWh	9,340	8,690	9,640
Performance On Average Ambient Day at 20 ft ASML, Maximum Degradation (1.0% heat rate and 1.0% net plant output)			
Net Single Unit Output, MW	495	970	492
NPHR (HHV), Btu/kWh	9,300	8,750	9,610

Note:
USCPC option has dual condensers, therefore both pressures are listed.
No margins are applied to performance estimates.

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Table 5-3. GE Radiant IGCC Performance Estimates, per Unit

Fuel	IGCC Blend
Combined Cycle Configuration	3 x 1 GE 7FB
Performance on Average Day at 20 ft ASML, Clean and New Equipment	
Coal to Gasifiers, MBtu/h	8,400
Gasifier Cold Gas Efficiency (Clean Syngas HHV/Coal HHVx100)	74
CTG Heat Rate (LHV), Btu/kWh	8,370
CTG(s) Gross Power, MW	687
Steam Turbine Gross Power, MW	451
Syngas Expander Power, MW	5
Total Gross Power, MW	1,143
Aux. Power Consumption, MW	203
Net Power, MW	940
Net Plant Heat Rate (HHV), Btu/kWh	8,990
Net Plant Efficiency (HHV), Btu/kWh	38.0
Performance on Hot Day at 20 ft ASML, Clean and New Equipment	
Net Power, MW	902
Net Plant Heat Rate (HHV), Btu/kWh	9,360
Performance on Average Day at 20 ft ASML, Maximum Degradation (2.5% heat rate and 2.5% net power output)	
Net Power, MW	917
Net Plant Heat Rate (HHV), Btu/kWh	9,215

Notes:
Based on publicly available data from technology vendor.
No margins are applied to performance estimates.

Table 5-4. Probable Air Emissions Limits

Emissions	SPC	USCPC	CFB	IGCC
SO_2, lb/MBtu	0.04	0.04	0.04	0.015[a]
NO_x, lb/MBtu	0.05	0.05	0.07	0.06
PM_{10}, lb/MBtu, filterable	0.013	0.013	0.015	0.014
SAM, lb/MBtu	0.004	0.004	0.004	NA[b]
Hg, lb/MWh	9.9×10^{-6}	9.9×10^{-6}	10×10^{-6}	20×10^{-6}

Notes:

All emission limits are on a HHV basis.

[a] Probable emission limit under continuous operation. Normalized annual emission rate considering four start-ups and shutdowns could reach 0.038 lb/MBtu.[11]

[b] If SO_2 is properly controlled. H_2SO_4 emissions estimated at 5.6 lb/hr.

Table 5-5. Probable Air Emissions Limits

Emissions	SPC	USCPC	CFB	IGCC
CO_2, lb/MBtu	208.1	208.1	208.1	209.8
CO_2, lb/MWh	1,935	1,821	1,989	1,933

Notes:

All emission limits are on a HHV basis.

Values are calculated based on fuel composition.

[11] Based on data presented in the Permit to Construct Application submitted on September 29, 2006, by AEP for the Mountaineer IGCC project.

6.0 Cost Estimates

This section provides representative high-level cost estimates consisting of the following:

- Overnight capital cost estimates presented on an EPC basis exclusive of Owner's costs.
- O&M costs as fixed O&M costs and variable nonfuel O&M costs.

The cost estimates presented in this section were developed assuming that multiple units would be constructed at a single greenfield site. Multiple units will be constructed to obtain 2,000 MW of net nominal capacity at a single facility. Therefore, the cost estimates will be reflective of the economies of scale savings that occur for multiple unit facilities.

6.1 Capital Costs

Market-based overnight capital cost estimates for the four coal technologies were estimated. The estimates are expressed in 2006 US dollars and were developed using the assumptions listed in Section 5.1. An EPC cost basis was utilized exclusive of Owner's costs. Typically, the scope of work for EPC costs is the base plant, which is defined as being "within the fence" with distinct boundaries and terminal points. The values presented are believed to be reasonable for today's market. More importantly, the EPC costs were developed in a consistent manner and are reasonable relative to one another.

The cost estimate includes estimated costs for equipment and materials, construction labor, engineering services, construction management, indirects, and other costs on an overnight basis. The estimates were based on Black & Veatch proprietary estimating templates and experience. These estimates are screening-level estimates prepared for the purposes of project screening, resource planning, comparison of alternative technologies, etc., and as such are expected to be in the range of ±25 percent. The cost estimates were made using consistent methodology between technologies, so while the absolute cost estimates are expected to vary within a band of accuracy, the relative accuracy between technologies is better. The information is consistent with recent experience and market conditions, but as demonstrated in the last few years, the market is dynamic and unpredictable. Power plant costs will be subject to continued volatility in the future, and the estimates in this report should be considered primarily for comparative purposes. The AQCS for each technology were selected to meet the proposed emissions levels for criteria pollutants including NO_x, SO_2, Hg, and PM_{10}.

Given the level of uncertainty with developing screening-level capital costs, particularly for technologies with a limited database of actual installed costs, it is recommended that sensitivity evaluations be conducted to determine the competitiveness of a technology that appears cost-effective under base case assumptions.

6.2 Owner's Costs

The sum of the EPC capital cost and the Owner's cost equals the total project cost or the total capital requirement for the project. Typical Owner's costs that may apply are listed in Table 6-1. These costs are not usually included in the EPC estimate and should be considered by the project developer to determine the total capital requirement for the project. Owner's cost items include costs for "outside the fence" physical assets, project development, and financing costs. Interconnection costs can be major cost contributors to a project and should be evaluated in greater detail during the site selection. The order of magnitude of these costs is project-specific and can vary significantly, depending upon technology and project-unique requirements.

For a screening-level analysis, the Owner's cost, exclusive of interest during construction (IDC), can be estimated as a percentage of the EPC cost. Typically, based on actual project financial data, Owner's costs exclusive of IDC and escalation have been found to be in the range of 15 to 20 percent of the EPC cost for PC and CFB projects.

Additional considerations are merited for IGCC. Without a historical basis, Black & Veatch has added an allowance of 6 percent of the EPC cost. This contingency is in addition to the 15 to 20 percent Owner's costs, exclusive of IDC, and would cover the unexpected repairs and modifications needed during the initial years of operation. To attain high availability, it is assumed that the Owner would have to aggressively correct deficiencies and implement enhancements as they were identified. Some of the costs for correcting deficiencies can be recovered from the EPC contractor, but the Owner should expect to have significant initial operating costs that will not be reimbursed by the EPC contractor. Depending on the contracting arrangement and guarantees obtained, some of this responsibility/liability might be accepted by the EPC contractor, but it can be assumed that it would result in an equivalent price increase by the EPC contractor to assume the additional risk.

Table 6-1. Potential Owner's Costs

Project Development:
- Site selection study
- Land purchase/options/rezoning
- Transmission/gas pipeline rights of way
- Road modifications/upgrades
- Demolition (if applicable)
- Environmental permitting/offsets
- Public relations/community development
- Legal assistance

Utility Interconnections:
- Natural gas service (if applicable)
- Gas system upgrades (if applicable)
- Electrical transmission
- Supply water
- Wastewater/sewer (if applicable)

Spare Parts and Plant Equipment:
- AQCS materials, supplies, and parts
- Acid gas treating materials, supplies, and parts
- Combustion and steam turbine materials, supplies, and parts
- HRSG, gasifier and/or boiler materials, supplies, and parts
- Balance-of-plant equipment/tools
- Rolling stock
- Plant furnishings and supplies

Owner's Project Management:
- Preparation of bid documents and selection of contractors and suppliers
- Provision of project management
- Performance of engineering due diligence
- Provision of personnel for site construction management

Plant Startup/Construction Support:
- Owner's site mobilization
- O&M staff training
- Initial test fluids and lubricants
- Initial inventory of chemicals/reagents
- Consumables
- Cost of fuel not recovered in power sales
- Auxiliary power purchase
- Construction all-risk insurance
- Acceptance testing
- Supply of trained operators to support equipment testing and commissioning

Taxes/Advisory Fees/Legal:
- Taxes
- Market and environmental consultants
- Owner's legal expenses:
  - Power Purchase Agreement (PPA)
  - Interconnect agreements
  - Contracts--procurement and construction
  - Property transfer

Owner's Contingency:
- Owner's uncertainty and costs pending final negotiation:
  - Unidentified project scope increases
  - Unidentified project requirements
  - Costs pending final agreement (e.g., interconnection contract costs)

Financing:
- Financial advisor, lender's legal, market analyst, and engineer
- Development of financing sufficient to meet project obligations or obtaining alternate sources of lending
- Interest during construction
- Loan administration and commitment fees
- Debt service reserve fund

6.3 Nonfuel O&M Costs

Preliminary estimates of O&M expenses for the technologies of interest were developed. The O&M estimates were derived from other detailed estimates developed by Black & Veatch and are based on vendor estimates and recommendations, actual performance information gathered from in-service units, and representative costs for staffing, materials, and supplies. Plant staffing was assumed to provide operating and routine maintenance. The estimated O&M costs were developed using the assumptions listed for each of the cases in Section 5.1. Additional assumptions specific to O&M cost development are as follows:

- 6 year cycle between major STG overhauls.
- 2 year cycle between major PC boiler overhaul.
- 1 year cycle between major CFB boiler overhaul.
- 1 year cycle between major IGCC gasification overhaul
- Average plant technician salary would be $62,900/year, plus a 40 percent burden rate.
- Staff supplies and material were estimated to be 10 percent of staff salary.
- Insurance and property taxes are not included.
- Estimated employee training cost and incentive pay/bonuses are included.
- The variable O&M analysis was based on a repeating maintenance schedule for the boiler and STG and considers replacement and refurbishment costs.
- The fixed O&M analysis assumes that the fixed costs would remain constant over the life of the plant.
- Costs of major consumables are listed in Table 6-2.

