060220-EC

SEMINOLE ELECTRIC COOPERATIVE, INC.

Petition to Determine Need for

Electric Power Plant

March 2006

Direct Testimony of:

Richard Klover

Seminole Electric

IN PARTNERSHIP WITH THOSE WE SERVE

060220-EC

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

SEMINOLE ELECTRIC COOPERATIVE, INC.

DIRECT TESTIMONY OF RICHARD KLOVER

DOCKET NO. 06____-EU

MARCH 10, 2006

Q. **Please state your name and business address.**

A. My name is Richard Klover. My business address is 9400 Ward Parkway, Kansas City, Missouri 64114.

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

A. I am employed by Burns & McDonnell Engineering Company, Inc. as Senior Project Manager in the Energy Division.

Q. Please describe your duties and responsibilities in that position.

A. I am responsible for managing the evaluation, design, procurement, construction management, and startup and testing of power generation facilities.

Q. Please describe your educational background and business experience.

A. I graduated from Kansas State University with a Bachelor of Science Degree in Mechanical Engineering in 1987. I have 18 years of experience in the evaluation, design and construction of power generation projects. I have been involved with several large coal fired projects, including serving as the on-site startup engineer for two units and project manager for two others. In addition, I have been involved in the development and evaluation of numerous coal fired projects. A more detailed description of my experience is in my Exhibit RAK-1.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe Burns & McDonnell's experience and role in the evaluation, design, procurement, construction, startup and testing of SGS Unit 3, to describe the feasibility studies and the technology assessment study that Burns & McDonnell performed to assist Seminole in deciding to build SGS Unit 3, and to describe the construction schedule for SGS Unit 3. In addition, I will provide a brief description of the operational characteristics of SGS Unit 3.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring the following exhibits:

Exhibit RAK-1	Summary of Richard Klover's Experience
Exhibit RAK-2	Summary of Burns & McDonnell Steam Electric Power Station Experience
Exhibit RAK-3	Seminole Generating Station 650 MW Solid Fuel Fired Unit Feasibility Study, dated August 2004
Exhibit RAK-4	Seminole Generating Station 750 MW (Net) Solid Fuel Fired Unit Feasibility Study, dated February 2005
Exhibit RAK-5	Seminole Generating Station Technology Assessment Study dated March 2005

Exhibit RAK-6	SGS Unit 3 Steam Cycle
Exhibit RAK-7	SGS Unit 3 Fact Sheet
Exhibit RAK-8	SGS Unit 3 Expected Construction Schedule

Q. Are you sponsoring any part of the Need Study in this proceeding?

A. Yes. I sponsor Section IV.H and co-sponsor Section IV.C of the Need Study.

I. BURNS & MCDONNELL'S EXPERIENCE

Q. Please describe Burns & McDonnell's experience and capabilities with respect to the evaluation, design and construction of coal fired power plants.

A. Burns & McDonnell currently employs over 2,000 people. Over the last 30 years, Burns & McDonnell has been involved in over 10 gigawatts (i.e., 10,000 MW) of coal fired generation in varying capacities. Burns & McDonnell is currently involved in over 5 gigawatts of new supercritical coal fired generation projects. Burns & McDonnell's most recent pulverized coal design experience was for Hawthorn 5, a 550 MW unit for Kansas City Power & Light. A detailed summary of Burns & McDonnell's experience with coal fired generation is contained in my Exhibit RAK-2.

Q. What is Burns & McDonnell's experience with cooperatives and RUS financed projects?

A. Burns & McDonnell has been serving electric cooperatives since the 1930s. We have provided services to over 25 electric cooperatives and have been involved in over

3,500 MW of coal-fired Rural Utilities Service (RUS) financed projects for cooperatives. Burns & McDonnell is an RUS approved supplier for engineering and management services to support RUS on review of applications for financial assistance and other approvals required of RUS.

Q. What is Burns & McDonnell's role in the SGS Unit 3 project?

A. Burns & McDonnell is involved with Seminole's SGS Unit 3 self build project in two principal capacities. Initially, we were retained by Seminole to assist in evaluating the technical and economic feasibility of alternative technologies for SGS Unit 3. This role led to the preparation of the 650 MW Solid Fuel Fired Unit Feasibility Study dated August 2004 (Exhibit RAK-3; the "August 2004 Feasibility Study"), the 750 MW (Net) Solid Fuel Fired Unit Feasibility Study dated February 2005 (Exhibit RAK-4; the "February 2005 Feasibility Study"), and the Technology Assessment Study dated March 2005 (Exhibit RAK-5; the "Technology Assessment"). Once Seminole decided to proceed with SGS Unit 3, Burns & McDonnell was also retained to provide detailed design, procurement, construction management and startup services to Seminole.

Q. Please describe your personal role in the SGS Unit 3 project.

A. I was the project manager for the August 2004 Feasibility Study, the February 2005 Feasibility Study and the Technology Assessment Study. I am now the project manager for SGS Unit 3.

II. FEASIBILITY STUDIES AND TECHNOLOGY ASSESSMENT

Q. What was the purpose of the feasibility and technology assessment studies that Burns & McDonnell performed for Seminole?

A. When Seminole decided that it would solicit bids for the purchase of needed capacity in the 2012 time frame, it first had to evaluate carefully what would be the most appropriate self-build alternative. As part of that evaluation process, Seminole asked Burns & McDonnell to bring its experience to bear on assisting Seminole in selecting the appropriate technology and providing a detailed, screening level evaluation of the cost of building and operating the preferred alternative. This request initially led to the preparation of the August 2004 Feasibility Study.

After Seminole had decided to self build, it considered whether it would be better served by building a 750 MW (net) unit rather than building a 600 MW (net) unit and purchasing 150 MW of capacity as it originally explored. Burns & McDonnell was asked to update the August 2004 Feasibility Study for the larger unit size, which led to the preparation of the February 2005 Feasibility Study. Finally, because there are multiple, complex and competing considerations involved in the selection of pulverized coal boiler technology, Burns & McDonnell was asked to perform the Technology Assessment, which addressed the relative merits of supercritical and subcritical boiler technology for SGS Unit 3.

Q. Please briefly describe the August 2004 Feasibility Study and the conclusions that it reaches.

A. The August 2004 Feasibility Study presents the results of pro forma economic analyses of three alternative self-build projects: a new brownfield 600 MW (net) subcritical solid fuel generating unit; a new brownfield 600 MW (net) supercritical solid fuel generating unit; and a new greenfield 500 MW (net) gas fired combined cycle unit. Burns & McDonnell also provided an assessment of a 600 MW (net) integrated gasification combined cycle ("IGCC") plant and recommended that the technology not be considered for new generation at this time due to insufficient operational experience and information on the cost and reliability of the technology. The pro forma economic analysis compared the 20-year levelized busbar cost for the three viable alternatives and found that the cost for the supercritical unit was the lowest at \$52.77/MWh, followed closely by the subcritical unit at \$52.97/MWh, with the combined cycle unit considerably more expensive at \$75.48/MWh.

To develop the economic analysis, the August 2004 Feasibility Study focused on a detailed, screening level identification of the necessary components, and the cost, performance and environmental impacts, for supercritical and subcritical units. The study concluded that both types of units were feasible. It further advised that Seminole needed to begin preliminary engineering in 2005 in order to meet the 2012 planned in-service date and that Seminole could benefit economically by increasing the size of the unit because of economies of scale. The study did not recommend that

Seminole choose either supercritical or subcritical technology, but Appendix A to the August 2004 Feasibility Study provided Seminole with a brief comparison of the technologies and their operating histories, performance, environmental impacts and economics.

Q. Why did Burns & McDonnell conclude that IGCC is not yet a sufficiently proven technology?

A. Appendix C to the August 2004 Feasibility Study contains a detailed assessment of the IGCC technology. Burns & McDonnell saw two principal areas of concern with the current generation of IGCC technology. The first was unit availability. Burns & McDonnell identified several issues that have prevented IGCC units from achieving acceptable availability levels: fouling within the synthetic gas cooler; design of the pressurized coal feeding system; molten slag removal from the pressurized gasifier; limited durability of the gas clean-up equipment; and solid particulate carryover to the combustion turbines, resulting in accelerated erosion of their internals. The second area of concern related to the limited operational flexibility of IGCC plants, which have longer cold start-up times than conventional pulverized coal units, on the order of ten times as long. IGCC plants also have limited ability to load-follow.

Q. Please briefly describe the February 2005 Feasibility Study.

A. As I stated earlier, this study was essentially an update of the August 2004 Feasibility Study to address Seminole's interest in increasing the output of the SGS Unit 3 project from 600 MW (net) to 750 MW (net). The study concluded that both the supercritical and subcritical units were feasible and would be substantially more economically sized at 750 MW than at 600 MW (the 20-year levelized busbar cost declined from $51.84/MWh to $48.85/MWh for the supercritical unit, and from $52.08/MWh to $49.15/MWh for the subcritical unit.) Both remained far preferable to a conventional gas fired combined cycle unit.

The February 2005 Feasibility Study also addressed in more detail the relative merits of supercritical vs. subcritical technology. It concluded that supercritical technology would be more fuel efficient and hence have lower air emissions and, because of the lower emissions, would face fewer permitting hurdles than subcritical technology. The study pointed out, however, that there is limited experience in operating supercritical units at elevated steam cycle temperatures on a fuel mix containing high sulfur coals and up to 30% pet coke as Seminole intends to burn and thus concluded that the subcritical technology would be preferable from an experience and operational reliability standpoint.

Q. What is the difference between supercritical and subcritical technology?

A. In supercritical technology, the steam that drives the turbine generator is generated at pressures high enough that water converts directly to steam without two phase fluid existing. Supercritical technology is thus designed for once-through steam generation in the boiler, whereas subcritical technology employs a steam drum to separate steam from the water before the steam is superheated and flows to the turbine generator. A supercritical steam cycle provides improved plant efficiency but tends to have slightly higher initial capital costs and more operating complexities.

Q. What was the purpose of the Technology Assessment?

A. Seminole was attracted to the benefits of the supercritical technology but concerned about the operational reliability issues raised in the February 2005 Feasibility Study. Therefore, it asked Burns & McDonnell to dig deeper into the available operational history on supercritical technology and provide more detailed advice on the two technologies.

Q. Please briefly describe the results of the Technology Assessment.

A. Burns & McDonnell found that, while the operational reliability of the early supercritical plants in the U.S. (i.e., those built in the 1950's and 1960's) had been less than expected, plants built later in Asia and in Western Europe had been redesigned to overcome most of those limitations. The impact of these improvements on operational reliability is captured in Figure 2.2 of the Technology Assessment, which plots the equivalent forced outage rate (EFOR) for supercritical units and subcritical units over the period from 1982 to 1997. Figure 2.2 shows that the EFOR for supercritical units was significantly higher than for subcritical units in the early 1980's, but has converged to the point that the EFOR for the two technologies is essentially identical in 1997.

As a result of these operational improvements, supercritical technology has become strongly favored in Asia and Europe. For example, the majority of fossil fired power plants built in Japan since 1967 that are larger than 500 MW use supercritical technology. Similarly, of the 20,000 MW of coal fired capacity installed in Europe between 1995 and 2000, approximately 85% uses supercritical technology. The main area of remaining concern over the operational reliability of supercritical coal-fired units relates to the use of corrosive (i.e., high sulfur) coal and pet coke as fuels. Supercritical boilers are more susceptible to corrosion damage from those fuels than subcritical boilers. The most recent designs of supercritical boilers are intended to address this issue, however, and Burns & McDonnell is involved in a project where the manufacturer of the supercritical boiler has stated that availability comparable to subcritical boilers can be achieved even with corrosive fuels by increasing preventive maintenance and inspections of the boiler water walls, superheater and reheater.

Q. As you are aware, Seminole ultimately chose supercritical technology for SGS Unit 3. Do you believe that this was a reasonable choice?

A. Yes. As is evident in the Technology Assessment, there are pros and cons to both supercritical and subcritical technologies. However, Seminole is certainly in the mainstream of a worldwide trend toward using the current generation of supercritical technology, which has addressed the operational reliability concerns of earlier generations of supercritical units while retaining the economic and environmental advantages that supercritical technology can offer.

III. UNIT CHARACTERISTICS

Q. Please describe the coal fired technology that will be used for SGS Unit 3.

A. SGS Unit 3 will utilize a supercritical pulverized coal boiler that will supply high pressure steam at a nominal 3700 psi and 1050 degrees F to the high pressure steam turbine and will supply hot reheat steam at 1050 degrees F to the intermediate steam turbine. SGS Unit 3 will be designed to burn high sulfur bituminous coal in combination with petcoke and will utilize the following state of the art emission controls:

- Low NO_x Burners and Staged Combustion / Overfire Air (OFA) for NO_x control.
- Selective Catalytic Reduction (SCR) for NO_x control.
- Electrostatic Precipitator (ESP) for particulate (PM) control.
- Wet Flue Gas Desulfurization (WFGD) for SO_2 control.
- Wet ESP for sulfuric acid mist (H_2SO_4) control.
- Mercury removal through application of the above technologies

Q. Please describe the steam cycle for SGS Unit 3.

A. SGS Unit 3 will utilize the steam cycle depicted in Exhibit RAK-6. Condensate pumps will take condensate from the condenser and pump the water through four low pressure feedwater heaters to the deaerator. The boiler feed pumps take suction from the deaerator and pump the water through three high pressure feedwater heaters to the boiler. The boiler feedwater enters the boiler through the economizer to recover heat from the combustion gases exiting the boiler. Downstream of the economizer, the heated feedwater is directed to the water wall circuits enclosing the furnace. After passing through the lower and then the upper radiant walls, the fluid passes through the convection enclosure circuits to become steam, and then is superheated in the superheater section of the boiler.

The steam then exits the boiler to the high-pressure (HP) section of the steam turbine at an inlet temperature of 1,050°F. As the steam energy is converted to shaft power in the HP section of the steam turbine, its temperature and pressure are reduced.

The cooled and lower pressure steam exits the HP section and returns to the reheater section of the boiler, where the steam temperature is raised back up to the expected intermediate-pressure (IP) turbine inlet temperature of 1,050°F. This step is called reheat, and it is used to increase the efficiency of the steam cycle. The steam then returns to the IP section of the steam turbine where again the steam energy is further converted to shaft power as its temperature and pressure drops. From the IP section, the steam is directed to the low-pressure (LP) section of the steam turbine, where the steam further expands to convert additional energy to the turbine shaft power that drives the electric generator. Steam exhausts from the LP section of the steam turbine to the condenser, where the steam is condensed back to liquid phase water. Cooling water from the condenser is circulated through a mechanical draft cooling tower before returning to the condenser.

Q. What are the expected operational performance parameters of SGS Unit 3?

A. The projected net plant heat rate for SGS Unit 3 is 9,000 Btu/kWh at average ambient conditions of 71° F dry bulb temperature and a relative humidity of 80%. SGS Unit 3 will also be designed to operate with the top feedwater heater out of service, which can provide approximately 33 MW of additional capacity at average ambient conditions. Additional information on the expected operational performance for SGS Unit 3 is contained in the fact sheet that is my Exhibit RAK-7.

IV. PROJECT COST AND SCHEDULE

Q. Has Burns & McDonnell estimated the capital cost of SGS Unit 3?

A. Yes. As part of the February 2005 Feasibility Study, we estimated the cost of building a 750 MW pulverized coal project adjacent to the existing units at the Seminole Generating Station. Table 5-1 of Exhibit RAK-5 shows the estimated cost of each principal component of the project and the total estimated capital cost of approximately $1,200,000,000 in 2012 dollars (excluding interest during construction, and certain other owner's costs to be incurred by Seminole). This estimate reflects cost escalation of certain major cost components at the rate of 2.5% per year to the mid-point of the construction schedule in 2010, which serves as a proxy for the average escalation on plant components that will be purchased at various times throughout the construction schedule.

Q. What is the proposed project schedule for SGS Unit 3?

A. Seminole will commence construction upon receipt of the necessary federal and state certifications and/or permits. The expected construction duration for SGS Unit 3 is approximately 42 months and is comparable to other coal fired projects of similar size. This means that, in order to achieve the planned commercial operation date of May 2012, construction needs to commence on or before October 2008. A summary of the construction milestone dates is shown in Exhibit RAK-8.

Q. Do you believe that this schedule is reasonable and achievable?

A. Yes, it is.

Q. Does this conclude your testimony?

A. Yes.

Summary of Richard Klover's Experience

Mr. Klover is the Project Manager for SGS Unit 3. He has a broad background in project development, detailed design, procurement, construction, startup and project management of coal fired power plants.

Mr. Klover recently was involved in the preparation of the EPC proposal for the 650 MW coal fired power plant at the Nebraska City Power Station for Omaha Public Power District in Nebraska City, NE. The project consisted of a subcritical pulverized coal boiler, SCR, dry scrubber and baghouse burning PRB coal.

Mr. Klover was involved in the development and permitting for the 275 MW coal fired power plant at the Southwest Power Station for City Utilities of Springfield, Mo. He also served as Proposal Manager on the EPC proposal for a 90 MW coal fired power plant for Corn Belt Energy Generation Cooperative.

Mr. Klover served as Project Manager on the Qitaihe Power Plant Project, a 2 x 350 MW coal-fired unit for Heilongjiang Electric Power Company in China. He was responsible for the detailed design of the steam turbine island for the project, coordination with the owner at design liaison meetings and involved in the procurement of Chinese equipment and materials.

Mr. Klover has been involved with several large coal fired projects. Mr. Klover served as project mechanical engineer on the Powder River Basin coal conversion project at the Associated Electric Cooperative; 2 x 600 MW New Madrid Power Plant. He was responsible for the preparation of the ash handling, coal handling, cyclone boiler modifications and construction contracts.

For the Old Dominion/Virginia Power Clover Project, a 2 x 440 MW pulverized coal power plant in Virginia, Mr. Klover served as the Mechanical Engineer during design and then as an on-site Start-up Engineer for the owner, responsible for the startup of all plant equipment and systems, including the boiler, turbine, water treatment, baghouse, and wet scrubber.

Additional coal-fired project experience includes:

Client	Services Performed
Minnkota Power Cooperative and Minnesota Power	Feasibility Study.
NIPSCO	ID Fan Replacement Study.
PSI Energy	Boiler improvements.
Kansas City Power & Light Company	Feasibility Study.
Crawfordsville Electric Light & Power	Coal Yard Runoff System.
Wisconsin Power & Light	Technology Assessment Study.

Summary of Burns & McDonnell Steam Electric Power Station Experience

Client Name & Location	Unit Name	MW	Fuel	Boiler	Turbine	Operation Date	Scope of Services
TXU Power	Oak Grove Units 1 & 2	860 MW 860 MW	Lignite	TBD	TBD	2010/2011	Condition Assessment, Conceptual Engineering, Owner's Engineer, EPC Specifications, EPC Negotiations, Contract Administration, Construction Management
City Water Light & Power, Springfield, IL	Dallman Unit 4	220MW	Coal	TBD	TBD	2011	Owner's Engineer, EPC specifications negotiations
Seminole Electric Coop., Inc. Palatka, FL	Seminole Generating Station Unit 3	750 MW	Coal 70/30 Blend Bit/Pet	TBD	TBD	May 2012	Life Cycle Assessment, Feasibility Study, Preliminary Engineering, Permitting Support, Detailed Design, Construction Management Startup/Commissioning
Kansas City Power & Light Kansas City, MO	Hawthorn 5	500 MW	Coal PRB	B&W	Existing GE 2520 P/1000F	Full load operation, June 22, 2001	Engineer and permitting for replacement of boiler and air pollution control equipment after major boiler explosion.
Western Farmers Electric Corp. Hugo, OK	Hugo 2	750MW	Coal PRB	TBD	TBD	2010	Owner;s Engineer, Project Definition, Siting Study, Dev. Support, Conc. Design, Detailed Cost Estimate, Permitting/Env. Feasibility EPC spec and negotiations, Contract Administration, Construction Management

Exhibit RAK-2
Page 1 of 9

Summary of Burns & McDonnell Steam Electric Power Station Experience

Client Name & Location	Unit Name	MW	Fuel	Boiler	Turbine	Operation Date	Scope of Services
MidAmerican Energy	Council Bluffs Unit 4	790 MW	Coal	Hitachi	Hitachi	2007	Owner's engineer, interface engineering, CM
Peabody Energy	Thoroughbred Unit 1 Unit 2	750 MW 750 MW	Coal Coal	Alstom	Alstom	TBD	Owner's Engineer
Kansas City Power & Light	Iatan Unit 2	750MW	Coal PRB	TBD	TBD	2010	Engineer for design of new coal-fired plant, permitting support, project definition
City of Public Service San Antonio, TX	JK Spruce 2	600MW	Coal	TBD	TBD	2009	Owner's Engineer, Conceptual design study, impact on existing units, EPC Contract, EPC Negotiation, EPC Contract Administration
Tanjung Bin Power Sdn Bhd. Johore, Malaysia	Tanjung Bin Units 1, 2, 3	3 x 700 MW	Coal	IHI	Toshiba 166 bars/538°C	2007/2008	Independent Engineer, Technical assessment, monthly site visits and progress reports to project financers.
Otter Tail Power (Big Stone II Partners)	Big Stone Unit II Big Stone City, SD	600 MW	Coal	TBD	TBD	2008/2009	Technology assessment, project cost estimate and economics, project development services, project scheduling, conceptual engineering, permitting, assist in joint ownership contracting

Exhibit RAK-2
Page 2 of 9

Summary of Burns & McDonnell Steam Electric Power Station Experience

Client Name & Location	Unit Name	MW	Fuel	Boiler	Turbine	Operation Date	Scope of Services
Tractebel – Mississippi, USA	Red Hills 1	500 MW	Lignite	2 – CFB, Stein (Alstom)	Toshiba 2400P/1000F	2001	Permitting, technical assistance, turnkey bid documents, evaluation, contract negotiation, design review, const. Monitoring.
Peabody Energy	Prairie State Energy Campus	2 x 750MW	Coal	TBD	TBD	TBD	Owner's Engineer, Development engineering support, Support Boiler and Turbine Procurement, Support Owner w/Contract Negotiations
Dominion Energy	Upshur County	450 MW	Coal	CFB	TBD	2005	Engineer for feasibility study, permitting support, EPC spec, cost estimate, bid evaluation, Owner's Engineer.
Louisville Gas & Electric Co. Louisville, KY	Trimble Unit 2	750 MW	Coal	TBD	TBD	TBD	Engineering for feasibility study, cost estimates, and conceptual design. Also preparatory BACT analysis for permitting efforts.
Reliant	Seward Project	500 MW	Waste Coal	2-CFB Alstom	Alstom 2400P/1000F	2004	Engineer for EPC Spec, cost estimate, bid evaluation, Owner's Engineer.
Sunflower Electric Power Corporation Hays, KS	Holcomb Unit 2	400 MW	PRB Coal	PC Unit Vendor TBD	TBD	TBD	Dev. Support, Fatal Flaw Review, Env./Air Permitting Unit 1 impact study

Exhibit RAK-2
Page 3 of 9

Summary of Burns & McDonnell Steam Electric Power Station Experience

Client Name & Location	Unit Name	MW	Fuel	Boiler	Turbine	Operation Date	Scope of Services
Mid-American Power, LLC Green Bay, WI	Stoneman II	250 MW	PRB Coal	PC Unit Vendor	TBD	2006	Owner engineering, Permit support.
Wisconsin Public Service Corporation	TBD	500 MW	PRB Coal	TBD	TBD	2007	Full Permitting Technical, feasibility, and capital cost study.
Rapids Power, LLC (Minnesota Power)	Rapids Power Unit 1	250 MW	Coal, Wood	CFB	TBD	2006	Conceptual design, detailed cost estimate.
City of Springfield, IL	New Generation	220 MW	Bit.	TBD	TBD	2010	Siting Study, Dev. Support, Conc. Design, Detailed Cost Estimate Permitting/Env. Feasibility
Nations Energy, Mexico	Sabinas 1	180	Coal	Lurgi	Siemens	2001	Owner's Engineer.
General Electric, China	Qitaihe 1 Qitaihe 2	350 350	Coal Coal	N/A N/A	General Electric TC/2F33 2400P/1000F	2000 2001	Detailed design of turbine island, equipment spec, procurement assistance.
Old Dominion Electric Cooperative - Richmond, VA	Clover 1 Clover 2	424 424	Coal Coal	CE Balanced Draft	Westinghouse TC/2F35 2400P/1000F	1995 1996	Turnkey spec., bid, contract negotiation, design compliance review, construction monitoring.
South Carolina Electric & Gas – Columbia, SC	Unit 1	350	Coal	CE Balanced Draft	Westinghouse TC/2F35 2400P/1000F	1995	Evaluation of turnkey bids, negotiation of final turnkey contract.

Exhibit RAK-2
Page 4 of 9

Summary of Burns & McDonnell Steam Electric Power Station Experience

Client Name & Location	Unit Name	MW	Fuel	Boiler	Turbine	Operation Date	Scope of Services
San Antonio Public Service - San Antonio, TX	JK Spruce 1	500	Coal	CE Balanced Draft	Westinghouse TC/4F30 2400P/1000F	1994	Evaluation of turnkey bids, negotiation of final turnkey contract.
Deseret G&T Cooperative - Sandy, UT	Bonanza 1	400	Coal	Foster Wheeler Balanced Draft	Westinghouse TC/2F35 2400P/1000F	1986	Feasibility study, site selection, environmental analysis, water supply analysis, system planning, detailed design, field services, start-up.
Plains Electric G&T Cooperative-Albuquerque, NM	Escalante 1	233	Coal	CE Balanced Draft	General Electric TC/2F26 1800P/1000F	1985	Feasibility study, financing assistance, site selection, environmental analysis & testing, fuel study, system planning, water supply analysis, design, field services, start-up and testing, preparation of operating manuals.
Western Farmers Electric Cooperative - Anadarko, OK	Hugo 1	400	Coal	B&W Balanced Draft	Westinghouse TC/2F35 2400P/1000F	1982	Feasibility study, financing assistance, site selection, environmental analysis, water supply and wastewater evaluations, fuel study and acquisition, design, field

Exhibit RAK-2
Page 5 of 9

Summary of Burns & McDonnell Steam Electric Power Station Experience

Client Name & Location	Unit Name	MW	Fuel	Boiler	Turbine	Operation Date	Scope of Services
							services, start-up and testing, preparation of operating manuals.
Sikeston Board of Municipal Utilities - Sikeston, MO	Sikeston 1	235	Coal	B&W Balanced Draft	General Electric TC/2F26 1800P/1000F	1981	Financing assistance, water supply analysis, design, field services, start-up.
Gainesville Regional Utilities – Gainesville, FL	Deerhaven 2	236	Coal	Riley Balanced Draft	Westinghouse TC/2F26 1800P/1000F	1981	Official statements, environmental analysis, fuel study and acquisition, water supply pilot plant study, design, field services, start-up.
Associated Electric Cooperative- Springfield, MO	Thomas Hill 3	670	Coal	B&W Balanced Draft	Westinghouse TC/4F33 2400P/1000F	1981	Feasibility study, fuel study, environmental analysis, environmental testing, design, field services, start-up and testing, preparation of operating manuals.
Basin Electric Power Cooperative- Bismarck ND	Laramie River 1 Laramie River 2 Laramie River 3	570 570 570	Coal Coal Coal	B&W Balanced Draft	General Electric TC/4F30 2400P/1000F	1980 1981 1982	Fuel study, site selection, regional siting study, water supply analysis, environmental analysis, environmental testing, feasibility study, Wyoming

Exhibit RAK-2
Page 6 of 9

Summary of Burns & McDonnell Steam Electric Power Station Experience

Client Name & Location	Unit Name	MW	Fuel	Boiler	Turbine	Operation Date	Scope of Services
							Industrial Siting Council application, testimony before state agency hearings, design, field services, start-up and testing, preparation of operating manuals.
Southern Illinois Power Cooperative - Marion, IL	Marion 4	173	Coal	B&W Cyclone	General Electric TC/2F23 1800P/1000F	1978	Feasibility study, financing assistance, environmental analysis, environmental testing, fuel study, system planning, water supply analysis, design, field services, electrical testing, start-up and testing.
Springfield Water Light & Power - Springfield, IL	VY Dallman 3		Coal	CE Balanced Draft	General Electric TC/2F23 2400P/1000F	1978	Feasibility study, financing assistance, site selection, environmental analysis, environmental testing, fuel study, water supply analysis, design, field services, start-up and testing.
Arizona Electric Power Cooperative - Benson, AZ	Apache 1 Apache 2	195 195	Coal Coal	Riley Balanced Draft	General Electric TC/2F23 2400P/1000F	1978 1979	Feasibility study, financing assistance, site selection, environmental analysis, environmental testing, fuel study, system planning, water supply analysis, design, field services, start-up and testing,

Exhibit RAK-2
Page 7 of 9

Summary of Burns & McDonnell Steam Electric Power Station Experience

Client Name & Location	Unit Name	MW	Fuel	Boiler	Turbine	Operation Date	Scope of Services
							preparation of operating manuals.
South Mississippi Electric Power Association – Hattiesburg, MS	RD Morrow 1 RD Morrow 2	204 204	Coal Coal	Riley Balanced Draft	General Electric TC/2F23 2400P/1000F	1977 1978	Feasibility study, financing assistance, site selection, environmental analysis, environmental testing, fuel study, water supply analysis, design, field services, start-up and testing.
Austin Electric Utility Department - Austin, TX	Decker Creek 2	400	Gas	B&W Balanced Draft	Westinghouse TC/2F35 2400P/1000F	1977	Feasibility study, fuel study, environmental analysis, design, field services.
Springfield City Utilities – Springfield, MO	Southwest 1	195	Coal	Riley Balanced Draft	Westinghouse TC/2F25 2400P/1000F	1976	Feasibility study, financing assistance, site selection, environmental analysis, environmental testing, fuel study, water supply analysis, design, field services, start-up and testing.
Henderson Municipal Power & Light – Henderson, KY	Station Two 1 Station Two 2	175 175	Coal Coal	Riley Balanced Draft	General Electric Westinghouse TC/2F23 1800P/1000F	1973 1974	Feasibility study, financing assistance, site selection, environmental analysis, environmental testing, fuel study, water supply analysis, design, field services, start-up and testing.

Exhibit RAK-2
Page 8 of 9

Summary of Burns & McDonnell Steam Electric Power Station Experience

Client Name & Location	Unit Name	MW	Fuel	Boiler	Turbine	Operation Date	Scope of Services
Associated Electric Cooperative- Springfield, MO	New Madrid 1 New Madrid 2	600 600	Coal Coal	B&W Cyclone	ABB TC/4F33 2400P/1000F	1972 1977	Initial planning, bond package assistance, site selection, env. studies, detailed design, procurement, resident const., start-up and testing, prep.of operating manuals.
Associated Electric Cooperative- Springfield, MO	Thomas Hill 2	275	Coal	B&W Cyclone	General Electric TC/2F30 2400P/1000F	1969	Initial planning, detailed design, procurement, resident construction, start-up and testing, preparation of operating manuals.
Singapore Public Utility Board, Singapore (ABM)	Tuas 1-8	8 x 600	Oil	IHI	Hitachi 2400P/1000F	1998	Feasibility studies.
Singapore Public Utilities Board, Singapore (ABM)	Pulau Seraya 7 Pulau Seraya 8 Pulau Seraya 9	250 250 250	Oil Oil Oil	Babcock-Hitachi	Parsons 2400P/1000F	1996	Evaluation of boiler and turbine tenders.

ABM indicates projects performed by UK registered joint venture company, Atkins • Burns & McDonnell.

Exhibit RAK-2
Page 9 of 9

Seminole Generating Station
650 MW Solid Fuel Fired Unit
Feasibility Study

Seminole Electric Cooperative, Inc.

IN PARTNERSHIP WITH THOSE WE SERVE

Seminole Electric Cooperative, Inc.

August 2004
Project 36571

Burns & McDonnell
SINCE 1898

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August 13, 2004

Mr. John Hurley
Seminole Electric Cooperative, Inc.
16313 North Dale Mabry Highway
Tampa, Florida 33618

Project No. 36571
650 MW Solid Fuel Fired Unit Feasibility Study

Mr. Hurley:

Burns & McDonnell is pleased to submit our 650 MW Solid Fuel Fired Unit Feasibility Study to Seminole Electric Cooperative, Inc. (SECI). The study evaluates the economics of a 600 MW (net) pulverized coal unit at the Seminole Generating Station (SGS) in Palatka, Florida. The purpose of the study is to provide a preliminary evaluation of a solid fuel fired generating resource at SGS to evaluate against other offers that SECI may receive in response to the power supply request for proposals issued by SECI.

The attached report summarizes the findings of the feasibility study and provides our recommendations regarding the most economical, long-term baseload energy resource for SECI. If you have any questions regarding the report, please contact me at 816-822-3274 or Jeff Greig at 816-822-3392.

It is a pleasure to be of service to SECI in this matter.

Sincerely,

Richard A. Klover

Richard Klover
Project Manager

Jeff Greig

Jeff Greig
General Manager

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TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

1.0 EXECUTIVE SUMMARY

1.1 SCOPE OF WORK

The purpose of this study was to evaluate the economics of a 600 MW net pulverized coal unit, Unit 3, for Seminole Electric Cooperative, Inc. (SECI) at the Seminole Generating Station (SGS). The study addresses site requirements, water supply requirements, capital cost, operating and maintenance costs, performance, schedule and bus bar cost for a new unit.

Additional assessment studies were completed to evaluate subcritical versus supercritical steam cycle technologies, natural draft versus mechanical draft cooling towers, and to address the engineering, environmental, and commercial issues associated with integrated gasification combined cycle (IGCC) technology. Each of these additional studies is described below and is included as an attachment to the report.

1.1.1 Subcritical vs. Supercritical Assessment

An evaluation of subcritical versus supercritical steam cycle technologies was completed and is included as Attachment A. The subcritical steam cycle was based on 7 feedwater heaters and steam turbine throttle conditions of 2,520 psig at 1,050 F and a reheat steam temperature of 1,050 F. The supercritical steam cycle was based on 8 feedwater heaters and steam turbine throttle conditions of 3,600 psig at 1,050 F and a reheat steam temperature of 1,050 F.

1.1.2 Cooling Tower Assessment

A preliminary economic evaluation was conducted to determine the impact of cooling tower technology on the capital and operating costs for the 600 MW net unit. The evaluation compared natural draft and mechanical draft cooling tower technologies. The results of the evaluation indicate the mechanical draft cooling tower has a differential net present value of $11.7M lower than a natural draft cooling tower. However, the cost estimates for the new unit are based on a natural draft tower. This assessment is included as Attachment B of this study.

1.1.3 Integrated Gasification Combined Cycle Assessment

Integrated Gasification Combined Cycle (IGCC) technology was evaluated due to the potential link between the relatively stable costs of solid fuels and the efficient operation of combined cycle gas turbines. An evaluation of a 600 MW net IGCC plant is included as Attachment C.

IGCC is a developing technology that has not performed reliably in commercial operation in the past, and whose capital cost basis is not well established at the present time. Therefore, it is recommended this technology not be considered for new generation at this time. There is planned development of gasification for coal in the near future, however it will be at least 4 -5 years before additional operational experience and information will be available on the cost and reliability of the technology.

1.2 ECONOMIC ANALYSIS SUMMARY

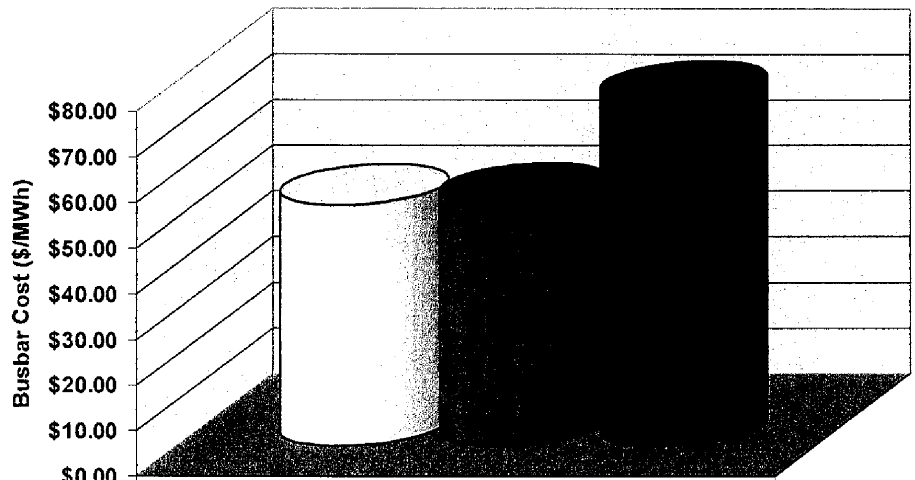
Burns & McDonnell prepared pro forma economic analyses of the following three alternatives:

- Construction of a new brownfield 600 MW net subcritical solid fuel fired generating unit
- Construction of a new brownfield 600 MW net supercritical solid fuel fired generating unit
- Construction of a new greenfield 500 MW net gas fired combined cycle unit

A 20-year economic analysis was prepared based on the estimated capital costs, performance, fuel costs, and operating costs for each alternative. A 500 MW greenfield combined cycle alternative was included to provide a relative comparison of the expected project economics of a gas-fired unit. The features and scope of the 600 MW net solid fuel fired units included in the cost estimate are provided in more detail in Section 3 of this study.

Economic pro forma analyses were used to determine the 20-year levelized busbar cost of power generated from each alternative. Figure 1-1 presents a graph of the resulting levelized busbar power costs for the three alternatives considered, in 2012 dollars. The levelized busbar costs of the supercritical and subcritical units ($52.77 and $52.97/MWh, respectively) are significantly lower than that of the greenfield, conventional combined cycle alternative ($75.48/MWh).

Figure 1-1
20-Year Levelized Busbar Costs (2012$)



	Alternatives
Supercritical PC	$52.77
Subcritical PC	$52.97
Combined Cycle	$75.48

1.3 SCHEDULE

A preliminary schedule was prepared for the design and construction of the 600 MW net solid fuel fired unit and is included in Section 3. For planning purposes, the key milestone dates working backward from a June,2012 commercial operation date for the new 600 MW net solid fuel fired unit would be as follows:

- Commercial Operation — June 2012
- Initial Synchronization — November 2011
- Substation Backfeed — December 2010
- Start Construction — September 2008
- Full Notice to Proceed — November 2007
- Award Turbine Contract — November 2007
- Award Boiler Contract — November 2007
- Permits Issued — November 2007
- File SCA and EA with FDEP and RUS — Mar 2006
- Begin preparation of SCA, PSD, and EA Documents — April 2005
- Start Preliminary Design to Support Permitting — April 2005

1.4 CONCLUSIONS AND RECOMMENDATIONS

Based upon economic criteria in Section 6, the construction of a new 600 MW net supercritical or subcritical unit is considered to be the most economical alternative to provide long-term baseload capacity and energy for SECI. The overall economics of a gas-fired combined cycle unit are not as favorable as those of the subcritical or supercritical solid fuel-fired units when operating at high capacity factors due to the higher fuel costs associated with natural gas.

1.5 FUTURE PLANNING CONSIDERATIONS

This study provides information for SECI to evaluate the alternatives identified in this study against SECI's request for proposals for additional capacity. Some additional steps for SECI consideration include the following:

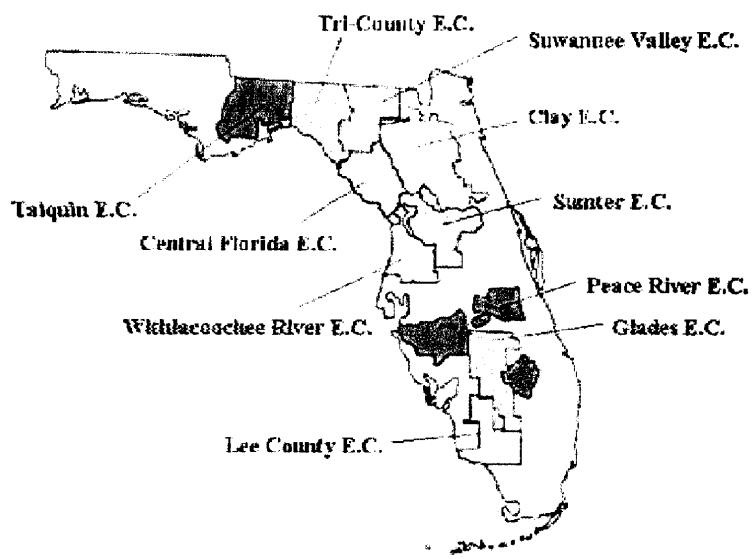
- The schedule reflects the need for preliminary engineering to start in 2005 in order to support preparation of permits. The process of selecting an engineer should be started.
- If the potential for additional power off-take participation exists, increasing the capacity of the new unit should be evaluated due to the economies of scale with larger units.
- It may be necessary to purchase additional property in order to support landfill requirements for the life of the unit.

2.0 INTRODUCTION

2.1 BACKGROUND

SECI has identified the need for additional baseload capacity by the 2012 timeframe. One option for meeting this need is the construction of an additional unit, Unit 3, at SGS. SECI seeks a generation resource with fuel price stability in order to secure long-term, low-cost generation for its member cooperatives. As a generation and transmission cooperative, SECI provides wholesale electric service to its ten member electric distribution cooperatives from a mix of firm resources. These resources include owned generation and purchased capacity, including two solid fuel fired units at SGS, a gas-fired combined cycle facility at Payne Creek, and an ownership interest in Progress Energy Florida's nuclear unit. The member electric distribution cooperatives are located throughout Florida, serving over 775,000 customers in 46 different counties. Figure 2-1 shows the SECI member system.

Figure 2-1
SECI Member System



2.2 SCOPE OF WORK

Seminole Electric Cooperative, Inc. retained Burns & McDonnell (B&McD) to evaluate the feasibility of developing and installing a new solid fuel generation resource adjacent to its present Seminole Generating Station. This additional solid fuel fired unit is designated and referred to in this study as SGS Unit 3. This study includes the following scope of work:

- Preparation of a preliminary site arrangement drawing for a new 600 MW net pulverized coal unit located on the SGS plant site.
- Preparation of a project scope description for the 600 MW net solid fuel fired unit.
- Preparation of capital and operating cost estimates for the new unit.
- Estimate of the plant output and heat rate.
- Preparation of preliminary plant water balance including the impact of the new unit.
- Preparation of a preliminary Level 1 schedule.
- Preparation of a preliminary assessment of the anticipated BACT/MACT requirements for the new unit.
- Preparation of a preliminary assessment of the existing infrastructure to support the new 600 MW net solid fuel fired unit.
- Development of a pro forma with an estimated bus-bar cost.
- Preparation of a preliminary assessment of subcritical and supercritical steam cycle technologies.
- Preparation of a preliminary assessment of mechanical draft versus natural draft cooling tower.
- Preparation of a preliminary evaluation of an IGCC plant.

The new unit is based on a 600 MW net solid fuel fired power plant. The boiler and emissions controls equipment for the new unit would be designed to operate with a blend of 70% eastern bituminous coal and 30% petcoke fuel. The operating and maintenance cost estimates for the economic pro forma were also based on a 70/30 blend of coal and petcoke.

Life cycle economic analysis of the new unit was conducted, resulting in a levelized bus-bar delivered cost of energy. In addition, a cost sensitivity analysis was performed.

2.3 OBJECTIVE

The purpose of the study is to provide a preliminary evaluation of a solid fuel generation resource at SGS to evaluate against the SECI request for capacity proposals.

3.0 DESCRIPTION OF PLANT

3.1 OVERVIEW

The description of the unit evaluated in this study is a 600 MW net pulverized coal (PC) fired steam generator (boiler) with a single reheat steam turbine on a brownfield site. The proposed location is adjacent to two existing subcritical 600 MW PC units at SGS.

The unit will be designed to operate on a 70/30 blend of bituminous coal and petcoke. An existing rail spur will be used to supply coal to the new unit via unit trains. Existing plant equipment and systems will be used for coal unloading and stockout.

The PC-fired steam generator will utilize balanced-draft combustion with reheat. Additional features will include selective catalytic reduction (SCR) for NO_x reduction, carbon injection for mercury control, an electrostatic precipitator (ESP) for particulate collection, a wet flue gas desulphurization system (FGD) for sulfur dioxide (SO_2) reduction and a wet ESP for sulfuric acid (H_2SO_4) reduction. Steam generated by the steam generator will be supplied to the steam turbine to complete the power generation cycle. Treated cooling water for the water-cooled surface condenser will be provided from the circulating water system that includes a natural draft cooling tower and circulating water pumps. Raw water for the cooling system will be supplied from the St. Johns River utilizing new pumps installed in the existing river water pump structure.

Electrical output from the new unit will be stepped up to 230 kV and interconnected into the existing transmission system through the existing 230 kV switchyard.

3.1.1 Schedule

A preliminary schedule was prepared for the design and construction of the 600 MW net solid fuel fired unit and is included at the end of Section 3. The schedule includes time for

- Permit preparation/engineering support, permit submittal and regulatory review.
- Equipment and construction package preparation and bid evaluation/award.
- Facility design.
- Equipment fabrication and delivery.
- Construction, startup and testing.

A project permit preparation and regulatory review time of 30 months was included in the schedule. Construction time is estimated to require 45 months for the 600 MW net unit. A construction schedule of 24 months was assumed for the 500 MW combined cycle alternative. The schedule includes the construction period required for upgrades to the existing switchyard. If new transmission lines are deemed necessary, the total time required for permitting and construction of the new unit would increase significantly.

The project execution method identified in the schedule is based on a multiple contract approach with an owner's engineer completing the engineering, SECI completing procurement, and multiple construction contracts. The schedule assumes that SECI would not commit to financial liabilities relative to the release of the major equipment and construction contracts until the critical construction permits are received.

3.1.2 Operating and Control Philosophy

The unit is expected to be operated at base load. The project is configured to normally operate at maximum continuous rating output. The proposed unit is capable of load following with overnight/weekend/holiday load reductions (steam generator at 50-percent load).

All routine start-up and shutdown operations will be from a central control room via a distributed control system (DCS). The SGS Unit 3 control room will be located in the existing control room. Facility automation will be designed to insure secure and safe operation of all plant equipment. Maintenance support will be supplied by on-site staff as required for routine maintenance activities. Maintenance support for major shutdowns is expected to be contracted.

The level of equipment redundancy included in the cost estimates for the unit is based on discussions with SECI and represents accepted industry standards for similar utility grade units.

The unit is not configured to generate electricity while isolated from the utility grid or to have "black-start" capability in the base cost estimate.

3.1.3 Pulverized Coal Boiler Technology

Conventional pulverized coal technology is a reliable energy producer around the world and is characterized by the operating pressure of the cycle, subcritical or supercritical. Subcritical and supercritical technology refers to the state of the water that is used in the steam generation process. The critical point of water is 3,208.2 psia and 705 °F. At this critical point, there is no difference in the density of water and steam. The majority of the steam generators built in the United States utilize subcritical technology. These units utilize a steam drum and internal separators to separate the steam from the water. In the steam generator, high pressure steam is generated for throttle steam to the steam turbine. In this study, both subcritical and supercritical PC boilers were evaluated. Attachment A of this report provides a more detailed explanation and comparison of the two boiler technologies considered.

3.1.4 Site Layout

The plant will be oriented with the axis of the steam generator perpendicular to the steam turbine axis. The ESP and wet FGD will be located symmetrically about the boiler axis and extend to the north. The stack will be located north of the wet FGD. The remaining permitted landfill expansion area and the associated stormwater runoff pond will be located to the east of the new unit. For a graphic interpretation of the site layout, refer to the site arrangement Drawings SK-YGA1 and SK-YGA2 located at the end of this section.

3.1.4.1 Main Structures

The primary structures include the turbine building, which will house the steam turbine-generator and auxiliaries, and steam cycle equipment. The main control room will be located in the existing control room. Auxiliary buildings will be provided as required for the functions of the power generating facilities. Auxiliary buildings will be constructed, wherever possible, utilizing a pre-engineered building system. The main structures will be the turbine, steam generator, wet FGD, ESP, wet ESP, fly ash silo, natural draft cooling tower and chimney. A new water treatment building and warehouse will be included. The steam generator, ESP, wet FGD, and wet ESP will be outdoors. The existing administration offices will support the needs of the new unit.

3.1.4.2 Equipment Location

The new unit will be laid out to facilitate access to equipment and systems for maintenance and operations. The steam turbine-generator will be located indoors and will be interconnected with the existing turbine hall. The condensate pumps, boiler feedwater pumps, feedwater heaters, deaerator, condensate polisher, closed cooling water pumps and heat exchangers, generator surge protection cabinet, DCS equipment, switchgear, motor control centers, 480-volt load centers, and DC power system equipment will be located in the turbine building. The steam generator will be located outdoors.

3.1.5 Fuel and Reagents

Primary fuel for the PC steam generator will be a blend of bituminous coal and petcoke. The boiler and air pollution control equipment would be selected to be capable of meeting the required thermal performance and emissions firing the fuels indicated in Attachment E. This fuel analysis represents a 70/30 blend of bituminous coal and petcoke, resulting in a sulfur content of approximately 4.25%.

The fuel oil system will be used to supply start-up fuel for the new steam generator. A new 150,000 gallon fuel oil storage tank will be provided for the new unit.

Limestone can be delivered to the new unit by truck to the site utilizing the existing limestone handling systems.

Anhydrous ammonia will be delivered by truck to the site. It will be diluted with air and be injected at the economizer outlet, upstream of the SCR catalyst to reduce NOx emissions.

Activated carbon will be delivered by truck. The activated carbon will then be injected into the flue gas upstream of the ESP for mercury control.

3.1.6 Water Supply & Wastewater Treatment

A water mass balance diagram was developed for SGS reflecting the impact of Unit 3 to the existing two units and is included at the end of this section. The diagram depicts the following water supply and wastewater treatment streams.

Raw water will be supplied from the St John's River using new river water supply pumps installed in the existing river water pump structure. A new raw water supply line will be installed from the river water pump structure to the plant. Raw water will be pumped to the cooling tower basin for makeup to the circulating water system. Cycle makeup water will be provided from the existing well water system.

Service water for pump seals and miscellaneous hose stations will be supplied from the existing service water system. New service water pumps and a head tank will be provided. Potable quality water for drinking fountains, washrooms, showers, and toilet facilities will be supplied from the existing potable water system.

Surface water, collected from floor drains and containment areas around equipment, that may contain small amounts of oil, will be directed through an oil/water separator. The water discharged from the oil/water separator will be combined with other waste streams and discharged to the existing equalization basin. Collected oil from the oil/water separator will be trucked off site by a licensed waste disposal firm.

Process wastewater, except cooling tower blowdown and site runoff, will be discharged to the equalization basin and reused as makeup to the wet FGD. Wastewater from the wet FGD will be directed to the existing clarifier and filters. The clarified FGD blowdown will be used for fly ash dust suppression with the excess being directed to the brine concentrator. Condensate from the brine concentrator will be recovered as makeup to the wet FGD with the waste concentrate from the brine concentrator being evaporated in a spray dryer. Cooling tower blowdown and site runoff will be discharged to the St. Johns River through the existing discharge pipeline. Although the pipeline has sufficient capacity, further evaluation of the water discharge permit limit will need to be completed. Storm water runoff from non-process equipment areas, such as parking lots and building roofs, will be directed through an on-site storm water collection and drainage system and discharged to the St. Johns River.

3.1.7 Electrical Interconnection

Electrical output from the new unit will be stepped up to 230 kV. The turbine generator output will be connected through three single phase generator step-up transformers to the existing 230 kV switchyard. The existing folded breaker-and-a-half switchyard will be modified to add one three-breaker bay to accommodate the new unit and its startup transformers.

The unit startup power will be through two 30/40/50 MVA, 230:6.9/6.9 kV startup transformers. Auxiliary power will transfer to the steam turbine-generator through two 30/40/50 MVA 23:6.9/6.9 kV auxiliary transformers after the unit is on line.

3.1.8 Ash and Scrubber Sludge Disposal

A dry bottom ash extraction system will be used to transport the dry bottom ash to a storage silo. The bottom ash silo will be sized for three day's capacity. Bottom ash from the new unit will be sold. One fly ash silo with a storage capacity of three days will be provided. Fly ash will be trucked from the storage silo to an on-site landfill for disposal or for off site sales. Gypsum will be sold to the adjacent wallboard plant.

3.2 MAJOR EQUIPMENT AND SYSTEM DESCRIPTIONS

3.2.1 Steam Generator

The plant will include one PC steam-generating unit. The steam generator is a subcritical unit designed to supply steam to the steam turbine at 2,520 psig and 1050 °F / 1050 °F at 100-percent load when burning a 70/30 blend of coal and petcoke.

Superheat and reheat temperature will be automatically controlled by regulating attemperator spray water flow to spray water control valves with automatic block valves.

Gravimetric feeders will meter raw coal to the pulverizers. Steam generator auxiliary equipment will also include two 60% capacity, electric motor-driven primary air (pulverized coal transport) fans and two 60% capacity, steam generator forced draft (secondary combustion air) fans with an air preheater. The steam generator features low NO_x burners and fuel oil igniters. Three 50% capacity induced draft fans will be included downstream of the ESP.

3.2.2 Air Pollution Control Equipment

Flue gas exiting the steam generator passes through the following equipment and systems to reduce emission levels.

- SCR to reduce NO_x emissions.
- Activated carbon injection system for mercury control.
- ESP for particulate control.
- Wet FGD to reduce the SO_2 emissions.
- Wet ESP to reduce sulfuric acid emissions.

3.2.3 Steam Turbine-Generator

The steam generator will provide steam to a main steam turbine-generator. The steam turbine-generator converts mechanical energy of the steam turbine to electrical energy. For this project a 2,520 psig, 1050 F/ 1050 F, single-reheat, dual casing, four-flow down-exhaust, condensing steam turbine is arranged with seven stages of feedwater heaters and a surface condenser. The turbine will drive an electric generator. The steam-turbine generator unit will be designed for indoor operation.

3.2.4 Surface Condenser

The water-cooled surface condenser will be a dual, rectangular shell, two pressure, split waterbox, two pass condenser with a retention hotwell for the subcritical cycle. The condenser will be designed to maintain the steam turbine backpressure at normal maximum continuous rating of the steam turbine at summer design conditions. The condenser will accept the steam exhausted from the low pressure steam turbine. Air removal from the condenser's upper portion will be via two full capacity vacuum pumps. To dissipate the energy in the condensing steam, a circulating water system will supply cooling water from the natural draft cooling tower to the water-cooled condenser.

3.2.5 Circulating Water System

The circulating water system will be designed to operate at up to approximately 3.5 cycles of concentration to maintain proper water quality while limiting the quantity of blowdown water. Blowdown from the circulating water system will be discharged into the St. Johns River.

The cooling tower will be a concrete, natural draft type with high efficiency fill. The cooling tower will be designed to maintain the rated turbine back pressure at the design ambient conditions. Cooling water is pumped from the natural draft cooling tower to the condenser by three 50-percent capacity circulating water pumps.

3.2.6 Closed Cooling Water System

The closed cooling water system is a closed-loop system that provides and cools cooling water for various equipment. This system includes the head tank, closed cooling water pumps, and plate and frame closed cooling water heat exchangers. Two 100 percent capacity, single-speed, horizontal, motor-driven, closed-cooling water pumps will be provided. Two 100 percent capacity closed cooling water heat exchangers will be provided. This system will be designed so that the flow to any piece of equipment can be controlled either by manual valves or control valves.

3.2.7 Steam System

The steam system transports steam from the steam generator to the main steam turbine-generator and feedwater heaters. A cross-tie with the existing boilers will be provided to supply steam for start-up and shutdown operations. A steam turbine bypass system is not included.

The main steam piping transports steam from the superheater outlet of the steam generator to the inlet of the high-pressure turbine. Steam is exhausted from the high-pressure turbine and transported through the cold reheat piping to the reheater section of the steam generator where steam is reheated. The hot reheat piping transports the reheated steam to the intermediate pressure turbine.

This system also transports steam from extractions in the turbine to the high-pressure heaters, boiler feedpump steam turbine drives, low-pressure heaters, and the deaerating feedwater heater. The main steam and hot reheat systems include attemperators, where feedwater is injected as necessary to control the temperature of the steam being supplied to the steam turbine.

The steam pipelines will be provided with drains at all low points. Drain pots will be provided to collect condensate from the low points in the steam piping and return it to the main condenser. The drain pots will drain the various low points of the piping system at the maximum steam flows.

All extraction lines from the steam turbine, except those leading to the heaters in the condenser neck, will be equipped with power assisted, nonreturn valves to ensure that steam will not flow back to the turbine. These lines will also be supplied with motor-operated shutoff valves to prevent steam turbine water induction.

3.2.8 Condensate System

The condensate system delivers deaerated condensate via three, 50-percent capacity vertical can, condensate pumps. These pumps transport condensate from the condenser hotwell, through the gland steam condenser and low-pressure feedwater heaters to the boiler feed pump. A minimum flow bypass system will be provided to assure the condensate pumps operate above their minimum flow rate at all times.

3.2.9 Feedwater System

The feedwater system provides water to the high-pressure feedwater heaters and then to the steam generator's economizer inlet via two 60-percent capacity boiler feed pumps. The main boiler feed pumps are furnished with steam turbine drives. The feedwater system also provides spray water for main steam and hot reheat attemperators for steam temperature control. A minimum flow system will be provided to assure the boiler feed pumps operate above their minimum flow rate at all times. A single, 30% capacity, motor driven start-up boiler feed pump is also included.

3.2.10 Coal Handling System

The coal handling system for the SGS Unit 3 will be based on handling bituminous coal with a density of 50 pounds per cubic foot and petroleum coke with a density of 45 pounds per cubic foot. The existing rotary dumper and stockout system has adequate capacity (approximately 3,000 tons per hour) to handle the new unit. A condition assessment is advisable to determine if existing equipment can meet expected capacity levels. Existing Units 1 and 2 currently receive approximately one unit train (10,000 tons per train) per day (320 trains per year). The addition of Unit 3 will increase this requirement to approximately 1.5 unit trains per day (485 trains per year).

The current long term coal storage pile, for Unit 1 and 2, maintains 45 to 60 days of coal. Adding Unit 3 requirements to the existing coal pile will equate to a total area of approximately 23 acres (1,200,000 tons) for all three units. The existing coal storage area has adequate capacity for all three units.

The existing as-received sampling tower will be modified by removing the existing as-received sampling system, providing a new motorized flop gate at the head end of Conveyor CB-2, providing a new belt feeder to transfer coal to a new reversible yard conveyor and a new enclosed structure attached to the existing tower. The new reversible yard conveyor will be provided with a new trencher type stacker / reclaimer (similar to the existing machine) and will be capable of stacking out 3,000 tph and reclaiming at 1,700 tph of bituminous coal or petroleum coke.

The new reversible yard conveyor will be approximately 1,500 feet long and will provide approximately 3 days of active reclaimable storage for all three units. The head end of the reversible yard conveyor will be located in the new structure, adjacent to the existing tower and will be provided with a diverter gate to direct coal to either existing Conveyor CB-7A or CB-7B.

The existing as-fired sampling tower will be modified by removing the existing as-fired sampling system and providing new motorized flop gates at the head end of Conveyors CB-8A and CB-8B. The new gates will direct coal to new Unit 3 feed conveyors to transfer coal from the as-fired tower to a new tower adjacent to Unit 3. The Unit 3 tower will be provided with a surge bin and variable speed belt feeders (2) which discharge to dual tripper conveyors. The tripper conveyors will be provided with dual pant leg traveling trippers complete with cable reels and floor seal system.

Replacement of the existing as-received and as-fired sampling systems will be accomplished by installing sweep arm primary samplers on the respective belt conveyors and modular self-contained secondary sampling systems, located at grade, immediately underneath the primary sampler(s).

Dust control for the new coal handling system will be a dry baghouse type collection system and will be provided to limit particulate emissions complying with all local, state and federal regulations. The baghouse collector will be provided with a walk-in clean air plenum, centrifugal fan, ductwork and dust return system. The existing dust collection systems will be upgraded as required to maintain current emission regulations.

3.2.11 Water and Wastewater Treatment Systems

The water and wastewater treatment systems will provide high purity water for use as makeup to the boiler and to maintain the high purity requirements of the condensate system. Wastewater treatment will allow the facility to operate in a zero discharge mode from all plant services other than cooling tower blowdown and site runoff. The water and wastewater treatment systems shall consist of the following subsystems:

- Cycle makeup treatment system
- Sampling and analysis system
- Condensate polishing system
- Brine Concentrator/spray dryer system

3.2.11.1 Cycle Makeup Treatment System

The cost estimate is based on providing a single two-pass reverse osmosis (RO) system with a design product flow of 150 gpm. The effluent from the second pass RO will be polished using an electrodionization (EDI) system. The EDI system will use electricity to maintain fully regenerated ion exchange resin within the EDI cells. The use of an EDI for polishing of the two-pass RO system will eliminate the need for acid and caustic regenerant storage and handling. Reject from the RO and EDI systems will be recovered in the existing equalization basin and recovered as makeup to the wet scrubbers.

3.2.11.2 Sampling and Analysis System

The sampling and analysis system will consist of three major components: a sample rack, a water quality panel, and a sample chiller. Samples from the plant shall be routed to the centrally located sampling and analysis system for continuous analyses, monitoring, data logging, and trending analysis and recording.

Analyzers will be shared by different sample points where continuous analysis of parameters is not critical (i.e. sodium and silica). System will include a conditioning panel utilizing condensate for primary cooling and cooling water or chilled water for secondary cooling to condition the samples to the necessary temperature. The wet section of the panel will contain the analyzers and sensors. The dry section of the panel will contain the monitors.

3.2.11.3 Condensate Polishing System

The condensate system will be provided with full flow (4 x 35 % capacity) deep bed polishers with external regeneration. The condensate polishing system will treat the water from the discharge of the condensate pumps. All of the condensate will flow from the condensate system through the condensate polisher exchangers. The condensate polisher vessels will consist of a mixture of cation and anion resins. The effluent of the condensate polishing system will be returned to the condensate system upstream of the gland steam condenser.

3.2.11.4 Brine Concentrator/Spray Dryer System

The scrubber blowdown from all units will be treated in the existing clarifier and filters for reduction of suspended solids. The filtered blowdown will be directed to two, 50% capacity, brine concentrators. Each brine concentrator will have a treatment capacity of 300 gpm. The solids in the brine concentrator makeup will be concentrated in a waste stream which will be about 10 percent of the brine concentrator inlet flow rate. This concentrate stream will be sent to a single spray dryer for final disposal. The water content of the brine concentrator waste will be evaporated and the resulting dry solids will be sent to a landfill. The remaining 90 percent of the brine concentrator influent will be evaporated and condensed with the condensate being recovered as makeup to the wet scrubbers.

3.2.12 Electrical Generation & Distribution

The electrical systems supply the power produced by the plant to the transmission system and supply the power required for operation of all plant equipment. The systems include all metering and protective relaying required for operation of the plant electrical systems.

The turbine generator output will be connected through single phase generator step-up transformers and power circuit breakers to the existing 230 kV switchyard. The generator step-up transformers will be three, single phase transformers. The unit start-up source will be provided through the addition of 230 kV breakers in the switchyard and via overhead cable taps to the high side terminals of two start-up transformers. Each start-up transformer will be a 50% rated three winding transformer.

The high side terminals of the two unit auxiliary transformers will tap into the isolated phase bus between the generator and the step-up transformers. Each unit auxiliary transformer will be three winding and 50% rated.

The secondary of each of the unit auxiliary and start-up transformers will each have two 6.9 kV windings that are connected by non-segregated bus duct to 6.9 kV switchgear buses.

3.2.13 Auxiliary Power Supply

This system receives power from the unit auxiliary transformers and startup transformers and steps it down to 6.9 kV and connects to 6.9 kV switchgear buses. The 6.9 kV switchgear buses distribute power throughout the plant with step down transformers to distribute to the various voltage levels to all of the systems requiring AC electrical power for their operation. Startup and initial commissioning will be accomplished by feeding power from the switchyard, through the startup transformers. After the generator is on-line, station power will transfer from the startup transformers to the unit auxiliary transformers that are tapped off the generator via isolated phase bus.

3.2.14 Control Systems

The control system will be a physically and functionally distributed microprocessor based, on-line distributed control system (DCS). The main DCS interface for Unit 3 will be located in the existing control room. The DCS will be used for supervisory control and monitoring of all major plant systems. In addition, programmable logic controllers (PLCs) will be provided for auxiliary systems such as coal handling, ash handling, water treatment, sootblowers, etc.

The boiler, turbine and auxiliary controls will be provided under various equipment contracts. In general, where equipment is furnished as a "package", the auxiliary control system will be included in that package. However, since the turbine, boiler and heat cycle are operated as a unit in response to load demand, the associated coordinated load, combustion and burner management controls will be provided under the Distributed Control System (DCS) package. In addition, the DCS will serve as the primary Human Machine Interface (HMI) for plant wide remote controls and monitoring, except where local control is mandated. The auxiliary systems, usually PLC based, are each to be designed using project standard requirements for control philosophy and electrical design.

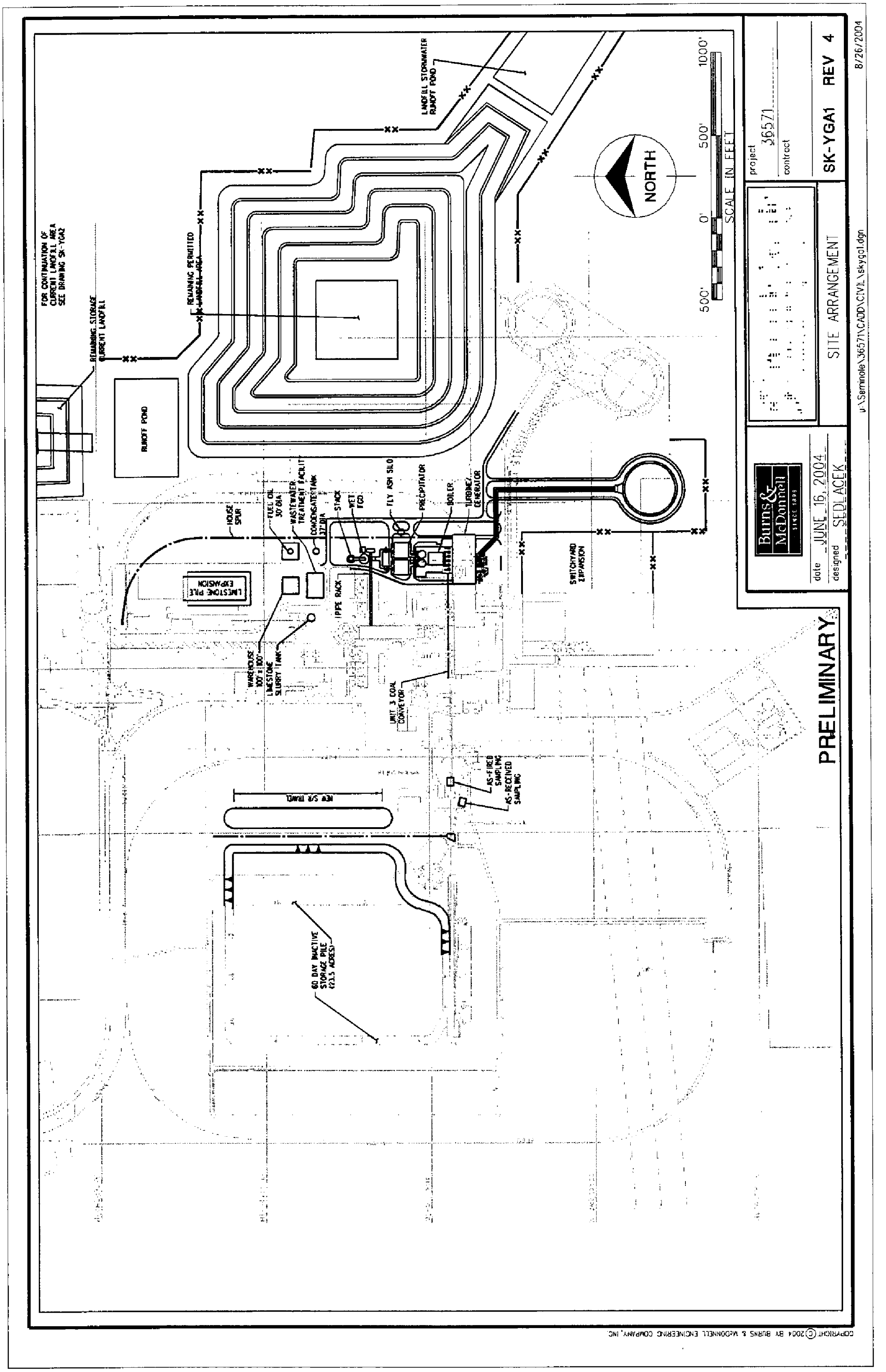
3.2.15 DCS and Related Systems

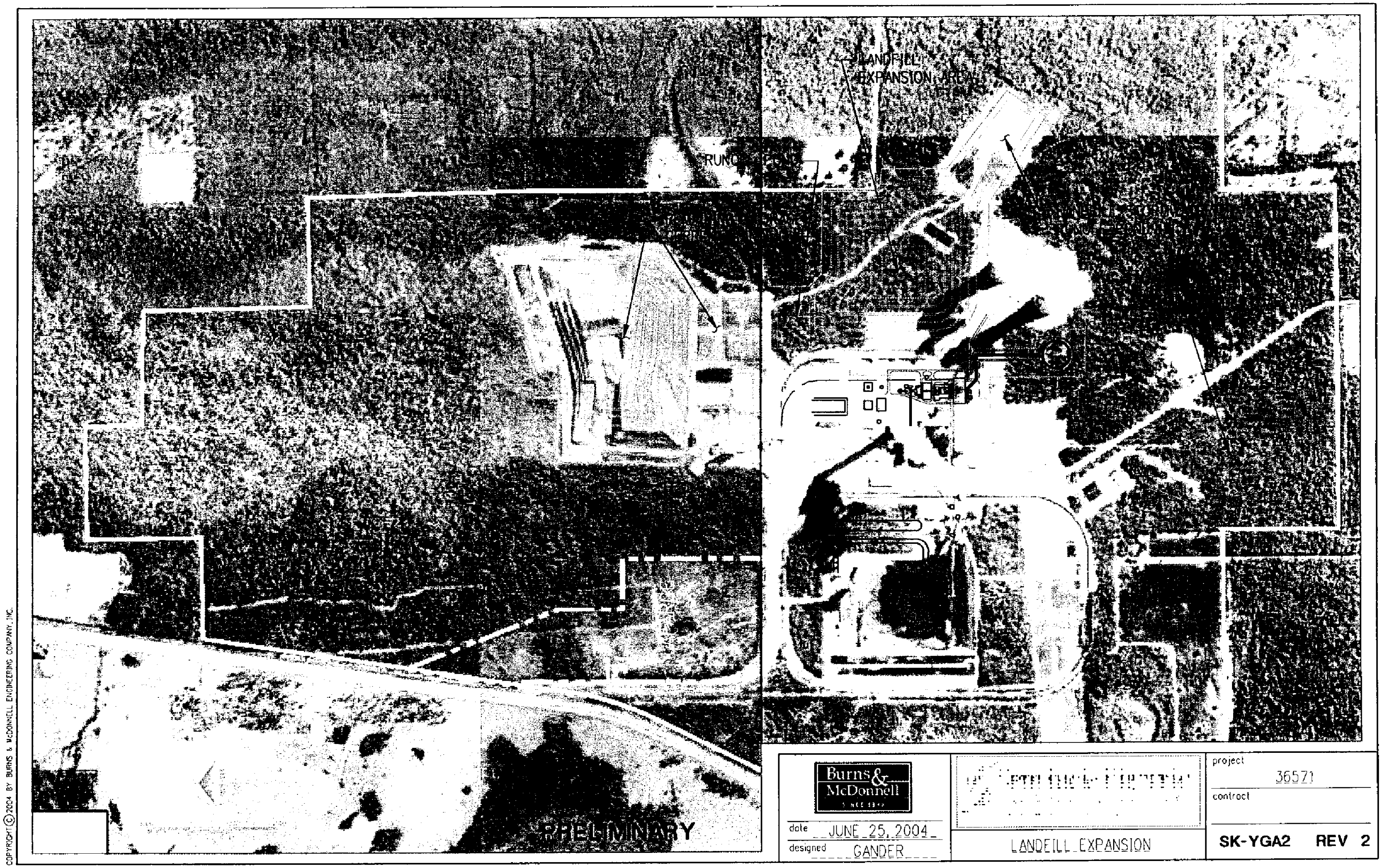
All information from DCS controllers and I/O is passed to the operator through operator server/client personal computers operating on a dedicated Ethernet Local Area Network (LAN), the DCS Information Network. Servers, located in a Computer Room or Control Equipment Room, will provide the gateway from the LAN to the proprietary DCS Data Highway. The servers and clients will be powered in two groups from two separate sources of power. The servers may be operated in a redundant mode if throughput allows operator updates once per second.

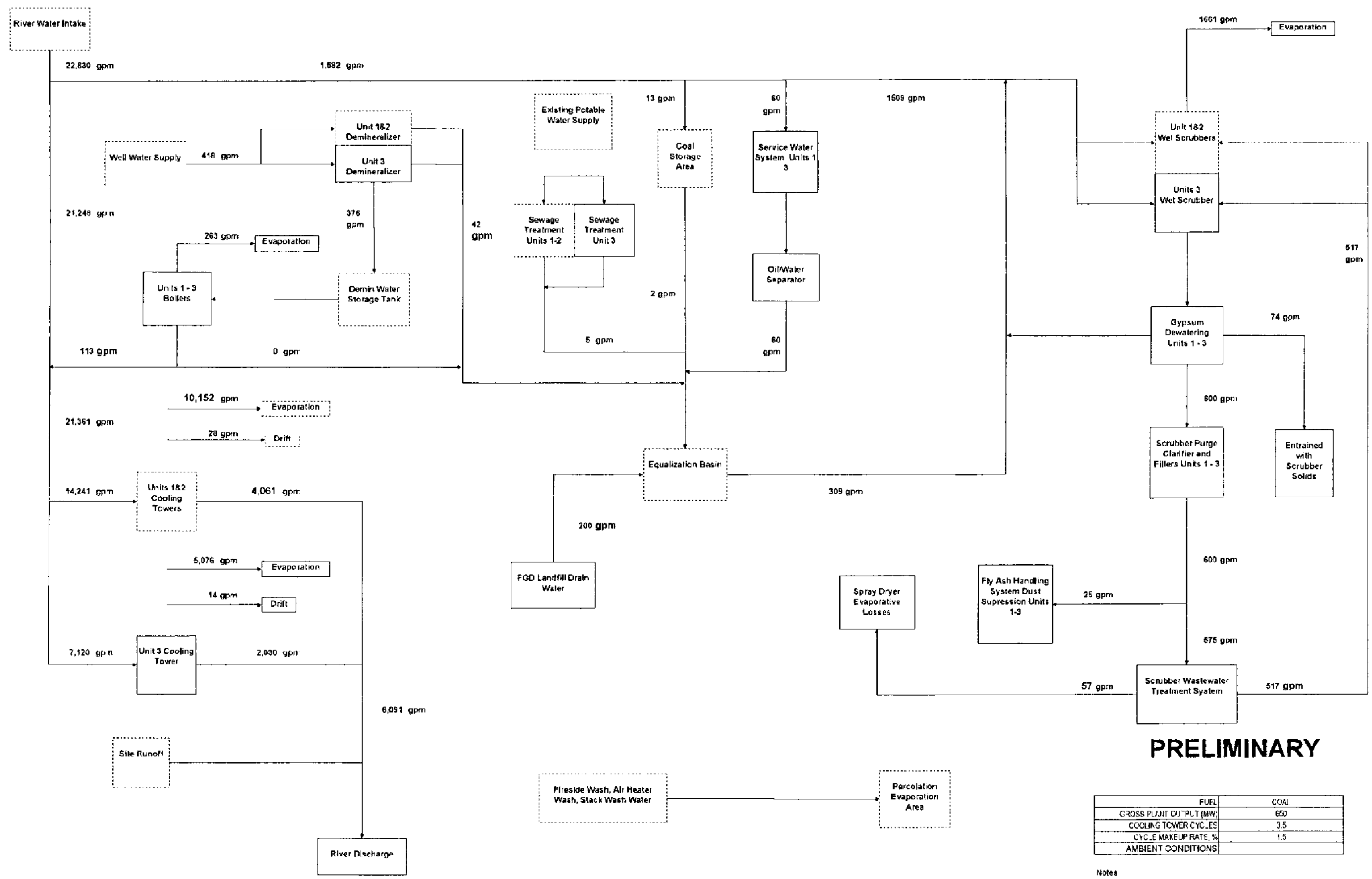
A plant historian will be provided to allow several months of data to be stored from and retrieved by the DCS. It shall also allow for the archive and retrieval of data through the use of CD R/W drive or streaming tape. The historian will supply data to all operator servers and client workstations. The DCS will allow the seamless retrieval of short-term and long-term data into the same DCS operator trends. The historian will be redundant for data backup or will be provided with short- term history storage to backup data for at least several days in event the historian is down.

3.2.16 Continuous Emissions Monitoring System (CEMS)

One CEMS downstream of the SCR/ESP/wet FGD/wet ESP and a data acquisition system is included. The final flue gas outlet CEMS will consist of sampling devices with sample tubing to the emissions rack mounted near the base of the stack in an enclosure. The system will include a cylinder rack for calibration gases. The CEMS monitors stack emissions with hardware and reporting package software will meet the requirements of 40 CFR 60 and 40 CFR 75 as determined by the permit requirements. The CEMS is designed to communicate with the plant DCS system to provide automatic report production compatible with permit requirements.