Table 6-2. O&M Consumable Assumptions, $2006

Waste Disposal Cost	$/ton	6
Limestone Cost	$/ton	15
Lime Cost	$/ton	60
Ammonia Cost	$/ton	300
Urea Cost	$/ton	315
SCR Catalyst Cost	$/m^3	5,400
Powder Activated Carbon	$/lb	0.50

6.4 Economies of Scale

6.4.1 Multiple Unit Sites

The benefit of economies of scale can be realized through facilities with high output and/or through multiple unit facilities. This assumes that the multiple units are duplicates of each other.

In most cases, a coal plant is initially designed for multiple units. Usually, the design calls for a minimum of two identical units, but can include three or four units. Capital intensive projects, such as PC units, realize substantial savings when the site includes multiple units. The savings will vary depending on the number of units installed at the site and the degree of interconnections and commonality of supporting systems.

The cost of the first unit on a two-unit site will be slightly higher than the cost for a single-unit site. This is because of the increased capacity of common systems or level of equipment redundancy and increased infrastructure. The increase in first-unit cost is expected to be in the range of 6 to 8 percent.

For a two-unit site, assuming identical units constructed within 1 to 2 years of each other, the second unit cost will be in the range of 75 to 80 percent of the first unit. A four-unit facility would typically be designed as two, two-unit plants. These economies of scale factors apply to EPC cost estimates that are exclusive of Owner's costs. The initial design of the plant should consider the economies of scale based on multiple units and/or unit size. The use of multiple identical units constructed in reasonable sequence will result in the greatest savings.

6.4.2 Economies of Scale Based on Unit Size

The cost per unit of output ($/kW) decreases as the output of the unit increases. This is mainly because there are many items (of cost) that are independent (in varying degrees) of unit size. Some examples include engineering for project design and manufacturing, manufacturing and construction management, distributed control system (DCS), instrumentation, plant infrastructure, project development cost, etc. Other independent costs, such as the Owner's costs (which were not estimated in this study), make the economies of scale based on unit size more significant.

6.5 Recent Experience

The estimated EPC costs were reviewed and adjusted according to recent conceptual-level cost estimates and Black & Veatch experience on actual projects. Black & Veatch has experienced substantial increases in costs over the past year. As an example, Black & Veatch had a experience with a boiler original equipment manufacturer (OEM) who increased a boiler quotation by about 20 percent. Additionally, it should be noted that AQCS prices have been increasing dramatically, and all AQCS OEMs are experiencing increased business. Costs continue to rise because of labor and material cost increases as well as market demand. For the present, the market has shifted to a seller's market. These cost increases apply to all of the technologies considered in this report.

6.6 Preliminary Cost Estimates

Preliminary capital cost estimates for the PC, CFB, and IGCC cases are presented in Table 6-3. These cost estimates were developed on an EPC basis and do not include Owner's costs. Nonfuel O&M cost estimates, including fixed costs and variable costs, are shown in Table 6-4. Both the capital and O&M costs estimates for the PC and CFB cases were developed on the basis of a multiple unit facility, so as to obtain nominal 2,000 MW of electrical power generation at a single facility.

Table 6-3. Capital Cost Estimates

Technology	SPC	USCPC	CFB	IGCC
Net Single Unit Output, MW	500	980	497	940
Net Multiple Unit Output, MW	2,000	1,960	1,988	1,880
EPC Cost, 2006$MM	3,078	2,646	3,240	3,541
Unit EPC Cost, 2006$/kW	**1,540**	**1,350**	**1,630**	**1,880**
Escalation to 2012$	490	421	516	564
Subtotal - EPC Cost 2012$	*3,568*	*3,067*	*3,756*	*4,105*
Owner's Costs, 2012$	1,218	1,153	1,236	1,411
IDC, 2012$	1,063	914	1,119	1,223
Project Cost, 2012$	*5,849*	*5,134*	*6,111*	*6,739*
Unit EPC Cost, 2012$/kW	**2,925**	**2,619**	**3,074**	**3,585**

Table 6-4. O&M Cost Estimates

Technology	SPC	USCPC	CFB	IGCC
Net Single Unit Output, MW	500	980	497	940
Net Multiple Unit Output, MW	2,000	1,960	1,988	1,880
Capacity Factor, percent	92.0	92.0	88.0	80.0
Annual Generation, GWh	16,100	15,800	15,300	13,200
Fixed Costs, 2006$, (1,000s)	35,780	27,500	38,800	47,810
Fixed Costs, 2006$/kW	17.89	14.03	19.54	25.43
Variable Costs, 2006$ (1,000s)	45,130	47,500	68,000	80,120
Variable Costs, 2006$/MWh	2.94	2.86	4.44	6.07
Fixed Costs, 2012$, (1,000s)	41,480	31,870	45,050	55,420
Fixed Costs, 2012$/kW	20.74	16.26	22.66	29.48
Variable Costs, 2012$ (1,000s)	54,900	52,300	78,600	92,930
Variable Costs, 2012$/MWh	3.41	3.31	5.14	7.04

7.0 Economic Analysis

A busbar analysis was developed to compare the four technologies. The economic criteria, summary of inputs, and results are presented in this section.

7.1 Economic Criteria

The economic criteria utilized for the busbar analysis are summarized in Table 7-1. Estimated forecasts for the delivered price of the AQCS and IGCC fuel blends to the proposed FGPP throughout the life of the project were provided by FPL and are shown in Table 7-2.

Table 7-1. Economic Criteria

Parameter	
Owner's IGCC Risk Contingency, Percent of EPC Cost, percent	6.0
General Inflation, percent	3.0
Present Worth Discount Rate, percent	8.82
Levelized Fixed Charge Rate, percent	N/A [1]
First year CO_2 Allowance Credit - Mild, \$/ton 2012 [2]	7
First year CO_2 Allowance Credit - Stringent, \$/ton 2012 [3]	14
First year NO_x Allowance Credit, \$/ton 2012 [3]	1,676
First year SO_2 Allowance Credit, \$/ton 2012 [3]	1,399
First year Hg Allowance Credit, \$/lb 2012 [3]	25,459

Note:
[1] LFCR is not used in the economic analysis. Instead, an annual revenue requirement provided by FPL is applied to capital expenditures.
[2] From 4 pollutant 2005 Bingaman Proposal – Escalated at 2.5 percent after forecast period.
[3] From 4 pollutant 2005 McCain Proposal – Escalated at 2.5 percent after forecast period.
[4] From 3 pollutant proposal – Escalated at 2.5 percent after forecast period.

The busbar costs were calculated starting in 2012 and extending over the previously described economic durations. The busbar costs are presented in 2012$ assuming escalation of annual costs over the life of the project.

Table 7-2. Fuel Forecasts ($/MBtu, delivered)

Year	AQCS Blend(1)	IGCC Blend(1)
2012	2.90	2.68
2013	2.97	2.76
2014	3.04	2.83
2015	3.10	2.89
2016	3.17	2.95
2017	3.25	3.01
2018	3.32	3.07
2019	3.40	3.14
2020	3.49	3.21
2021	3.57	3.29
2022	3.66	3.36
2023	3.76	3.45
2024	3.85	3.53
2025	3.95	3.62
2026	4.04	3.70
2027	4.14	3.80
2028	4.24	3.89
2029	4.34	3.98
2030	4.45	4.08
2031	4.56	4.18
2032	4.68	4.29
2033	4.80	4.40
2034	4.92	4.51
2035	5.05	4.63
2036	5.19	4.75
2037	5.33	4.87
2038	5.49	5.02
2039	5.65	5.17
2040	5.82	5.33

Table 7-2. Fuel Forecasts ($/MBtu, delivered)

Year	AQCS Blend[1]	IGCC Blend[1]
2041	6.00	5.49
2042	6.18	5.65
2043	6.36	5.82
2044	6.55	5.99
2045	6.75	6.17
2046	6.95	6.36
2047	7.16	6.55
2048	7.37	6.75
2049	7.60	6.95
2050	7.82	7.16
2051	8.06	7.37

(1) Developed from blends of Appalachian coal, Colombian coal, and petcoke. Blending calculated by %weight.

7.2 Busbar Analysis

A levelized busbar cost analysis was performed using several sets of data. These include:

- Economic criteria provided by FPL, shown in Table 7-1.
- Fuel forecasts provided by FPL, shown in Table 7-2.
- Performance estimates for the PC, CFB, and IGCC cases listed in Table 5-2 and Table 5-3.
- EPC capital cost estimates listed in Table 6-3.
- O&M cost estimates listed in Table 6-4.

The PC and CFB cases were run with a 40 year book and 20 year tax life. The IGCC case was run with a 25 year book and 20 year tax life.

Performance was based on the annual average day conditions. The capacity factors for the PC, CFB, and IGCC units were assumed to be 92, 88, and 80 percent, respectively.

The IGCC analysis has not supplemented the capacity factor by assuming operation on natural gas to bring the capacity factor up to the same levels as the PC and CFB units. IGCC availability will be lower in the earlier years of operation as the operators learn how to run the plant and design modifications are made. The first year availability is expected to be around 50 percent. The base analysis has not reflected the ramp up from 50 to 80 percent in IGCC equivalent availability that is expected over the first five years of operation, and instead assumes that IGCC equivalent availability is 80 percent from the outset. This assumption is favorable for IGCC by overestimating annual generation.