LANDFILL STORMWATER RUNOFF POND
REMAINING PERMITTED LANDFILL AREA
FOR CONTINUATION OF CURRENT LANDFILL AREA SEE DRAWING SK-YGA2
REMAINING STORAGE CURRENT LANDFILL
RUNOFF POND
HOUSE SPUR
FUEL OIL
WASTEWATER TREATMENT FACILITY
CONDENSATE TANK
STACK
WET FGD
FLY ASH SILO
PRECIPITATOR
BOILER
TURBINE/ GENERATOR
SWITCHYARD EXPANSION
LIMESTONE PILE EXPANSION
PIPE RACK
WAREHOUSE
LIMESTONE SLURRY TANK
UNIT 3 COAL CONVEYOR
AS-FIRED SAMPLING
AS-RECEIVED SAMPLING
NEW S/R TRAVEL
60 DAY INACTIVE STORAGE PILE
NORTH
0'
500'
1000'
SCALE IN FEET
project 36571
contract
SK-YGA1
REV 4
8/26/2004
SITE ARRANGEMENT
Burns & McDonnell
date JUNE 16, 2004
designed SEDLACEK
PRELIMINARY


COPYRIGHT © 2004 BY BURNS & McDONNELL ENGINEERING COMPANY, INC.
LANDFILL EXPANSION AREA
PRELIMINARY
Burns & McDonnell
date JUNE 25, 2004
designed GANDER
LANDFILL EXPANSION
project 36571
contract
SK-YGA2 REV 2



PRELIMINARY

FUEL	COAL
GROSS PLANT OUTPUT (MW)	650
COOLING TOWER CYCLES	3.5
CYCLE MAKEUP RATE, %	1.5
AMBIENT CONDITIONS	

Notes
1. Existing facilities indicated by dashed lines.
2. New or commom facilities shown by solid lines.

NO	DATE	REVISIONS AND RECORD OF ISSUE	DES	CHK	APP
B	2-Jul-04	Revised Scrubber Evaporation and Wastewater			

Burns & McDonnell SINCE 1898

ENGINEER DAS DRAWN DAS
CHECKED DATE 6/22/2004

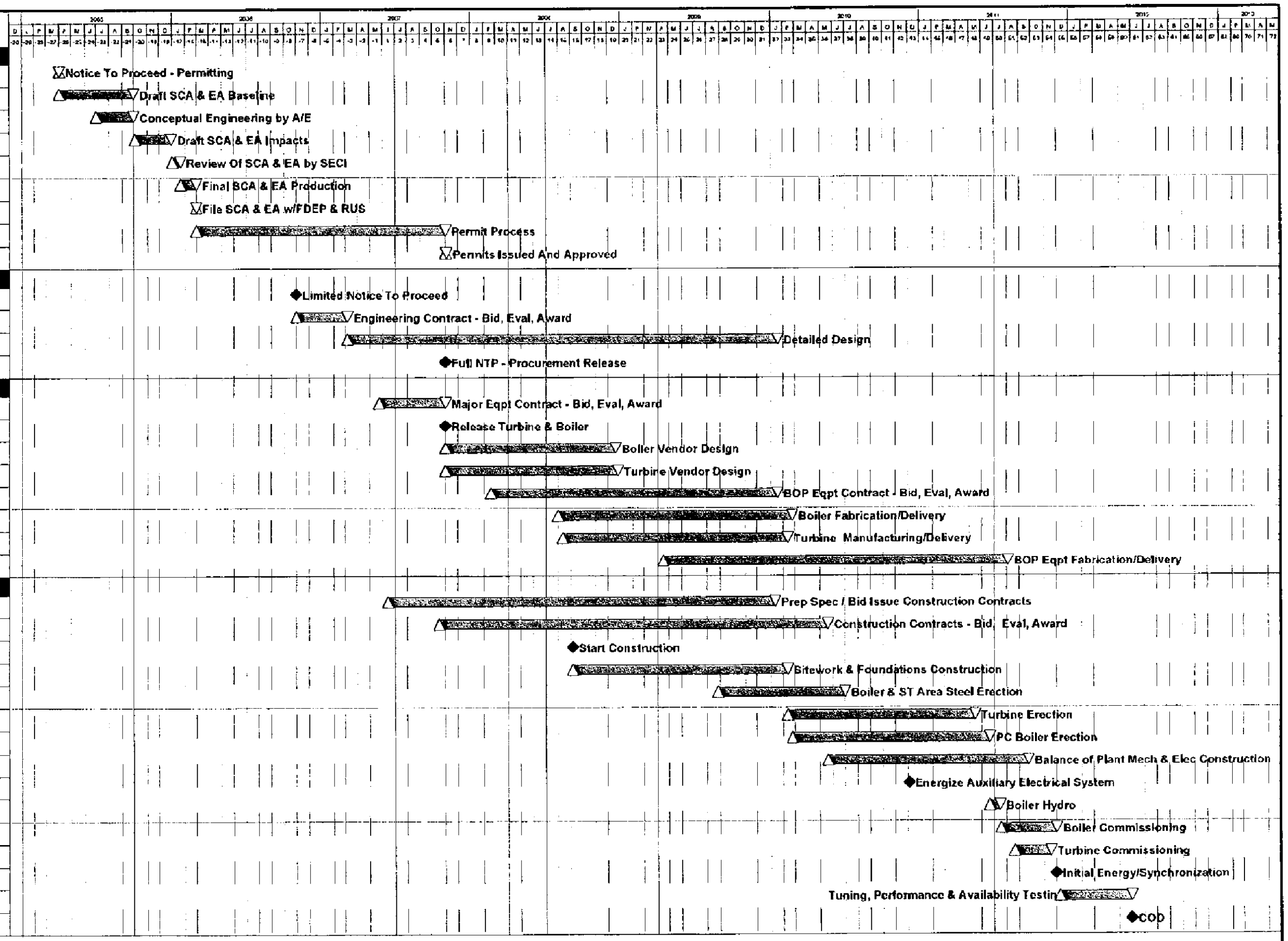
SEMINOLE ELECTRIC COOPERATIVE, INC
Seminole Generating Station

WATER MASS BALANCE
(Units 1 - 3)

PROJECT DRAWING NUMBER 36571
REV B
CODE
AREA

Exhibit RAK-3
28 of 89

Activity ID	Activity Description	Orig Dur	Early Start	Early Finish
Permitting				
C61311	Notice To Proceed - Permitting	1	01APR05*	01APR05
C61312	Draft SCA & EA Baseline	131	01APR05	30SEP05
C61313	Conceptual Engineering by A/E	66	01JUL05	30SEP05
C61314	Draft SCA & EA Impacts	65	03OCT05	30DEC05
C61315	Review Of SCA & EA by SECI	15	02JAN06	20JAN06
C61316	Final SCA & EA Production	27	23JAN06	28FEB06
C61317	File SCA & EA w/FDEP & RUS	1	01MAR06	01MAR06
C61318	Permit Process	436	01MAR06	31OCT07
C61319	Permits Issued And Approved	1	01NOV07	01NOV07
Engineering				
C61012	Limited Notice To Proceed	0	01NOV06*	
C61172	Engineering Contract - Bid, Eval, Award	90	01NOV06	06MAR07
C61210	Detailed Design	750	07MAR07	19JAN10
C61010	Full NTP - Procurement Release	0	01NOV07	
Procurement				
C61182	Major Eqpt Contract - Bid, Eval, Award	117	22MAY07	31OCT07
C61020	Release Turbine & Boiler	0	01NOV07	
C61170	Boiler Vendor Design	297	01NOV07	19DEC08
C61180	Turbine Vendor Design	300	01NOV07	24DEC08
C61183	BOP Eqpt Contract - Bid, Eval, Award	500	20FEB08	19JAN10
C61050	Boiler Fabrication/Delivery	410	31JUL08	24FEB10
C61040	Turbine Manufacturing/Delivery	394	11AUG08	11FEB10
C61052	BOP Eqpt Fabrication/Delivery	600	15APR09	02AUG11
Construction & Startup				
C61185	Prep Spec / Bid Issue Construction Contracts	675	14JUN07	13JAN10
C61030	Construction Contracts - Bid, Eval, Award	675	18OCT07	19MAY10
C61060	Start Construction	0	05SEP08	
C61220	Sitework & Foundations Construction	375	05SEP08	11FEB10
C61070	Boiler & ST Area Steel Erection	220	27AUG09	30JUN10
C61080	Turbine Erection	326	12FEB10	13MAY11
C61150	PC Boiler Erection	343	25FEB10	20JUN11
C61230	Balance of Plant Mech & Elec Construction	350	20MAY10	21SEP11
C61090	Energize Auxiliary Electrical System	0		03DEC10
C61110	Boiler Hydro	19	21JUN11	15JUL11
C61120	Boiler Commissioning	98	18JUL11	30NOV11
C61100	Turbine Commissioning	65	19AUG11	17NOV11
C61130	Initial Energy/Synchronization	0		30NOV11
C61160	Tuning, Performance & Availability Testing	127	08DEC11	01JUN12
C61140	COD	0		01JUN12



Start Date 01SEP04
Finish Date 01JUN12
Data Date 01SEP04
Run Date 02SEP04 16:16

Early Bar
Progress Bar
Critical Activity

SM12

Seminole Electric Cooperative, Inc.
Seminole Generating Station
Unit 3
600 MW Net Pulverized Coal Plant

Sheet 1 of 1

Burns & McDonnell
SINCE 1898

4.0 PERFORMANCE AND EMISSIONS

4.1 PERFORMANCE

Estimated performance was developed for 600 MW net subcritical and supercritical PC units at SGS. The estimates summarized in this section are based on in-house data and information from similar projects. A performance summary is shown in Table 4-1.

Table 4-1: 600 MW (net) Performance

Boiler Type	Pulverized Coal Subcritical 1,050 F/1,050 F	Pulverized Coal Supercritical 1,050 F/1,050 F
Net Plant Output (kW)	600,000	600,000
STG Heat Rate (Btu/kW-hr)	7,430	7,172
STG Gross Output (kW)	648,649	652,174
Boiler Efficiency (%)	87.1	87.1
Auxiliary Power (kW)	48,649	52,174
Auxiliary Power (%)	7.5%	8.0%
Net Plant Heat Rate (Btu/kW-hr)	9,220	8,949

4.1.1 Start-up and Load Following

Cold start-up times for a PC boiler are commonly in the 5-6 hour range. Supercritical boilers are capable of reaching maximum load 15% to 20% faster than subcritical units because supercritical boilers do not have thick wall components like a steam drum. However, supercritical units are typically base loaded units due to the economic advantage of the steam cycle efficiency.

4.2 EMISSIONS

A preliminary assessment of the anticipated Best Available Control Technology (BACT) was performed and the anticipated emissions requirements for a new 600 MW net PC unit at SGS were developed. The BACT levels estimated for this study are not absolute. BACT emission levels change with time, unit type, and fuel type. The emission rates represent Burns & McDonnell's best estimated BACT levels taking into account technology limitations and current expected guaranteed performance levels.

4.2.1 Emissions Control Technologies

The control technologies required for either a subcritical or supercritical unit is based on firing a blend consisting of 70% bituminous coal and 30% pet coke. The fuel analysis for the blended fuel is shown in Appendix E. As a result, the emissions control equipment required to accommodate the blended fuel is as follows:

- SCR for NO_x control.
- Activated Carbon Injection System for mercury (Hg) control.
- ESP for particulate (PM) control.
- FGD for SO_2 control.
- Wet ESP for sulfuric acid mist (H_2SO_4) control.

4.2.1.1 Selective Catalytic Reduction System

The SCR system uses anhydrous ammonia, which is injected into the flue gas at the economizer exit and a catalyst that reduces NO_x to molecular nitrogen and water. Ammonia slip would be below 2 ppm. Sonic horns are used for removal of fly ash from the catalyst during operation.

The anhydrous ammonia is pumped from the storage tank as a liquid to the ammonia vaporization and injection equipment. The liquid ammonia is vaporized by an electric heater and fed to the dilution equipment. The ammonia is mixed with air and injected into the flue gas ductwork upstream of the catalyst.

4.2.1.2 Activated Carbon Injection System

The reagent injection system injects activated carbon into the flue gas upstream of the ESP for mercury control. The mercury present in the flue gas absorbs the activated carbon and is collected in the ESP downstream. Fly ash collected in the ESP downstream will not be saleable due to the injection of carbon.

The carbon injection system consists of a pneumatic loading system, storage silos, hoppers, blowers, transport piping, and control system. The injection equipment would likely be skid mounted. There is a high probability for the need of additional air compressors to convey the carbon to the injection point and provide the flow and pressure to get the carbon into the flue gas stream and properly mixed.

4.2.1.3 Electrostatic Precipitator

An ESP will be provided to reduce particulate emissions. The ESP will generate a high voltage electrical field that will give the particulate matter an electric charge (positive or negative). The charged particles will then be collected on a collection plate. A rapper or hammer system will be utilized to vibrate the particles off of the collection plates and into the hoppers for disposal.

4.2.1.4 Wet FGD

In the wet FGD process, a slurry of finely ground limestone ($CaCO_3$) in water is recirculated through an absorber tower to provide turbulent contact with the flue gas. The contact between the flue gas and the slurry cools and saturates the gas and results in the absorption of SO_2 into the slurry liquid. The gas/liquid contact also results in removal of a significant amount of the residual fly ash. Chemical reactions between the limestone and the absorbed SO_2 take place within the absorber and in the absorber sump, resulting in the formation of solid particles of calcium sulfite ($CaSO_3$). Some of the oxygen in the flue gas participates in the reactions, resulting in the formation of particles of calcium sulfate ($CaSO_4$) as well. A forced oxidation system will be utilized to inject air into the absorber sump to promote the formation of calcium sulfate and minimize the formation of calcium sulfite solids. The resultant slurry is recycled and processed in the dewatering system.

4.2.1.5 Wet ESP

The utilization of a high sulfur fuel along with a wet FGD requires a wet ESP to decrease the concentration of sulfuric acid aerosol (acid mist) particles entering the stack. The wet ESP would be located at the top of the absorber tower in a vertical flow configuration to minimize layout space requirements. The wet ESP will introduce an electric field that will remove the acid mist from the flue gas onto collecting plates. A washing system will be provided to remove the particulate matter deposited on the collecting plates. The liquid will be collected and either diverted to the wet FGD system, recycled, or disposed of.

4.2.2 Expected Pollutant Limits

Based on the control technologies described above, the preliminary BACT emission limits for the subcritical and supercritical units being evaluated are as follows:

Table 4-2: Preliminary BACT Emission Limits

Pollutant	Emission Limit
NO_x	0.07 lb/MMBtu
SO_2	0.18 lb/MMBtu
PM	0.015 lb/MMBtu
Hg	6×10^{-6} lb/MW-hr
CO	0.15 lb/MMBtu
H_2SO_4	0.005 lb/MMBtu

The PM emission rate of 0.015 lb/MMBtu is filterable particulate matter only. A PM_{10} emission limit including filterables and condensibles has not been guaranteed by vendors on the condensable portion. Further, the mercury emission limit specified is based on recent test data and does not represent a typical vendor guarantee. In addition, the CO limit is based on the expected byproducts from the combustion process in the boiler and is not a controlled pollutant.

4.2.3 Emission Allowances

This study does not account for the purchasing of emission allowances that may be required for compliance.

5.0 COST ESTIMATES

5.1 CAPITAL COST ESTIMATES

The cost estimates summarized in this section represent screening-level cost estimates used in evaluating the installation of a 600 MW net PC unit adjacent to the existing units at SGS. Equipment costs are based on recent vendor quotes for similar equipment and in-house data. Construction commodities and indirect costs are based on Burns & McDonnell's experience. Burns & McDonnell did not solicit bids from equipment manufacturers or contractors for equipment or construction services.

The capital cost estimates for 600 MW net subcritical and supercritical PC units are included in Table 5-1.

TABLE 5-1: COST ESTIMATES (2010$)

Description	600 MW PC Subcritical	600 MW PC Supercritical
PROCUREMENT		
Mechanical Procurement		
Steam Turbine - Generator	$ 38,973,000	$ 41,359,000
Boiler Island/APC Equipment	$ 145,386,000	$ 146,594,000
Surface Condenser & Air Removal Equipment	$ 4,892,000	$ 4,608,000
Boiler Feed Pumps	$ 1,457,000	$ 1,861,000
Condensate Pumps/Circulating Water Pumps	$ 1,796,000	$ 1,796,000
Miscellaneous Mechanical Equipment	$ 27,370,000	$ 31,091,000
Electrical & Control Procurement		
GSU, Auxiliary Transformers	$ 5,280,000	$ 5,280,000
Medium Voltage Metal-Clad Switchgear	$ 5,320,000	$ 5,320,000
480 V Switchgear & Transformers	$ 1,108,000	$ 1,108,000
Miscellaneous Electrical Equipment	$ 2,379,000	$ 2,379,000
Control Procurement	$ 2,931,000	$ 2,931,000
Water Treatment Procurement	$ 16,960,000	$ 16,960,000
Structural Procurement	$ 7,382,000	$ 7,382,000
CONSTRUCTION		
Major Equipment Erection		
Steam Turbine - Generator Erection	$ 6,193,000	$ 5,428,000
Boiler Island/APC Equipment Erection	$ 141,499,000	$ 143,896,000
Furnish & Erect Packages		
Cooling Tower	$ 20,000,000	$ 18,560,000
Material Handling Systems	$ 20,272,000	$ 20,272,000
Chimney	$ 12,500,000	$ 12,500,000
Civil / Structural Construction	$ 58,619,000	$ 58,638,000
Mechanical Construction	$ 76,999,000	$ 83,653,000
Electrical Construction	$ 54,010,000	$ 54,010,000
PROJECT INDIRECTS		
Construction Management	$ 12,625,000	$ 12,625,000
Preoperational Testing, Startup, & Calibration	$ 11,933,000	$ 11,933,000
Miscellaneous Construction Indirects	$ 7,569,000	$ 7,569,000
Project Management & Engineering	$ 39,256,000	$ 39,256,000
Project Bonds	$ 7,834,000	$ 7,834,000
Escalation	$ 115,365,000	$ 116,673,000
Project Development	$ 3,000,000	$ 3,000,000
Owner Operations Personnel	$ 2,856,000	$ 2,856,000
Substation / Transmission Upgrades	$ 2,400,000	$ 2,400,000
Land	$ -	$ -
Permitting & License Fees	$ 2,643,000	$ 2,643,000
Initial Fuel Inventory	$ 12,096,000	$ 11,850,000
Miscellaneous Owner Costs	$ 11,485,000	$ 11,578,000
Sales Tax & Duties	$ 1,196,000	$ 1,345,000
Owner Contingency	$ 88,158,000	$ 89,719,000
TOTAL PROJECT COST	**$ 969,742,000**	**$ 986,906,000**

5.1.1 Capital Cost Estimate Assumptions

The cost basis for the subcritical and supercritical solid fuel fired options is defined in Table 5-2. More specifically, the following are the major assumptions and exclusions upon which the facility cost estimates are based:

- Project will be executed under a multiple contract method. This contracting method assumes an engineer for plant design, procurement by SECI, and construction performed by multiple contractors.
- Cost estimate is based on a non-union labor force for the Palatka, Florida area, 40-hour work week, single shift with some overtime.
- Rail access is nearby and suitable for receipt of heavy equipment.
- Cost estimate includes escalation to support commercial operation in June 1, 2012. Escalation at the rate of 2.5% to the midpoint of construction in 2010 is included in the estimate.
- No piles have been included. All foundations are assumed to be spread footings or matt foundations.
- Rock, existing structures, underground utilities, or other obstructions will not be encountered in the area of the plant.
- Hazardous substances will not be encountered in the area of the plant.
- No aesthetic landscaping or structures are included.
- Off-site road, bridge, or other improvements are not included.
- Transmission system costs are not included.

Table 5-2: 600 MW (net) Subcritical Plant Cost Basis/Assumptions

General:	
Water Supply:	
Cooling Tower Make-up:	
Source:	River water will be used for makeup to the cooling tower.
Supply:	Cooling tower makeup water will be supplied from new pumps installed in the existing intake structure. New supply piping will included.
Storage:	None.
Cycle Make-up:	Existing well water system will feed the water treatment system.
Service Water:	New service water pumps and head tank will be included to supply service water to the new unit.
Potable Water:	Potable water will be supplied from existing system.
Wastewater Disposal:	
Process Wastewater:	Plant wastewater except cooling tower blowdown and site runoff (does not include landfill and coal pile runoff) will be discharged to the equalization basin and reusued or evaporated in brine concentrators. Cooling tower blowdown and site runoff will be discharged to the St. Johns River.
Contaminated Wastewater:	Drains from areas around equipment that could be contaminated with oil will be directed through an oil/water separator and discharged to the existing equalization basin.
Sanitary Wastewater:	Sanitary waste will be treated in a new package sewage treatment plant and effluent will be discharged to the equalization basin.
Stormwater Discharge:	Stormwater (except for coal pile and landfill runoff) will be collected in a storm drainage system and discharged to St. Johns River.
Start-up Fuel:	Start-up fuel for the project will be fuel oil. A new fuel oil storage tank will be included to provide adequate capacity for the new unit. New fuel oil pumps will be required for the new unit.
Solid Fuel:	
Types:	Plant will be designed to operate with a 70/30 blend of eastern bituminous coal and petcoke.
Delivery:	Solid fuel will be delivered to the plant by rail only. Trains are anticipated to be up to 100 car unit trains.
Dead Storage:	Solid fuel will be stored in uncovered outdoor piles. Total storage for all three units of 60 days will be provided.
Live Storage:	New unit outdoor active pile shall have approximately 24 hours of full load operation.
Boiler Storage:	Boiler building silo storage shall have a minimum of 24 hours of full load operation.
Blending:	70% coal and 30% petcoke blend.
Sorbent Supply (Scrubber):	
Source:	Current limestone supplier or as required.
Size:	Limestone size shall be a maximum of 3".
Delivery:	The existing truck unloading system has adequate capacity for the new unit.
Storage:	15 days of covered storage and 40 to 60 days of total storage. Sizing of sorbent storage will be based upon design fuel.
Fly Ash & Scrubber Sludge Disposal:	
Disposal:	Fly ash will be disposed of in the on-site landfill. Gypsum will be sold to the adjacent wallboard plant. Landfill capacity (including expansion requirements) will be based on 25-30 year production assuming a 70/30 blend of coal and pet coke. Landfill costs will include a composite liner with leachate collection system installed on both the current landfill area and the expansion area. Cover material thickness will be 3 feet.
Day Storage:	One fly ash silo with minimum of 3 days of fly ash storage will be provided. Silo will be sized for the fuel with highest ash production rate.
Transportation:	Fly ash will be transported to the landfill via trucks.
Bottom Ash Disposal:	
Ash Disposal:	Bottom ash will be sold.
Ash Storage:	Bottom ash will be collected and stored in a silo sized for 3 days of bottom ash storage.
Ash Transportation:	Bottom ash will be extracted using a dry ash handling system and phenumatically conveyed to a silo. The bottom ash will then be trucked off for off-site sale.
Ammonia:	
Types:	Anhydrous Ammonia
Delivery:	Truck with self contained unloading pump
Storage:	15 day storage tank capacity
Construction Utilities:	
Water Supply:	Water supply for construction will be from the existing plant make-up water system (well water pumps).
Construction Power:	Power supply for construction will be from the existing plant via a power line and temporary transformer.
Equipment Delivery:	Major equipment will be delivered to the site via rail. Other equipment will be received via rail or truck, whichever is more economical.

Civil:	
Disposal of Spoils:	Spoils will be disposed of on site. No hazardous materials are anticipated to be found in the soils.
Soil Conditions / Stability:	Existing soils are assumed to be stable in and around the area of the new unit and suitable for use as laydown without any further preparation. Soils are assumed to be adequate for structural fill. No overexcavation and recompaction is included.
Subsurface Rock:	Removal of subsurface rock is not included.
Cut & Fill:	Site will be developed as a balanced site requiring minimal off-site fill and minimal disposal of spoils. Assumed minimal site slopes across the width and off-site fill will be available from within 10 miles of the site.
Dewatering:	Some dewatering of the main power plant structures is anticipated. This will be confirmed with preliminary geotechnical studies.
Construction Stormwater Control:	Silt fences will be required for construction erosion control. No other special erosion control is included.
Roads:	Existing main plant roads will be used. Minor roads and maintenance areas associated with the new unit will have an asphalt finish.
Parking:	Parking areas will be surfaced with asphalt concrete.
Rail Scale:	Existing weight measurement system will be used.
Coal Pile Run-off:	New coal storage areas will not be required. Coal pile run-off will be directed to the existing equalization basin.
Site Security:	Assume existing fencing and gates are adequate except where landfill expansion requires modification to existing fence and where fencing is required around new facilities such as the cooling tower.
Landscaping:	Minimal landscaping is included. Disturbed areas will be seeded for erosion control.
Structural:	
Soil Bearing Capacity:	Soils are assumed to be suitable for bearing capacities greater than 2500 psf. Therefore, spread footings and matt foundations are anticipated for all structures under this scope of work.
Piling:	No piling is anticipated.
Groundwater:	Some dewatering costs will be included.
Boiler Enclosure:	Boiler will not be enclosed.
Steam Turbine Enclosure:	Steam turbine will be enclosed. The steam turbine hall will interface with the existing steam trubine hall.
Administration Facilities:	No additional administration space will be required.
Control Facilities:	Existing control room will be utilized for new operator stations.
Warehouse/Storage Facilities:	An additional 100 ft. x 100 ft. warehouse will be included.
Water Treatment Building:	Additional building space will be included for water treatment equipment.
Maintenance Shop:	No additional maintenance shop area will be included.
Yard Maintenance Building	No additional yard maintenance facilities will be included.
Electrical Enclosures	Several buildings of various sizes located to reduce wiring runs.
Stack:	Stack to be provided with manlift for access.
Height	675' tall.
Velocity	A maximum of 60 feet per second.
Diameter	Exit diameter of 24'.
Liner Material	Clad C-276
Mechanical:	
Boiler:	Drum type, balanced draft, natural circulation, pulverized coal boiler with steam turbine throttle conditions of 2520 psig and 1050F and with reheat at 1050 F designed for 100% of VWO output on the steam turbine.
Steam Turbine Generator:	Nominally 600MW, 3,600 rpm, down-exhaust, reheat, tandem compound, four flow type designed to normally operate at maximum output (turbine or generator limited) at a 0.9 PF.
Feedwater Heaters:	Seven stages of feedwater heating.
Steam Turbine Bypass:	Not included as the unit is intended to be base loaded.
Auxiliary Boiler:	Will use an auxiliary steam system for new unit start-up.
Heat Rejection:	
Condenser:	Split waterbox, wet surface condenser with 316SS tubes.
Cooling Tower/Cooling Pond:	Utilize a concrete, natural draft cooling tower without fire protection.
Fans:	
FD Fans:	2x60% motor driven, constant speed, centrifugal, with inlet guide vanes.
ID Fans:	3x50% motor driven, constant speed, centrifugal with inlet guide vanes.
PA Fans:	2x60% motor driven, constant speed, centrifugal with inlet dampers
Air Heaters:	2x50%
Pumps:	
Boiler Feed Pumps:	2x60% steam turbine driven, constant speed, barrel pumps
Start-up boiler feed pump:	1x30% motor driven start-up pump.
Condensate Pumps:	3x50% constant speed motor driven pumps
Circulating Water Pumps	3x50% motor driven constant speed, standard construction

Water Treatment:	
Steam Cycle Make-up:	Additional 150 gpm of demineralizer capacity will be provided.
Cooling Tower Make-up:	Chemical feed for pH adjustment, corrosion/scale control, and blowdown treatment as required.
Cooling Tower Sidestream:	Notincluded.
Service Water Make-up:	Service water will be supplied from existing system.
Condensate Polishing	4x35% capacity deep bed polisher vessels with external regeneration.
Wastewater Treatment:	
Scrubber Purge Water	Brine concentrators (2) with spray dryer provided to treat scrubber purge water from Units 1 - 3. Solid waste hauled to the on-site landfill.
Compressed Air Supply:	3x50% capacity rotary screw air compressors with desiccant type air dryers
Fire Protection:	Fire protection system per NFPA. The fire water loop will be extended around the new unit. New diesel driven, motor driven, and motor driven jockey pumps will be included for the new unit.
Water Storage:	
Condensate Storage:	Additional 300,000 gallons of storage capacity is included.
Raw Water Storage:	Use existing well water and river water system. However, a new 15,000 gallon surge tank and pumps will be added to the well water system.
Demineralized Water Storage:	Combined with condensate storage.
Potable Water Storage	Potable water will be supplied from existing system.
Auxiliary Cooling:	
Type:	Closed Cooling Water System
Exchangers:	Plate & Frame with 316SS plates
Coal Handling:	
Unloading:	Existing rotary car dumper will be used.
Check Weighing:	Belt scale on existing conveyor will be used.
Stockpiling:	As recommended by Burns & McDonnell.
Dead Storage Reclaim:	Dozer w/ hoppers as this is not the normal fuel reclaim method. Only used in emergencysituations. Existing dozers will be used in conjunction with new trencher.
Live Storage Reclaim:	New trencher stacker / reclaimer and existing trencher stacker / reclaimer.
Reclaim redundancy:	Use existing and new trencher.
Crushers:	Use existing crushers.
Reclaim Sizing:	Fill 24 hour usable volume.
Pulverizers:	One redundant coal silo / pulverizer unit based upon design fuel blend. Worst case fuel may utilize the redundant unit without any further redundancy.
Limestone Handling	
Unloading:	Use existing truck unloading system.
Storage:	Short term and long term storage will be indoor/outdoor storage piles using existing mobile equipment with existing reclaim equipment. Storage will be expanded to maintain 45-60 days of limestone storage.
Delivery to Scrubber:	Reclaimed and delivered to 1x100% limestone bins (12 hour storage) via 1x100% limestone conveyor.
Preparation:	Crushed limestone will be prepared in existing 2x100% ball mills. One new limestone slurry storage tanks will be added for the new unit.
Fly Ash Handling	
Removal from ESP	Pressurized pneumatic conveying systems including 2x50% trains with 3x50% blowers to the ash silo. Conveying system will be sized to remove 24 hours of ash in an 8 hour shift.
Ash Load-out:	Ash truck loadout systems will be provided below the silo via gravity or pneumatic conveying. Ash loadout will include 2x100% ash conditioning systems (pug mills). Fly ash transport to the on-site landfill will be by truck. Alternate dry loadout capability via truck will be provided to support ash sales.
Bottom Ash Handling	
Removal from Boiler	Dry extraction bottom ash removal system.
Ash Load-out:	Trucked from Silo.
Scrubber Sludge Handling:	
Hydroclones	Radial hydroclone assembly with a minimum of 2 spare cyclones.
Vacuum Filter	Two 100% capacity belt filters sized for all 3 units.
Pug Mills	Not required
Ash Storage:	Included with fly ash handling.
Sludge Storage	Notincluded.
Sludge Disposal	Gypsum conveyed to wall board plant on site.
Scrubber	
Type:	Wet FGD - Forced Oxidized
Size:	1x100% module for the 600 MW unit.
Turndown capability:	5:1 as a minimum.
Redundancy:	A spare recycle pump or organic acid feed system shall be provided.
Accessories:	

ESP	
Redundancy	None
Type:	Ridgid frame
SCA:	(To be determined)
Activated Carbon Injection	An activated carbon injection system will be provided for mercury control.
Maximum Injection Rate	20 lbs/mmACF
Wet ESP	
Type	Vertical flow located above absorber module.
Number of fields	A minimum of 2 fields.
SCA:	(To be determined)
SCR	
Catalyst type	Honeycomb
Space Velocity	(To be determined)
SCR Bypass	There will be a SCR bypass for fuel oil starting.
Economizer Bypass	There will be an economizer bypass on the water side to maintain temperature at low loads.
Emissions Control:	
Emissions Control:	
NOx:	SCR guaranteed for 0.07 lb/MMBtu of exhaust NOx.
Ammonia Slip:	3 ppmvd @ 3% O2
CO:	Combustion controls to 0.15 lb/MMBtu.
SOx:	Wet scrubber to accomplish 0.18 lb/MMBtu. Equipment guaranteed for 98% removal of the inlet SO_2 concentration.
PM10:	Electrostatic precipitator to accomplish emissions of 0.015 lb/MMBtu (filterable only).
Mercury:	Carbon injection system to reduce mercury emissions to 6 x 10^{-6} lb/MW-hr (Approximately 0.6 lb/Tbtu heat input).
Sulfuric Acid Mist:	Wet ESP guaranteed for 0.005 lb/mmBtu.
General Notes - Not Scope Items	
Coal Handling:	Covered conveyors with dust collection at transfers and wet suppression at stockout.
Stack Height:	"Good Engineering Practice" - per US Code Title 42, Ch 85,Sub 1, Part A, Section 7423 - approx. 2.5 times the height of the tallest adjacent structure (boiler). Assumed 675 feet for estiamte.
Electrical	
Generator Step-up Transformer:	Three, single phase step-up transformers to provide ability to use the existing spare transformer. Transformers will be rated at OA/FA/FOA.
Black Start Capability:	Not Included.
Emergency Generator:	Included for essential power only.
Emergency Power:	2 hour DC system with a UPS for supply to the control system and critical instrumentation.
Start-up / Back-up Power:	Start-up of unit will be accomplished using 2X 50% three winding start up transformers.
Auxiliary Power Supply:	Two 50% three winding auxiliary transformers connected to the bus between the generator and the GSU. Transfer from start up power to unit auxiliary power after the bus is synchronized to the generator.
Plant Control System:	Distributed control system with remote located I/O panels.
Plant Communications:	
External and Office to Office	Tie into existing infrastructure.
Internal around plant	Gaitronics communication system throughout the plant.
Switchyard Communications	Notincluded.
Transmission / Interconnection:	
Switchyard:	Included.
Transmission:	Notincluded.
Interconnection to Existing Transmission:	Included.
Construction:	
General Liability Insurance:	Included
Builder's Risk Insurance:	Not Included
Performance Bonds:	Included
Performance/Stack Testing:	Included
Commissioning / Start-up:	Included
Operator Training:	Included
Permits:	Building permits and construction permits will be included. Air, NPDES, and other plant discharge permits will not be included.
Construction Schedule	It is assumed that the construction schedule will be adequate to allow the project to be completed with minimal overtime. Construction schedule will be estimated as a 5x8 with some overtime.

Miscellaneous:	
Permanent Plant Operating Spare Parts:	Allowance will be included.
Maintenance Tools & Equipment.	Allowance will be included.
Fuel, Lime, and Ash Transportation Equipment:	Allowances will be included to cover the cost of any permanent on-site mobile equipment purchased for fuel, ash, or limestone transportation.

Items Excluded from the Scope:
1. Legal Costs.
2. Costs for Owner's operations personnel (during construction and commissioning/start-up).
3. Fuel, limestone, and ash transportation equipment or rental costs for equipment required to transport such materials to or from the site. Allowances will be included for on-site equipment.
4. Land Costs.
5. Sound abatement above normal supply.
6. Aesthetic landscaping other than erosion control.
7. Emergency diesel generator (black start capability).
8. Waste water treatment or disposal other than discharge to a location on site.

5.1.2 Limitations, Qualifications and Estimate Risk Assessment

The estimates and projections prepared by Burns & McDonnell relating to construction costs and schedules are based on our experience, qualifications and judgment as a professional consultant. Since Burns & McDonnell has no control over weather, cost and availability of labor, material and equipment, labor productivity, construction contractor's procedures and methods, unavoidable delays, construction contractor's method of determining prices, economic conditions, government regulations and laws (including interpretation thereof), competitive bidding and market conditions or other factors affecting such estimates or projections, Burns & McDonnell does not guarantee that actual rates, costs, performance, schedules, etc., will not vary from the estimates and projections prepared by Burns & McDonnell.

Due to the capital intensive nature of solid fuel generation projects resources and length of construction period, there is capital cost risk due to interest costs, labor availability and costs, and general inflation. Other risk factors associated with the construction of new solid fuel generation plants include the fact several US boiler manufacturers are currently under financial duress, and the skilled workforce that constructed a number of coal units in the 1970's and 1980's have aged without a significant influx of younger construction workers with similar specialized skills and experience. If a number of new coal units initiate construction within the next decade, the supply of skilled construction workers could be strained. The primary tradeoff for these higher capital risks with a solid fuel generation resource is the long-term stability of coal and other solid fuel alternatives, which have few competing uses relative to natural gas that is used by almost all economic sectors including residential heating.

5.1.3 Black Start Alternate Pricing

Although not included in the capital cost estimates being evaluated in the pro forma analyses, SECI requested a screening level cost for providing black start capability for the new unit. The cost associated with providing black start capability is estimated at $14,000,000. This price represents an installed cost for the black start emergency diesel generator sets including exhaust gas ducting and stacks, switchgear, transformers, radiator coolers, instrumentation, testing and commissioning.

The estimated load required by the diesel generator sets is approximately 20 MW. This auxiliary load estimate is based on starting a single primary air fan, forced draft fan, induced draft fan, circulating water pump, and condensate pump. In addition, the vacuum pumps, closed cooling water pump, auxiliary cooling water pump and various other smaller auxiliary systems were considered in the start-up power consumption estimate.

5.2 OPERATIONS & MAINTENANCE (O&M) COST ESTIMATES

A summary of the calculated variable and fixed O&M costs for the subcritical and supercritical solid fuel fired alternatives are included in Tables 5-3 and Table 5-4. These costs were estimated based on the assumptions discussed in this section.

Table 5-3: O&M Cost Estimate
Seminole Generating Station Unit 3
1 x 600 MW Subcritical

Operating Assumptions					
Basis Year for Cost Estimate					2004
Capacity Factor					85.0%
Load Factor					100.0%
Net Unit Output, kW					600,000
Number of Units					1
Net Output, kW					600,000
Net Annual Output, MWh					4,467,600
Net Steam Turbine Heat Rate					7,430
Net Plant Heat Rate, Btu/kWh					9,220
Fuel Consumption, MMBtu/hr					5,532
Annual Fuel Consumption, MMBtu					41,191,272
Boiler Technology					Pulverized Coal
Type of NOx Control					SCR
Type of SO2 Control					Wet
Type of Particulate Control					ESP
Type of H2SO4 Control					Wet ESP
Type of Mercury Control					Carbon Injection
Type of Heat Rejection					Cooling Tower
Cooling Tower Materials of Construction					Concrete
Make-up Water Softening Required					Yes
Zero Discharge Facility					Yes
Type of Sidestream Treatment					None
Fixed O&M					
Labor	46 people @	$ 70,448			***$ 3,240,610***
Office & Admin					***$ 75,000***
G&A (Home Office / Support)					**By Seminole**
Other Fixed O&M					***$ 1,350,000***
Employee Expenses/Training					
Contract Labor					
Environmental Expenses					
Safety Expenses					
Buildings, Grounds, and Painting					
Other Supplies & Expenses					
Communication					
Control Room/Lab Expenses					
Annual Steam Turbine Inspections					***$ 100,000***
Annual Boiler Inspections					***$ 80,000***
Annual APC Inspections					***$ 100,000***
Start-up power demand charge	$ -	per kW-Mo	15,000	KW	***$ -***
Water supply demand charge	$ -	per acre-ft	0	acre-ft	***$ -***
Water discharge demand charge	$ -	per acre-ft	0	acre-ft	***$ -***
Standby Power Energy Costs	$ -	per kW-hr	3,942,000	KW-hr	***$ -***
Standby Power Service Fee	$ -	per Month	12	Mo	***$ -***
Property Taxes					**In Proforma**
Insurance					**In Proforma**
Total Fixed O&M Annual Cost					***$ 4,945,610***
Major Maintenance Costs (Capitalized)					
Steam Turbine / Generator Overhaul	7446	Op Hours/yr $	50.00	$/hour	***$ 372,300***
Steam Generator Major Replacements (Boiler $10MM@10yrs & Burners @ 20 yrs & Walls)			968,052	$/yr	***$ 968,100***
Baghouse Bag Replacement	-	$/Replacement	5	years	***$ -***
SCR Catalyst Replacement	$3,153,759	Catalyst Cost	3	yrs life	***$ 1,051,300***
Water Treatment System Replacements			4,843	$/yr	***$ 4,800***
Total Annual Major Maintenance Costs					***$ 2,396,500***

Non-Fuel Variable O&M					
Water Consumption					
Raw Water	3455	MMGal/yr @	$0.00 /kGal	$	-
Raw Water Make-up Treatment	3455	MMGal/yr @	$0.14 /kGal	$	488,300
Potable Water	1	MMGal/yr @	$1.00 /kGal	$	1,500
Water Discharge	907	MMGal/yr @	$0.00 /kGal	$	-
Cooling Tower Treatment Chemicals	3181	MMGal/yr @	$0.05 /kGal	$	174,900
Demin Water Treatment	56	MMGal/yr @	$0.04 /kGal	$	2,500
Boiler Treatment Chemicals	2893	MMGal/yr @	$0.0158 /kGal	$	45,600
Maintenance & Consumables (lube oil, nitrogen, hydrogen, etc.)					
SCR System General Maintenance					
General Maintenance			$67,082 $/yr	$	67,100
S Scrubber System General Maintenance					
Absorber, Dewatering & Accessories			$126,114 $/yr	$	126,100
Limestone Preparation			$367,064 $/yr	$	367,100
V Water Treatment System General Maintenance			$63,878 $/yr	$	63,900
V Cooling Tower System General Maintenance			$200,000 $/yr	$	200,000
Brine Concentrator and Spray Dryer System O&M			$2,349,000 $/yr	$	2,349,000
Other Variable O&M				$	5,383,800
Electronics, Controls, BOP Electrical					
Steam Generators					
BOP					
Misc. Maintenance Expenses					
Consumables					
Emissions Controls					
Lime Consumption	NA	tpy @	$107.89 /ton	$	-
Limestone Consumption	245,789	tpy @	$8.66 /ton	$	2,128,500
SCR Ammonia (Anhydrous)	1,601	tpy @	$250.00 /ton	$	400,300
Gypsum (Sales) / Disposal	423,509	tpy @	-$10.80 /ton		(4,573,900)
Ash (Sales) / Disposal (Wet Scrubber)	107,282	tpy @	$4.00 /ton		429,100
Ash (Sales) / Disposal (Dry Scrubber)	NA	tpy @	$4.00 /ton		-
Bottom Ash (Sales) / Disposal	26,820	tpy @	-$6.50 /ton		(174,300)
Carbon Injection	4,762	tpy @	$1,040.00 /ton		4,952,200
Total Non-Fuel Variable O&M Annual Cost				$	12,431,700
Total Fixed and Variable O&M Annual Cost				$	19,773,810
Total Fixed O&M Annual Cost, $/kW-yr					8.24
Total Emission Allowance Costs, $/yr				$	-
Total Major Maintenance (Capitalized Costs), $/MWh				$	0.54
Total Non-Fuel Variable O&M Annual Cost, $/MWh				$	2.78
Total O&M Cost, $/MWHr					4.43

Notes:

1. O&M costs do not include the following:
   - Taxes
   - Insurance
   - Firm fuel supply costs
   - Wheeling costs
   - Fuel
   - Backup or standby power
   - Initial spares, pre-op costs (computers, software, office equipment, etc.), or O&M mobilization fees
2. Assumes limestone / lime are 90% $CaCO_3$ and limestone has 10% moisture.
3. Assumes SO_2 removal of 98% for wet.
4. Assumes 0.2 lb/MMBtu of boiler NO_x production and .04 lb/MMBtu NO_x out of stack.
5. Assumes Ash and gypsum contains 5% moisture.
6. Carbon injection assumes control to meet proposed MACT.
7. SCR replacements assumes that catalyst is regenerated and not disposed of.
8. The above costs and heat rate information assume the unit is operating at 100% load.
9. Staffing costs assume non-union operator wage rates and assume 5% overtime.

Table 5-4: O&M Cost Estimate
Seminole Generating Station Unit 3
1 x 600 MW Supercritical

Operating Assumptions						
Basis Year for Cost Estimate						2004
Capacity Factor						85.0%
Load Factor						100.0%
Net Unit Output, kW						600,000
Number of Units						1
Net Output, kW						600,000
Net Annual Output, MWh						4,467,600
Net Steam Turbine Heat Rate						7,172
Net Plant Heat Rate, Btu/kWh						8,949
Fuel Consumption, MMBtu/hr						5,369
Annual Fuel Consumption, MMBtu						39,980,552
Boiler Technology						Pulverized Coal
Type of NOx Control						SCR
Type of SO2 Control						Wet
Type of Particulate Control						ESP
Type of H2SO4 Control						Wet ESP
Type of Mercury Control						Carbon Injection
Type of Heat Rejection						Cooling Tower
Cooling Tower Materials of Construction						Concrete
Make-up Water Softening Required						Yes
Zero Discharge Facility						Yes
Type of Sidestream Treatment						None
Fixed O&M						
Labor	46 people @	$	70,448		$	***3,240,610***
Office & Admin					$	***75,000***
G&A (Home Office / Support)						**By Seminole**
Other Fixed O&M					$	***1,350,000***
Employee Expenses/Training						
Contract Labor						
Environmental Expenses						
Safety Expenses						
Buildings, Grounds, and Painting						
Other Supplies & Expenses						
Communication						
Control Room/Lab Expenses						
Annual Steam Turbine Inspections					$	***100,000***
Annual Boiler Inspections					$	***80,000***
Annual APC Inspections					$	***100,000***
Start-up power demand charge	$ -	per kW-Mo	15,000	KW	$	-
Water supply demand charge	$ -	per acre-ft	0	acre-ft	$	-
Water discharge demand charge	$ -	per acre-ft	0	acre-ft	$	-
Standby Power Energy Costs	$ -	per kW-hr	3,942,000	KW-hr	$	-
Standby Power Service Fee	$ -	per Month	12	Mo	$	-
Property Taxes						**In Proforma**
Insurance						**In Proforma**
Total Fixed O&M Annual Cost					$	***4,945,610***
Major Maintenance Costs (Capitalized)						
Steam Turbine / Generator Overhaul	7446	Op Hours/yr $	50.00	$/hour	$	***372,300***
Steam Generator Major Replacements (Boiler $10MM@10yrs & Burners @ 20 yrs & Walls)			968,052	$/yr	$	***968,100***
Baghouse Bag Replacement	-	$/Replacement	5	years	$	-
SCR Catalyst Replacement	$3,153,759	Catalyst Cost	3	yrs life	$	***1,051,300***
Water Treatment System Replacements			4,843	$/yr	$	***4,800***
Total Annual Major Maintenance Costs					$	***2,396,500***

Non-Fuel Variable O&M					
Water Consumption					
Raw Water	3455	MMGal/yr @	$0.00 /kGal	$	-
Raw Water Make-up Treatment	3455	MMGal/yr @	$0.14 /kGal	$	488,300
Potable Water	1	MMGal/yr @	$1.00 /kGal	$	1,500
Water Discharge	907	MMGal/yr @	$0.00 /kGal	$	-
Cooling Tower Treatment Chemicals	3181	MMGal/yr @	$0.05 /kGal	$	174,900
Demin Water Treatment	56	MMGal/yr @	$0.04 /kGal	$	2,500
Boiler Treatment Chemicals	2793	MMGal/yr @	$0.0158 /kGal	$	44,100
Maintenance & Consumables (lube oil, nitrogen, hydrogen, etc.)					
SCR System General Maintenance					
General Maintenance			$67,082 $/yr	$	67,100
Scrubber System General Maintenance					
Absorber, Dewatering & Accessories			$126,114 $/yr	$	126,100
Limestone Preparation			$367,064 $/yr	$	367,100
Water Treatment System General Maintenance			$63,878 $/yr	$	63,900
Cooling Tower System General Maintenance			$200,000 $/yr	$	200,000
Brine Concentrator and Spray Dryer System O&M			$2,349,000 $/yr	$	2,349,000
Other Variable O&M				$	5,383,800
Electronics, Controls, BOP Electrical					
Steam Generators					
BOP					
Misc. Maintenance Expenses					
Consumables					
Emissions Controls					
Lime Consumption	NA	tpy @	$107.89 /ton	$	-
Limestone Consumption	238,564	tpy @	$8.66 /ton	$	2,066,000
SCR Ammonia (Anhydrous)	1,601	tpy @	$250.00 /ton	$	400,300
Gypsum (Sales) / Disposal	411,062	tpy @	-$10.80 /ton		(4,439,500)
Ash (Sales) / Disposal (Wet Scrubber)	104,128	tpy @	$4.00 /ton		416,500
Ash (Sales) / Disposal (Dry Scrubber)	NA	tpy @	$4.00 /ton		-
Bottom Ash (Sales) / Disposal	26,031	tpy @	-$6.50 /ton		(169,200)
Carbon Injection	4,762	tpy @	$1,040.00 /ton		4,952,200
Total Non-Fuel Variable O&M Annual Cost				$	12,494,600
Total Fixed and Variable O&M Annual Cost				$	19,836,710
Total Fixed O&M Annual Cost, $/kW-yr					8.24
Total Emission Allowance Costs, $/yr				$	-
Total Major Maintenance (Capitalized Costs), $/MWh				$	0.54
Total Non-Fuel Variable O&M Annual Cost, $/MWh				$	2.80
Total O&M Cost, $/MWHr					4.44

Notes:

1. O&M costs do not include the following:
   - Taxes
   - Insurance
   - Firm fuel supply costs
   - Wheeling costs
   - Fuel
   - Backup or standby power
   - Initial spares, pre-op costs (computers, software, office equipment, etc.), or O&M mobilization fees
2. Assumes limestone / lime are 90% $CaCO_3$ and limestone has 10% moisture.
3. Assumes SO_2 removal of 98% for wet.
4. Assumes 0.2 lb/MMBtu of boiler NO_x production and .04 lb/MMBtu NO_x out of stack.
5. Assumes Ash and gypsum contains 5% moisture.
6. Carbon injection assumes control to meet proposed MACT.
7. SCR replacements assumes that catalyst is regenerated and not disposed of.
8. The above costs and heat rate information assume the unit is operating at 100% load.
9. Staffing costs assume non-union operator wage rates and assume 5% overtime.

5.2.1 Staffing

In addition to the existing operations staff, the Unit 3 operations staff will consist of two control room operators, two support system operators, and one roving operator on the day shift. During all other shifts, the tasks of the support system operators will be shared by the two control room operators. There will also be an additional fuel/ash operator on all shifts. The control room operators for each shift will be thoroughly trained in all aspects of plant controls and will be fully qualified to operate all plant systems.

Unit 3 will share operational staff with the existing units. The existing shift supervisor will direct shift operations, make assignments, and perform required administrative duties for the new unit. The shift supervisor will also serve as a second operator during emergencies and provide periodic relief for the primary control room operator. The existing plant staffing will be expanded by 46 employees to accommodate the new unit. By sharing staff, all units will benefit from added flexibility and will be able to operate with fewer on-site staff per unit. The additional staff required for the new unit was included as part of the fixed O&M cost and is summarized in Table 5-5.

Table 5-5: Additional Staffing Plan

Seminole Generating Station Unit 3: 600 MW Pulverized Coal, Brownfield

	Employees	Salary	OT %	OT	Bonus	Additions	Payroll Cost
Plant Manager	0	$ 100,000	5.00%	$7,500	$ 10,000	$ 36,125	$ 153,625
Administrative Assistant	1	$ 45,000	0.00%	$0	$ 4,500	$ 15,750	$ 65,250
Fuel/Ash Analysis Technician	0	$ 55,000	0.00%	$0	$ 5,500	$ 19,250	$ 79,750
Trainer	1	$ 60,000	0.00%	$0	$ 6,000	$ 21,000	$ 87,000
Technical Document Control Clerk	1	$ 40,000	0.00%	$0	$ 4,000	$ 14,000	$ 58,000
IS Analyst/Network Administrator	0	$ 70,000	0.00%	$0	$ 7,000	$ 24,500	$ 101,500
Quality Assurance Specialist	0	$ 60,000	0.00%	$0	$ 6,000	$ 21,000	$ 87,000
Safety & Health Engineer	0	$ 60,000	0.00%	$0	$ 6,000	$ 21,000	$ 87,000
Plant Engineer	1	$ 70,000	0.00%	$0	$ 7,000	$ 24,500	$ 101,500
Environmental Engineer	0	$ 70,000	0.00%	$0	$ 7,000	$ 24,500	$ 101,500
Technical Services Manager	0	$ 85,000	0.00%	$0	$ 8,500	$ 29,750	$ 123,250
Maintenance/Technicians							
Maintenance Superintendent	0	$ 85,000	0.00%	$0	$ 8,500	$ 29,750	$ 123,250
Maintenance Planner	0	$ 70,000	0.00%	$0	$ 7,000	$ 24,500	$ 101,500
CMMS Specialist	0	$ 70,000	0.00%	$0	$ 7,000	$ 24,500	$ 101,500
I&C/E Supervisor	0	$ 70,000	0.00%	$0	$ 7,000	$ 24,500	$ 101,500
Lead I&C/E Technician	1	$ 55,000	5.00%	$4,125	$ 5,500	$ 19,869	$ 84,494
I&C/E Technician (days)	1	$ 45,000	10.00%	$6,750	$ 4,500	$ 16,763	$ 73,013
I&C/E Technician (shift)	1	$ 45,000	10.00%	$6,750	$ 4,500	$ 16,763	$ 73,013
I&C/E Technician (Night)	1	$ 47,250	10.00%	$7,088	$ 4,725	$ 17,601	$ 76,663
I&C/E Technician (Weekends)	1	$ 47,250	10.00%	$7,088	$ 4,725	$ 17,601	$ 76,663
I&C/E Technician (Vacation)	1	$ 40,000	10.00%	$6,000	$ 4,000	$ 14,900	$ 64,900
Helper (days)	1	$ 30,000	10.00%	$4,500	$ 3,000	$ 11,175	$ 48,675
Helper (shift)	1	$ 30,000	10.00%	$4,500	$ 3,000	$ 11,175	$ 48,675
Helper (Night)	1	$ 30,000	10.00%	$4,500	$ 3,000	$ 11,175	$ 48,675
Mechanical Supervisor	0	$ 70,000	0.00%	$0	$ 7,000	$ 24,500	$ 101,500
Lead Mechanic	1	$ 55,000	5.00%	$4,125	$ 5,500	$ 19,869	$ 84,494
Mechanic (days)	1	$ 45,000	10.00%	$6,750	$ 4,500	$ 16,763	$ 73,013
Mechanic (shift)	1	$ 45,000	10.00%	$6,750	$ 4,500	$ 16,763	$ 73,013
Mechanic (nights)	1	$ 47,250	10.00%	$7,088	$ 4,725	$ 17,601	$ 76,663
Mechanic (Weekends)	1	$ 47,250	10.00%	$7,088	$ 4,725	$ 17,601	$ 76,663
Mechanic (Vacation)	1	$ 40,000	10.00%	$6,000	$ 4,000	$ 14,900	$ 64,900
Helper (days)	1	$ 30,000	10.00%	$4,500	$ 3,000	$ 11,175	$ 48,675
Helper (shift)	1	$ 30,000	10.00%	$4,500	$ 3,000	$ 11,175	$ 48,675
Helper (Night)	1	$ 30,000	10.00%	$4,500	$ 3,000	$ 11,175	$ 48,675
Operators							
Operations Superintendent	0	$ 85,000	0.00%	$0	$ 8,500	$ 29,750	$ 123,250
Senior Operations Specialist	0	$ 75,000	0.00%	$0	$ 7,500	$ 26,250	$ 108,750
Shift Supervisor	0	$ 60,000	5.00%	$4,500	$ 6,000	$ 21,675	$ 92,175
Control Room Operator (Day)	4	$ 45,000	10.00%	$6,750	$ 4,500	$ 16,763	$ 73,013
Control Room Operator (Shift)	2	$ 45,000	10.00%	$6,750	$ 4,500	$ 16,763	$ 73,013
Control Room Operator (Night)	2	$ 47,250	10.00%	$7,088	$ 4,725	$ 17,601	$ 76,663
Control Room Operator (Weekends)	2	$ 47,250	10.00%	$7,088	$ 4,725	$ 17,601	$ 76,663
Control Room Operator (Vacation)	1	$ 40,000	10.00%	$6,000	$ 4,000	$ 14,900	$ 64,900
Roving Operator (Day)	1	$ 45,000	10.00%	$6,750	$ 4,500	$ 16,763	$ 73,013
Roving Operator (Shift)	1	$ 45,000	10.00%	$6,750	$ 4,500	$ 16,763	$ 73,013
Roving Operator (Night)	1	$ 47,250	10.00%	$7,088	$ 4,725	$ 17,601	$ 76,663
Roving Operator (Weekends)	1	$ 47,250	10.00%	$7,088	$ 4,725	$ 17,601	$ 76,663
Limestone Operator (Days)	0	$ 40,000	10.00%	$6,000	$ 4,000	$ 14,900	$ 64,900
Fuel Yard Lead Operator	0	$ 55,000	10.00%	$8,250	$ 5,500	$ 20,488	$ 89,238
Fuel Yard Operator (Days)	1	$ 45,000	10.00%	$6,750	$ 4,500	$ 16,763	$ 73,013
Fuel Yard Operator (Shift)	1	$ 45,000	10.00%	$6,750	$ 4,500	$ 16,763	$ 73,013
Fuel Yard Operator (Night)	1	$ 47,250	10.00%	$7,088	$ 4,725	$ 17,601	$ 76,663
Fuel Yard Operator (Weekends)	1	$ 47,250	10.00%	$7,088	$ 4,725	$ 17,601	$ 76,663
Ash Disposal Operator (Day)	1	$ 40,000	10.00%	$6,000	$ 4,000	$ 14,900	$ 64,900
Ash Disposal Operator (Shift)	1	$ 40,000	10.00%	$6,000	$ 4,000	$ 14,900	$ 64,900
Ash Disposal Operator (Night)	1	$ 42,000	10.00%	$6,300	$ 4,200	$ 15,645	$ 68,145
Ash Disposal Operator (Auxiliary)	1	$ 42,000	10.00%	$6,300	$ 4,200	$ 15,645	$ 68,145
Ash / Fuel Yard Operator (Vacation)	1	$ 40,000	10.00%	$6,000	$ 4,000	$ 14,900	$ 64,900
Water Treatment Tech/Chemist (Day)	0	$ 50,000	20.00%	$15,000	$ 5,000	$ 19,750	$ 89,750
Water Treatment Tech/Chemist (Shift)	0	$ 50,000	20.00%	$15,000	$ 5,000	$ 19,750	$ 89,750
Water Treatment Tech/Chemist (Night)	0	$ 52,500	20.00%	$15,750	$ 5,250	$ 20,738	$ 94,238
Water Treatment Tech/Chemist (Auxiliary)	0	$ 52,500	20.00%	$15,750	$ 5,250	$ 20,738	$ 94,238
Water Treatment Tech/Chemist (Vacation)	0	$ 48,000	10.00%	$7,200	$ 4,800	$ 17,880	$ 77,880

TOTAL UNIT 3 EMPLOYEES:	**46.0**
TOTAL PAYROLL: $	**3,240,610**

Additions:	35%	Percentage of base hourly wage
	15%	Percentage of overtime hourly wage
Overtime Pay:	150%	Multiple of base hourly wage
Bonus:	10%	Percentage of base salary cost

5.2.2 O&M Cost Estimate Assumptions

The following costs were assumed in estimating the non-fuel variable O&M Costs:

- Ash Disposal, $4.00/ton
- Limestone, $8.66/ton
- Anhydrous Ammonia, $250/ton
- Activated Carbon, $1,040/ton
- Gypsum Sales, $10.80/ton
- Bottom Ash Sales, $6.50/ton
- Property taxes, insurance, and interest during construction are included in the proforma analysis.
- Costs associated with emission allowances are not included in the O&M cost estimates.

6.0 ECONOMIC ANALYSIS

6.1 OBJECTIVE

Pro forma financial analyses were prepared to compare the 600 MW net subcritical pulverized coal alternative to the supercritical pulverized coal and gas-fired combined cycle alternatives. The economic analyses were based on the estimated capital costs, performance, fuel costs, and operating costs for the alternatives. The two solid fuel-fired alternatives were benchmarked to a combined cycle alternative for economic comparison. The economic results are summarized in the following sections.

6.2 SOLID FUEL ASSUMPTIONS & COST ESTIMATES

The following estimates and economic assumptions were utilized in the pro forma financial analyses for the solid fuel-fired units.

• Capital Costs including Owner Costs and Contingency	Table 5-1
• Heat Rate and Performance Estimates	Table 4-1
• Delivered Solid Fuel Cost Assumption (see section 6.2.1):	
Assumes 70%/30% coal/petcoke blend	2012: \$2.06 (\$/MMBtu)
	2013: \$2.09 (\$/MMBtu)
	2014: \$2.17 (\$/MMBtu)
	2%/yr Escalation after 2014
• Operating Assumptions:	
Planned Dispatch	8,016 hours per year (one month planned outage)
Overall Capacity Factor	85.0%
• Financing Assumptions:	
Interest Rate	6%
Term	30 years
Debt/Equity Percentage	100%/0%
Return on Equity	N/A

Construction Financing Fees	0.50%
Permanent Financing Fees	1.00%
Construction Financing	45 months

- O&M Cost Assumptions:

Fixed O&M Costs	Tables 5-3 and 5-4
Insurance	0.16% of Replacement Cost per year
Property Taxes	2% of Net Book Value per year
Variable O&M Costs	Tables 5-3 and 5-4
Transmission Costs	Not Included – Busbar Cost Evaluation
Lime/Limestone Costs	Included in Variable O&M
Emissions Allowances	Not Included

- Economic Assumptions:

O&M Inflation	2.5% per annum
Construction Cost Inflation	2.5% per annum
Delivered Solid Fuel Inflation	2.0% per annum (after 2014)
Discount Rate	6%
Effective Tax Rate	0%
Book Depreciation (Straight Line)	30 years

6.2.1 Solid Fuel Supply Availability

Fuel supply for the existing units and proposed third unit consists of a 70%/30% blend of Illinois Basin (West Kentucky) coal and petcoke. Coal prices from the Illinois Basin (ILB) region and petcoke from refineries are impacted by many factors. The following sections provide information regarding historical solid fuel availability and pricing and future issues that may impact coal and petcoke pricing.

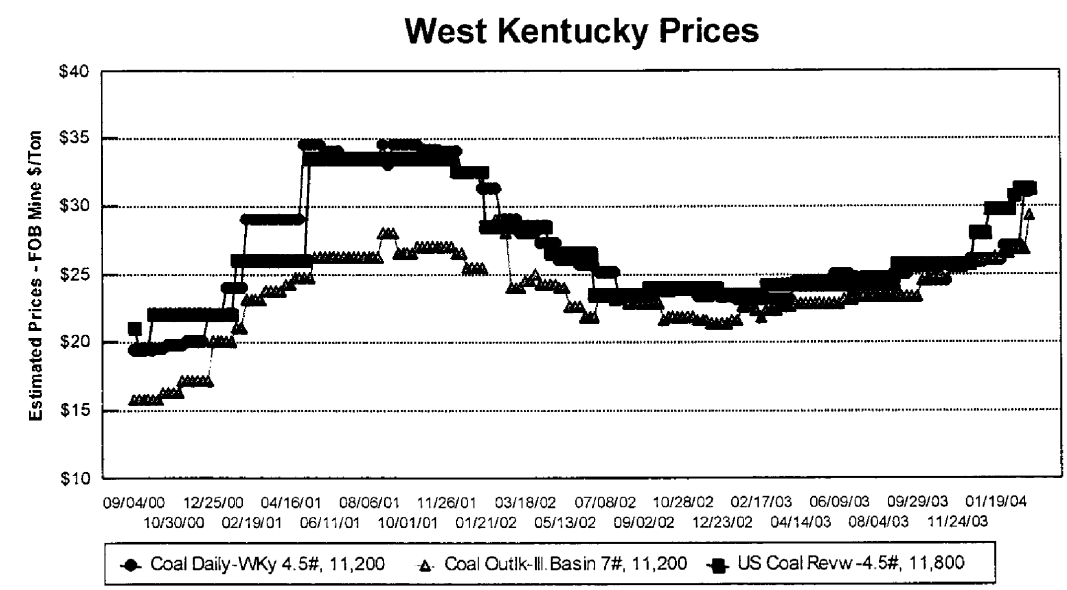
6.2.1.1 Illinois Basin Coal

The ILB coal region is comprised of bituminous coal production principally from mines in western Kentucky, Indiana, and Illinois. The coal is wide ranging in quality, generally ranging from 10,000 – 12,800 BTU, and from about 0.5 % - 5.0 % sulfur. The ILB is the fourth largest coal producing region in the U.S., accounting for about 89 million tons of coal production in 2003. The coal is shipped to markets within the U.S. by rail, or rail-to-water, with some local deliveries by truck. As with some of the other coal regions in the Eastern U.S., two major railroads, the NS and CSX, originate a great deal of the ILB shipments, but there are many regional (short-line) railroads that deliver these coals.

The high prices and strong demand during 2001 allowed Illinois Basin production to rebound from 93 million tons in 2000 to 95 million tons in 2001; however, the high prices of 2001 also allowed other regions to expand in coal production. A mild 2001/02 winter, a new generation of gas plants, and a poor economy drove coal demand down and stockpiles up, which resulted in a drop in Illinois Basin production to 92 million tons in 2002. Prices dropped accordingly. The Basin's production dropped further to 89 million tons in 2003; however, production is expected to increase to 93 million tons for 2004. Longwall problems at ExxonMobil's Monterey and Murray's Galatia mines caused most of this decline. These mines have now resumed normal production.

Prices for Illinois Basin coals have also been variable, depending upon prices from other coal supply regions, gas prices, etc., ranging from a low of $15.00 per ton in late 2000 to as high as $35.00 per ton in 2001. Current prices, again coming back up, are around $30.00 per ton, as shown in Figure 6-1. Since the beginning of 2004 prices for Illinois Basin coal have increased, reflecting the supply shortage situation in the Eastern U.S. and internationally. Every available ton of Illinois Basin low sulfur coal is now moving into various markets to satisfy the lack of supply and high demand.

Figure 6-1



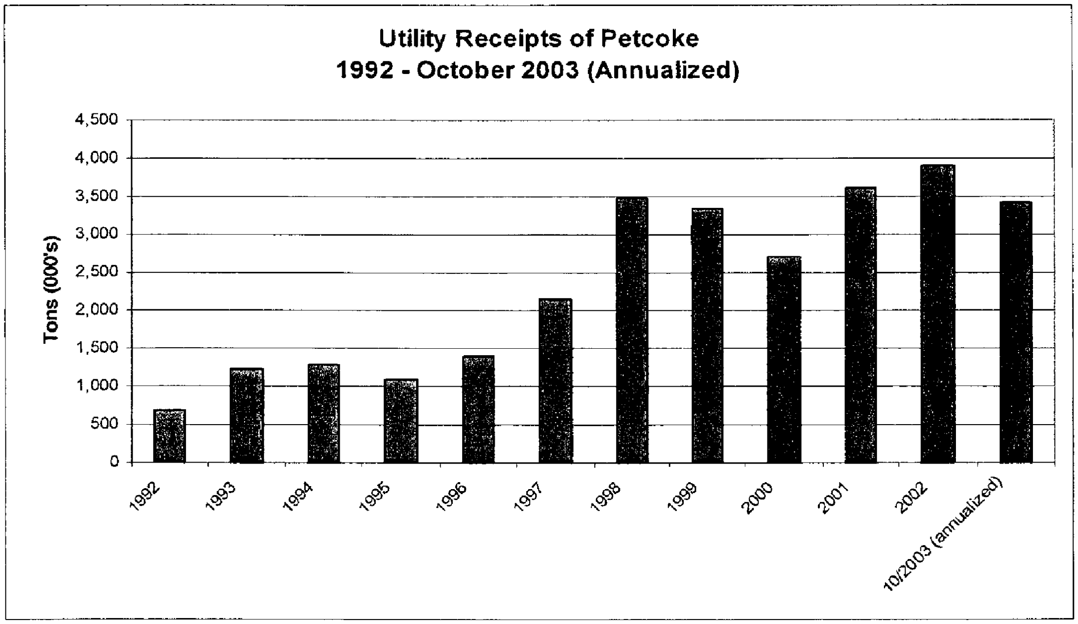
Key issues and market drivers for ILB:

- Tremendous coal reserves exist and significant expansion is possible in the ILB
- The large mines are controlled by a few major producers (Peabody, Alliance, Freeman, Consol, etc.), but there are also a number of smaller mines in the region
- Most mines have either CSX or NS rail service, but not both
- Some mines have access to waterways, but at additional transportation cost to the docks
- Production has declined in recent years

6.2.1.2 Petroleum Coke

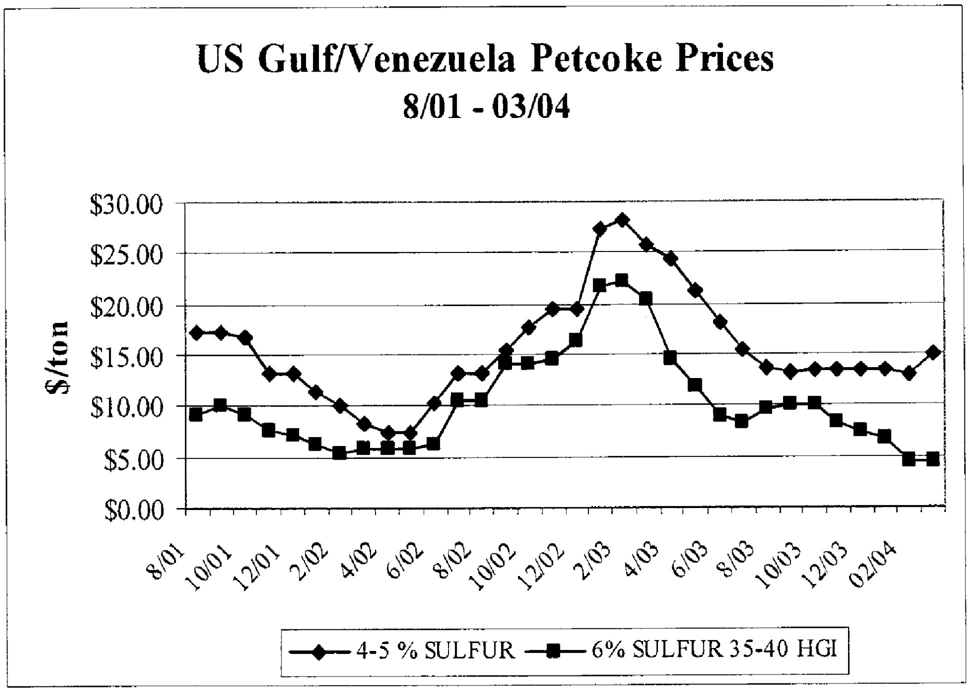
Petroleum coke has increasingly become an important swing fuel or fuel-blend candidate for a number of utilities in the U.S. Petcoke is a by-product of the oil refining process. There are various grades of petcoke production, with different sulfur, BTU and HGI contents. The fuel has a lot of value in the marketplace because it is a high BTU product (generally around 14,000 BTU), but its value is limited because it also contains very high sulfur content, ranging from 3% to 6%. Grindability is variable from very soft to very hard (35 – 70 HGI is typical). Figure 6-2 shows the increasing deliveries of petcoke to utility plants since 1992.

Figure 6-2



The price of petcoke depends upon a number of factors and prices for other fuels, such as coal. Since petcoke is a waste-product of the oil refining process, it can literally be given away at any price and refiners will sell for low prices rather than paying storage and environmental cleanup charges. Therefore, refineries are generally inclined to dump the petcoke to keep it moving. Likewise, because of the negative impacts of burning this fuel, its upward price is capped by coal and gas prices. However, the price of petcoke generally tends to follow coal prices. Figure 6-3 shows the variation present in petcoke pricing over a 2 ½ year time period.

Figure 6-3



Prices for petcoke dropped from early 2003 as a result of higher ocean freight rates which triggered a drop in demand from consumers relying on spot ocean freight rates. Some consumers have or will switch to alternatives such as high sulfur U.S. coal.

Key issues and market drivers for petcoke:

- Principal supplies are available in the U.S. and Venezuela
- Availability is variable since production is dependent upon refineries' processing of crude oils; i.e. petcoke production is directly related to and dependent upon oil refining
- Prices are highly variable depending upon supply, demand and quality, typically ranging from $6.00 - $30.00 per ton; prices are normally closer to the low end of this range
- New production capacity is coming online in the U.S., Venezuela and the Caribbean region
- Transportation issues and costs may be significant depending upon the location of the refineries (e.g. Houston/US Gulf, Chicago, Venezuela, etc.)

6.3 COMBINED CYCLE BENCHMARK ASSUMPTIONS & COST ESTIMATES

The following estimates and economic assumptions were utilized in the gas-fired combined cycle pro forma economic analysis.

• Capital Costs including Owner Costs and Contingency	$369,600,000
• Heat Rate Performance Assumptions	6,775 Btu/kWh (HHV)
• Delivered Natural Gas Cost Assumption	2004: $5.50 ($/MMBtu) 2.5% Escalation after 2004
• Operating Assumptions:	
Planned Dispatch	8,016 hours per year
Overall Capacity Factor	85.0%
• Financing Assumptions:	
Interest Rate	6%
Term	30 years
Debt/Equity Percentage	100%/0%
Return on Equity	N/A
Construction Financing Fees	0.50%
Permanent Financing Fees	1.00%
Construction Financing	24 months
• O&M Cost Assumptions:	
Fixed O&M Costs	$2,724,000
Insurance	0.16% of Replacement Cost per year
Property Taxes	2% of Net Book Value per year
Variable O&M Costs	$3.25 ($/MWh)
Transmission Costs	Not Included – Busbar Cost Evaluation
Emissions Allowances	Not Included

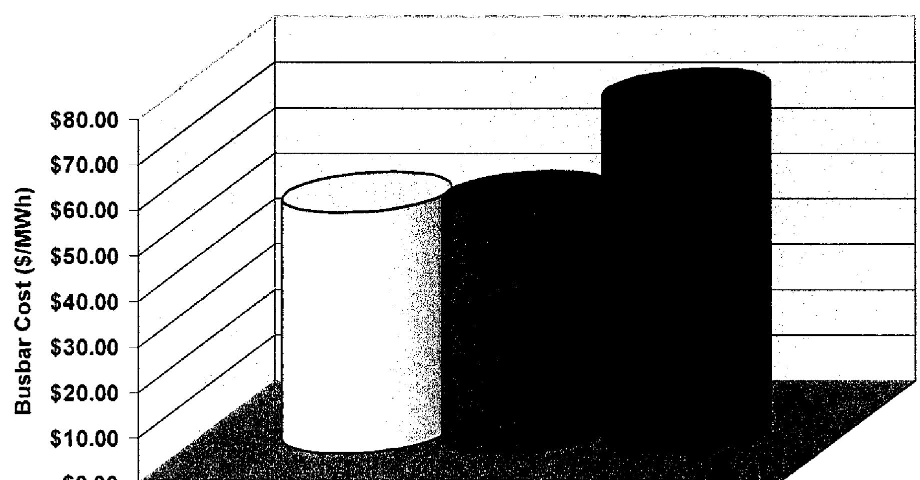
- Economic Assumptions:

O&M Inflation	2.5% per annum
Construction Cost Inflation	2.5% per annum
Delivered Natural Gas Fuel Inflation	2.5% per annum (after 2004)
Discount Rate	6%
Effective Tax Rate	0%
Book Depreciation (Straight Line)	30 years

6.4 ECONOMIC ANALYSIS RESULTS

The economic pro forma analyses were used to determine the 20-year levelized busbar cost of power for each alternative. Figure 6-4 presents a graph of the resulting 20-year levelized busbar power costs for the benchmark and both project alternatives. Figure 6-4 was developed by preparing a project pro forma for the benchmark and both alternatives under consideration. The busbar cost represents the energy cost in 2012$. The 20-year levelized busbar power costs for the supercritical PC unit, subcritical PC unit, and combined cycle benchmark unit are $52.77, $52.97, and $75.48 respectively.

Figure 6-4
20-Year Levelized Busbar Costs (2012$)



	Alternatives
Supercritical PC	$52.77
Subcritical PC	$52.97
Combined Cycle	$75.48

6.5 ECONOMIC CONCLUSIONS

Both the supercritical and subcritical PC units provide a low 20-year levelized busbar cost when compared to the gas-fired combined cycle plant. Combined cycle technology has a much higher fuel cost, but is much less capital cost intensive. For this reason, coal-fired technology is preferred to combined cycle technology for facilities with high capacity factors. Both of the coal-fired options are preferred to a combined cycle plant for baseload dispatch.

6.6 SENSITIVITY ANALYSIS RESULTS

Sensitivity analyses were prepared for the project alternatives under the following cases:

- Capital Cost (plus or minus 10%)
- Interest Rate (plus or minus one (1) percentage point)
- Capacity Factor (plus or minus 5%)
- Delivered Fuel Cost (plus or minus 10%)
- O&M Costs (plus or minus 10%)

The results of the sensitivity analyses are presented in tornado diagrams in Figures 6-5, 6-6, and 6-7. A tornado diagram illustrates the range of results for each sensitivity case and its impact on the levelized power cost, and ranks the results from greatest impact to least impact. The sensitivity analysis indicates that the interest rate, followed closely by fuel cost and capital cost, is the most significant factor affecting the economics of a solid fuel-fired unit. Since the pro forma analyses assume the project alternatives are to be financed with 100 percent debt, changes in the interest rate will have the greatest affect on the economics of the plant.