A summary of the inputs consisting of estimates of performance and capital and O&M costs for each of the technologies used in the busbar analysis is provided in Table 7-3. Several cases were run:

- Degraded performance at average ambient conditions with no emissions allowance cost included.
- New and clean performance at average ambient conditions with no emissions allowance cost included.
- Degraded performance at average ambient conditions with emissions allowance cost included for NO_x, SO_2, and Hg. Emission allowance costs were estimated by multiplying a forecasted allowance cost by the total annual emissions of each pollutant based on the assumed control limits minus annual emission allocations for FGPP.
- New and clean performance at average ambient conditions with emissions allowance costs included for NO_x, SO_2, and Hg.

- Degraded performance at average ambient conditions with emissions allowance cost included for NO_x, SO_2, Hg, and CO_2 using the Bingaman carbon tax estimate. No carbon capture was included.

Estimates of emissions allowance costs for NO_x, SO_2, Hg and the two CO_2 cases were taken from a report prepared by ICF International.[12] The costs are forecast through 2024. This study escalates the 2024 values by 2.5 percent annually through the last year of the economic analysis for each generation technology.

The results of the busbar analysis are provided in Table 7-4. From the analysis, the USCPC unit is the most cost effective technology. The analysis was run with the costs of emissions allowances included and excluded from the annual operating costs. In all instances, the USCPC is the most cost effective technology.

Table 7-3. Summary of Busbar Model Inputs

Technology	SPC	USCPC	CFB	IGCC
Cost Estimates				
EPC Capital Cost, 2006 $1,000	$3,078,000	$2,646,000	3,240,000	$3,541,000
Project Cost, Installed, 2012 $1,000	$5,850,000	$5,135,000	$6,111,000	$6,740,000
Fixed O&M, 2006 $/kW	17.89	14.03	19.54	$25.43
Variable O&M, 2006 $/MWh	2.94	2.86	4.44	$6.07
Fixed O&M, 2012 $/kW	20.74	16.26	22.66	$29.48
Variable O&M, 2012 $/MWh	3.41	3.33	5.14	$7.04
Average Day Performance				
New & Clean NPO, kW	2,000,000	1,960,000	1,988,000	1,880,000
Degraded NPO, kW	1,980,000	1,940,000	1,968,000	1,834,000
New & Clean NPHR, Btu/kWh (HHV)	9,210	8,660	9,510	8,990
Degraded NPHR, Btu/kWh (HHV)	9,300	8,750	9,610	9,215
Capacity Factor	92%	92%	88%	80%

[12] "U.S. Emission and Fuel Markets Outlook 2006," ICF International, Winter 2006/2007.

Table 7-4. Busbar Cost Analysis Results, ¢/kWh

Case	SPC	USCPC	CFB	IGCC
Degraded performance, w/o emissions	9.56	8.63	10.54	12.69
New and clean performance, w/o emissions	9.47	8.54	10.43	12.38
Degraded performance, w/ emissions	9.68	8.74	10.66	12.81
New and clean performance, w/ emissions	9.58	8.65	10.56	12.50
Degraded performance, w/ emissions including CO_2	10.96	9.94	11.99	14.00

Note: Results were based on economic criteria from Table 7-1, fuel forecasts from Table 7-2, and the inputs from Table 7-3. These results are based on the maximum assumed capacity factors at average ambient conditions. Results are based on using 2012 cost estimates.

Three charts are provided to illustrate sensitivities of the busbar cost analysis. Figure 7-1 shows a breakdown of the components of the base case busbar cost without emissions allowances. It is seen that fuel and capital requirements make up the majority of the total busbar costs. Variations in these two cost categories will have the largest effect on the estimated busbar cost for any technology. Figures 7-2 and 7-3 are similar to Figure 7-1, but show the affect of adding the cost of emissions allowances. Figure 7-2 shows the incremental cost of adding allowance costs for NO_x, SO_2 and Hg. It can be seen that variations in emissions translate to minimal cost variations between the technologies. Figure 7-3 shows that the affect of adding CO_2 allowances (using the Bingaman case with no carbon capture). The carbon tax causes a noticeable increase to the absolute busbar costs, but because CO_2 emissions are relatively equal between technologies there is no effect on the rank order of busbar costs.

A sensitivity case was run that included potential costs of carbon capture. There have been many studies performed by other parties to quantify the cost of capturing carbon. Brief descriptions of available technologies were provided in Sections 3 and 4 of the report. Because study of the potential cost of carbon capture was not a focus of this effort, high level assessments have been made to provide a representation of the cost of carbon capture and show the relative effect of this added cost on the economic comparison between technologies.

A review of recent literature, including the US EPA "Environmental Footprints and Cost of Coal-Based Integrated Gasification and Pulverized Coal Technologies" and the Alstom chilled ammonia position paper indicates a probable range of carbon capture as shown in Table 7-5.

Table 7-5. Probable Carbon Capture Costs, 2006$/Avoided Ton CO_2.

Case	Low Cost	High Cost
Post-Combustion	20	40
Pre-Combustion	20	30

The cost range for pre-combustion is representative of current literature values published by technology neutral sources. The cost range for post-combustion uses Alstom's cost projection for their technology to establish the low value and then makes an assumption that the commercial cost could be 100 percent more for the high value. Estimated costs for other post combustion carbon capture systems published in other studies are higher than those published for this unique Alstom technology.

When these costs are added to the busbar cost analysis, with adjustments for output and net plant heat rate made as needed, the percentage increase of busbar cost over the base case analysis for new & clean conditions are as shown in Table 7-6.

Table 7-6. Probable Busbar Percentage Cost Increase with Carbon Capture and Emissions Allowances.

Case	Low Cost	High Cost
SPC	20	30
USCPC	20	30
CFB	20	30
IGCC	20	25

Note:

Assumes 90 percent carbon capture for conditions at average ambient temperatures compared to case with no emissions allowance costs. Includes emissions allowances for NO_x, SO_2, Hg, and emitted CO_2 using the 2005 McCain cost proposal.