Figure 6-5

600 MW Pulverized Coal Supercritical Unit Sensitivity Analysis - Tornado Diagram

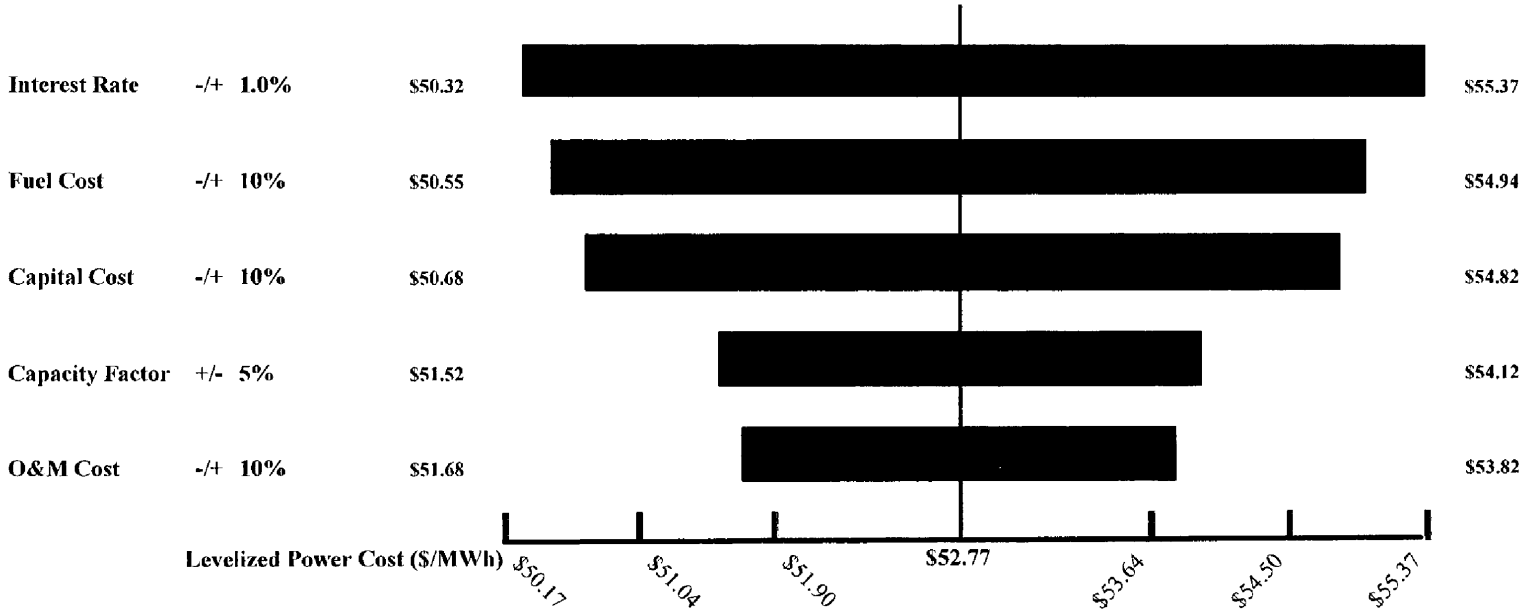


Figure 6-6

600 MW Pulverized Coal Subcritical Unit
Sensitivity Analysis - Tornado Diagram

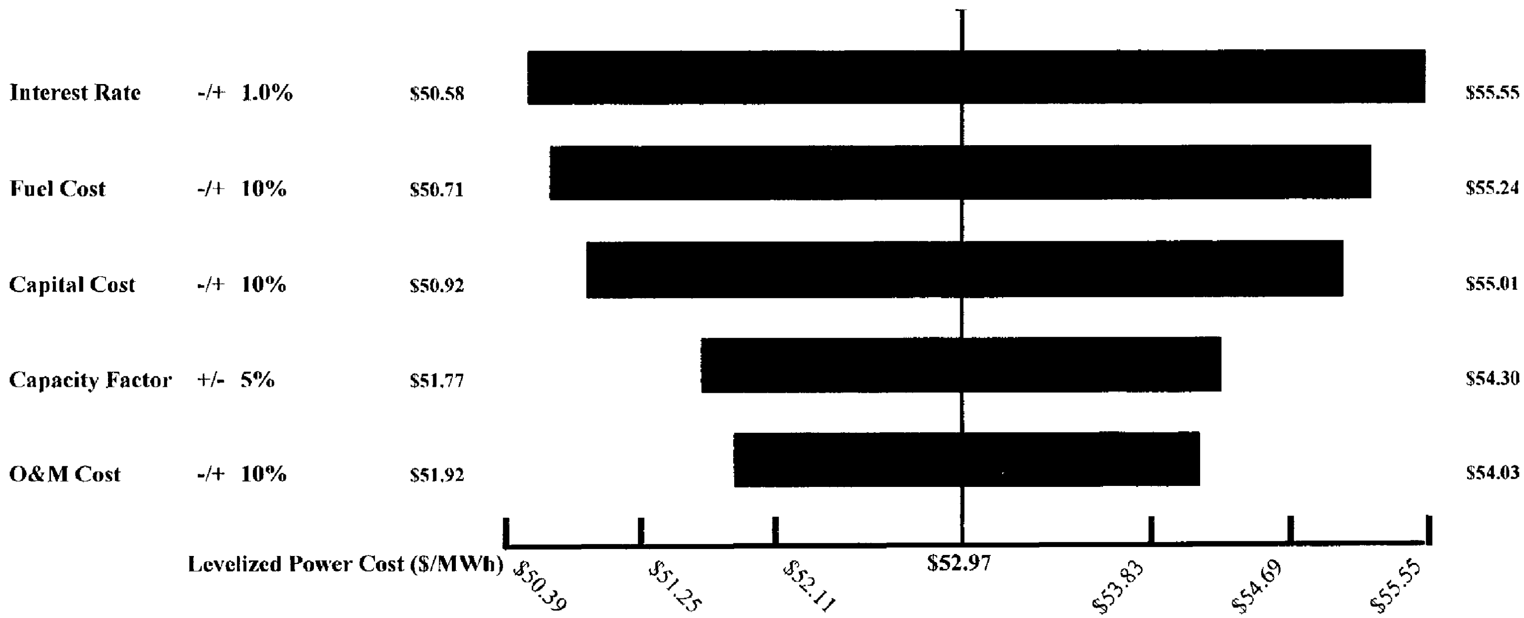
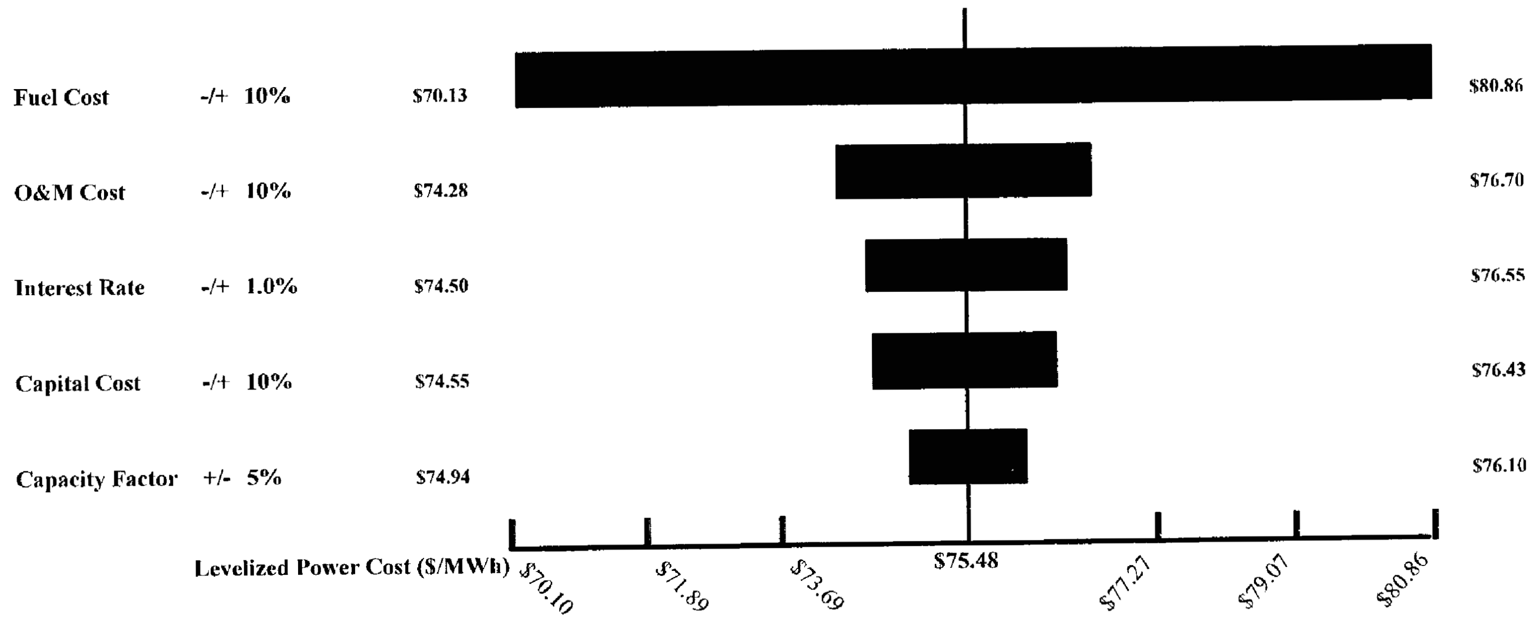


Figure 6-7

500 MW 2x1 Combined Cycle
Sensitivity Analysis - Tornado Diagram



7.0 CONCLUSIONS AND RECOMMENDATIONS

7.1 CONCLUSIONS

Both the supercritical and subcritical pulverized coal units provide a low 20-year levelized busbar cost when compared to the gas-fired combined cycle plant. Combined cycle technology has a much higher fuel cost, but is much less capital cost intensive. For this reason, solid fuel fired technology is preferred to combined cycle technology for facilities with high capacity factors. Both of the solid fuel fired alternatives are preferred to a combined cycle plant for baseload dispatch.

The supercritical unit has a slightly lower levelized bus bar cost of $52.77/MWh versus the subcritical unit bus bar cost of $52.97/MWh. Some of the considerations when selecting either a supercritical or subcritical steam cycle include:

- Operator familiarity with subcritical technology at the SGS plant.
- Lower emissions due to the higher efficiencies of the supercritical technology.
- Permitting may face fewer hurdles with a supercritical cycle versus a subcritical cycle.

The results of the cooling tower assessment indicate the mechanical draft cooling tower has a differential net present value of $11.7M lower than a natural draft cooling tower. However, the capital cost estimates include the cost of a natural draft cooling tower.

IGCC is a developing technology that has not performed reliably in commercial operation in the past. Therefore, it is recommended this technology not be considered for new generation at this time. There is planned development of gasification for coal in the near future, however it will be at least 4 -5 years before additional operational experience and information will be available on the cost and reliability of the technology.

7.2 FUTURE PLANNING CONSIDERATIONS

This study provides information for SECI to evaluate the alternatives identified in this study against SECI's request for proposals for additional capacity. Some additional steps for SECI consideration include the following:

- The schedule reflects the need for preliminary engineering to start in 2005 in order to support preparation of permits. The process of selecting an engineer should be started.
- If the potential for additional power off take participation exists, increasing the capacity of the new unit should be evaluated due to the economies of scale with larger units.
- It may be necessary to purchase additional property in order to support landfill requirements for the life of the unit.

7.3 STATEMENT OF LIMITATIONS

In preparation of this Feasibility Study, Burns & McDonnell has made certain assumptions regarding future market conditions for construction and operation of solid fuel generation resources. While we believe the use of these assumptions is reasonable for the purposes of this Study, Burns & McDonnell makes no representations or warranties regarding future inflation, labor costs and availability, material supplies, equipment availability, weather, and site conditions. To the extent future actual conditions vary from the assumptions used herein, perhaps significantly, the estimated costs presented in this Study may vary.

8.0 ATTACHMENTS

8.1 ATTACHMENT DESCRIPTIONS

These attachments support the body of the document and provide additional technical detail where necessary. Section 8 includes the following attachments:

- Attachment A – Subcritical vs. Supercritical Assessment: This attachment includes a summary of an evaluation regarding subcritical and supercritical technology.
- Attachment B – Cooling Tower Assessment: This attachment is an evaluation of a natural draft cooling tower versus a mechanical draft tower for the new unit.
- Attachment C – IGCC Assessment: This attachment provides an assessment of the Integrated Gasification Combined Cycle technology.
- Attachment D – Water Analysis: Includes water analyses for the river water and the well water supply. This information was provided by SECI.
- Attachment E – Coal Analysis: Includes analyses of the bituminous coal and petcoke fuels being proposed for the SGS Unit 3 addition. This information was provided by SECI.

Attachment A – Subcritical vs Supercritical Assessment

ATTACHMENT A - SUBCRITICAL VS. SUPERCRITICAL ASSESSMENT

1.0 GENERAL

Rankine cycle steam power plants employ three main technologies for generation. These technologies are characterized by the steam cycle operating pressure: subcritical (<3200 psia) and supercritical (3200 psia to 5000 psia). The primary advantages of supercritical cycles are, improved plant efficiency due to elevated operating pressures, lower emissions, and lower fuel costs as compared to subcritical designs. However, supercritical technology requires more initial capital and has more operating complexities.

The vast majority of utility coal fired generating units in the United States utilize subcritical technology. The U.S. market includes supercritical boilers; however, most of the units were installed between 1950 and 1980. The poor maintenance history of early supercritical units combined with the lack of coal-fired unit additions hindered the development of supercritical technology within the U.S. after 1980. However, many countries beyond the U.S. continued to develop and install supercritical technology. Continued use outside the U.S. is a result of the high fuel costs overseas and has led to the development and installation of several ultra supercritical units. To date, the U.S. has no ultra supercritical units. As a result, ultra supercritical units remain an unproven technology in the U.S. Therefore, this report focuses only on the comparison of subcritical and supercritical units.

1.1 SUBCRITICAL

1.1.1 General Description of Subcritical Units

Subcritical power plants utilize pressures below the critical point of water (3206 psia) where there is a distinct difference in the state of the liquid when it is boiling. The majority of the steam generators built in the United States utilize subcritical technology with steam turbine throttle pressures up to about 2520 psig. Burning fuel in the furnace generates high pressure steam in the tubes of the boiler through convection and radiation energy transfer. This steam exits the tubes with excess water such that a two phase fluid exists. The steam separates from the water in a steam drum with internal separators and then is superheated utilizing superheater tubes.

Typical historical design steam conditions for subcritical units are 2400 psig and 1000°F at the steam turbine main steam inlet and 1000°F steam at the reheat steam inlet. Normally, these units were provided with the capability to increase steam pressure to 2520 psig at the overpressure operating condition with the steam turbine inlet throttle valves wide open (VWO). Recent subcritical units, however, have main steam design conditions of 2520 psig at the steam turbine inlet with VWO to afford some of the efficiency improvements during normal operation that previously only overpressure operation could provide. In addition, improvements in steam cycle materials of construction have resulted in the ability to increase main steam and reheat steam temperatures to 1050°F, providing additional cycle efficiency improvements with minimal impact on project costs. The increase in main steam pressure and main steam and reheat steam temperatures results in a net heat rate improvement of approximately 2 percent over heat rates of plants operated at historical design steam conditions.

Another change to recent units is the elimination of the turbine control stage. Most of the newer units are proposed to be base-loaded with existing units or with gas turbine plants providing the load following. The benefit of an internal turbine control stage is higher operating efficiencies at reduced load. This benefit comes with a penalty to efficiency at base load. Since new base load units are not expected to operate at part-load for significant amount of time, the most economical configuration is with external throttle control valves in lieu of the internal control stage. This configuration results in a reduction in steam turbine costs and an improvement in base-load efficiency.

1.1.2 Operating Considerations

Start-up time for a subcritical pulverized coal boiler from a cold start (after a 36 hour shutdown) is a minimum of 5 hours. Historically, start-up time has been longer than the 5 hour minimum due to condensate water quality issues. Typical ramp rates are between 3-5 percent per minute for 50-100 percent loads and 3 percent for loads below 50 percent. Generally, the faster the ramp rate the larger the steam temperature control range. Thermal stresses in the steam drum limit the minimum start-up times and the maximum ramp rates.

1.1.3 Performance

Estimated annual average operational heat rates for a subcritical pulverized coal unit are between 9000 and 9600 Btu/kWh (HHV) at full load conditions. These performance estimates are based on a new and clean steam turbine operating with steam conditions of 2520psig/1050°F/1050°F and with the boiler burning a bituminous/petcoke mixture for fuel.

1.2 SUPERCRITICAL

1.2.1 General Description of Supercritical Units

Supercritical units typically operate at 3500 to 3700 psig with main steam and reheat steam temperatures of 1000°F or greater. Recent supercritical units under design in the U.S. utilize main steam temperatures between 1050°F and 1075°F and reheat steam temperatures between 1050°F and 1100°F.

Supercritical units are very similar to the subcritical units described earlier. The major difference is that the boiler operates in the supercritical region where water converts directly to steam without a two phase fluid existing. As a result of this, the supercritical boiler uses a once-through system which excludes a steam drum. Since there is no steam drum to allow the removal and blowdown of impurities in the system, all impurities carried by the steam go into the steam turbine. For this reason, the condensate system typically incorporates a full-flow condensate polisher to maintain high water quality.

Supercritical boiler designs use either spiral or vertical tube arrangements. Both designs attempt to minimize areas in the corners of the boiler where flow through the tubes is starved, which can result in elevated tube wall temperatures and premature failure. The spiral tube design has more than 30 years of experience. The primary disadvantages to the spiral tube arrangement are the complexity in supporting the tubes and the additional tube-to-tube buttwelds which results in increased construction costs. The spiral tube design also imparts additional friction drop in the system requiring larger boiler feedwater pumps. The vertical tube design (Benson technology) has less operating history, but is gaining interest due to the reduced pressure drop and simpler configuration. Siemens owns the Benson technology and licenses it to various boiler manufacturers.

1.2.2 Operating Considerations

In the past, most of the supercritical units built in the U.S. were designed for base-load operation; however, with construction of several base-load nuclear plants, many were required to load-follow. Cyclic operation of the early supercritical units caused excessive valve wear (boiler valves located within the evaporation or fluid transition zone), turbine thermal stresses and solid particle erosion (SPE) of the steam turbine blades. In addition to these issues, the complex starting sequence of supercritical boilers caused tubes to frequently overheat and fail. These problems resulted in lower availability and higher maintenance costs as compared to subcritical units.

Numerous supercritical units installed in Europe and Asia since the start of the 1980s allowed the technology to mature and resolved many problems with the earlier designs. The development of high strength materials at elevated temperatures helps to minimize the thermal stresses that caused problems in the early units. Variable pressure operation of all the circuits within the boiler eliminates the need for boiler valves in the fluid transition zone of the boiler. The development of distributed control systems (DCS) helps make the complex starting sequence much easier to control. The newer units also use a steam/water separator during startup to minimize solid particle carryover, which erodes the steam turbine blades. These changes corrected many of the early problems with supercritical units and availability of modern supercritical units now closely matches that of similar subcritical units. Only a minor maintenance increase is now required for supercritical units due to thicker tube and pipe walls.

Most operating experience in the U.S. is with the single reheat subcritical drum units. Seminole Electric Cooperative's existing units are subcritical. Therefore, installing a supercritical unit at that site would add a different technology with different operating aspects, adding complexity to the site. However, the additional complexity can be resolved through additional operator training.

The start-up time of a modern supercritical unit from a cold start (after a 36 hour shutdown) is 2 to 3 hours which is limited by thermal stresses in the boiler. Ramp rates are faster than a comparable subcritical unit at 5-7 percent per minute for 50-100 percent load and 5 percent per minute for loads under 50 percent.

1.2.3 Performance

Estimated annual average operational heat rates for a supercritical pulverized coal unit are between 8700 and 9400 Btu/kWh (HHV) at full load conditions. These performance estimates are based on a new and clean steam turbine operating with steam conditions of 3645 psig/1050°F/1050°F and with the boiler burning a bituminous/petcoke mixture for fuel.

1.3 ECONOMICS

The capital cost of a supercritical plant is approximately 1.5-percent more than an equivalent subcritical plant. Fixed operating costs for the supercritical unit are slightly higher than for a subcritical unit even though the plants require the same operating personnel because insurance costs are expected to increase with the supercritical units higher capital cost.

Non-fuel variable operating and maintenance cost is typically lower for a supercritical unit. Maintenance costs are essentially the same for either option, but the supercritical unit offers the advantage of reduced operating inputs (water, fuel, etc), emissions inputs (lime, limestone, ammonia, etc.), and waste (ash, scrubber sludge, and waste water) production due to the higher efficiencies. Further, with lower waste production rates the supercritical unit offers the benefit of reduced disposal costs. However, since SGS can sell the majority of their solid wastes, specifically bottom ash and gypsum, the subcritical unit provides the lower non-fuel variable operating and maintenance cost.

Available emissions control technologies are the same for either subcritical or supercritical units. As such, the emissions reduction capability for the two technologies is identical. However, since a supercritical unit is more efficient, it will consume less fuel. Therefore, it will generate less boiler emissions, and with the same emissions controls, will result in less emissions.

Attachment B – Cooling Tower Assessment

ATTACHMENT B - COOLING TOWER ASSESSMENT

1.0 GENERAL

Burns & McDonnell completed an economic evaluation of the differences between a mechanical draft cooling tower and a natural draft cooling tower to determine the impact of tower technology on the capital and operating costs for a 600 MW net subcritical unit at the Seminole Generating Station. To evaluate the cooling tower technologies, the net present value (NPV) was determined of the capital and operating cost differences over the life cycle of the plant and the levelized busbar cost difference between the cooling tower technologies. Further discussion of the assumptions, the estimates, and the results of the evaluation are provided below.

1.1 ASSUMPTIONS

The assumptions used in developing this cost comparison are detailed in the following sections.

1.1.1 Project Configuration

The project configuration was assumed to be as follows:

- Pulverized coal
- Bituminous/Pet Coke (70/30 Blend)
- 600 MW net plant output
- Subcritical steam conditions of 2520 psig/1050°F/1050°F
- Commercial operation date of 2012
- 100% load factor
- 85% unit capacity factor
- Steam turbine driven boiler feed pumps
- Wet limestone flue gas desulfurization (wet FGD) with forced oxidation for SO_2 control and to make gypsum
- Selective catalytic reduction for NO_x control
- Electrostatic precipitator (ESP) for particulate control
- Activated Carbon Injection for Hg control
- Wet ESP for Sulfuric Acid Mist Control
- Fly ash disposal in onsite landfill
- All gypsum and bottom ash produced is sold

1.1.2 Economic and Cost Factors

Annual economic and cost factors assumed for this evaluation are listed below.

- Evaluation term of 30 years.
- After tax discount rate of 6-percent.
- Interest during construction of 6-percent.
- Fuel Escalation of 2-percent.
- Chemical inputs (water treatment, emissions, etc) escalation of 2.5-percent.
- Material cost escalation of 2.5-percent.
- Labor cost for daily operations escalation of 2.5-percent.
- Average operator annual, all-inclusive labor cost of $75,000 ($2004).
- Property tax of 2-percent of net book value.
- Insurance rate of 0.16-percent of capital.
- Sales tax exempt.

1.1.3 Cooling Tower Design Basis

The design conditions for the two cooling towers are defined in Table 1.1.

Table 1.1 Cooling Tower Design Parameters

Parameter	Mechanical Draft Tower	Natural Draft Tower
Inlet Wet Bulb Temperature, °F	81 (note 1)	79
Range, °F	21	21
Approach, °F	11	13
Circulating Water Flow, GPM	300,000	300,000

Notes:
1. Inlet wet bulb temperature for mechanical draft cooling tower includes a 2°F recirculation allowance.

1.1.4 Plant Performance

The impact of cooling tower technology on steam turbine performance is considered minimal. However, the mechanical draft cooling tower auxiliary loads do require additional boiler and steam turbine output. A mechanical draft cooling tower designed to the parameters outlined in Table 1.1 would require 18 cells in back to back arrangement with 175 horsepower fans based on manufacturer's quotes. The resulting impact of the additional auxiliary loads is an increase in net plant heat rate of approximately 34 Btu/kWh for the mechanical draft cooling tower alternative.

1.2 CAPITAL COSTS

The differential capital cost estimate for the two cooling tower alternatives is based on vendor supplied cost data and a cost estimate for a similar sized subcritical unit from Burns & McDonnell's database as a basis. Cost adjustments reflect the differences in scope and operating requirements between the cooling tower alternatives. A summary of the capital cost comparison is included in Table 1.2.

Table 1.2 Capital Cost Comparison (2012$)

Item	Mechanical Draft Tower	Natural Draft Tower
Cooling Tower (F&E)	Base	$11,610,000
Balance of Plant	Base	($1,100,000)
Escalation	Base	$530,000
Contingency (10%)	Base	$1,050,000
Interest During Construction	Base	$1,500,000
Total Differential Cost	**Base**	**$13,590,000**

The cost difference between the alternatives is primarily in the cooling tower furnish and erection price. Other cost differences for balance of plant equipment in the table are due to the reduction in boiler heat input/steam flow with the natural draft cooling tower. The savings in auxiliary power by using a natural draft cooling tower results in less output required from the steam turbine and therefore less heat input to the boiler. Further, the natural draft cooling tower requires no fan wiring or motor control centers for additional savings.

1.3 OPERATING COSTS

As a result of the higher plant heat rate, the mechanical draft cooling tower alternative represents greater annual fuel consumption costs.

Fixed operating costs for the natural draft cooling tower are slightly higher than for a mechanical draft cooling tower even though the plants require the same operating personnel. Insurance costs are expected to increase with the natural draft tower due to its higher capital cost.

Non-fuel variable operating and maintenance however, is lower for the natural draft cooling tower. Maintenance costs are essentially the same for either alternative, but the natural draft cooling tower offers the advantage of reduced operating inputs (water, fuel, etc), emissions inputs (lime, limestone, ammonia, etc.), and waste production (ash, scrubber sludge, and waste water) due to the slightly higher efficiency. Further, the natural draft cooling tower offers the benefit of reduced ash and water disposal costs. Table 1.3 provides a summary of the operating inputs for the two cooling tower alternatives.

Table 1.3 Operating Cost Differentials (2012$)

Fuel Costs	**Mechanical Draft Tower**	**Natural Draft Tower**
Annual Fuel Consumption, MMBtu	Base	(150,000)
Annual Fuel Cost	Base	($260,000)
Differential Annual Fuel Cost:	**Base**	**($260,000)**
Differential Annual Fuel Costs, $/MWh	**Base**	**<$0.01**
Fixed Operating Costs		
Differential Annual Operator Cost	Base	$0
Differential Annual Maintenance Costs		
Fill Replacement	Base	$0
Fan & Motor Repairs	Base	($40,000)
Relative Property Tax Cost	Base	$166,000
Relative Insurance Cost	Base	$22,000
Differential Annual Fixed Operating Costs:	**Base**	**$148,000**
Differential Fixed Operating Costs, $/kW-yr:	**Base**	**<$0.01**
Variable Operating Costs		
Limestone Consumption	Base	($8,000)
Ammonia Consumption	Base	($1,000)
Activated Carbon	Base	($6,000)
Ash Disposal	Base	($3,000)
Gypsum Sales	Base	$13,000
Bottom Ash Waste Disposal	Base	$1,000
Water Consumption	Base	$0
Differential Annual Variable Operating Cost:	**Base**	**($4,000)**
Differential Variable Operating Cost, $/MWh:	**Base**	**($0.001)**

This feasibility study details the costs for fuel, limestone, ammonia, activated carbon, ash disposal, gypsum sales, bottom ash waste disposal, and water consumption used to determine total costs in Table 1.3. The feasibility study also contains the insurance rates and property tax rates. Both insurance and property tax costs use the capital cost difference between the alternatives as a basis. SECI provided the annual maintenance costs for the natural draft cooling tower. For this analysis, fill requirements including maintenance and replacement are essentially equal for the tower alternatives. However, the mechanical draft tower does require additional maintenance due to fan and motor repair and replacement.

1.4 EVALUATION RESULTS

The net present value of capital and operating costs for the mechanical draft cooling tower is $11.7 million less than the natural draft cooling tower. The busbar cost comparison shows that the mechanical draft cooling tower has a $0.19 per megawatt hour lower levelized electrical production cost. The electrical production cost includes fuel costs, operating and maintenance costs and initial capital investment cost for each of the alternatives. In summary, the fuel and operations savings associated with the natural draft cooling tower do not provide enough benefit to justify the much greater initial capital cost of the natural draft cooling tower.

Attachment C – Integrated Gasification Combined Cycle Assessment

ATTACHMENT C - INTEGRATED GASIFICATION COMBINED CYCLE

1.0 GENERAL DESCRIPTION

Integrated Gasification Combined Cycle (IGCC) technology produces a low calorific value syngas from coal or solid waste, to be fired in a conventional combined cycle plant. The gasification process in itself is a proven technology utilized extensively for production of chemical products such as ammonia for use in fertilizer. Utilizing coal as a solid feedstock in a gasifier is currently under development for projects jointly funded by the Department of Energy (DOE) at several power plant facilities throughout the United States. The gasification process represents a link between solid fossil fuels such as coal and existing gas turbine technology. The IGCC process is shown in Figure 1 below.

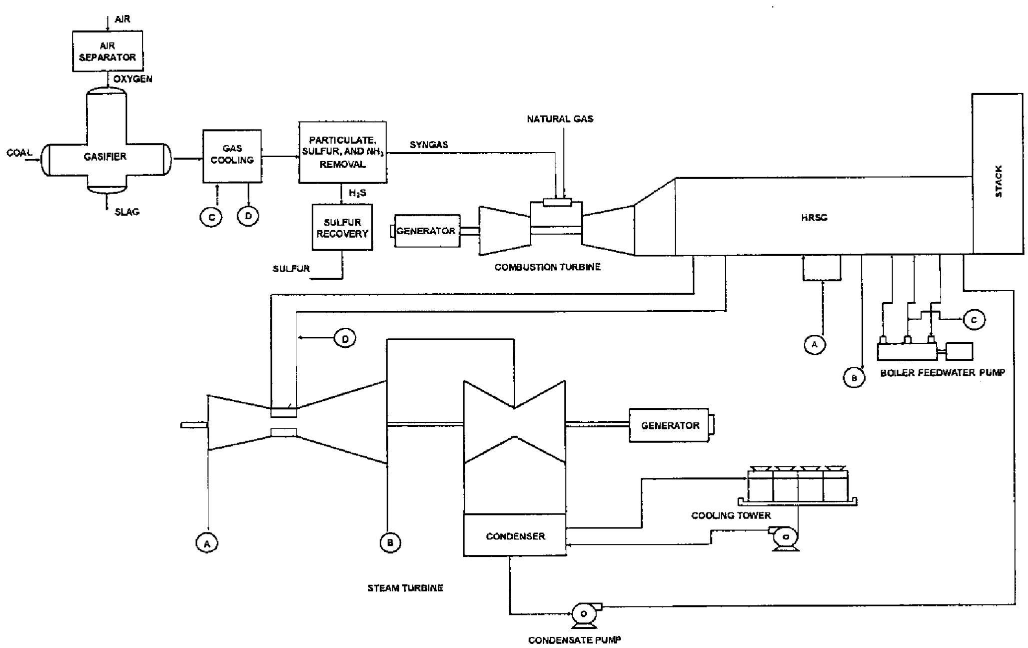


Figure 1 – IGCC Process Diagram

A 600 MW net IGCC plant would typically be composed of two coal gasifiers, a coal handling system, an air separation unit, a gas conditioning system to remove sulfur and particulate, two gas turbines, two heat recovery steam generators with supplemental duct firing and a single steam turbine. Cooling water for the steam turbine would be based on a wet cooling tower.

Integrating proven gasifier technology with proven gas turbine combined cycle technology is a recent development, and continues to be improved at the existing DOE jointly funded power plants.

Gasifiers designed to accept coal as a solid fuel generally fall into three categories: entrained flow, fluidized bed, and moving bed.

Entrained Flow

The entrained flow gasifier reactor design converts coal into molten slag. This gasifier design utilizes high temperatures with short residence time and will accept either liquid or solid fuel. Chevron Texaco, Conoco Phillips (E-Gas), Prenflo, and Shell produce this gasifier design. General Electric (GE) and Chevron Texaco have recently announced plans for GE to acquire Chevron Texaco's gasification business.

Fluidized Bed

Fluidized-bed reactors are highly back-mixed and efficiently mix feed coal particles with coal particles already undergoing gasification. Fluidized bed gasifiers accept a wide range of solid fuels, but are not suitable for liquid fuels. The KRW and High Temperature Winkler designs use this technology.

Moving Bed

In moving-bed reactors, large particles of coal move slowly down through the bed while reacting with gases moving up through the bed. Moving-bed gasifiers are not suitable for liquid fuels. The Lurgi Dry Ash gasification process is a moving bed design and has been utilized both at the Dakota Gasification plant for production of SNG and the South Africa Sasol plant for production of liquid fuels. BGL is another manufacturer of the moving bed design.

The majority of the DOE test facilities utilize the entrained flow gasification design with coal as feedstock. Pulverized coal is fed in conjunction with water and oxygen from an air separation unit (ASU) into the gasifier at around 450 psig where the partial oxidation of the coal occurs. The raw syngas produced by the reaction in the gasifier exits at around 2400 °F and is cooled to less than 400 °F in a gas cooler, which produces additional steam for both the steam turbine and gasification process. Scrubbers then remove particulate, ammonia (NH_3), hydrogen chloride and sulfur from the raw syngas stream. The cooled syngas then feeds into a modified combustion chamber of a gas turbine specifically designed to accept the low calorific syngas. Exhaust heat from the gas turbine then generates steam in a heat recovery steam generator (HRSG) to power a steam turbine. Reliability issues associated with fouling and/or tube leaks within the syngas cooler have challenged the existing IGCC installations. The syngas cooler greatly improves thermal efficiencies when compared to a quench cooler system typical to those utilized in chemical production gasifiers.

1.1 CURRENT STATUS

The following table identifies the DOE jointly funded test facilities constructed in the United States, with various gasification system designs.

Table 1.1 Department of Energy IGCC Test Facilities

Facility	Owner	Capacity (MW)	Commercial Operation Date	Gasifier Manufacturer	Status
Polk County	Tampa Electric	252	1996	Chevron Texaco	Operating
Wabash River	PSI Energy	262	1995	Conoco Phillips	Operating
Pinon Pine	Sierra Pacific	99	1997	KRW	Decommissioned
LGTI	Dow Chemical	160	1987	Conoco Phillips	Decommissioned
Cool Water	Texaco	125	1984	Chevron Texaco	Decommissioned

There are several IGCC projects currently in the development phase, including the 540 MW power station for Global Energy, Inc. located in Lima, OH, and Excelsior Energy's 530 MW Mesaba Energy Project located in Minnesota.

1.2 PLANT CHARACTERISTICS

1.2.1 Performance

Cold start-up times for IGCC plants have typically ranged from 40-50 hours compared to a conventional PC boiler start-up time of 4-6 hours. Hot restart procedures are in testing at several of these facilities, and Eastman Kodak has developed a proprietary process that allows a fairly rapid startup, but the startup process requires flaring the syngas produced until it is adequate quality for introduction into the gas turbine. The gasification plant requires stable operation in order to maintain syngas quality and the technology to support load following continues to be developed.

Operational heat rates for DOE test facilities range from 7,800 Btu/kWh (43.7% efficiency) for Pinion Pine to 8,910 Btu/kWh (38.3% efficiency) for Wabash River. It should be noted that the Pinion Pine project did not achieve long term continued commercial operation. The Polk County facility operated at around 8,500 Btu/kWh (40.2% efficiency), but modifications to improve gas clean-up reliability reduced efficiency and increased heat rate for the plant to approximately 9,350 Btu/kWh (36.5% efficiency).

The anticipated performance for a 600 MW (net) IGCC is highly contingent upon the level of integration of the gasification process and combined cycle, the gasifier design, and the selection of the supporting systems and equipment. Estimates have ranged from 8,600 Btu/kWh to over 9,500 Btu/kWh. This estimated performance is based on new and clean equipment. Degradation is not included.

Significant design issues have prevented coal gasification units from achieving acceptable availability levels. These design issues include fouling within the syngas cooler, design of the pressurized coal feeding system, molten slag removal from the pressurized gasifier, durability of gas clean-up equipment and solid particulate carryover resulting in erosion within the gas turbine. The complexity of the combined cycle unit in conjunction with the reliability of numerous systems, including the gasifier, O_2 generator, air separation unit and multiple scrubbers have contributed to reduced plant availability.

Unit availability at the DOE jointly funded plants has been improving due to design modifications intended to improve equipment life and reliability. Polk County was able to achieve 83% availability for 2003 and Wabash River achieved 83.7% availability for 2003. All of these coal gasification plants have experienced down-time for design modifications and replacement of equipment. Polk County and Wabash River are the only two coal IGCC plants in the United States that have achieved extended periods of commercial operation. The current generation of IGCC plants should be capable of operation with an availability of around 85 percent compared to around 90 percent for conventional steam electric plants.

1.2.2 Emissions Controls

Sulfur capture for coal gasifiers at the DOE funded power plants ranged from >95% (Polk County) to >99% (Wabash River). NO_x emissions are controlled through nitrogen injection into the gas turbine at Polk County to 0.10 lb/MMBtu (25 ppm) and through steam injection into the gas turbine at Wabash River to 0.10 lb/MMBtu (25 ppm). However, Wabash did not go through Prevention of Significant Deterioration (PSD) permitting for NO_x. Polk County was required to reopen their NO_x Best Available Control Technology (BACT) analysis 18 months after startup of the facility. As a result, Polk County is currently required to meet 15 ppm NO_x.

The raw syngas produced by the IGCC process is cleaned to remove particulate, ammonia (NH_3), sulfur and nitrogen prior to being fired in the gas turbine. Acid gas cleanup processes are very effective and have been proven by the oil and gas industries for many years with over 99.8% sulfur recovery. Removal of pollutants from the syngas stream results in lower emissions than from a conventional plant utilizing the same fuels.

Mercury can be controlled in the IGCC process as well. The gasification industry has shown excellent mercury removal capability (greater than 99%).

1.2.3 Waste Disposal

The syngas sulfur removal process can result in 99.9 percent pure sulfur, which is a saleable by-product. The gasifier converts coal ash to a low-carbon vitreous slag and fly ash. The slag has beneficial use and can be utilized as grit for abrasives, roofing materials, or as an aggregate in construction. Fly ash entrained in the syngas is recovered in the particulate removal system and is either recycled to the gasifier or combined with other solids in the water treatment system and shipped off site for reuse or to be landfilled.

1.2.4 Water Requirements

An IGCC plant uses approximately one third the cooling water for condensing steam compared to a conventional steam electric plant. However, a large cooling water supply is required for coal gasification and for the air separation unit used to produce pure oxygen and when combined with the steam condensing requirements, the amount of water is comparable to a conventional steam electric plant.

1.2.5 Project Schedule

The permitting process for a greenfield 600 MW net IGCC takes approximately 18 months. The design and construction duration is approximately 48 months. In most cases, the permitting phase and design/construction phase will partially overlap to decrease the overall implementation period; however this schedule does expose the Owner to some risk if the permit is not approved. Total implementation time for a 600 MW net IGCC including permitting, design, and construction is approximately 52 – 64 months.

1.2.6 Capital Cost Estimates

Initial capital construction cost (in 1995 dollars) for the existing coal gasification plants ranged from $1,213/kW for Polk County to $1,590/kW for Wabash River.

The DOE estimates coal-based IGCC plants in the range of $1,200-1,600/kW (2004$). These estimates vary considerably based on the amount of equipment and system redundancy included in order to achieve a desired availability, based on the level of integration required to achieve a desired efficiency, and the equipment or systems required to achieve specific emissions limits. The DOE is currently contracting for studies to evaluate cost, performance, and emissions optimizations of the next generation of IGCC facilities.

1.2.7 Operations and Maintenance

Note that there has not been a long operating history for IGCC units. Scheduled maintenance consists of an outage of approximately 3 weeks/year and 4-5 weeks every five years.

1.2.8 Long Term Development

Much of future technology development will be supported through government funding support of Clean Coal Technology within the power industry. A few large scale (550 MW and greater) IGCC power plants are currently in the preliminary project development and/or permitting stage in the United States, however, commercial operation of these plants is at least 4 to 5 years in the future.

1.3 IGCC AT SEMINOLE GENERATING STATION

A greenfield 600 MW net IGCC plant requires approximately 120 acres which includes areas for coal handling, construction laydown and parking. The Seminole Generating Station site has existing coal handling infrastructure to support an IGCC plant. The space required for the IGCC power block is approximately 45 acres. The existing site is capable of accommodating an IGCC plant however, some of the remaining permitted landfill area to the east of the existing units may have to be utilized which would reduce the life of that landfill.

The slag from an IGCC plant could be sold similar to the bottom ash from the existing units. In addition, the sulfur byproduct could also be sold if a market exits. Therefore, the potential landfill requirements would be less than a conventional steam electric plant.

The availability and reliability of the current IGCC plants is improving but is not comparable with conventional steam electric plants. The penalty for higher availability is with more redundancy and therefore higher capital costs.

Much of future IGCC technology development will be supported through government funding of clean coal technology in the power industry. Operational flexibility for rapid start-up and load following remains to be demonstrated and may be required for an IGCC plant to compete effectively within the current U.S. power market.

Acceptance of coal within the power industry and the relative price of natural gas will also influence the future development and commercialization of IGCC in the United States. The technical barriers to commercialization still remain to be addressed through future generations of government jointly funded coal IGCC facilities. Once the development effort has been successfully completed, coal fueled IGCC technology has the potential to be a reliable clean-coal generation technology.

Attachment D – Water Analysis

Surface Water Intake D-005

Date	O&G (mg/l)	Turbidity (mg/l)	Ammonia (mg/l)	Un NH4 (mg/l)	TKN (mg/l)	NO2/NO3 (mg/l)	Cu (ug/l)	Cyanide (ug/l)	Fe (mg/l)	Hg (ug/l)	Se (ug/l)	Zn (ug/l)	Cond (umho)	Ag (ug/l)	Chlorides	Sulfate	Flouride	Bromide	Magnesium	Calcium	Sodium	Potassium	Boron
1/1/00																							
2/1/00	<5	5.6																					
3/1/00	<5	7.3	<0.02	<0.02	0.86	<0.5	<10	<5	0.25	<0.5	<10	170	846										
4/1/00	<5.0	11																					
5/1/00	<5.0	6.8																					
6/1/00	<5.0	3.1	<0.02	<0.02	1.5	<0.5	<10	<5	0.1	<0.5	<10	<10	921										
7/1/00	<5	4.9																					
8/1/00	<5.0	4.4																					
9/1/00	<5	4.1	<0.0079	<0.0079	0.63	<0.032	<1.4	6.2	0.061	<0.04	<2	14	1042										
10/1/00	<0.89	5.3																					
11/1/00	1	5.7																					
12/1/00	0.7	5.9	0.021	<0.02	1.9	<0.50	<6.0	<5.0	0.097	<0.2	<2.0	17	1384										
1/1/01	1	20																					
2/1/01	0.7	7.3																					
3/1/01	1.5	13	0.11	0.0031	1	0.185	<0.9	<5	0.17	<0.072	4.9	3.9	1282	<1.9									
4/1/01	1	6.8																					
5/1/01	1.2	8.9																					
6/1/01	1.2	6.4	<0.030	<0.012	1.3	<0.050	<0.90	<10	0.13	<0.072	<4.2	<5.9	1500		330	110	<0.20	1	24	64	150	6.6	0.4
7/1/01	2.1	5.7	0.088	0.02	93	<0.050	<0.90	<10	0.11	<0.072	<4.2	<5.9		<0.050	300	110	0.17	1.1	25	34	150	6	0.32
8/1/01	6.4	8.5																					
9/1/01	3	5.5																					
10/1/01	3.7	3.7																					
11/1/01	<0.55	3.9																					
12/1/01	3.9	3.6	0.1	0.002	1.5	0.28	<0.9	<10.0	0.49	<0.072	<4.2	<30	661										
1/1/02	3.2	5.6																					
2/13/02			0.14												170	74	<0.2		14	42	96	5.9	0.22
2/1/02	0.8	4.3																					
3/1/02	1.7	8.9	0.11	<0.020	1.4	0.41	1.8	<5.0	0.52	<0.072	<3.3	<5.9	950	<1.9									
4/1/02	0.73	8.5																					
5/1/02	1.1	9.4																					
6/1/02	<0.55	7	0.075	<0.03	1.2	0.15	<0.9	<4	0.096	0.076	<3.3	14	1269	<0.17									
7/1/02	4.6	5.4																					
7/29/02			0.04	<0.002	1.3	<0.05	1.9	<8	0.21	<0.072	<4.2	<5.9	999										
8/1/02	2.5	3.9																					
9/1/02	4	3.5																					
10/1/02	0.55	2.3																					
2-Oct	0.55	2.3	<0.05																				
10/22/02			0.086	0.0012	0.91	0.19	3	<4	0.38	0.087	<4.2	<5.9		<0.17									
10/29/02			<0.05																				
11/1/02	0.55	4.4																					
12/1/02	0.55	6.2																					
1/28/03	<2.7	4.8	0.043	0.0006	2.1	0.01	0.9	4	0.35	<0.072	<4.2	<5.9	740										
3-Feb		8.9																					
3-Mar	<2.7	6.7																					
3-Apr	0.73	8.2																					
3-May	0.73	4																					
5/13/03			0.21	<0.01	0.9	0.048	2.8	<4	0.37	<0.072	<4.2	<5.9	727										
3-Jun	0.73	6.3																					
7/1/03	0.73	12																					
8/26/03			0.13	<0.01	1.3	0.017	1.7	<4	0.34	<0.072	<4.2	<5.9	712										
3-Aug	0.73	7.9																					
9/1/03																							
10/1/03																							
11/1/03	0.73	4.2																					
3-Dec	0.73	5.3																					

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SEMINOLE

Attachment D - River Water Analysis

Rev A

North Production Well

	Calcium (mg/l)	Sodium (mg/l)	Magnesium (mg/l)	Hardness (mg/l)	Silica (mg/l)	Alkalinity (mg/l)	Chloride (mg/l)	Sulfate (mg/l)	Ortho phosphate (mg/l)
North Well	43	27	19	190	14	100	69	39	<0.05
Clear Well	40	34	7.5	130	6.3	32	97	48	<0.05

Palatka Groundwater Quality - Production Wells

	North Well	South Well	North Well	After pre-treatment
Chlorides (mg/l)	67.4	173	69	97
Sulfate (mg/l)	36.9	85	39	48
Hardness (mg/l)	194	273	190	130
Fluoride (mg/l)	0.2	0.21		
Silica (mg/l)	13.76	14.64	14	6.3
COD (mg/l)	<5.0	15.6		
Alkalinity CACO3 (mg/l)	<5.0	<5.1		
Alkalinity Bicarbonate (mg/l)	126	114		
Alkalinity total (mg/l)	126	114		
Alkalinity hydroxide (mg/l)	<5.0	<5.1		
Nitrogen (mg/l)	<0.01	<0.010		
Calcium (mg/l)	42.7	59.9	43	40
Iron (mg/l)	<45	77.1		
Manganese (mg/l)	<5	<5		
Potassium (mg/l)	1.71	2.37		
Sodium (mg/l)	27.1	71.7	27	34
Magnesium (mg/l)	18.4	28.1	19	7.5

Burns & McDonnell SINCE 1898	SEMINOLE Attachment D - Well Water Analysis	Rev A

Attachment E – Coal Analysis

Fuel Analysis

	Eastern Bituminous	Pet Coke	Blend of 70% Eastern Bituminous, 30% Pet Coke
Proximate Analysis, Wt%			
Moisture	12.00	12.00	12.00
Volatile Matter	38.85	10.01	30.20
Fixed Carbon	46.97	80.62	57.07
Ash	10.50	1.50	7.80
Sulfur	3.50	6.00	4.25
Ultimate Analysis, Wt%			
Carbon	61.72	75.37	65.82
Hydrogen	4.79	3.12	4.29
Nitrogen	1.31	1.48	1.36
Chlorine	0.30	0.30	0.30
Oxygen	5.88	0.23	4.19
Heating Value (HHV)			
Btu/lb	12,000	13,000	12,300

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SEMINOLE

Attachment E - Fuel Analysis

REV A

Seminole Generating Station
750 MW (Net) Solid Fuel Fired Unit
Feasibility Study

Seminole Electric
COOPERATIVE, INC.
IN PARTNERSHIP WITH THOSE WE SERVE

Seminole Electric Cooperative, Inc.

February 2005

Burns & McDonnell
SINCE 1898

Burns & McDonnell
SINCE 1898

February 24, 2005

Mr. Tom Wess
Seminole Electric Cooperative, Inc.
16313 North Dale Mabry Highway
Tampa, Florida 33618

750 MW (Net) Solid Fuel Fired Unit Feasibility Study

Mr. Wess:

Burns & McDonnell is pleased to submit our 750 MW (Net) Solid Fuel Fired Unit Feasibility Study to Seminole Electric Cooperative, Inc. (SECI). The study evaluates the economics of a 750 MW (net) pulverized coal unit at the Seminole Generating Station (SGS) in Palatka, Florida and compares it to the 600 MW (net) solid fuel generation options provided previously.

The attached report summarizes the findings of the feasibility study and provides our recommendations regarding the most economical, long-term baseload energy resource for SECI. If you have any questions regarding the report, please contact me at 816-822-3274 or Jeff Greig at 816-822-3392.

It is a pleasure to be of service to SECI in this matter.

Sincerely,

Richard A. Klover

Richard Klover
Project Manager

Jeff Greig
General Manager

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TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

1.0 EXECUTIVE SUMMARY

1.1 SCOPE OF WORK

The purpose of this study is to evaluate the economics of a 750 MW (net) pulverized coal unit, Unit 3, for Seminole Electric Cooperative, Inc. (SECI) at the Seminole Generating Station (SGS). Both subcritical and supercritical technologies are evaluated. The study addresses site infrastructure, capital cost, operating and maintenance costs, performance, and busbar cost for a new unit.

The major assumptions and conceptual design basis used in generating the results for this assessment are identical to the 600 MW (Net) Solid Fuel Fired Unit Feasibility Study provided previously.

1.2 ECONOMIC ANALYSIS SUMMARY

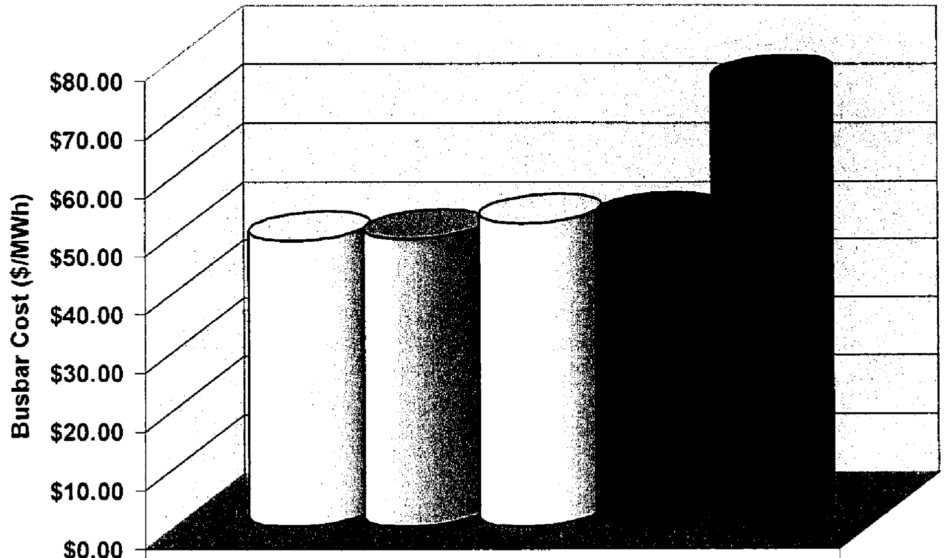
Burns & McDonnell (B&McD) prepared pro forma economic analyses of the following alternatives:

- Construction of a new, brownfield 750 MW (net) subcritical solid fuel fired generating unit
- Construction of a new, brownfield 750 MW (net) supercritical solid fuel fired generating unit

A 20-year economic analysis was prepared based on the estimated capital costs, performance, fuel costs, and operating costs for each alternative. The results from the previous 600 MW (Net) Solid Fuel Fired Unit Feasibility Study are also shown for comparison purposes.

Economic pro forma analyses were used to determine the 20-year levelized busbar cost of power generated from each alternative. Figure 1-1 presents a graph of the resulting levelized busbar power costs for the two 750 MW alternatives and three previous alternatives from the 600 MW study. Results are shown in 2012 dollars. The levelized busbar costs of the 750 MW supercritical and subcritical units are \$48.85 and \$49.15/MWh, respectively. These costs are slightly lower than the 600 MW supercritical and subcritical alternatives (\$51.84 and \$52.08/MWh respectively). Additionally, the busbar costs of all the coal alternatives are significantly lower than the busbar cost for the greenfield, conventional combined cycle alternative (\$75.48/MWh).

Figure 1-1: 20-Year Levelized Busbar Costs (2012$)



	Alternatives
□750 MW Supercritical	$48.85
□750 MW Subcritical	$49.15
□600 MW Supercritical	$51.84
▩600 MW Subcritical	$52.08
■500 MW CC	$75.48

1.3 CONCLUSIONS AND RECOMMENDATIONS

Based upon economic criteria presented in Section 6, the construction of a new 750 MW supercritical or subcritical unit has the lowest busbar cost and, therefore, is considered to be the most economical alternative to provide long-term baseload capacity and energy for SECI. The 600 MW supercritical or subcritical unit busbar costs are only slightly higher than the busbar costs for the 750 MW units. The overall economics of a gas-fired combined cycle unit are not as favorable as those of the subcritical or supercritical solid fuel-fired units when operating at high capacity factors due to the higher fuel costs associated with natural gas.

Other factors to consider when selecting between subcritical and supercritical steam cycle include the following:

- Operator familiarity with subcritical technology at the SGS plant.
- Lower emissions due to the higher efficiencies of the supercritical technology.
- Permitting may face fewer hurdles with a supercritical cycle verses a subcritical cycle.

- Corrosive coals, such as that anticipated for use at SGS Unit 3, can cause excessive wastage and circumferential cracking in the water walls and liquid phase corrosion in the superheater and reheater when burned in supercritical units with elevated steam temperatures.
- There is currently no supercritical PC operating experience with 30% pet coke blend (i.e. high sulfur fuel), regardless of steam temperature.
- There is currently no subcritical PC boiler operating experience with 30% pet coke blend (i.e. high sulfur fuel) above 1000°F/1000°F steam conditions.

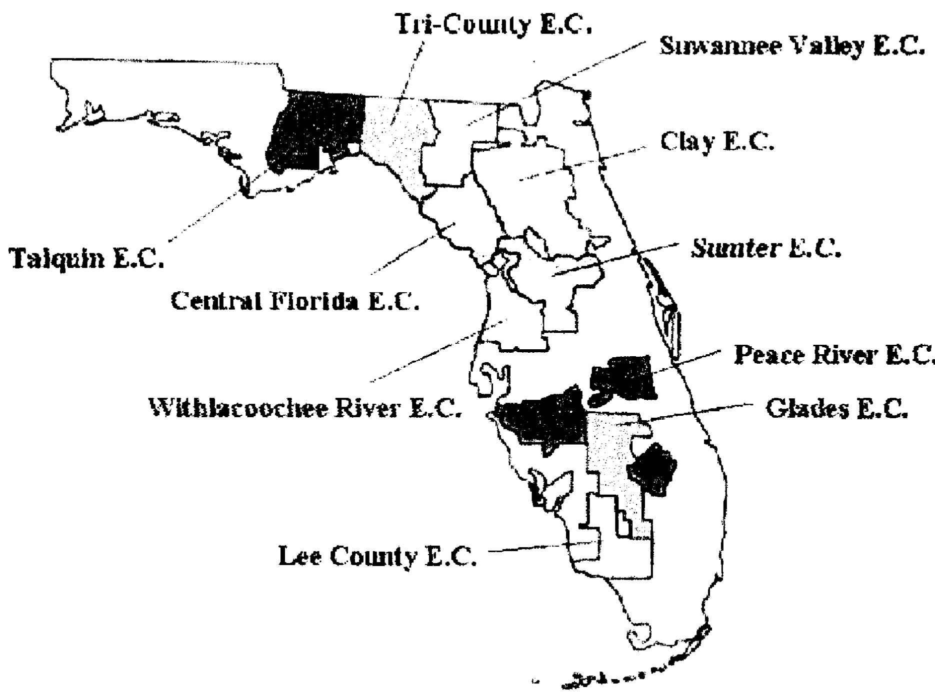
Due to the lack of experience with supercritical technology operation on high sulfur coals and the increased potential for excessive wastage, circumferential cracking, and liquid phase corrosion anticipated on a supercritical unit, B&McD recommends subcritical technology be employed for SGS Unit 3.

2.0 INTRODUCTION

2.1 BACKGROUND

SECI has identified the need for additional baseload capacity by 2012. One option for meeting this need is the construction of an additional unit, Unit 3, at SGS. SECI seeks a generation resource with fuel price stability in order to secure long-term, low-cost generation for its member cooperatives. As a generation and transmission cooperative, SECI provides wholesale electric service to its ten member electric distribution cooperatives from a mix of firm resources. These resources include owned-generation and purchased capacity. These units owned by SECI include two solid fuel fired units at SGS, a gas-fired combined cycle facility at Payne Creek, and an ownership interest in Progress Energy Florida's nuclear unit. The member electric distribution cooperatives are located throughout Florida, serving over 775,000 customers in 46 different counties. Figure 2-1 shows the SECI member system.

Figure 2-1: SECI Member System



2.2 SCOPE OF WORK

Seminole Electric Cooperative, Inc. retained Burns & McDonnell (B&McD) to evaluate the feasibility of developing and installing a new solid fuel generation resource adjacent to its present Seminole Generating Station. This additional solid fuel fired unit is designated and referred to in this study as SGS Unit 3.

The new unit is based on a 750 MW (net) solid fuel fired power plant. The boiler and emissions controls equipment for the new unit are designed to operate with a blend of 70% eastern bituminous coal and 30% petroleum coke fuel. The operating and maintenance cost estimates for the economic pro forma are also based on a 70/30 blend of coal and petroleum coke.

This study includes the following scope of work:

- Preparation of a project scope description for the 750 MW solid fuel fired unit.
- Preparation of a preliminary assessment of the existing infrastructure to support the new 750 MW solid fuel fired unit.
- Preparation of capital and operating cost estimates for the new unit.
- Estimate of the plant output and heat rate.
- Preparation of preliminary plant water balance including the impact of the new unit.
- Preparation of a preliminary assessment of the anticipated BACT/MACT requirements for the new unit.
- Development of a pro forma with an estimated busbar cost.
- Cost sensitivity analysis

2.3 OBJECTIVE

The purpose of the study is to provide a preliminary evaluation of a 750 MW solid fuel generation resource at SGS for comparison to the 600 MW solid fuel generation information provided previously and to evaluate against the SECI request for capacity proposals.

3.0 SITE INFRASTRUCTURE EVALUATION

3.1 OVERVIEW

This section is provided to determine the potential upgrades required to the existing site infrastructure due to the addition of a new 750 MW unit to the site. Impacts to the existing raw water supply, wastewater discharge, coal handling, limestone handling, and electrical interconnection are evaluated. Transmission and fuel delivery are outside the scope of this study. More detailed infrastructure studies should be performed if the preliminary economics of the project are favorable.

3.2 RAW WATER SUPPLY

A preliminary water mass balance diagram was developed for SGS reflecting the impact of Unit 3 (750 MW) to the existing two units. The water mass balance is included as Figure 3-1 at the end of this section.

Raw water is supplied from the St. John's River. Based upon preliminary information, it is expected that a new line from the intake structure to the pump structure may be required to avoid excessive pressure drop. A $300,000 allowance has been included in the capital cost estimate for the addition of this new pipe and modifications to the intake structure. Additionally a $150,000 allowance has been included for new raw water pumps and pump structure modifications.

Additional studies should be performed on the intake structure, pump structure, raw water pumps, and pipelines to more accurately establish the required upgrades.

3.3 WASTEWATER DISCHARGE

Cooling tower blowdown and site runoff is discharged to the St. Johns River through the existing discharge pipeline. Wastewater discharge booster pumps are included to increase the discharge capacity of the existing line. Storm water runoff from non-process equipment areas, such as parking lots and building roofs, is directed through an on-site storm water collection and drainage system and discharged to the St. Johns River.

Evaluation of the water discharge permit is required to determine if discharge limitations exist.

3.4 COAL HANDLING SYSTEM

Coal handling upgrades required for the addition of a new 750 MW unit are expected to be the same as that required for a new 600 MW unit. These upgrades are summarized below.

The coal handling system for the SGS Unit 3 is based on handling bituminous coal with a density of 50 pounds per cubic foot and petroleum coke with a density of 45 pounds per cubic foot. The existing rotary dumper and stockout system has adequate capacity (approximately 3,000 tons per hour) to handle the new unit. B&McD recommends that SECI perform a condition assessment of this existing equipment to determine if it can meet expected capacity levels. Existing Units 1 and 2 currently receive approximately one unit train (10,000 tons per train) per day (320 trains per year). The addition of Unit 3 increases this requirement to approximately 1.6 unit trains per day (550 trains per year).

The current long term coal storage pile, for Units 1 and 2, maintains 45 to 60 days of coal storage. Adding Unit 3 requirements to the existing coal pile equates to a total area of approximately 23.5 acres (1,225,000 tons) for all three units. The existing coal storage area has adequate capacity for all three units.

The existing as-received sampling tower is modified by removing the existing as-received sampling system, providing a new motorized flop gate at the head end of Conveyor CB-2, providing a new belt feeder to transfer coal to a new reversible yard conveyor and a new enclosed structure attached to the existing tower. The new reversible yard conveyor is provided with a new trencher type stacker / reclaimer (similar to the existing machine) and is capable of stacking out 3,000 tph and reclaiming at 1,700 tph of bituminous coal or petroleum coke.

The new reversible yard conveyor is approximately 1,500 feet long and provides approximately 3 days of active reclaimable storage for all three units. The head end of the reversible yard conveyor is located in the new structure, adjacent to the existing tower and is provided with a diverter gate to direct coal to either existing Conveyor CB-7A or CB-7B.

The existing as-fired sampling tower is modified by removing the existing as-fired sampling system and providing new motorized flop gates at the head end of Conveyors CB-8A and CB-8B. The new gates direct coal to new Unit 3 feed conveyors to transfer coal from the as-fired tower to a new tower adjacent to Unit 3. The Unit 3 tower is provided with a surge bin and two variable speed belt feeders which discharge to dual tripper conveyors. The tripper conveyors are provided with dual pant leg traveling trippers complete with cable reels and floor seal system.

Replacement of the existing as-received and as-fired sampling systems are accomplished by installing sweep arm primary samplers on the respective belt conveyors and modular self-contained secondary sampling systems, located at grade, immediately underneath the primary sampler(s).

Dust control for the new coal handling system is a dry baghouse type collection system. The baghouse collector is provided with a walk-in clean air plenum, centrifugal fan, ductwork and dust return system. The existing dust collection systems will be upgraded as required to maintain current emission regulations.

3.5 LIMESTONE HANDLING SYSTEM

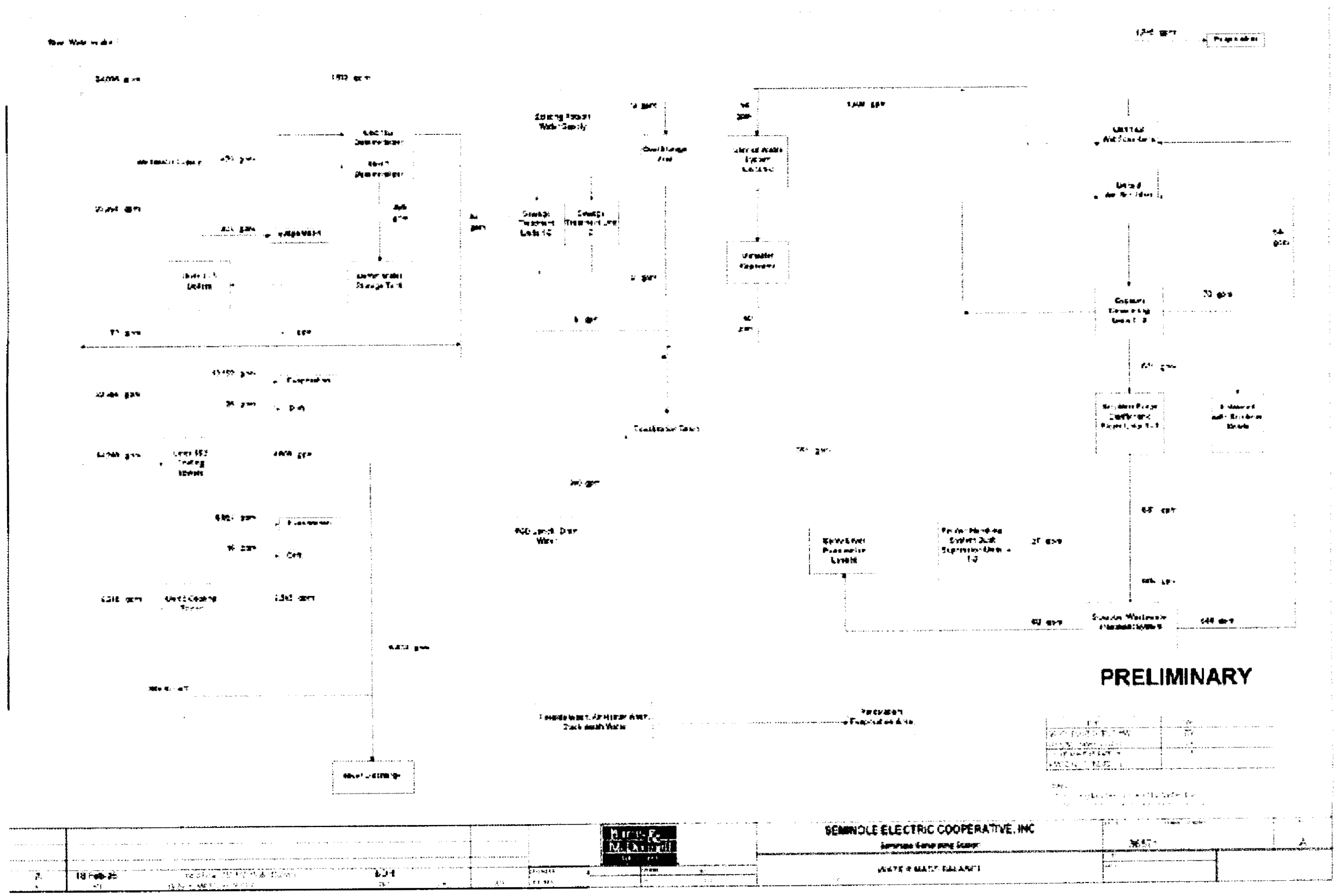
The existing limestone handling system is adequate to supply the Unit 3 limestone demand. The current outdoor limestone storage area is expanded to allow for limestone storage requirements for Unit 3. Assuming a density of 85 pounds per cubic foot, a pile height of approximately 40 feet and maintaining 45 days of storage, this new area requires approximately 2.5 acres.

3.6 ELECTRICAL INTERCONNECTION

Electrical output from the new unit will be stepped up to 230 kV. The turbine generator output will be connected through three single phase generator step-up transformers to the existing 230 kV switchyard. The existing folded breaker-and-a-half switchyard will be modified to add one three-breaker bay to accommodate the new unit and its startup transformers.

The unit startup power will be through two 30/40/50 MVA, 230:6.9/6.9 kV startup transformers. Auxiliary power will transfer to the steam turbine-generator through two 30/40/50 MVA 23:6.9/6.9 kV auxiliary transformers after the unit is on line.

Figure 3-1: Preliminary Site Water Mass Balance



4.0 PERFORMANCE AND EMISSIONS

4.1 PERFORMANCE

Estimated performance was developed for 750 MW subcritical and supercritical PC units at SGS. The estimates summarized in this section are based on in-house data and information from similar projects. A performance summary is shown in Table 4-1. Performance shown is for 100% load operation at new and clean conditions.

Table 4-1: 750 MW PC Performance

Boiler Type	Pulverized Coal Subcritical 1,050 F/ 1,050 F	Pulverized Coal Supercritical 1,050 F/ 1,050 F
Net Plant Output (kW)	750,000	750,000
STG Heat Rate (Btu/kW-hr)	7,476	7,233
STG Gross Output (kW)	810,811	815,217
Boiler Efficiency (%)	87.1	87.1
Auxiliary Power (kW)	60,811	65,217
Auxiliary Power (%)	7.5%	8.0%
Net Plant Heat Rate (Btu/kW-hr)	9,277	9,024

4.2 EMISSIONS

The results of the 600 MW preliminary Best Available Control Technology (BACT) assessment provided previously are applicable for a 750 MW unit. Those results are summarized below.

The BACT levels estimated for this study are not absolute. BACT emission levels change with time, unit type, and fuel type. The emission rates represent B&McD's best estimated BACT levels taking into account technology limitations and current expected guaranteed performance levels.

4.2.1 Emissions Control Technologies

The control technologies required for either a subcritical or supercritical unit is based on firing a blend consisting of 70% bituminous coal and 30% pet coke. As a result, the emissions control equipment required to accommodate the blended fuel is as follows:

- SCR for NO_x control.
- Activated carbon injection system for mercury (Hg) control.
- Electrostatic precipitator (ESP) for particulate (PM) control.

- Flue gas desulfurization (FGD) for SO_2 control.
- Wet ESP for sulfuric acid mist (H_2SO_4) control.

4.2.2 Expected Pollutant Limits

Based on the control technologies described above, the preliminary BACT emission limits for the subcritical and supercritical units being evaluated are as follows:

Table 4-2: Preliminary BACT Emission Limits

Pollutant	Emission Limit
NO_x	0.07 lb/MMBtu
SO_2	0.18 lb/MMBtu
PM	0.015 lb/MMBtu
Hg	6×10^{-6} lb/MW-hr
CO	0.15 lb/MMBtu
H_2SO_4	0.005 lb/MMBtu

The PM emission rate of 0.015 lb/MMBtu is filterable particulate matter only. A PM_{10} emission limit including filterables and condensables has not been guaranteed by vendors on the condensable portion. Further, the mercury emission limit specified is based on recent test data and does not represent a typical vendor guarantee. In addition, the CO limit is based on the expected byproducts from the combustion process in the boiler and is not a controlled pollutant.

4.2.3 Emission Allowances

Emissions allowances may be required for compliance with regulations. Costs for emissions allowances are not included for this study.

5.0 COST ESTIMATES

5.1 CAPITAL COST ESTIMATES

The cost estimates summarized in this section represent screening-level cost estimates used in evaluating the installation of a 750 MW PC unit adjacent to the existing units at SGS. Equipment costs are based on recent vendor quotes for similar equipment and in-house data. Construction commodities and indirect costs are based on B&McD's experience. B&McD did not solicit bids from equipment manufacturers or contractors for equipment or construction services.

The capital cost estimates for 750 MW subcritical and supercritical PC units are included in Table 5-1.

Table 5-1: Capital Cost Estimates

Description	750 MW PC Subcritical	750 MW PC Supercritical
PROCUREMENT		
Mechanical Procurement		
Steam Turbine - Generator	$ 45,257,000	$ 47,885,000
Boiler Island/APC Equipment	$ 172,900,000	$ 174,410,000
Surface Condenser & Air Removal Equipment	$ 5,979,000	$ 5,632,000
Boiler Feed Pumps	$ 1,814,000	$ 2,316,000
Condensate Pumps/Circulating Water Pumps	$ 2,175,000	$ 2,175,000
Miscellaneous Mechanical Equipment	$ 30,303,000	$ 34,486,000
Electrical & Control Procurement		
GSU, Auxiliary Transformers	$ 6,600,000	$ 6,600,000
Medium Voltage Metal-Clad Switchgear	$ 5,801,000	$ 5,801,000
480 V Switchgear & Transformers	$ 1,229,000	$ 1,229,000
Miscellaneous Electrical Equipment	$ 2,613,000	$ 2,613,000
Control Procurement	$ 2,931,000	$ 2,931,000
Water Treatment Procurement	$ 17,594,000	$ 17,594,000
Structural Procurement	$ 9,197,000	$ 9,197,000
CONSTRUCTION		
Major Equipment Erection		
Steam Turbine - Generator Erection	$ 6,548,000	$ 6,548,000
Boiler Island/APC Equipment Erection	$ 164,968,000	$ 165,994,000
Furnish & Erect Packages		
Cooling Tower	$ 23,277,000	$ 21,601,000
Material Handling Systems	$ 20,272,000	$ 20,272,000
Chimney	$ 17,500,000	$ 17,500,000
Civil / Structural Construction	$ 63,979,000	$ 63,979,000
Mechanical Construction	$ 81,120,000	$ 86,042,000
Electrical Construction	$ 58,278,000	$ 58,278,000
PROJECT INDIRECTS		
Construction Management	$ 13,467,000	$ 13,467,000
Preoperational Testing, Startup, & Calibration	$ 12,407,000	$ 12,407,000
Miscellaneous Construction Indirects	$ 7,569,000	$ 7,569,000
Project Management & Engineering	$ 41,508,000	$ 41,508,000
Project Bonds	$ 9,152,000	$ 9,152,000
Escalation	$ 130,261,000	$ 131,771,000
Project Development	$ 3,000,000	$ 3,000,000
Owner Operations Personnel	$ 2,973,000	$ 2,973,000
Substation / Transmission Upgrades	$ 2,400,000	$ 2,400,000
Land	$ -	$ -
Permitting & License Fees	$ 2,643,000	$ 2,643,000
Initial Fuel Inventory	$ 15,120,000	$ 14,812,000
Miscellaneous Owner Costs	$ 12,970,000	$ 13,056,000
Sales Tax & Duties	$ 1,270,000	$ 1,313,000
Owner Contingency	$ 99,508,000	$ 100,916,000
TOTAL PROJECT COST	**$ 1,094,584,000**	**$ 1,110,072,000**

5.1.1 Capital Cost Estimate Assumptions

The cost basis for the subcritical and supercritical solid fuel fired options is defined in Table 5-2. Additionally, the following are the major assumptions and exclusions upon which the facility cost estimates are based:

- Project is executed under a multiple contract method. This contracting method assumes an engineer for plant design, procurement by SECI, and construction performed by multiple contractors.
- Cost estimate is based on a non-union labor force for the Palatka, Florida area, 40-hour work week, single shift with some overtime.
- Cost estimate includes escalation to support commercial operation in June 1, 2012. Escalation at the rate of 2.5% to the midpoint of construction in 2010 is included in the estimate.
- Interest during construction and financing fees are not included.

Table 5-2: 750 MW Plant Cost Basis/Assumptions

General:	
Water Supply:	
Cooling Tower Make-up:	
Source:	River water is used for makeup to the cooling tower.
Supply:	Cooling tower makeup water is supplied from new pumps installed in the existing intake structure. New supply piping from the intake structure to the pump structure will be evaluated during detailed design.
Storage:	None.
Cycle Make-up:	Existing well water system will feed the water treatment system.
Service Water:	New service water pumps and head tank is included to supply service water to the new unit.
Potable Water:	Potable water is supplied from existing system.
Wastewater Disposal:	
Process Wastewater:	Plant wastewater except cooling tower blowdown and site runoff (does not include landfill and coal pile runoff) is discharged to the equalization basin and reusued or evaporated in brine concentrators. Cooling tower blowdown and site runoff is discharged to the St. Johns River.
Contaminated Wastewater:	Drains from areas around equipment that could be contaminated with oil is directed through an oil/water separator and discharged to the existing equalization basin.
Sanitary Wastewater:	Sanitary waste is treated in a new package sewage treatment plant and effluent is discharged to the equalization basin.
Stormwater Discharge:	Stormwater (except for coal pile and landfill runoff) is collected in a storm drainage system and discharged to St. Johns River.
Start-up Fuel:	Start-up fuel for the project is fuel oil. A new fuel oil storage tank is included to provide adequate capacity for the new unit. New fuel oil pumps are required for the new unit.
Solid Fuel:	
Types:	Plant is designed to operate with a 70/30 blend of eastern bituminous coal and petroleum coke.
Delivery:	Solid fuel is delivered to the plant by rail only. Trains are anticipated to be up to 100 car unit trains.
Dead Storage:	Solid fuel is stored in uncovered outdoor piles. Total storage for all three units of 60 days is provided.
Live Storage:	New unit outdoor active pile shall have approximately 24 hours of full load operation.
Boiler Storage:	Boiler building silo storage shall have a minimum of 24 hours of full load operation.
Blending:	70% coal and 30% petroleum coke blend.
Sorbent Supply (Scrubber):	
Source:	Current limestone supplier or as required.
Size:	Limestone size shall be a maximum of 3".
Delivery:	The existing truck unloading system has adequate capacity for the new unit.
Storage:	15 days of covered storage and 40 to 60 days of total storage. Sizing of sorbent storage is based upon design fuel.
Fly Ash & Scrubber Sludge Disposal:	
Disposal:	Fly ash is disposed of in the on-site landfill. Gypsum is sold to the adjacent wallboard plant. Landfill capacity (including expansion requirements) is based on 25-30 year production assuming a 70/30 blend of coal and pet coke. Landfill costs include a composite liner with leachate collection system installed on both the current landfill area and the expansion area. Cover material thickness is 3 feet.
Day Storage:	One fly ash silo with minimum of 3 days of fly ash storage is provided. Silo is sized for the fuel with highest ash production rate.
Transportation:	Fly ash is transported to the landfill via trucks.
Bottom Ash Disposal:	
Ash Disposal:	Bottom ash is sold.
Ash Storage:	Bottom ash is collected and stored in a silo sized for 3 days of bottom ash storage.
Ash Transportation:	Bottom ash is extracted using a dry ash handling system and pneumatically conveyed to a silo. The bottom ash is then trucked off for off-site sale.
Ammonia:	
Types:	Anhydrous Ammonia
Delivery:	Truck with self contained unloading pump
Storage:	15 day storage tank capacity
Construction Utilities:	
Water Supply:	Water supply for construction is from the existing plant make-up water system (well water pumps).
Construction Power:	Power supply for construction is from the existing plant via a power line and temporary transformer.
Equipment Delivery:	Major equipment is delivered to the site via rail. Other equipment is received via rail or truck, whichever is more economical.