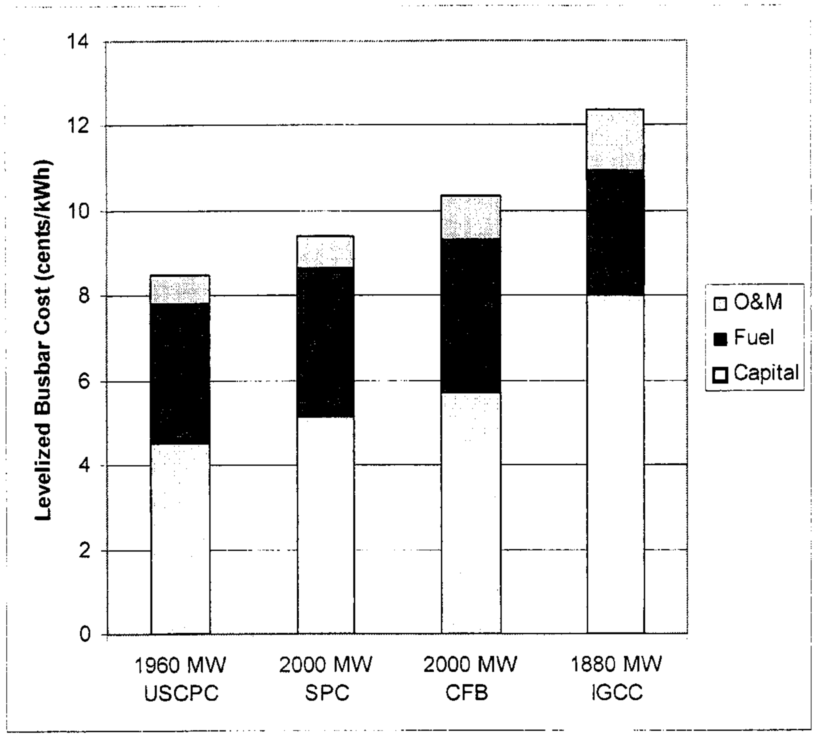

Figure 7-1. Busbar Cost Component Analysis without Emissions

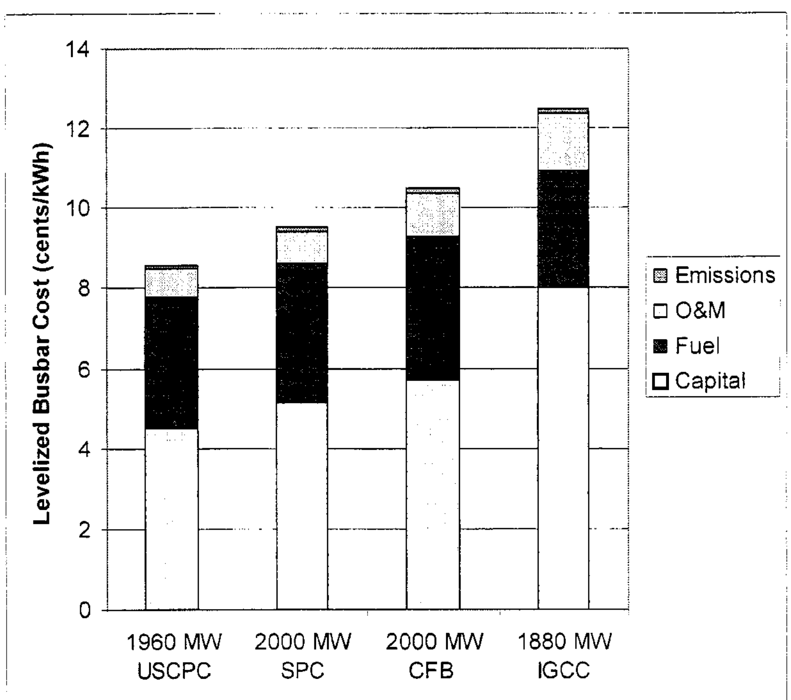

Figure 7-2. Busbar Cost Component Analysis with Emissions

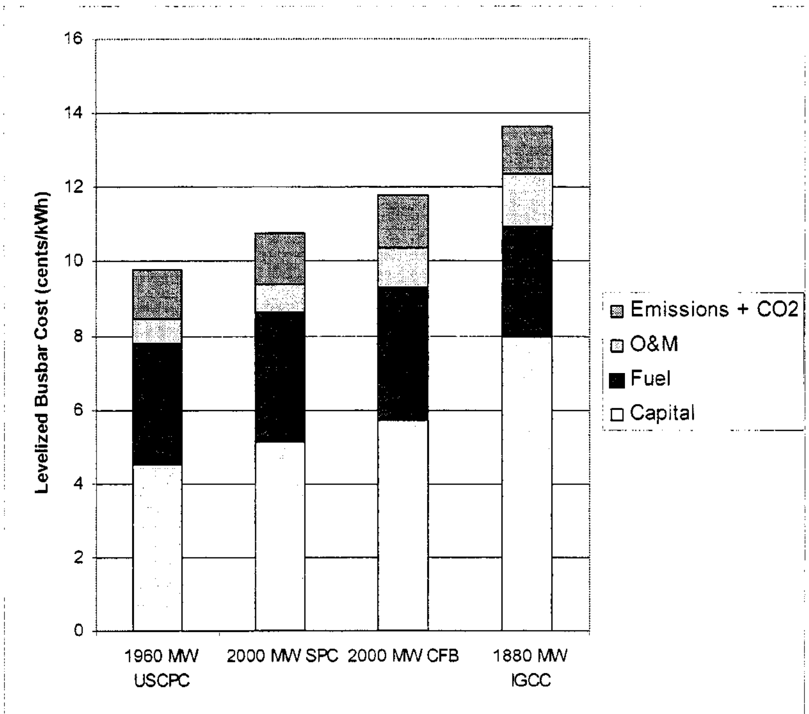

Figure 7-3. Busbar Cost Component Analysis with CO_2

A sensitivity analysis was run to show the effect variations in capacity factor have on economic analysis outputs. Figures 7-4 and 7-5 show the variations in busbar cost in cents per unit of generation (¢/kWh) and net levelized annual cost in dollars per unit of net plant output ($/kW) versus annual capacity factor. The sensitivity analysis was run over a range of capacity factors, from 40 percent to the maximum for each technology. The net plant heat rate was kept constant for all capacity factors, assuming full load operation. It can be seen that while all of the technologies have dramatic changes in busbar and net levelized annual cost across the range of capacity factors, the rank order of costs does not vary with capacity factor.

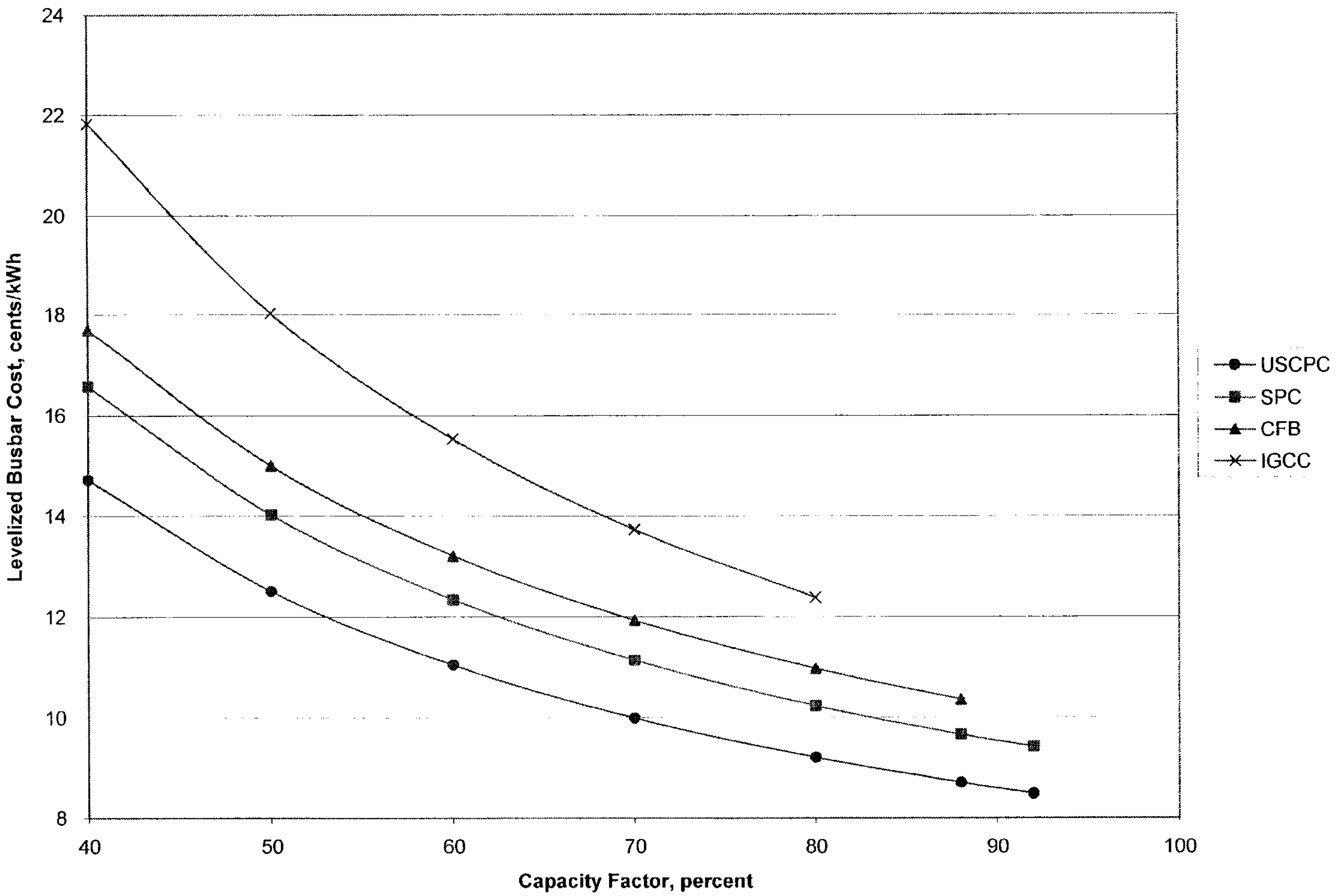

Figure 7-4. Busbar Cost Variation with Capacity Factor

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Clean Coal Technology Selection Study

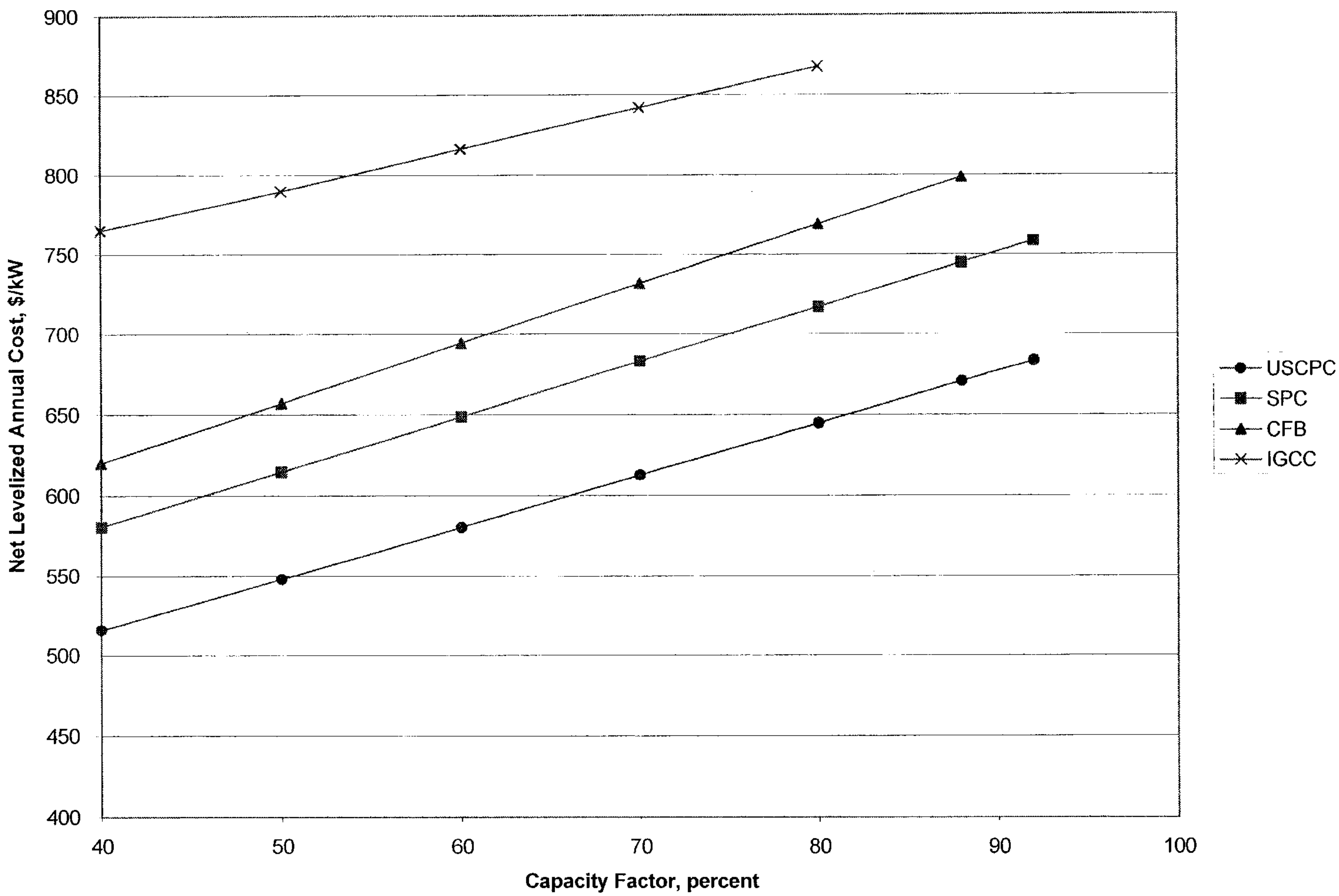

Figure 7-5. Net Levelized Annual Cost Variation with Capacity Factor

8.0 Conclusions

This study made a comparison of performance and cost of four commercially available coal-fired power generation technologies. These were USPC, subcritical PC, CFB and IGCC. The estimates for performance were made using publicly available data and engineering data that has been collected by Black & Veatch and FPL. The results of the study are not intended to be absolute for any given technology but rather are intended to be accurate relative from one technology to another.