Civil:	
Disposal of Spoils:	Spoils are disposed of on site. No hazardous materials are anticipated to be found in the soils.
Soil Conditions / Stability:	Existing soils are assumed to be stable in and around the area of the new unit and suitable for use as laydown without any further preparation. Soils are assumed to be adequate for structural fill. No overexcavation and recompaction is included.
Subsurface Rock:	Removal of subsurface rock is not included.
Cut & Fill:	Site is developed as a balanced site requiring minimal off-site fill and minimal disposal of spoils. Assumed minimal site slopes across the width and off-site fill is available from within 10 miles of the site.
Dewatering:	Some dewatering of the main power plant structures is anticipated. This will be confirmed with preliminary geotechnical studies.
Construction Stormwater Control:	Silt fences are required for construction erosion control. No other special erosion control is included.
Roads:	Existing main plant roads are used. Minor roads and maintenance areas associated with the new unit will have an asphalt finish.
Parking:	Parking areas are surfaced with asphalt concrete.
Rail Scale:	Existing weight measurement system are used.
Coal Pile Run-off:	New coal storage areas is not required. Coal pile run-off is directed to the existing equalization basin.
Site Security:	Assume existing fencing and gates are adequate except where landfill expansion requires modification to existing fence and where fencing is required around new facilities such as the cooling tower.
Landscaping:	Minimal landscaping is included. Disturbed areas are seeded for erosion control.
Structural:	
Soil Bearing Capacity:	Soils are assumed to be suitable for bearing capacities greater than 2500 psf. Therefore, spread footings and mat foundations are anticipated for all structures under this scope of work.
Piling:	Piling is not included
Groundwater:	Some dewatering costs are included.
Boiler Enclosure:	Boiler is not enclosed.
Steam Turbine Enclosure:	Steam turbine is enclosed. The steam turbine hall will interface with the existing steam turbine hall.
Administration Facilities:	No additional administration space is required.
Control Facilities:	Existing control room is utilized for new operator stations.
Warehouse/Storage Facilities:	An additional 100 ft. x 100 ft. warehouse is included.
Water Treatment Building:	Additional building space is included for water treatment equipment.
Maintenance Shop:	No additional maintenance shop area is included.
Yard Maintenance Building	No additional yard maintenance facilities are included.
Electrical Enclosures	Several buildings of various sizes located to reduce wiring runs.
Stack:	Stack is provided with manlift for access.
Height	675' tall.
Velocity	A maximum of 60 feet per second.
Diameter	Exit diameter of 24'.
Liner Material	Clad C-276
Mechanical:	
Boiler:	
Subcritical	Drum type, balanced draft, natural circulation, pulverized coal boiler with steam turbine throttle conditions of 2520 psig and 1050F and with reheat at 1050 F designed for 100% of VWO output on the steam turbine.
Supercritical	Once-through, pulverized coal boiler with steam turbine throttle conditions of 3645 psig and 1050F and with reheat at 1050 F designed for 100% of VWO output on the steam turbine.
Steam Turbine Generator:	Nominally 815 MW, 3,600 rpm, down-exhaust, reheat, tandem compound, four flow type designed to normally operate at maximum output (turbine or generator limited) at a 0.9 PF.
Feedwater Heaters:	Seven stages of feedwater heating for subcritical unit. Eight stages for supercritical unit.
Steam Turbine Bypass:	Not included as the unit is intended to be base loaded.
Auxiliary Boiler:	Will use an auxiliary steam system for new unit start-up.
Heat Rejection:	
Condenser:	Split waterbox, wet surface condenser with 316SS tubes.
Cooling Tower/Cooling Pond:	Utilize a concrete, natural draft cooling tower without fire protection.
Fans:	
FD Fans:	2x60% motor driven, constant speed, centrifugal, with inlet guide vanes.
ID Fans:	3x50% motor driven, constant speed, centrifugal with inlet guide vanes.
PA Fans:	2x60% motor driven, constant speed, centrifugal with inlet dampers
Air Heaters:	2x50%
Pumps:	
Boiler Feed Pumps:	2x60% steam turbine driven, constant speed, barrel pumps
Start-up boiler feed pump:	1x30% motor driven start-up pump.
Condensate Pumps:	3x50% constant speed motor driven pumps
Circulating Water Pumps	3x50% motor driven constant speed, standard construction

Water Treatment:	
Steam Cycle Make-up:	Additional 185 gpm of demineralizer capacity is provided.
Cooling Tower Make-up:	Chemical feed for pH adjustment, corrosion/scale control, and blowdown treatment as required.
Cooling Tower Sidestream:	Not included.
Service Water Make-up:	Service water is supplied from existing system.
Condensate Polishing	4x35% capacity deep bed polisher vessels with external regeneration.
Wastewater Treatment:	
Scrubber Purge Water	Brine concentrators (2) with spray dryer provided to treat scrubber purge water from Units 1 - 3. Solid waste hauled to the on-site landfill.
Compressed Air Supply:	3x50% capacity rotary screw air compressors with desiccant type air dryers
Fire Protection:	Fire protection system per NFPA. The fire water loop is extended around the new unit. New diesel driven, motor driven, and motor driven jockey pumps are included for the new unit.
Water Storage:	
Condensate Storage:	Additional 375,000 gallons of storage capacity is included.
Raw Water Storage:	Use existing well water and river water system. However, a new 15,000 gallon surge tank and pumps are added to the well water system.
Demineralized Water Storage:	Combined with condensate storage.
Potable Water Storage	Potable water is supplied from existing system.
Auxiliary Cooling:	
Type:	Closed Cooling Water System
Exchangers:	Plate & Frame with 316SS plates
Coal Handling:	
Unloading:	Existing rotary car dumper is used.
Check Weighing:	Belt scale on existing conveyor is used.
Stockpiling:	As recommended by Burns & McDonnell.
Dead Storage Reclaim:	Dozer w/ hoppers as this is not the normal fuel reclaim method. Only used in emergency situations. Existing dozers will be used in conjunction with new trencher.
Live Storage Reclaim:	New trencher stacker / reclaimer and existing trencher stacker / reclaimer.
Reclaim redundancy:	Use existing and new trencher.
Crushers:	Use existing crushers.
Reclaim Sizing:	Fill 24 hour usable volume.
Pulverizers:	One redundant coal silo / pulverizer unit based upon design fuel blend. Worst case fuel may utilize the redundant unit without any further redundancy.
Limestone Handling	
Unloading:	Use existing truck unloading system.
Storage:	Short term and long term storage is indoor/outdoor storage piles using existing mobile equipment with existing reclaim equipment. Storage is expanded to maintain 45-60 days of limestone storage.
Delivery to Scrubber:	Reclaimed and delivered to 1x100% limestone bins (12 hour storage) via 1x100% limestone conveyor.
Preparation:	Crushed limestone is prepared in existing 2x100% ball mills. One new limestone slurry storage tanks is added for the new unit.
Fly Ash Handling	
Removal from ESP	Pressurized pneumatic conveying systems including 2x50% trains with 3x50% blowers to the ash silo. Conveying system is sized to remove 24 hours of ash in an 8 hour shift.
Ash Load-out:	Ash truck loadout systems is provided below the silo via gravity or pneumatic conveying. Ash loadout includes 2x100% ash conditioning systems (pug mills). Fly ash transport to the on-site landfill is by truck. Alternate dry loadout capability via truck is provided to support ash sales.
Bottom Ash Handling	
Removal from Boiler	Dry extraction bottom ash removal system.
Ash Load-out:	Trucked from Silo.
Scrubber Sludge Handling:	
Hydroclones	Radial hydroclone assembly with a minimum of 2 spare cyclones.
Vacuum Filter	Two 100% capacity belt filters sized for all 3 units.
Pug Mills	Not required
Ash Storage:	Included with fly ash handling.
Sludge Storage	Not included.
Sludge Disposal	Gypsum conveyed to wall board plant on site.
Scrubber	
Type:	Wet FGD - Forced Oxidized
Size:	1x100% module
Turndown capability:	5:1 as a minimum.
Redundancy:	A spare recycle pump or organic acid feed system is provided.

ESP	
Redundancy	None
Type:	Rigid frame
SCA:	(To be determined)
Activated Carbon Injection	An activated carbon injection system is provided for mercury control.
Maximum Injection Rate	20 lbs/mmACF
Wet ESP	
Type	Vertical flow located above absorber module.
Number of fields	A minimum of 2 fields.
SCA:	(To be determined)
SCR	
Catalyst type	Honeycomb
Space Velocity	(To be determined)
SCR Bypass	There is a SCR bypass for fuel oil starting.
Economizer Bypass	There is an economizer bypass on the water side to maintain temperature at low loads.
Emissions Control:	
Emissions Control:	
NOx:	SCR guaranteed for 0.07 lb/MMBtu of exhaust NOx.
Ammonia Slip:	3 ppmvd @ 3% O2
CO:	Combustion controls to 0.15 lb/MMBtu.
SOx:	Wet scrubber to accomplish 0.18 lb/MMBtu. Equipment guaranteed for 98% removal of the inlet SO_2 concentration.
PM10:	Electrostatic precipitator to accomplish emissions of 0.015 lb/MMBtu (filterable only).
Mercury:	Carbon injection system to reduce mercury emissions to 6 x 10^{-6} lb/MW-hr (Approximately 0.6 lb/Tbtu heat input).
Sulfuric Acid Mist:	Wet ESP guaranteed for 0.005 lb/mmBtu.
General Notes - Not Scope Items	
Coal Handling:	Covered conveyors with dust collection at transfers and wet suppression at stockout.
Stack Height:	Good Engineering Practice" - per US Code Title 42, Ch 85,Sub 1, Part A, Section 7423 - approx. 2.5 times the height of the tallest adjacent structure (boiler). Assumed 675 feet for estimate.
Electrical	
Generator Step-up Transformer:	Three, single phase step-up transformers to provide ability to use the existing spare transformer. Transformers are rated at OA/FA/FOA.
Black Start Capability:	Not Included.
Emergency Generator:	Included for essential power only.
Emergency Power:	2 hour DC system with a UPS for supply to the control system and critical instrumentation.
Start-up / Back-up Power:	Start-up of unit is accomplished using 2X 50% three winding start up transformers.
Auxiliary Power Supply:	Two 50% three winding auxiliary transformers connected to the bus between the generator and the GSU. Transfer from start up power to unit auxiliary power after the bus is synchronized to the generator.
Plant Control System:	Distributed control system with remote located I/O panels.
Plant Communications:	
External and Office to Office	Tie into existing infrastructure.
Internal around plant	Gaitronics communication system throughout the plant.
Switchyard Communications	Not included.
Transmission / Interconnection:	
Switchyard:	One new 230 KV bay.
Transmission Upgrades:	Not included.
Interconnection to Existing Transmission:	Included.
Construction:	
General Liability Insurance:	Included
Builder's Risk Insurance:	Not Included
Performance Bonds:	Included
Performance/Stack Testing:	Included
Commissioning / Start-up:	Included
Operator Training:	Included
Permits:	Building permits and construction permits are included. Air, NPDES, and other plant discharge permits are not included.
Construction Schedule	It is assumed that the construction schedule is adequate to allow the project to be completed with minimal overtime. Construction schedule is estimated as a 5x8 with some overtime.

Miscellaneous:	
Permanent Plant Operating Spare Parts:	Allowance is included.
Maintenance Tools & Equipment.	Allowance is included.
Sales Tax	Estimated sales tax is included.
Other Owner's Costs	Estimated project development costs, Owner's CM, permitting costs, initial fuel inventory, building furnishings, and warehouse shelves are included.

Items Excluded from the Scope:
1. Legal Costs.
2. Fuel, limestone, and ash transportation equipment or rental costs for equipment required to transport such materials to or from the site.
3. Land Costs.
4. Sound abatement above normal supply.
5. Aesthetic landscaping other than erosion control.
6. Black start capability.
7. Waste water treatment or disposal other than discharge to a location on site.
8. Interest During Construction and financing fees.
9. Mobile Equipment.

5.1.2 Estimate Risk Assessment

Due to the capital intensive nature of solid fuel generation projects resources and length of construction period, there is capital cost risk due to interest costs, labor availability and costs, and general inflation. Other risk factors associated with the construction of new solid fuel generation plants include the fact several US boiler manufacturers are currently under financial duress, and the skilled workforce that constructed a number of coal units in the 1970's and 1980's have aged without a significant influx of younger construction workers with similar specialized skills and experience. If a number of new coal units initiate construction within the next decade, the supply of skilled construction workers could be strained. The primary tradeoff for these higher capital risks with a solid fuel generation resource is the long-term stability of coal and other solid fuel alternatives, which have few competing uses relative to natural gas that is used by almost all economic sectors including residential heating.

5.2 OPERATIONS & MAINTENANCE (O&M) COST ESTIMATES

A summary of the variable and fixed O&M costs for the 750 MW subcritical and supercritical solid fuel fired alternatives are included in Tables 5-3 and Table 5-4. These costs are estimated based on the assumptions discussed in this section.

Table 5-3: O&M Cost Estimate – 750 MW Subcritical

Operating Assumptions						
Basis Year for Cost Estimate						2004
Capacity Factor						85.0%
Load Factor						100.0%
Net Unit Output, kW						750,000
Number of Units						1
Net Output, kW						750,000
Net Annual Output, MWh						5,584,500
Net Steam Turbine Heat Rate						7,430
Net Plant Heat Rate, Btu/kWh						9,220
Fuel Consumption, MMBtu/hr						6,915
Annual Fuel Consumption, MMBtu						51,489,090
Boiler Technology						Pulverized Coal
Type of NOx Control						SCR
Type of SO2 Control						Wet
Type of Particulate Control						ESP
Type of H2SO4 Control						Wet ESP
Type of Mercury Control						Carbon Injection
Type of Heat Rejection						Cooling Tower
Cooling Tower Materials of Construction						Concrete
Make-up Water Softening Required						Yes
Zero Discharge Facility						Yes
Type of Sidestream Treatment						None
Fixed O&M						
Labor	46 people @		$	70,448		***$ 3,240,610***
Office & Admin						***$ 75,000***
G&A (Home Office / Support)						**By Seminole**
Other Fixed O&M						***$ 1,350,000***
Employee Expenses/Training						
Contract Labor						
Environmental Expenses						
Safety Expenses						
Buildings, Grounds, and Painting						
Other Supplies & Expenses						
Communication						
Control Room/Lab Expenses						
Annual Steam Turbine Inspections						***$ 100,000***
Annual Boiler Inspections						***$ 80,000***
Annual APC Inspections						***$ 100,000***
Start-up power demand charge	$	-	per kW-Mo	15,000	KW	***$ -***
Water supply demand charge	$	-	per acre-ft	0	acre-ft	***$ -***
Water discharge demand charge	$	-	per acre-ft	0	acre-ft	***$ -***
Standby Power Energy Costs	$	-	per kW-hr	3,942,000	KW-hr	***$ -***
Standby Power Service Fee	$	-	per Month	12	Mo	***$ -***
Property Taxes						**In Proforma**
Insurance						**In Proforma**
Total Fixed O&M Annual Cost						***$ 4,945,610***
Major Maintenance Costs (Capitalized)						
Steam Turbine / Generator Overhaul	7446	Op Hours/yr	$	58.45	$/hour	***$ 435,241***
Steam Generator Major Replacements (Boiler $10MM@10yrs & Burners @ 20 yrs & Walls)				1,187,500	$/yr	***$ 1,187,500***
Baghouse Bag Replacement	-	$/Replacement		5	years	***$ -***
SCR Catalyst Replacement	$3,686,935	Catalyst Cost		3	yrs life	***$ 1,229,000***
Water Treatment System Replacements				5,429	$/yr	***$ 5,400***
Total Annual Major Maintenance Costs						***$ 2,857,141***

Table 5-3 - (Continued)

Non-Fuel Variable O&M					
Water Consumption					
Raw Water	4318	MMGal/yr @	$0.00 /kGal	$	-
Raw Water Make-up Treatment	4318	MMGal/yr @	$0.14 /kGal	$	610,400
Potable Water	1	MMGal/yr @	$1.00 /kGal	$	1,500
Water Discharge	1134	MMGal/yr @	$0.00 /kGal	$	-
Cooling Tower Treatment Chemicals	3976	MMGal/yr @	$0.05 /kGal	$	218,600
Demin Water Treatment	70	MMGal/yr @	$0.04 /kGal	$	3,100
Boiler Treatment Chemicals	4520	MMGal/yr @	$0.0126 /kGal	$	57,100
Maintenance & Consumables (lube oil, nitrogen, hydrogen, etc.)					
SCR System General Maintenance					
General Maintenance			$75,000 $/yr	$	75,000
Scrubber System General Maintenance					
Absorber, Dewatering & Accessories			$141,000 $/yr	$	141,000
Limestone Preparation			$438,803 $/yr	$	438,800
Water Treatment System General Maintenance			$75,515 $/yr	$	75,500
Cooling Tower System General Maintenance			$215,900 $/yr	$	215,900
Brine Concentrator and Spray Dryer System O&M			$2,816,250 $/yr	$	2,816,250
Other Variable O&M				$	6,508,200
Electronics, Controls, BOP Electrical					
Steam Generators					
BOP					
Misc. Maintenance Expenses					
Consumables					
Emissions Controls					
Lime Consumption	NA	tpy@	$107.89 /ton	$	-
Limestone Consumption	309,129	tpy @	$8.66 /ton	$	2,677,100
SCR Ammonia (Anhydrous)	2,002	tpy@	$250.00 /ton	$	500,400
Gypsum (Sales) / Disposal	532,647	tpy@	-$10.80 /ton		(5,752,600)
Ash (Sales) / Disposal (Wet Scrubber)	134,929	tpy @	$4.00 /ton		539,700
Ash (Sales) / Disposal (Dry Scrubber)	NA	tpy @	$4.00 /ton		-
Bottom Ash (Sales) / Disposal	33,732	tpy @	-$6.50 /ton		(219,300)
Carbon Injection	5,952	tpy@	$1,040.00 /ton		6,190,200
Total Non-Fuel Variable O&M Annual Cost				$	15,096,850
Total Fixed and Variable O&M Annual Cost				$	22,899,601
Total Fixed O&M Annual Cost, $/kW-yr					6.59
Total Emission Allowance Costs, $/yr				$	-
Total Major Maintenance (Capitalized Costs), $/MWh				$	0.51
Total Non-Fuel Variable O&M Annual Cost, $/MWh				$	2.70
Total O&M Cost, $/MWHr					4.10

Table 5-4: O&M Cost Estimate – 750 MW Supercritical

Operating Assumptions						
Basis Year for Cost Estimate						2004
Capacity Factor						85.0%
Load Factor						100.0%
Net Unit Output, kW						750,000
Number of Units						1
Net Output, kW						750,000
Net Annual Output, MWh						5,584,500
Net Steam Turbine Heat Rate						7,172
Net Plant Heat Rate, Btu/kWh						8,949
Fuel Consumption, MMBtu/hr						6,712
Annual Fuel Consumption, MMBtu						49,975,691
Boiler Technology						Pulverized Coal
Type of NOx Control						SCR
Type of SO2 Control						Wet
Type of Particulate Control						ESP
Type of H2SO4 Control						Wet ESP
Type of Mercury Control						Carbon Injection
Type of Heat Rejection						Cooling Tower
Cooling Tower Materials of Construction						Concrete
Make-up Water Softening Required						Yes
Zero Discharge Facility						Yes
Type of Sidestream Treatment						None
Fixed O&M						
Labor		46 people @	$ 70,448		$	***3,240,610***
Office & Admin					$	***75,000***
G&A (Home Office / Support)						**By Seminole**
Other Fixed O&M					$	***1,350,000***
Employee Expenses/Training						
Contract Labor						
Environmental Expenses						
Safety Expenses						
Buildings, Grounds, and Painting						
Other Supplies & Expenses						
Communication						
Control Room/Lab Expenses						
Annual Steam Turbine Inspections					$	***100,000***
Annual Boiler Inspections					$	***80,000***
Annual APC Inspections					$	***100,000***
Start-up power demand charge	$ -	per kW-Mo	15,000	KW	$	-
Water supply demand charge	$ -	per acre-ft	0	acre-ft	$	-
Water discharge demand charge	$ -	per acre-ft	0	acre-ft	$	-
Standby Power Energy Costs	$ -	per kW-hr	3,942,000	KW-hr	$	-
Standby Power Service Fee	$ -	per Month	12	Mo	$	-
Property Taxes						**In Proforma**
Insurance						**In Proforma**
Total Fixed O&M Annual Cost					$	***4,945,610***
Major Maintenance Costs (Capitalized)						
Steam Turbine / Generator Overhaul	7446	Op Hours/yr	$ 58.45	$/hour	$	***435,241***
Steam Generator Major Replacements (Boiler $10MM@10yrs & Burners @ 20 yrs & Walls)			1,187,500	$/yr	$	***1,187,500***
Baghouse Bag Replacement	-	$/Replacement	5	years	$	-
SCR Catalyst Replacement	$3,686,935	Catalyst Cost	3	yrs life	$	***1,229,000***
Water Treatment System Replacements			5,429	$/yr	$	***5,400***
Total Annual Major Maintenance Costs					$	***2,857,141***

Table 5-4 - (Continued)

Non-Fuel Variable O&M					
Water Consumption					
Raw Water	4318	MMGal/yr @	$0.00 /kGal	$	-
Raw Water Make-up Treatment	4318	MMGal/yr @	$0.14 /kGal	$	610,400
Potable Water	1	MMGal/yr @	$1.00 /kGal	$	1,500
Water Discharge	1134	MMGal/yr @	$0.00 /kGal	$	-
Cooling Tower Treatment Chemicals	3976	MMGal/yr @	$0.05 /kGal	$	218,600
Demin Water Treatment	70	MMGal/yr @	$0.04 /kGal	$	3,100
Boiler Treatment Chemicals	4363	MMGal/yr @	$0.0126 /kGal	$	55,100
Maintenance & Consumables (lube oil, nitrogen, hydrogen, etc.)					
SCR System General Maintenance					
General Maintenance			$75,000 $/yr	$	75,000
Scrubber System General Maintenance					
Absorber, Dewatering & Accessories			$141,000 $/yr	$	141,000
Limestone Preparation			$438,803 $/yr	$	438,800
Water Treatment System General Maintenance			$75,515 $/yr	$	75,500
Cooling Tower System General Maintenance			$215,900 $/yr	$	215,900
Brine Concentrator and Spray Dryer System O&M			$2,816,250 $/yr	$	2,816,250
Other Variable O&M				$	6,508,200
Electronics, Controls, BOP Electrical					
Steam Generators					
BOP					
Misc. Maintenance Expenses					
Consumables					
Emissions Controls					
Lime Consumption	NA	tpy @	$107.89 /ton	$	-
Limestone Consumption	300,705	tpy @	$8.66 /ton	$	2,604,100
SCR Ammonia (Anhydrous)	2,002	tpy @	$250.00 /ton	$	500,400
Gypsum (Sales) / Disposal	518,136	tpy @	-$10.80 /ton		(5,595,900)
Ash (Sales) / Disposal (Wet Scrubber)	131,251	tpy @	$4.00 /ton		525,000
Ash (Sales) / Disposal (Dry Scrubber)	NA	tpy @	$4.00 /ton		-
Bottom Ash (Sales) / Disposal	32,812	tpy @	-$6.50 /ton		(213,300)
Carbon Injection	5,952	tpy @	$1,040.00 /ton		6,190,200
Total Non-Fuel Variable O&M Annual Cost				$	15,169,850
Total Fixed and Variable O&M Annual Cost				$	22,972,601
Total Fixed O&M Annual Cost, $/kW-yr					6.59
Total Emission Allowance Costs, $/yr				$	-
Total Major Maintenance (Capitalized Costs), $/MWh				$	0.51
Total Non-Fuel Variable O&M Annual Cost, $/MWh				$	2.72
Total O&M Cost, $/MWHr					4.11

5.2.1 Staffing

The staffing plan for the 750 MW solid fuel generation alternative is anticipated to be identical to the staffing plan provided for the 600 MW solid fuel generation alternative. Unit 3 will share operational staff with the existing units. The existing shift supervisor will direct shift operations, make assignments, and perform required administrative duties for the new unit. The shift supervisor will also serve as a second operator during emergencies and provide periodic relief for the primary control room operator. The existing plant staffing will be expanded by 46 employees to accommodate the new unit. By sharing staff, all units will benefit from added flexibility and will be able to operate with fewer on-site staff per unit.

5.2.2 O&M Cost Estimate Assumptions

The following assumptions are used in determining the O&M costs:

- Limestone is 90% $CaCO_3$.
- SO_2 removal of 98%.
- 0.2 lb/MMBtu Boiler NO_x production and 0.07 lb/MMBtu from stack.
- Ash and gypsum contain 5% moisture.
- Activated carbon injection at 20 lb/MACF.
- SCR replacement cost assumes the catalyst is regenerated and not disposed of.
- The O&M costs assume the unit is operating at 100% load.
- Staffing costs assume non-union operator wage rates and assume 5% overtime.
- O&M costs are presented in 2004 dollars (for consistency with the previous 600 MW study).
- The following unit costs are assumed in estimating the non-fuel variable O&M costs:
  - Ash Disposal $4.00/ton
  - Limestone $8.66/ton
  - Anhydrous Ammonia $250/ton
  - Activated Carbon $1,040/ton
  - Gypsum Sales $10.80/ton
  - Bottom Ash Sales $6.50/ton

The O&M costs do not include the following:

- Property taxes and insurance (included in pro forma analysis)
- Costs associated with emission allowances
- Fuel supply costs
- Wheeling costs
- Initial spares, pre-op costs (computers, software, office equipment, etc)
- O&M mobilization fees

6.0 ECONOMIC ANALYSIS

6.1 OBJECTIVE

Pro forma financial analyses were prepared to compare the 750 MW subcritical and supercritical pulverized coal alternatives to the 600 MW subcritical and supercritical pulverized coal alternatives as well as a 500 MW gas-fired combined cycle unit. The economic analyses are based on the estimated capital costs, performance, fuel costs, and operating costs for the alternatives. The economic results are summarized in the following sections.

6.2 SOLID FUEL ASSUMPTIONS & COST ESTIMATES

The following estimates and economic assumptions are utilized in the pro forma financial analyses for the solid fuel-fired units.

• Capital Costs including Owner Costs and Contingency	Table 5-1
• Heat Rate and Performance Estimates	Table 4-1
• Delivered Solid Fuel Cost Assumption	
Assumes 70%/30% coal/petroleum coke blend	2012: $2.06 ($/MMBtu)
	2013: $2.09 ($/MMBtu)
	2014: $2.17 ($/MMBtu)
	2%/yr escalation after 2014
• Operating Assumptions:	
Planned Dispatch	8,016 hours per year
	(one month planned outage)
Overall Capacity Factor	85.0%
• Financing Assumptions:	
Interest Rate	6%
Term	30 years
Debt/Equity Percentage	100%/0%
Return on Equity	N/A

Construction Financing Fees	0.50%
Permanent Financing Fees	1.00%
Construction Financing	45 months

- O&M Cost Assumptions:

Fixed O&M Costs	Tables 5-3 and 5-4
Insurance	0.16% of Replacement Cost per year
Property Taxes	2% of Net Book Value per year
Variable O&M Costs	Tables 5-3 and 5-4
Transmission Costs	Not included – busbar cost evaluation
Lime/Limestone Costs	Included in variable O&M
Emissions Allowances	Not included

- Economic Assumptions:

O&M Inflation	2.5% per annum
Construction Cost Inflation	2.5% per annum
Delivered Solid Fuel Inflation	2.0% per annum (after 2014)
Discount Rate	6%
Effective Tax Rate	0%
Book Depreciation (Straight Line)	30 years

6.3 COMBINED CYCLE BENCHMARK ASSUMPTIONS & COST ESTIMATES

The following estimates and economic assumptions are utilized in the gas-fired combined cycle pro forma economic analysis.

• Capital Costs including Owner Costs and Contingency	$369,600,000
• Heat Rate Performance Assumptions	6,775 Btu/kWh (HHV)
• Delivered Natural Gas Cost Assumption	2004: $5.50 ($/MMBtu) 2.5% escalation after 2004

- Operating Assumptions:

Planned Dispatch	8,016 hours per year
Overall Capacity Factor	85.0%

- Financing Assumptions:

Interest Rate	6%
Term	30 years
Debt/Equity Percentage	100%/0%
Return on Equity	N/A
Construction Financing Fees	0.50%
Permanent Financing Fees	1.00%
Construction Financing	24 months

- O&M Cost Assumptions:

Fixed O&M Costs	$2,724,000
Insurance	0.16% of Replacement Cost per year
Property Taxes	2% of Net Book Value per year
Variable O&M Costs	$3.25 ($/MWh)
Transmission Costs	Not Included – busbar cost evaluation
Emissions Allowances	Not included

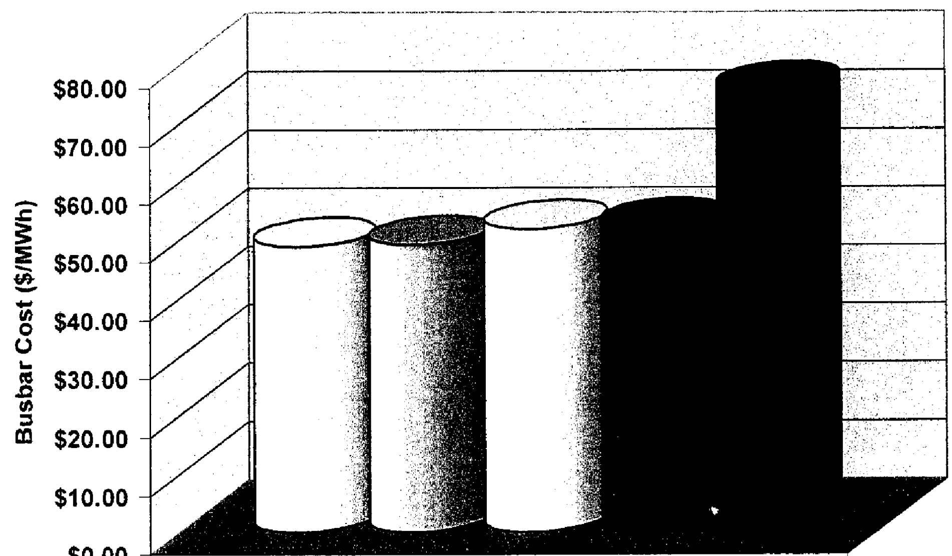
- Economic Assumptions:

O&M Inflation	2.5% per annum
Construction Cost Inflation	2.5% per annum
Delivered Natural Gas Fuel Inflation	2.5% per annum (after 2004)
Discount Rate	6%
Effective Tax Rate	0%
Book Depreciation (Straight Line)	30 years

6.4 ECONOMIC ANALYSIS RESULTS

The economic pro forma analyses were used to determine the 20-year levelized busbar cost of power for each alternative. Figure 6-1 presents a graph of the resulting 20-year levelized busbar power costs for the benchmarks and both project alternatives. Figure 6-1 was developed by preparing a project pro forma for the benchmarks and both alternatives under consideration. The busbar cost represents the energy cost in 2012\$. The 20-year levelized busbar power costs for the 750 MW supercritical PC unit and 750 MW subcritical PC unit are \$48.85/MWh and \$49.15/MWh, respectively.

Figure 6-1: 20-Year Levelized Busbar Costs (2012\$)



	Alternatives
☐ 750 MW Supercritical	\$48.85
☐ 750 MW Subcritical	\$49.15
☐ 600 MW Supercritical	\$51.84
■ 600 MW Subcritical	\$52.08
■ 500 MW CC	\$75.48

6.5 ECONOMIC CONCLUSIONS

Both the 600 MW and 750 MW supercritical and subcritical PC units provide a low 20-year levelized busbar cost when compared to the gas-fired combined cycle plant. Combined cycle technology has a much higher fuel cost, but is much less capital cost intensive. For this reason, coal-fired technology is preferred to combined cycle technology for facilities with high capacity factors. Both of the coal-fired options are preferred to a combined cycle plant for baseload dispatch. Additionally, both 750 MW alternatives provide larger economies of scale than the 600 MW alternatives, as illustrated by their slightly lower levelized busbar costs.

6.6 SENSITIVITY ANALYSIS RESULTS

Sensitivity analyses were prepared for the project alternatives under the following cases:

- Capital Cost (plus or minus 10%)
- Interest Rate (plus or minus one (1) percentage point)
- Capacity Factor (plus or minus 5%)
- Delivered Fuel Cost (plus or minus 10%)
- O&M Costs (plus or minus 10%)

The results of the sensitivity analyses are presented in tornado diagrams in Figures 6-2 and 6-3. A tornado diagram illustrates the range of results for each sensitivity case and its impact on the levelized power cost, and ranks the results from greatest impact to least impact. The sensitivity analysis indicates that the interest rate, followed closely by fuel cost and capital cost, is the most significant factor affecting the economics of a solid fuel-fired unit.

Figure 6-2: Sensitivity Analysis – 750 MW Supercritical Unit

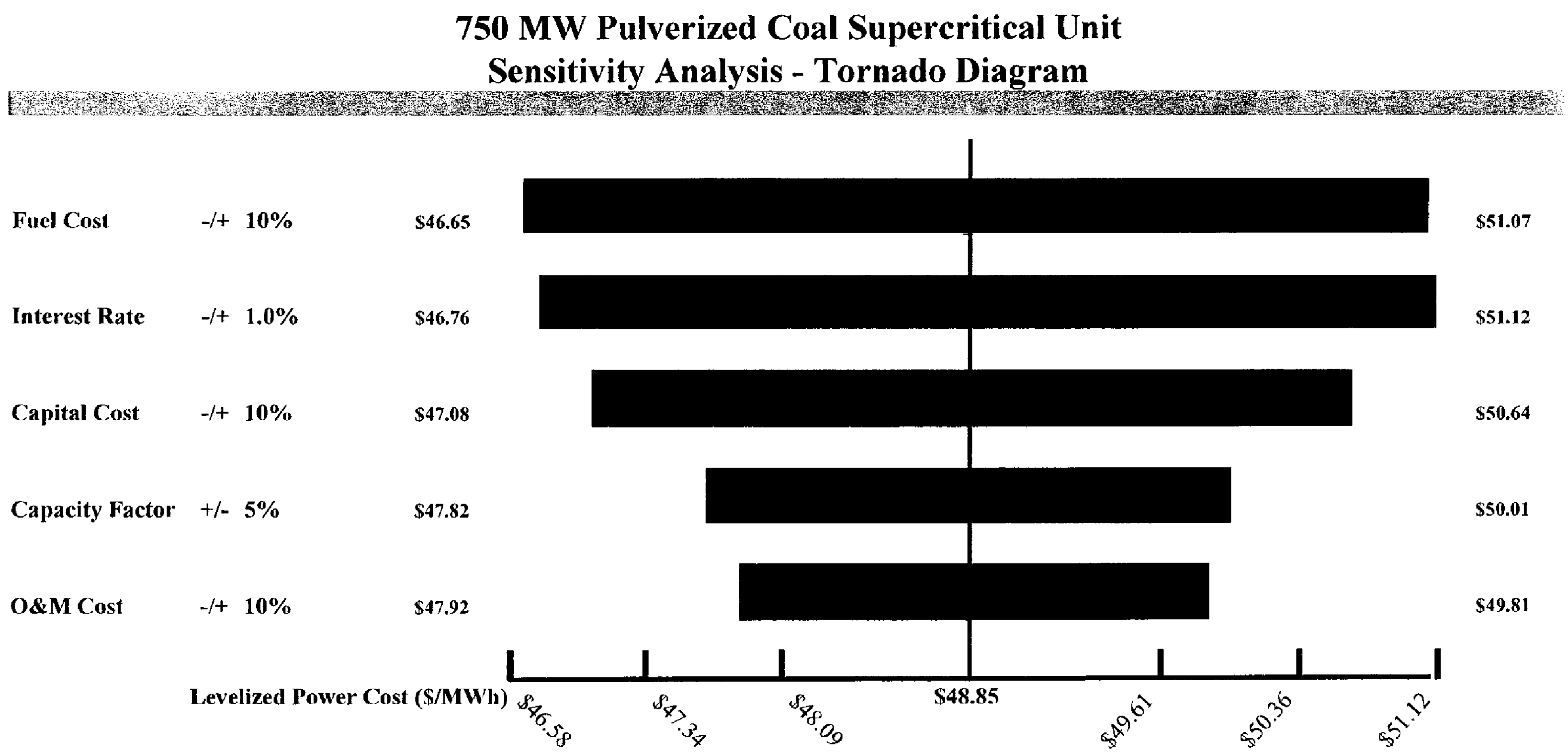
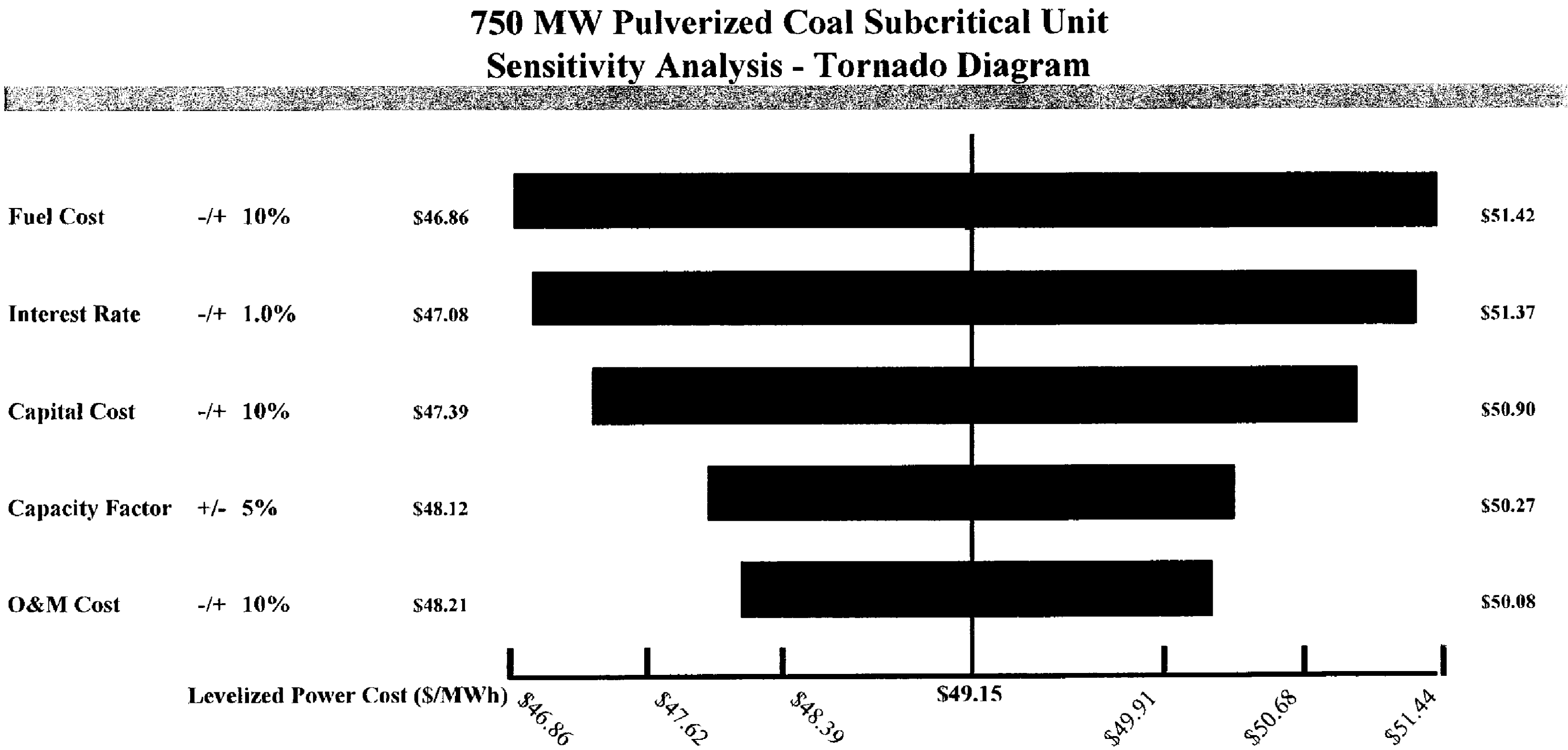


Figure 6-3: Sensitivity Analysis – 750 MW Subcritical Unit



7.0 CONCLUSIONS AND RECOMMENDATIONS

7.1 CONCLUSIONS

Both the 750 MW and 600 MW supercritical and subcritical pulverized coal units provide a lower 20-year levelized busbar cost when compared to the gas-fired combined cycle plant. Combined cycle technology has a much higher fuel cost, but is much less capital cost intensive. For this reason, solid fuel-fired technology is preferred to combined cycle technology for facilities with high capacity factors. Additionally, the solid fuel fired alternatives are preferred to a combined cycle plant for baseload dispatch.