This study addresses technology risks known or assumed for each type of plant. Clearly PC plants are commercial and have been a dependable generation technology for years. The advancement of operation at ultrasupercritical steam conditions is somewhat new, but has been commercially demonstrated and proven around the world. CFB is also proven its dependability over the past two decades and is considered a mature technology. IGCC has been demonstrated on a commercial scale for over ten years. A second round of commercial scale IGCC plants is being planned currently. Many utilities will reserve decisions on making future IGCC installations until they have observed the installation and operation of these new plants.

Capital cost estimates for all power generation technologies are exhibiting considerable upward trends. Market pricing of technology components, coupled with commodity and labor demand worldwide, is rapidly escalating capital costs. These costs increases are not confined to any particular generation technology; they apply across the industry. The +/-25 percent accuracy range reflects the market volatility and the screening level nature of the estimate methodology.

Based on the assumptions, conditions, and engineering estimates made in this study, the USCPC option is the preferred technology selection for addition of a nominal 2,000 MW net output at the Glades site. The busbar cost of the USCPC case is nearly 10 percent less than SPC, which is the second lowest busbar cost case. USCPC will have good environmental performance because of its high efficiency. Emissions of NO_x and PM will be very similar across all technologies. Sulfur emissions would be slightly lower for IGCC than the PC and CFB options, although start-up and shutdown flaring will reduce the potential benefit of IGCC. The lower expected reliability of IGCC, particularly in the first years of operation, could compromise FPL's ability to meet the baseload generation requirement and require FPL to run existing units at higher capacity factors.

For the 2012-2014 planning time period, USCPC will be the best technical and economic choice for the installation of 2,000 MW of capacity at the Glades site.

9.0 Contributors

This report was prepared collaboratively by Black & Veatch and FPL, as co-authors. Project team leads were David Hicks, Senior Director of Project Development, FPL, and Samuel Scupham, Technology Consultant, Black & Veatch Corporation. Messers Hicks and Scupham were supported in the preparation of this report by technical staff of their respective companies, to who they express their appreciation.

FGPP DEVELOPMENT MILESTONES

Milestone	Planned Dated	Actual Date
Glades County Site Plan Approval		9/11/2006
File PSD and UIC Applications		12/19/2006
File Site Certification and ACOE D/F Applications		12/22/2006
Need Filing	1/2007	
Land Use Hearing	4/2007	
Need Hearing	4/2007	
Need Order	6/2007	
Land Use Order	7/2007	
Certification Hearing	9/2007	
Final Certification Order	2/2008	

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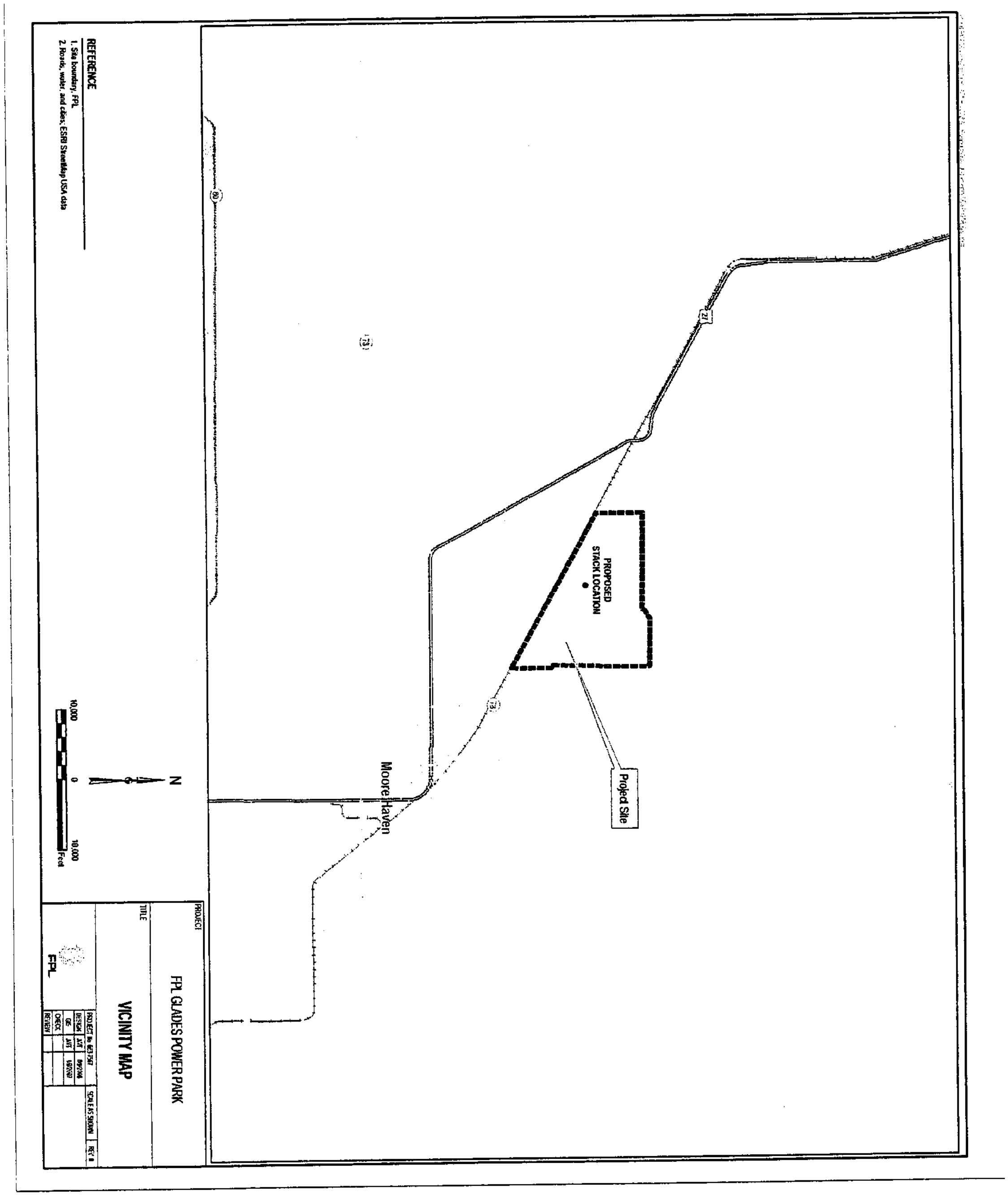
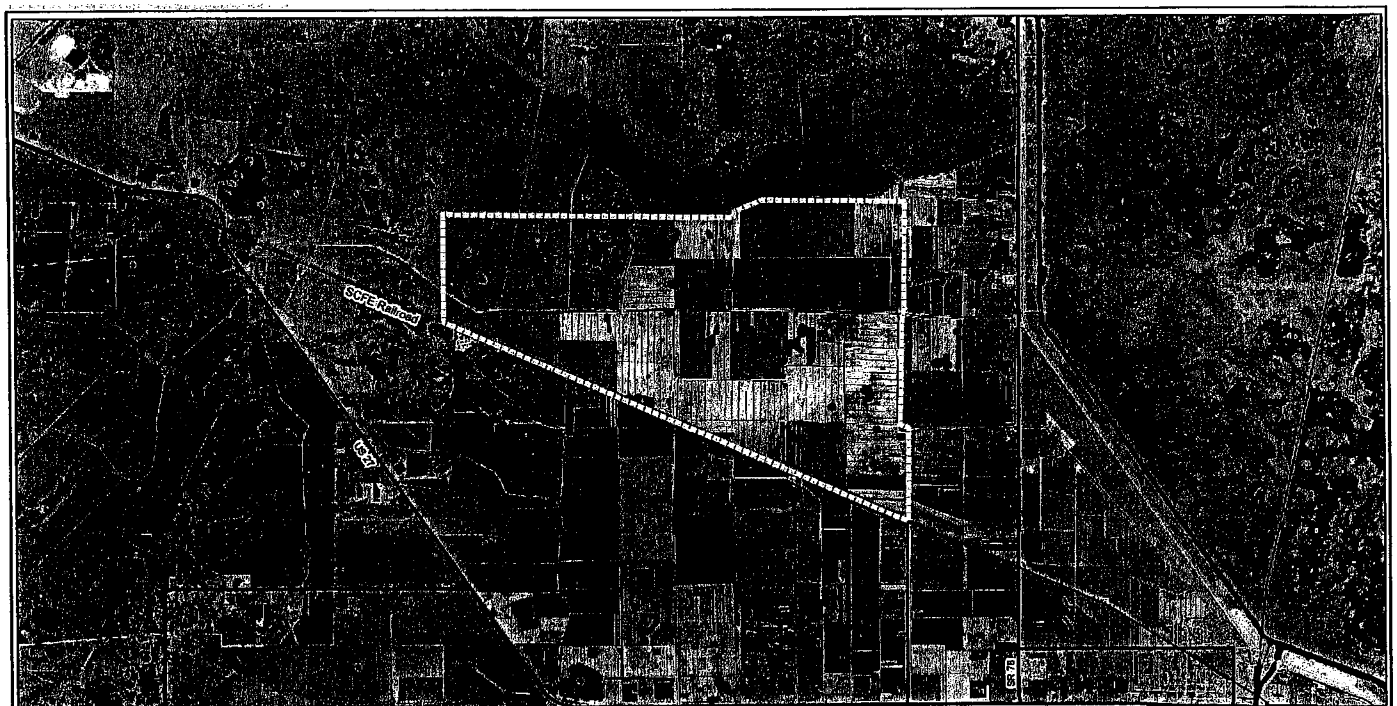
D. Hicks, Exhibit No.__
Document No. DNH-4, Page 1 of 1
Vicinity Map

VICINITY MAP OF PROPOSED GLADES POWER PARK



Docket No. 07______-EI
D. Hicks, Exhibit No.__
Document No. DNH-5, Page 1 of 1
Project Boundary Aerial

GLADES POWER PARK PROJECT BOUNDARY AERIAL



LEGEND

Site Boundary
— Major road
–+– Railroad

REFERENCE

1. Site boundary, FPL
2. Aerial photography, 2004 USGS Digital Ortho Quarter Quandrangles, LABINS www.labins.org
3. Major roads and railroads, FGDL

N

4,000 0 4,000 Feet

PROJECT

FPL GLADES POWER PARK

TITLE

PROJECT BOUNDARY AREA

FPL

PROJECT No. 063-7567			SCALE AS SHOWN	REV. 0
DESIGN	JMT	8/9/2006		
GIS	JMT	11/22/2006		
CHECK				
REVIEW				

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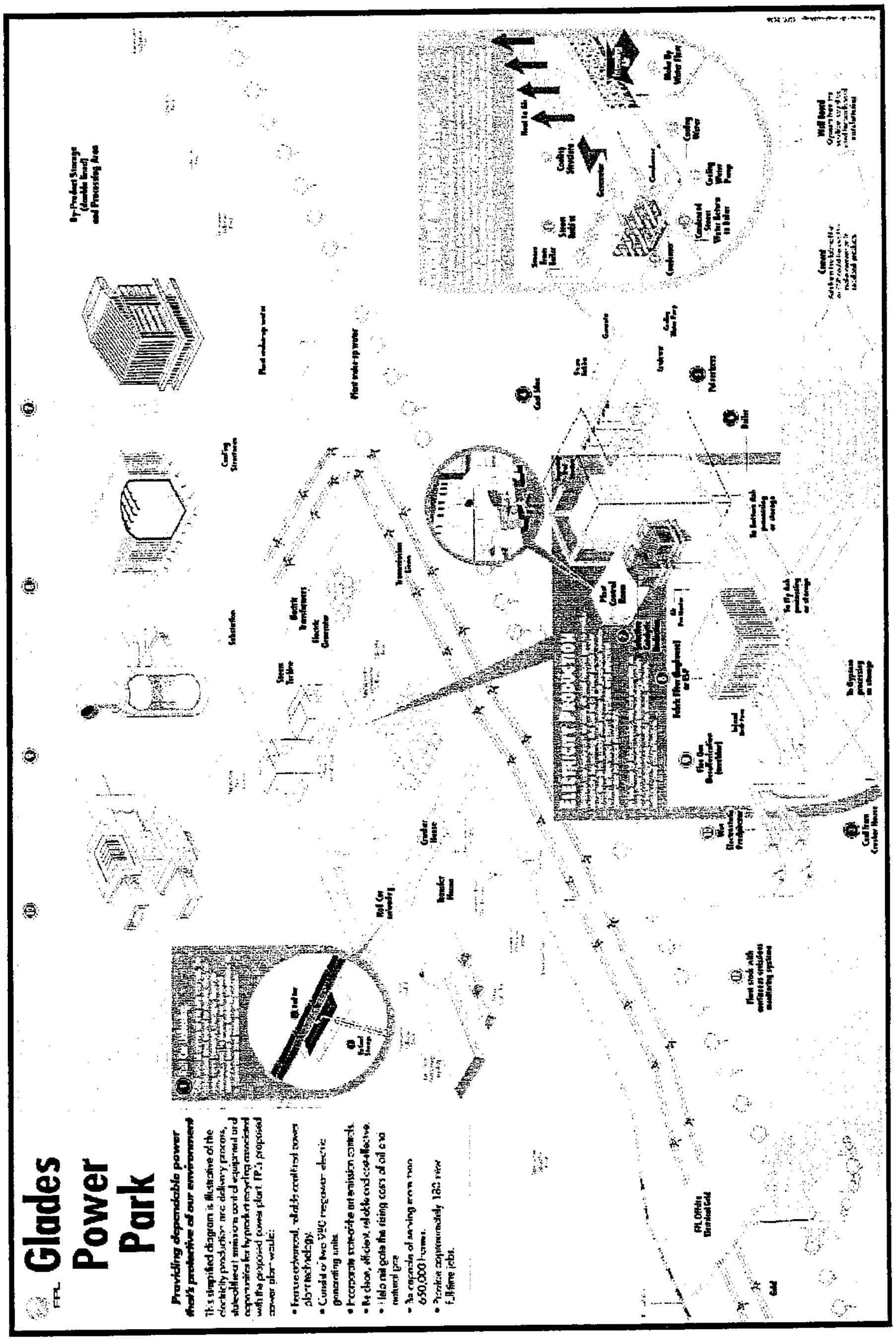
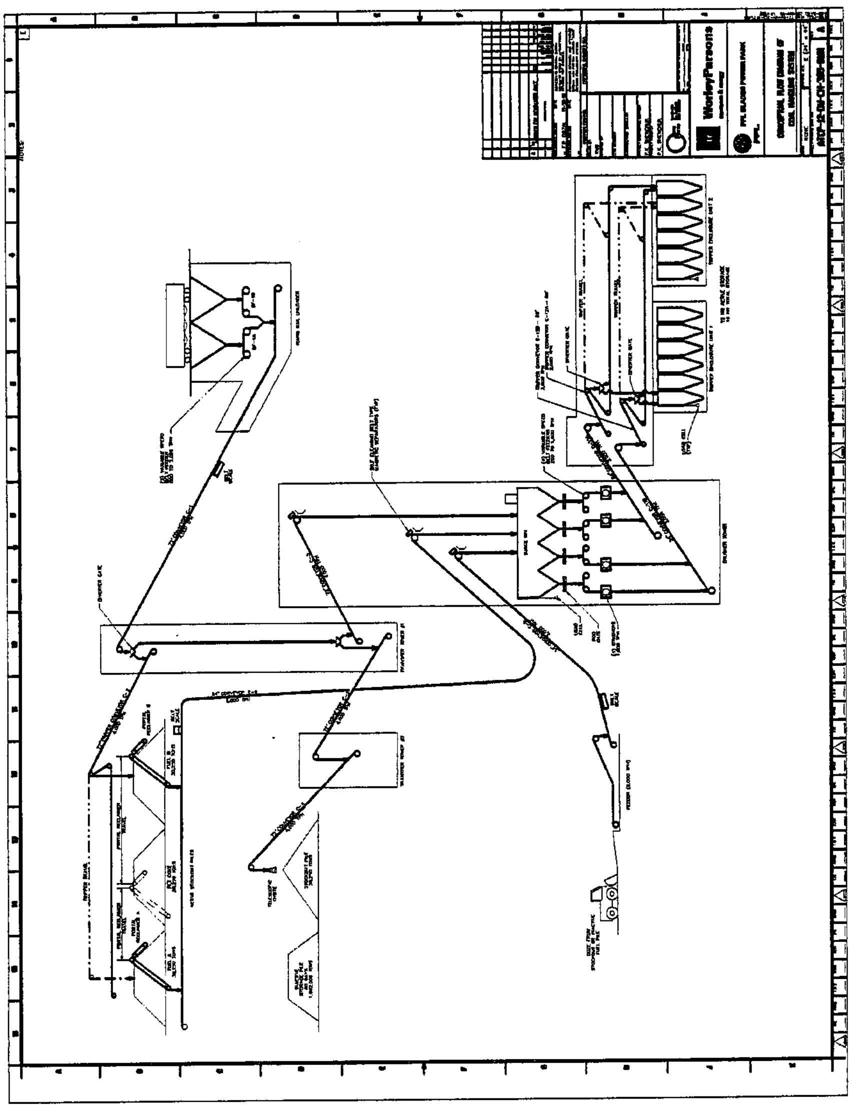
D. Hicks, Exhibit No.__
Document No. DNH-6, Page 1 of 1
Glades Power Park Process Diagram
Overview

GLADES POWER PARK PROCESS DIAGRAM OVERVIEW



Docket No. 07_____-EI
D. Hicks, Exhibit No.__
Document No. DNH-7, Page 1 of 1
Process Diagram Coal Handling System

GLADES POWER PARK PROCESS DIAGRAM COAL HANDLING SYSTEM



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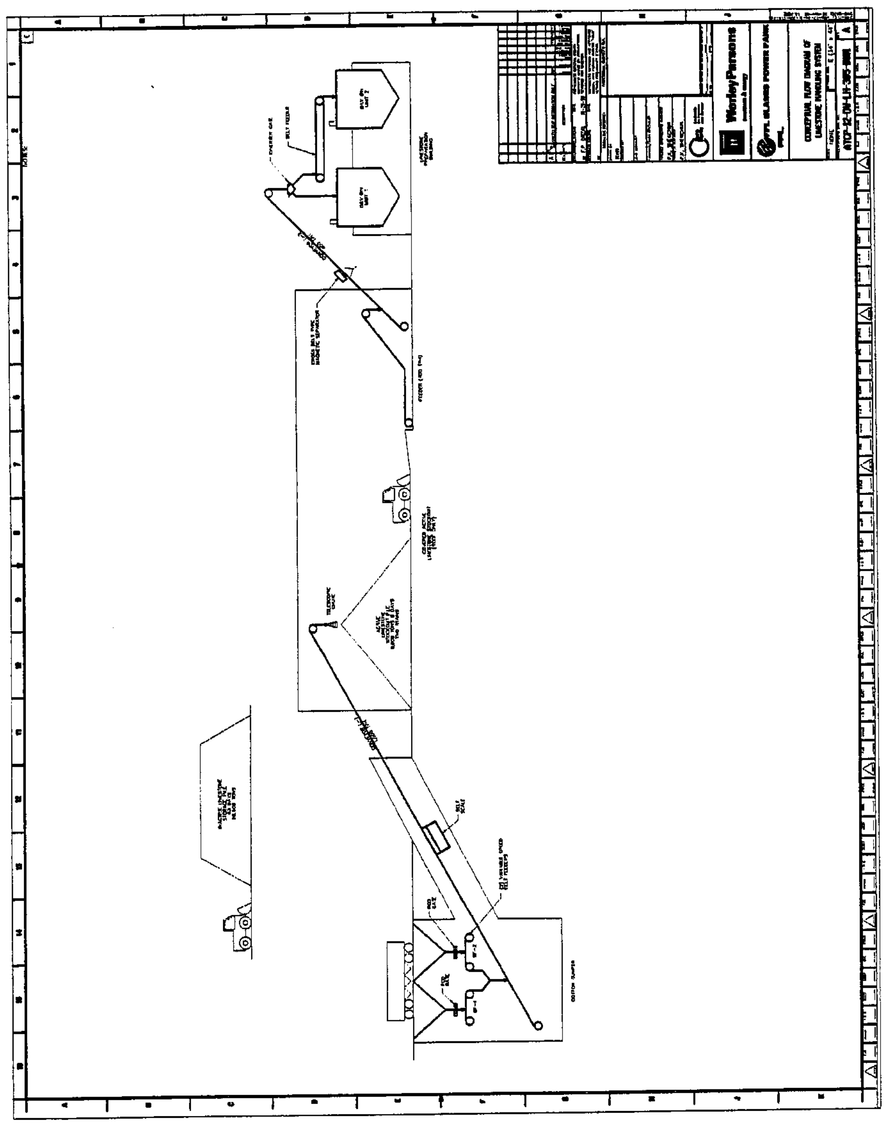
D. Hicks, Exhibit No.__
Document No. DNH-8, Page 1 of 1
Process Diagram Limestone Handling System

GLADES POWER PARK PROCESS DIAGRAM LIMESTONE HANDLING SYSTEM



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D. Hicks, Exhibit No.__
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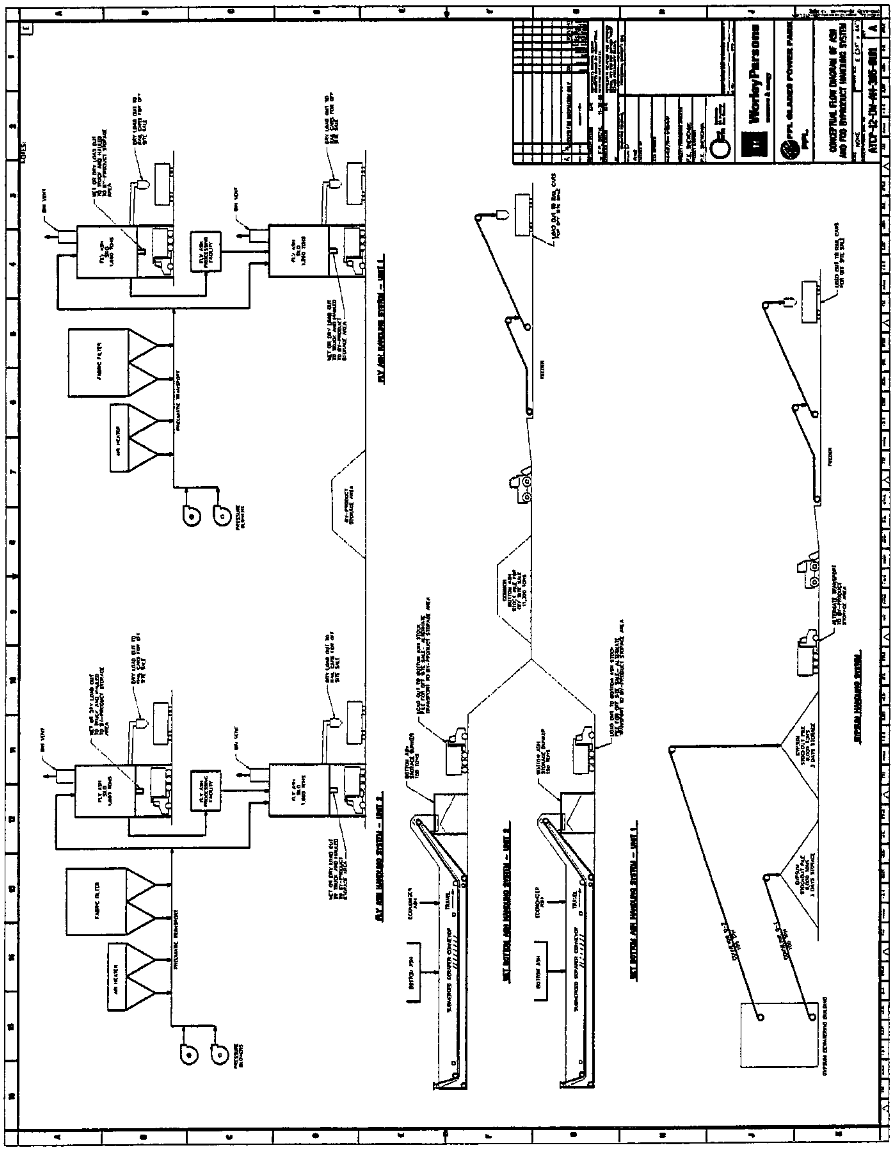
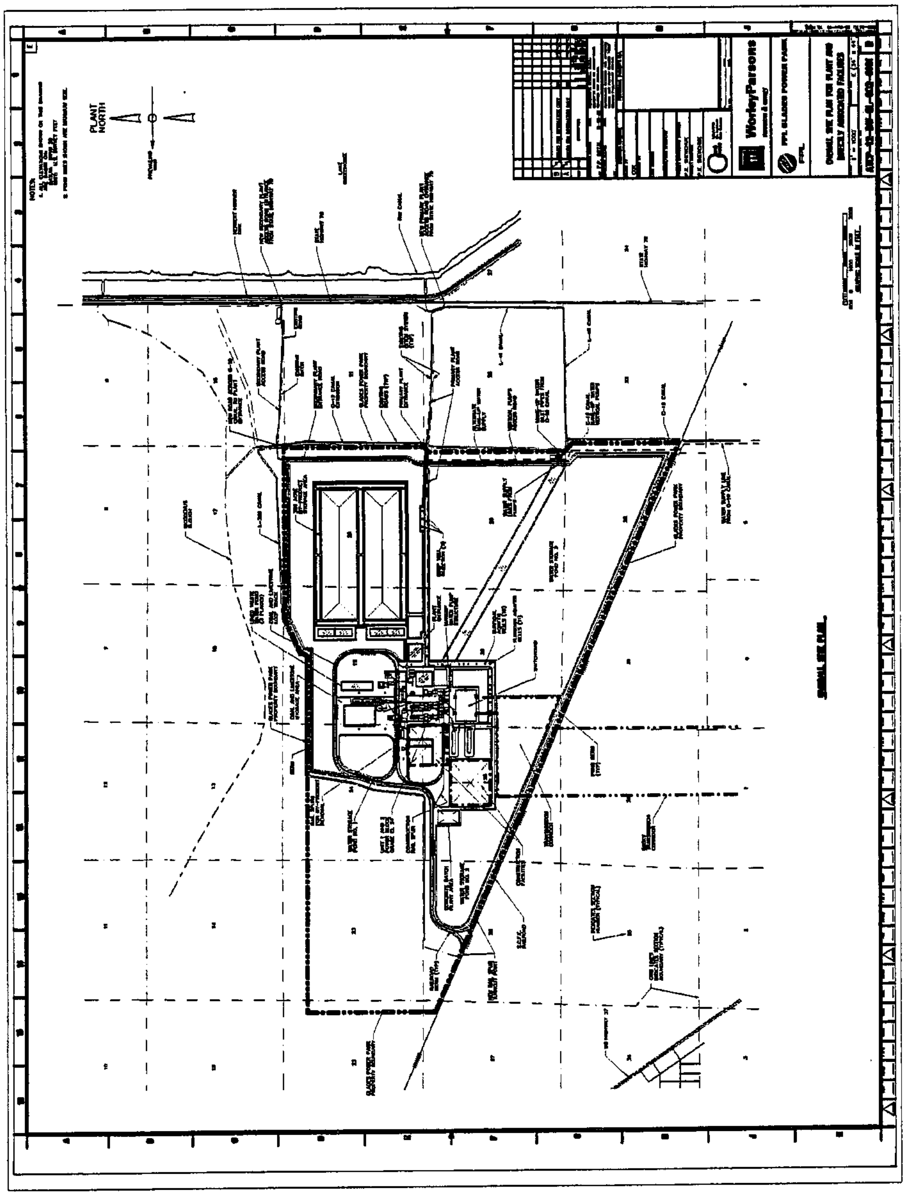
Process Diagram By Product Handling System

GLADES POWER PARK PROCESS DIAGRAM BY-PRODUCT HANDLING SYSTEM



Docket No. 07____-EI
D. Hicks, Exhibit No.__
Document No. DNH-10, Page 1 of 1
Site Plan Overall

GLADES POWER PARK SITE PLAN OVERALL



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D. Hicks, Exhibit No.__
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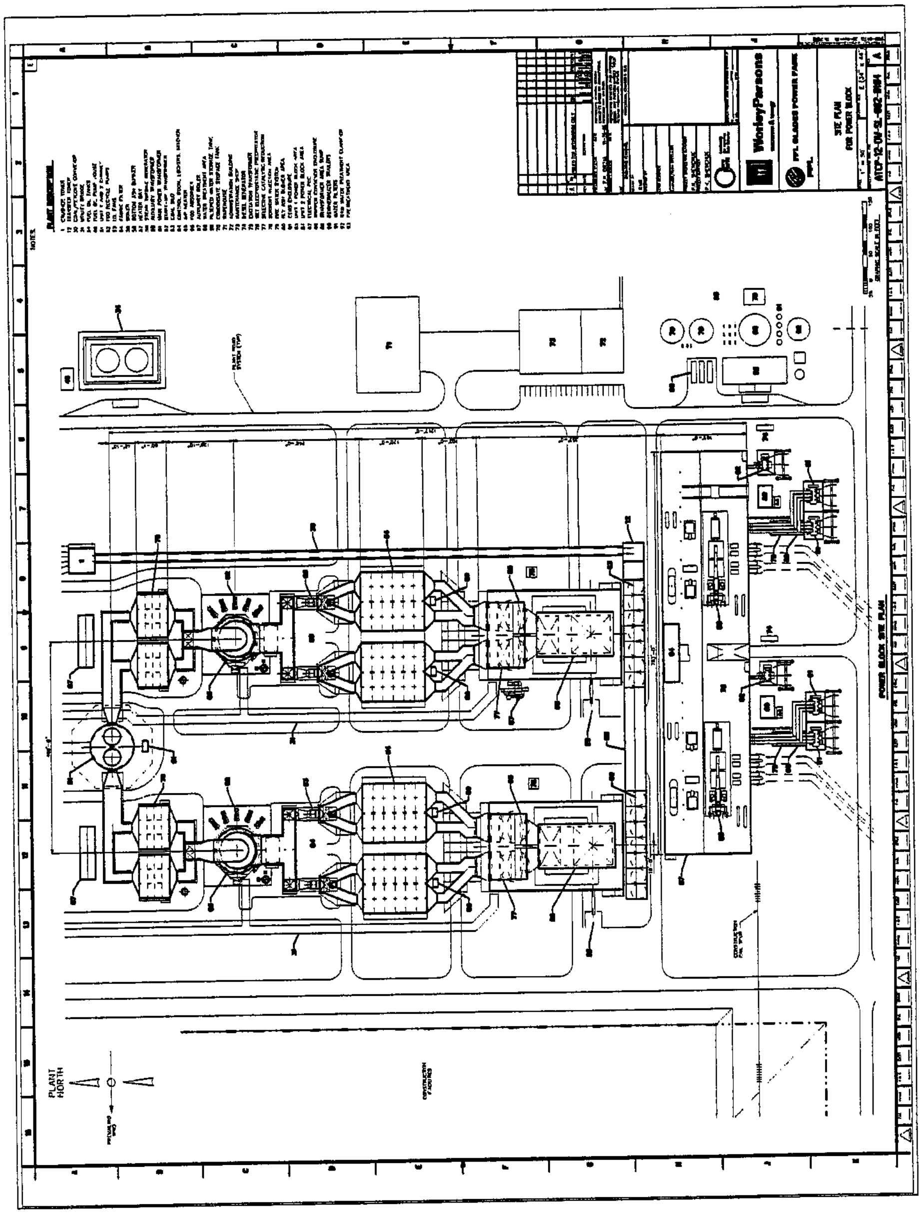
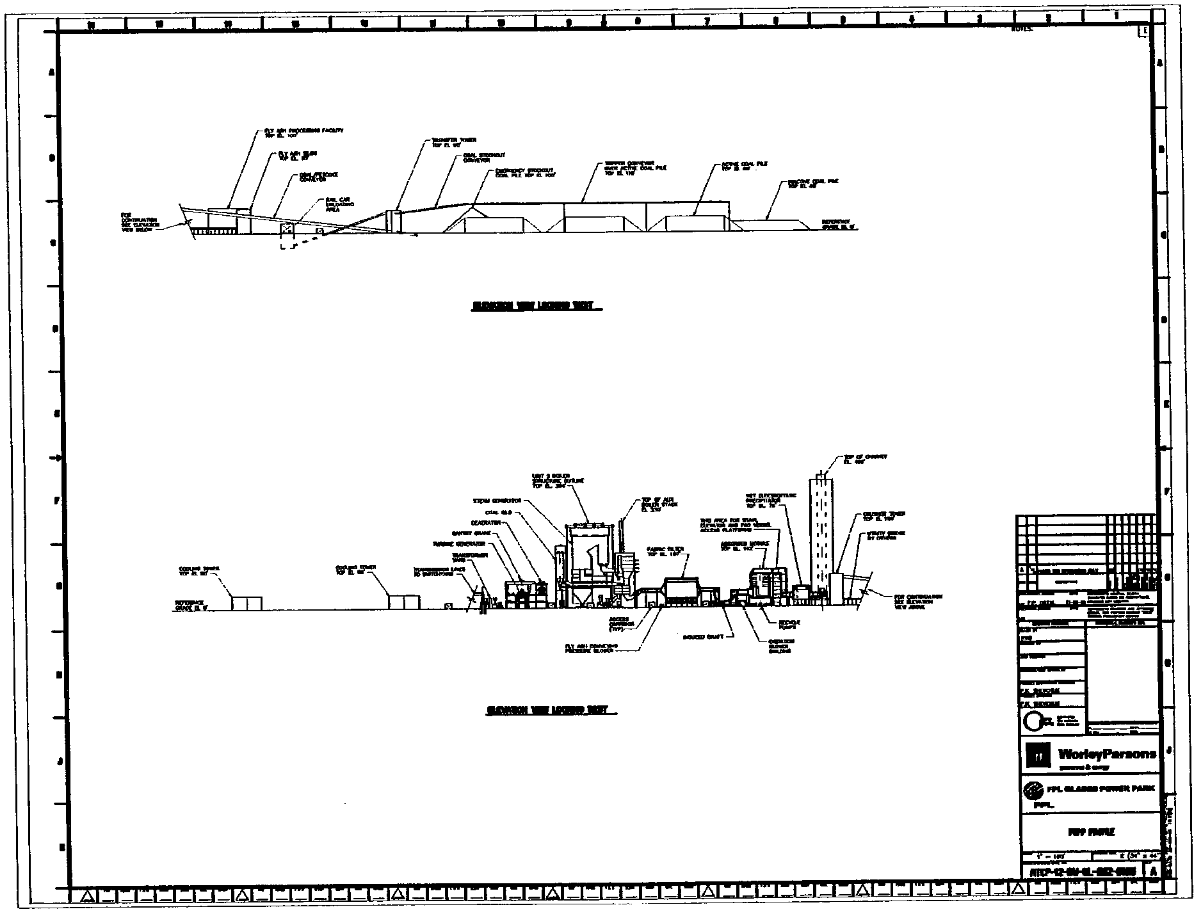
Site Plan Power Island

GLADES POWER PARK SITE PLAN POWER ISLAND



GLADES POWER PARK SITE PLAN TYPICAL ELEVATIONS



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Site Plan Typical Elevations

FGPP 1 AND 2 FACT SHEET

Generation Technology – Ultra-Supercritical Pulvarized Coal Steam Electric Generator:

- Two (2) 3700 # Coal Fired Steam Electric Generators (Boiler)
- Two (2) Single-Reheat Steam Turbine Generator
- Two (2) Mechanical Draft Cooling Towers
- Particulate Matter Environmental Controls- Two (2) Fabric Filter Baghouses
- Nitrogen Oxide Environmental Controls- Two (2) Selective Catalytic Reduction Systems
- Sulfur Dioxide Environmental Controls- Two (2) Wet Flue Gas Desulfurization Systems
- SAM and Fine Particulate Environmental Controls- Two (2) Wet Electric Static Precipitators

Expected Plant Peak Capacity:

Summer (95°F / 50% RH)	980 MW
Winter (35°F / 60% RH)	990 MW

Projected Unit Performance Data:

Average Forced Outage Rate (EFOR)	3.0%
Average Scheduled Maintenance Outages	2.6 wks/yr (5.0% POF)
Average Equivalent Availability Factor (EAF)	92%
Base Average Net Operating Heat Rate @ 75°F / 60% RH	8,800 Btu/kWh (HHV)
Annual Fixed O&M – average 2 Units (2013 dollars)	$28.02/kW-yr
Variable O&M –average 2 Units (2013 dollars) (excluding fuel)	$1.75/MWh

Fuel Type and Base Load Typical Usage @ 75°F:

Primary Fuel	Coal
Alternate Fuel	Petroleum Coke (up to 20%)
Maximum Heat Input	8,700 mmbtu/hr/Unit

Expected Base Load Air Emissions Per Train @ 75°F:

NO_x	0.05 lb/mmBtu
CO_2	205 lb/mmBtu
Hg	1.2×10^{-6} lb/mmBtu
SO_2	0.04 lb/mmbtu

Water Balance:

- Annual average consumptive use for FGPP 1 and 2 is approximately 30 MGD.
- Wastewater deep well injected

Linear Facilities:

- One (1) Off-Site Transmission Sub-Station
- Approximately 170 Circuit Miles of 500 kV Transmission

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Overall Water Balance

GLADES POWER PARK OVERALL WATER BALANCE