The 750 MW supercritical unit has a slightly lower levelized busbar cost of $48.85/MWh versus the 750 MW subcritical unit busbar cost of $49.15/MWh.

Both of the 750 MW alternatives have lower levelized busbar costs than the 600 MW PC benchmark alternatives. The reason for these lower costs is the reduction in capital costs on a dollars per kilowatt ($/kW) basis for the larger 750 MW units.

Other factors to consider when selecting between subcritical and supercritical steam cycle include the following:

- Operator familiarity with subcritical technology at the SGS plant.
- Lower emissions due to the higher efficiencies of the supercritical technology.
- Permitting may face fewer hurdles with a supercritical cycle verses a subcritical cycle.
- Corrosive coals, such as that anticipated for use at SGS Unit 3, can cause excessive wastage and circumferential cracking in the water walls and liquid phase corrosion in the superheater and reheater when burned in supercritical units with elevated steam temperatures.
- There is currently no supercritical PC operating experience with 30% pet coke blend (i.e. high sulfur fuel), regardless of steam temperature.
- There is currently no subcritical PC boiler operating experience with 30% pet coke blend (i.e. high sulfur fuel) above 1000°F/1000°F steam conditions.

Due to the lack of experience with supercritical technology operation on high sulfur coals and the increased potential for excessive wastage, circumferential cracking, and liquid phase corrosion anticipated on a supercritical unit, B&McD recommends subcritical technology be employed for SGS Unit 3.

7.2 STATEMENT OF LIMITATIONS

In preparation of this Feasibility Study, B&McD has made certain assumptions regarding future market conditions for construction and operation of solid fuel generation resources. While we believe the use of these assumptions is reasonable for the purposes of this Study, B&McD makes no representations or warranties regarding future inflation, labor costs and availability, material supplies, equipment availability, weather, and site conditions. To the extent future actual conditions vary from the assumptions used herein, perhaps significantly, the estimated costs presented in this Study may vary.

Seminole Generating Station
Technology Assessment Study

Seminole Electric
COOPERATIVE, INC.
IN PARTNERSHIP WITH THOSE WE SERVE

Seminole Electric Cooperative, Inc.

March 2005
Project 38404

Burns & McDonnell
SINCE 1898

Burns & McDonnell
SINCE 1898

March 9, 2005

Mr. Tom Wess
Manager of Generation Engineering
Seminole Electric Cooperative, Inc.
16313 North Dale Mabry Highway
Tampa, Florida 33618

Project No. 38404
Technology Assessment Study

Mr. Wess:

Burns & McDonnell is pleased to submit our Technology Assessment Study to Seminole Electric Cooperative, Inc. (SECI). The purpose of the study is to provide an evaluation of supercritical pulverized coal technology, a 600 MW – 800 MW unit size assessment, and an update of the IGCC technology.

If you have any questions regarding the report, please contact me at 816-822-3274 or Jeff Greig at 816-822-3392.

It is a pleasure to be of service to SECI in this matter.

Sincerely,

Richard A. Klover

Richard Klover
Project Manager

Richard Klover
Project Manager

JG

Jeff Greig
General Manager

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TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

1.0 EXECUTIVE SUMMARY

1.1 SCOPE OF WORK

The purpose of this study was to assist Seminole Electric Cooperative, Inc. in evaluating the technical merits of supercritical pulverized coal technology, to provide a unit size assessment, and an update of the IGCC technology. The study consisted of the following assessments described below.

1.1.1 Supercritical Technology Assessment

Supercritical steam generation offers potential advantages over subcritical units. Advancements in supercritical technology make it the technology choice for some new coal-fired projects. When fuel costs are relatively high, or when reduced emissions offer a particular benefit, supercritical technology may be attractive. This assessment provides the status of the technology, examines the economics (efficiency, capital costs, and O&M costs) of supercritical steam generation and identifies the current supercritical projects in North America. Table 1.1 identifies the advantages of supercritical and subcritical steam cycles.

Table 1.1: Steam Cycle Evaluation

Criteria	Supercritical	Subcritical
Plant Efficiency	✓	
Simpler Controls		✓
Capital Cost		✓
Fuel Consumption	✓	
Fixed O&M	=	=
Variable O&M	✓	
Fuel Flexibility	=	=
Lower Design Pressure		✓
Startup Time	✓	
Ramp Rates	✓	
Emissions	✓	
Feedwater Quality Requirements		✓
Plant Availability	=	=

Supercritical steam generation in the United States experienced a troublesome operating history with the first generation of units. However, as recent data indicates that the availability of newer supercritical units both here and overseas is comparable to that of subcritical units of the same vintage. Supercritical units have significant advantages in efficiency and reduced emissions per kilowatt-hour of energy produced. They also have better plant cycling and load ramping capabilities than conventional drum type subcritical units.

1.1.2 Steam Cycle and Unit Size Assessment

The Steam Cycle and Unit Size Assessment evaluates the impact of steam parameters, turbine last stage blade length, and feedwater heater configuration on pulverized coal units. In addition, capital costs and O&M costs were developed between 600 MW and 800 MW net. Figure 1.1 shows the capital costs for both subcritical and supercritical units between 600 MW and 800 MW net.

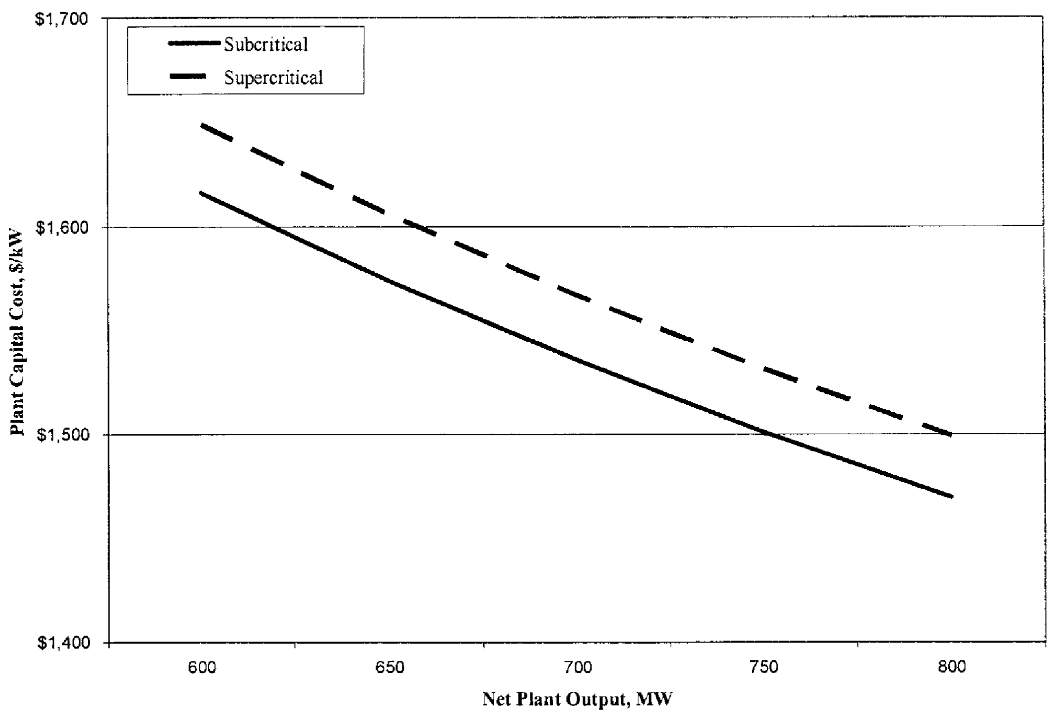


Figure 1.1: Plant Capital Cost vs. Net Plant Output

Figure 1.2 shows the differences in expected performance for both subcritical and supercritical units between 600 MW and 800 MW net. All heat rates in this report are HHV.

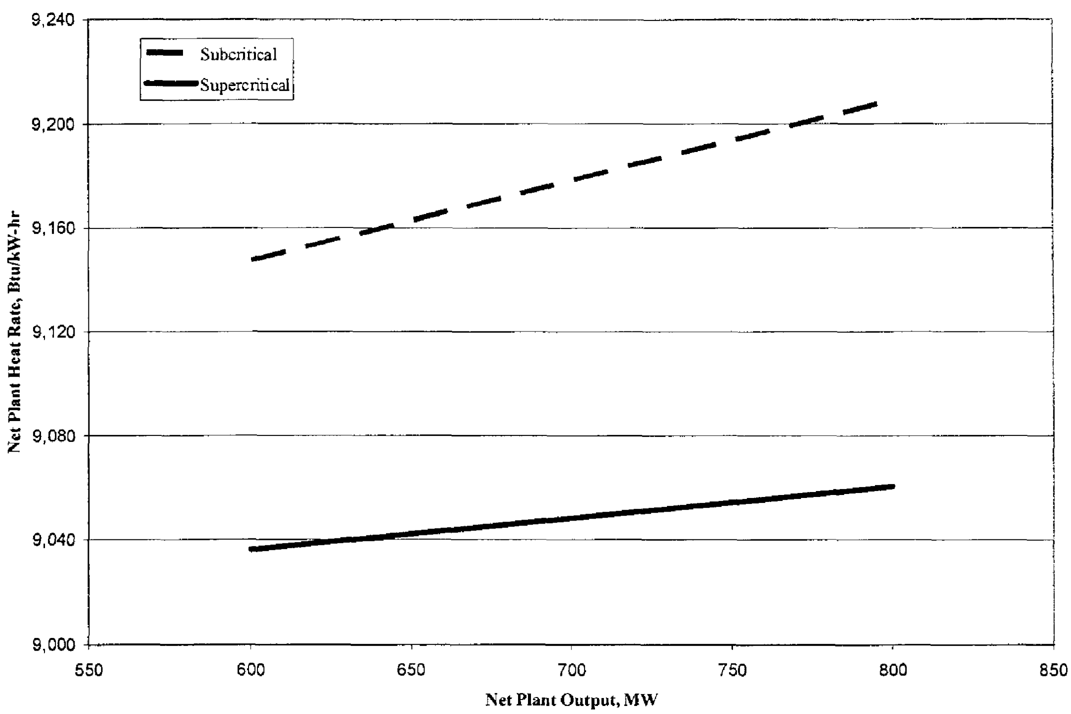


Figure 1.2: Net Plant Heat Rate vs. Net Plant Output

As the turbine output increases, the plant heat rate increases in the unit size range evaluated due to higher exhaust losses in the steam turbine. Supercritical steam cycles utilize less steam flow and therefore result in less performance degradation at the larger unit sizes. Feedwater heater configuration, turbine last stage blade lengths, and steam parameters also affect overall plant performance and are discussed in the assessment.

1.1.3 Integrated Gasification Combined Cycle Assessment

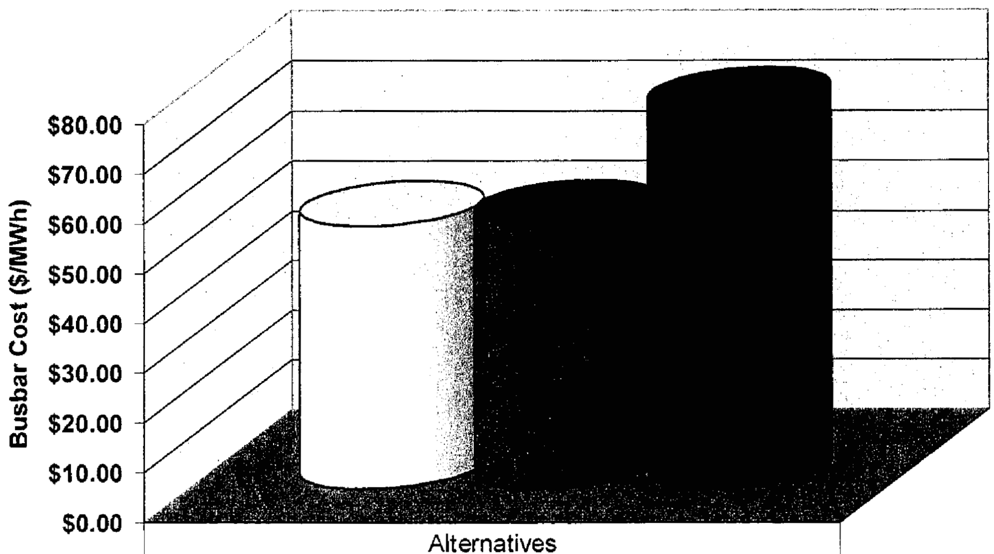
An assessment of Integrated Gasification Combined Cycle (IGCC) technology was performed due to the potential link between the relatively stable costs of solid fuels and the efficient operation of combined cycle gas turbines. This section presents current performance and economic information from the U.S. Department of Energy and General Electric, who now owns the Chevron Texaco technology. The information presented in this section is based on demonstration facilities and should be considered preliminary. There is planned development of IGCC units in the near future; however, it will be at least 4 -5 years before additional operational experience and cost information will be available.

2.0 SUPERCRITICAL ASSESSMENT

2.1 INTRODUCTION

This Supercritical Assessment is to assist Seminole Electric Cooperative, Inc. (SECI) in evaluating the technical merits of subcritical versus supercritical technology for Unit 3 at the Seminole Generating Station (SGS). The economic merits of supercritical technology were evaluated in the study "Seminole Generating Station 650 MW Solid Fuel Fired Unit Feasibility Study" and are shown in Figure 2.1.

Figure 2.1
650 MW Solid Fuel Fired Unit
20-Year Levelized Busbar Costs (2012$)



	Alternatives
Supercritical PC	$52.77
Subcritical PC	$52.97
Combined Cycle	$75.48

Rankine cycle steam power plants employ two main technologies for power generation. These technologies are characterized by the steam cycle operating pressure: subcritical (<3200 psia) and supercritical (3200 psia to 5000 psia). The primary advantages of supercritical cycles are, improved plant efficiency due to elevated operating pressures, lower emissions, and lower fuel costs as compared to subcritical cycles. However, supercritical technology has higher initial capital costs and has more operating complexities.

Supercritical units are very similar to the subcritical units. The major difference is the boiler operates in the supercritical region where water converts directly to steam without a two phase fluid existing. As a result, the supercritical boiler uses a once-through system, which does not use a steam drum. Since there is no steam drum to allow the removal and blowdown of impurities in the system, all impurities carried by the steam go into the steam turbine. For this reason, condensate systems typically incorporate a full-flow condensate polisher to maintain high water quality necessary for supercritical technology.

Supercritical boiler designs use either spiral or vertical tube arrangements. Both designs attempt to minimize areas in the corners of the boiler where flow through the tubes is typically starved, which can result in elevated tube wall temperatures and premature failure. The spiral tube design has more than 30 years of experience. The primary disadvantages of the spiral tube arrangement are the complexity in supporting the tubes and the additional tube-to-tube buttwelds, which results in increased construction costs. The spiral tube design also imparts additional friction drop in the system requiring higher head for the boiler feedwater pumps. The vertical tube design (Benson technology) has less operating history than spiral, but is gaining interest due to the reduced pressure drop and simpler construction configuration. Siemens owns the Benson technology and licenses it to various boiler manufacturers.

2.2 OPERATING HISTORY OF SUPERCRITICAL UNITS

The first generation of supercritical power plants were commissioned in the mid-1950s. These units operated at constant pressure, and were typically designed for steam turbine throttle conditions of 3500 psig and 1000°F main steam and 1000°F reheat temperatures. The second generation of supercritical units were commissioned in the 1960s and used constant waterwall pressure and sliding superheat steam pressure at the same steam conditions as the earlier units. By the mid-1960s, about half of all of U.S. units ordered were supercritical. The purchase of supercritical units in the U.S. dropped off dramatically in the 1970s primarily due to the onset of base-load nuclear power stations. New fossil fuel plants in this period were built to follow load. The subcritical cycle was selected for load following service because experience with cycling supercritical units was minimal. Also, at that time the supercritical units in the U.S. had a poor track record and suffered from a variety of problems.

In 1985, third generation supercritical units began operation primarily in Asia and Western Europe. These units incorporated new technologies and new materials that addressed the maintenance problems of previous supercritical units. Third generation supercritical units incorporated significant changes, including full sliding inlet turbine pressure and higher steam temperatures.

Most supercritical units in the U.S. burn coal. More than half have pressurized furnaces, and one-quarter of the supercritical units are equipped with double reheat sections. During the development of the supercritical unit in the 1960's, the average fossil unit grew in size from 247 MW to 500 MW. The typical U.S. supercritical unit suffered more from the rapid increase in unit size than from the high-pressure technology.

Much of the U.S. utility industry's initial dissatisfaction with supercritical units was actually due to the use of pressurized furnaces and due to furnaces being undersized, which resulted in excessive slagging burning Midwestern U.S. bituminous coals. Initial supercritical designs also operated at constant pressure, which required pressure reduction valves prior to the steam turbine. The pressure drop these valves were required to take proved to be a significant maintenance problem. In addition, the units had complex startup systems that proved to be difficult to operate. Table 2.1 is a summary of some of the typical problems with early generation supercritical units, and the countermeasures taken to address these issues.

Table 2.1: Problems and Countermeasures with Early Generation Supercritical Units

Problems Experienced in Early Generation Supercritical Units	Causes	Countermeasures (As applied in new supercritical units)
Start-up valve erosion	High differential pressure due to constant pressure operation and complicated start-up system.	Sliding pressure operation, simplified start-up system, and low load recirculation system.
Longer start-up times	Complicated start-up system and operation (ramping operation required, difficulty establishing turbine metal matching conditions, etc).	Sliding pressure operation, simplified start-up system, and low load recirculation system.
Low ramp rates	Turbine thermal stresses caused temperature change in HP turbine during load changing (due to constant pressure operation).	Sliding pressure operation.
High minimum stable operating load	Turbine bypass operation and pressure ramp-up operation required.	Application of low load recirculation system.
Slagging	Undersized furnace and inadequate coverage by soot blower system.	Design of adequate plan area heat release rate and furnace height, without division walls. Provision of adequate system of soot blowing devices and/or water blowers.
Circumferential cracking of water wall tubes	Metal temperature rise due to inner scale deposit and fire side wastage.	Oxygenated water treatment (OT). Protective surface in combustion zone of furnace for higher sulfur coal, e.g. thermal spray or weld overlay.
Frequent acid cleaning required	Inappropriate water chemistry	Application of OT
Lower efficiency than expected	High flue gas leakage due to pressurized furnace. RH spray injection required due to complications of RH steam temperature control in the double reheat cycle configuration.	Tight seal construction. Single reheat system with high steam temperature and temperature control by parallel damper gas biasing.
Turbine blade solid particle erosion	Inappropriate water chemistry	OT treatment
Low availability	All of the above	All of the above

2.3 CURRENT SUPERCRITICAL EXPERIENCE

Numerous supercritical units installed in Europe and Asia since the early 1980s allowed the technology to mature and resolved many problems with the early generation designs. Development of high strength materials for elevated temperatures helped to minimize the thermal stresses that caused problems in the early units. Variable pressure operation of all the circuits within the boiler eliminated the need for boiler valves in the fluid transition zone of the boiler. Development of distributed control systems (DCS) helped make the complex starting sequence much easier to control. Newer units also use a steam/water separator during startup to minimize solid particle carryover, which leads to the erosion of the steam turbine blades. These changes corrected many of the early problems with supercritical units. Availability of modern supercritical units closely matches that of similar subcritical units. Further, maintenance for supercritical units is only slightly higher than subcritical, due to thicker tube and pipe walls currently being used.

2.3.1 North American Projects

Currently planned supercritical pulverized coal units in North America are shown in Table 2.2.

Table 2.2: Currently Planned North American Supercritical Plants

Project	Owner	Cycle Parameters	Fuel	MW	Boiler Supplier
Genesee 3	Epcor & TransAlta Alberta Canada	3625 psig/1050F/1050F	PRB	450	Hitachi
Oak Creek	Wisconsin Energy Oak Creek, WI	3625 psig/1050F/1050F	PRB	2 x 600	Hitachi
Council Bluffs	MidAmerican Council Bluffs, IA	3675 psig/1050F/1100F	PRB	790	Hitachi
Weston 4	Wisconsin Public Service Weston, WI	3600 psig/1050F/1080F	PRB	500	Babcock & Wilcox
Prairie State	Peabody Marissa, IL	3670 psig/1050F/1050F	S. IL Bit	2 x 750	Undecided

2.3.2 European Experience

While the U.S. power industry shifted away from supercritical units due to problems initially experienced, the higher fuel costs common in Europe and Asia made the technology attractive. Advancements in the technology reduced significantly the types of problems that plagued the first generation units. By the 1990's supercritical units dominated new capacity projects overseas. Between 1995 and 2000 about 20,000 MW of new coal-fired capacity was installed in Europe. Supercritical boilers represented about 85 percent of that new capacity.

2.3.3 Japanese Experience

The first Japanese supercritical unit was commissioned in 1967. Since that time, the majority of 500 MW and larger fossil-fired power plants in Japan have been supercritical. Supercritical boilers commissioned in Japan in the 1970's operated in a constant pressure mode. In the 1980's, Japan experienced the onset of new base-loaded nuclear power stations and two-shift cycling (on-line during the day and off-line during the night) of some large capacity units was required. Presently, new fossil-fired units in Japan are being designed to cycle and use variable pressure supercritical cycles.

2.4 SUPERCRITICAL BOILER TECHNOLOGIES

Present day supercritical designs are descendants of earlier Benson and Sulzer Monotube once-through boilers from which most U.S. once-through boiler designs originate. Siemens holds the license for Benson boiler technology although they do not manufacture boilers. ABB (Switzerland) owns the Sulzer technology. The differences between these supercritical technologies are minor. A list of manufacturers holding a license for supercritical boilers is listed in Table 2.3.

Table 2.3: Licensed Supercritical Boiler Manufacturers

Manufacturer	Country	Benson - Siemens	Sulzer - ABB
Alstom	France		X
Ansaldo Energia	Italy	X	
Babcock & Wilcox	USA	X	
Babcock-Hitachi	Japan	X	
BWE	Denmark	X	
Deutsche-Babcock	Germany	X	
Formosa Heavy Industries	Taiwan		X
Foster Wheeler	USA	X	
Ishikawajima-Harima Heavy Industries (IHI)	Japan	X	
Korean Heavy Industries	Korea		X
Mitsubishi Heavy Industries	Japan		X
Mitsui Babcock	Britain	X	
Steinmuller	Germany	X	

Note: Combustion Engineering (Alstom) signed with Sulzer. Riley Stoker manufactured supercritical units, but now they are a part of Babcock Borsig and therefore are not currently designing or manufacturing supercritical boilers.

2.5 COMBUSTION CHAMBER WALL DESIGN

The combustion chamber wall designs of the once-through supercritical boiler have undergone significant evolution. First generation designs consisted of vertical and smooth tubes. Second generation designs employed a smooth spiral tube design in order to increase the mass velocity in the tubes and maintain proper heat transfer. Within the last ten years, some boiler manufacturers have designed supercritical units with vertical and rifled tubes.

The evaporator (or combustion chamber walls) in most once-through boilers is lined with tubes spiraling upward from the bottom of the furnace. The spiral wound furnace allows all tubes in the evaporator to be exposed to the heat flux at all four walls. Consequently, differences in tube-to-tube heat absorption are minimized and furnace wall exit gas temperatures are more uniform.

Although the spiral wound furnace offers performance advantages, there are several disadvantages associated with the spiral wound design:

- Due to the high mass flow through the reduced number of tubes in the spiral wound portion of the furnace walls, pressure drop is generally higher (100 psi or greater) than for a vertical wall unit, increasing boiler feed pump power requirements.
- Many designs use the spiral configuration in the lower furnace and a vertical configuration in the upper furnace. A header at the transition between these two portions of the furnace is required with this design.
- Because the angled walls are more difficult to support, and because there are typically four times as many tube-to-tube buttwelds in a spiral tube arrangement, the furnace is more expensive to manufacture and construct.
- Wall penetrations in the spiral walls are also more difficult to manufacture.

Some manufacturers are now offering a vertical wall design with rifled tubes. The vertical wall design offers a reduction in quantity of tubes, allows easier support of the furnace, reduces manufacturing costs, and reduces construction costs. Rifled tube design allows steam film to be dispersed by means of the grooves on the inside surface of the rifled tubes, thereby inhibiting film boiling and maintaining lower metal temperatures. Because the metal temperature of rifled tubes is kept sufficiently low, the design flow velocity can be reduced without difficulty. Mitsubishi first implemented this tube design at Shinchi Unit 2, a 1000 MW supercritical unit in Japan. Mitsui Babcock has also applied this technology at Yaomeng Power Plant in the Peoples Republic of China[2]. In this application, the bottom half of the boiler waterwalls were replaced with rifled vertical tubes in the once through boiler. Due to the operating success of this design, MHI and Mitsui Babcock recommend the use of the vertical rifled tube design to their customers because of its advantages.

Recent advancements have allowed designs up to 4500 psig with steam temperatures exceeding 1100°F. Units in this range of pressure are sometimes referred to as "ultra-supercritical." There is currently very limited operating experience with units at these steam conditions.

Most new supercritical units are being designed for variable pressure operation. This provides better part load efficiency, but complicates the design since the boiler operates at subcritical conditions at reduced loads, which changes the heat transfer in the water walls. Constant pressure operation requires a bypass operation for start-up to maintain minimum flow in the furnace at a constant supercritical pressure. This complex system requires bypass valves to take a high pressure drop, which results in valve erosion and hence more frequent valve maintenance. In addition, constant pressure operation leads to longer startup times and low ramp rates. The change to variable pressure operation is accountable for several of the performance improvements in third generation supercritical units.

2.6 STEAM TURBINE IMPACTS

The pressure difference between subcritical steam pressures and supercritical steam pressures requires turbine stationary components to be more massive to keep stresses associated with the high pressure steam within allowable limits. Components affected include steam turbine stop and control valves, steam leads to the high pressure steam turbine, steam chest, and inner and outer shells. The higher steam pressure associated with the supercritical cycle reduces steam specific volume, which allows turbine steam path components to be smaller. Overall, the cost of the steam turbine is not significantly different between subcritical and supercritical units.

The impact of throttle pressure on steam turbine availability has been reported to be small. Sliding pressure operation results in minimal variation in first stage shell temperature during operation. Design problems experienced with the early supercritical turbines were attributed to the rapid increase (scale-up) in unit size, not to the supercritical steam cycle being utilized. The most significant problems experienced for steam turbines operating at either subcritical or supercritical pressures are solid particle erosion (SPE) of turbine blades and valves and stress corrosion cracking of low-pressure turbine blades.

Solid particle erosion of steam turbine blades and valves of U.S. units has proved to be more of a maintenance and heat rate concern than a cause of forced outages. Although SPE has caused units to be forced out of service, the erosion (which typically occurs over a two to ten year period) is likely to be discovered during routine inspections prior to the strength of the turbine blades becoming an issue. The likelihood of increasing the length of a turbine inspection outage is increased with the presence of SPE.

SPE in steam turbines has caused serious heat rate degradation, and substantial maintenance costs, in many domestic units. In contrast, European steam turbines with 100 percent steam turbine bypass systems have been mostly free of SPE. Newer supercritical units with integral separators and steam bypass systems to the condenser included in the start-up system design are not expected to experience the same level of SPE. Including a turbine bypass system may reduce SPE induced fuel costs, repair and replacement costs, scheduled outage costs, and forced outage costs.

Stress corrosion cracking is considered the primary cause of low-pressure steam turbine blade failure. Chlorides and other contaminants that enter the feedwater-steam cycle from the condenser cooling water system through condenser tube leaks are usually removed by condensate polishing systems. If a malfunction or improper operation of the condensate polishing system occurs without immediate operator action, these steam contaminants could adversely affect the steam turbine blade material.

2.7 PLANT AVAILABILITY

Most of the U.S. supercritical units were constructed during a time of rapidly increasing unit size, which complicates a comparative assessment of the availability of the U.S. plants with supercritical cycles versus those with subcritical cycles. Various studies of operating data have concluded that the availability of supercritical units should be similar to subcritical units. This tends to be true in other parts of the world. Availability data for a specific unit will depend on specific operational factors, such as a utility's maintenance practices, operating philosophy, and power generation needs.

Several boiler design improvements have lead to the increasing availability of supercritical units. First generation constant pressure supercritical units were susceptible to start-up valve erosion and were required to ramp-up to full pressure. This resulted in longer start-up time and higher minimum stable load. Thermal stresses are reduced with sliding pressure operation and therefore faster ramp rates can be achieved.

Historically, the availability of supercritical power plants in the U.S. has not been as good as noted for subcritical power plants. This is due in a large part to the specific design of the early units. However, the availability of supercritical units has been steadily improving in the past 20 years, as shown by the equivalent forced outage rates in Figure 2.2.

Several studies[1] conclude that, for today's plant designs, there is no significant difference in availability between subcritical and supercritical units. Note that the availability data described in this study is based primarily on supercritical units operating at 3600 psig/ 1000°F/ 1000°F.

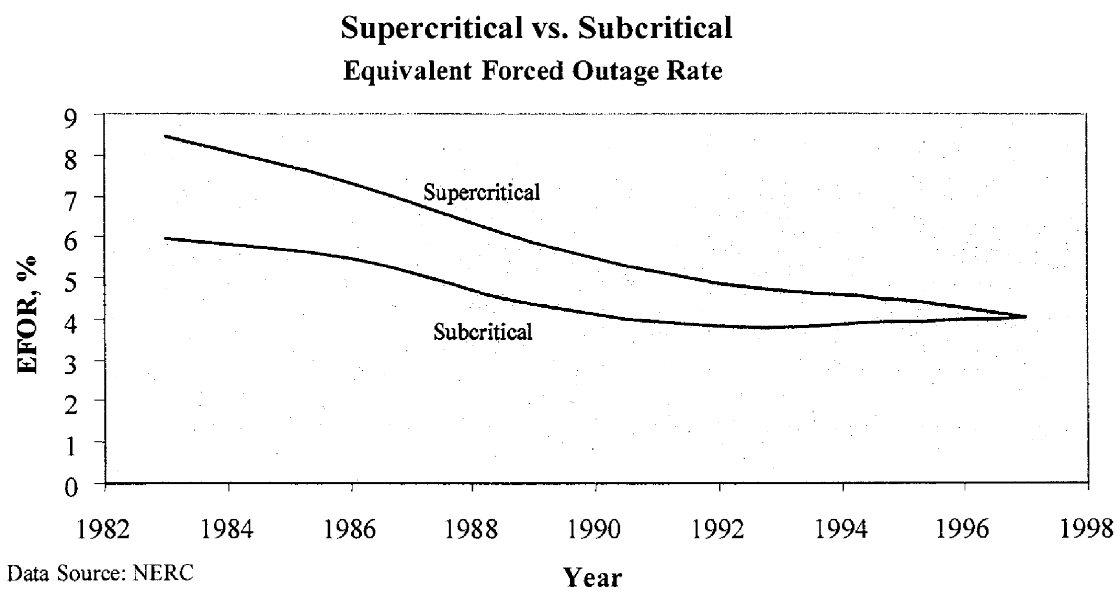


Figure 2.2: Supercritical vs. Subcritical Equivalent Forced Outage Rates

The long-term availability of the recent supercritical units with elevated steam temperatures is still unknown.

2.8 CORROSIVE COAL IMPACTS

Corrosive coals, which typically have greater than two percent sulfur and relatively high levels of vanadium or chlorine, can cause excessive wastage and circumferential cracking in the water walls and liquid phase corrosion in the superheater and reheater when burned in supercritical units with elevated steam temperatures.

Liquid phase corrosion is primarily a superheater/reheater phenomenon. The general mechanism and sequence of events for liquid phase corrosion begins with the formation of an oxide film on the furnace side metal surface. Alkali sulfates and sulfur oxides are deposited over the oxide scale on superheater/reheater materials. Eventually, because of an increasing temperature gradient, the outer surface of the alkali sulfate layer becomes sticky, and particles of fly ash adhere. With further increase in temperature, thermal dissociation of sulfur compounds in the ash releases SO_3, which migrates toward the cooler metal surface, while a layer of slag forms on the outer surface. With more ash in the outer layer, the temperature of the sulfate layer falls, and reaction occurs between the oxide scale and SO_3. Temperature excursions due to de-slagging or soot blowing exposes the alkali-iron tri-sulfates to higher temperatures and leads to dissociation of sulfate and generation of SO_3. This causes further corrosive attack of the metal surfaces.

The main impacts to the water walls are wall wastage and circumferential cracking. The wall wastage is caused by corrosion due to the sulfur in the fuel. Circumferential cracking is a phenomenon almost exclusively associated with supercritical units and is due to two inter-related effects. A local reducing environment at the furnace wall promotes accelerated wastage of tube metal by an oxidation-sulfation reaction. Compounding this are thermal stresses generated by the rapid change in metal surface temperature due to insulating ash layer being removed from the tube, either by soot blowing or by natural sluffing off of the slag, which causes circumferential cracking in the protective oxide layer on the metal surface. Both of these effects are evident in both sub and supercritical pressure boilers; however, the rate of attack is higher for supercritical boilers due to the higher operating water wall temperatures. One means of counteracting the water wall wastage is to ensure an oxidizing atmosphere at the water wall. For example, Alstom does this by directing a portion of the combustion air along the wall.

Alstom provided the following compilation of NERC data, based on over 450 unit-years for supercritical units and over 1000 unit-years for subcritical units. Figure 2.3 shows the significant difference in boiler forced outage rates for supercritical units burning corrosive coal.

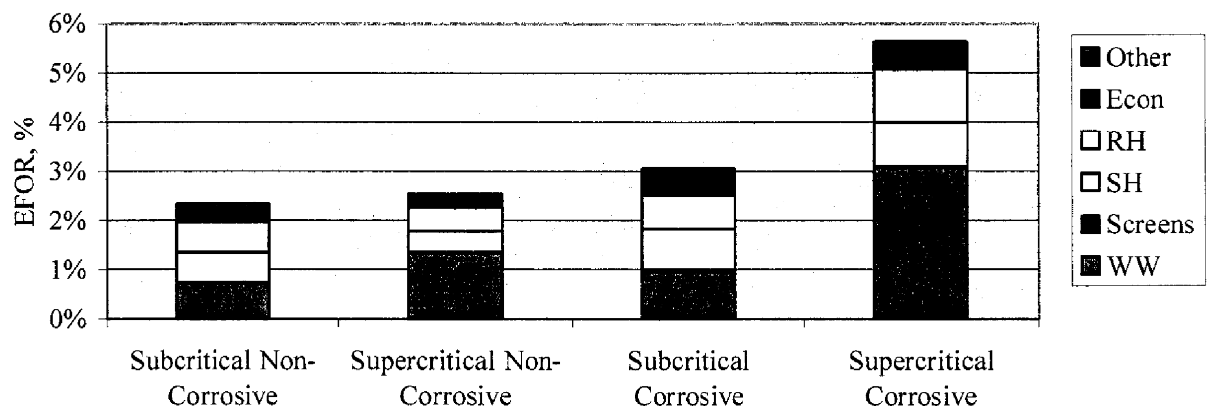


Figure 2.3: Boiler Forced Outage Rates

Boilers account for the majority of coal-fired plant forced outages. Babcock & Wilcox is currently conducting research for the U.S. Department of Energy on new materials that may prove to be more resistant to corrosion in corrosive fuel applications.

Currently there is no experience firing up to 30% pet coke at 1050°F/1050°F steam conditions. However, Santee Cooper is currently adding two 600 MW subcritical units firing 30% pet coke at these steam conditions. According to Alstom, thicker tubes and high nickel overlays are necessary as steam temperature rises to prevent sulfur-induced corrosion. It also may be necessary to increase the furnace size and rearrange the location of the superheat and reheat surface. These modifications all increase the cost of the boiler and may affect maintenance costs.

BMcD has been involved in projects where the boiler manufacturer recommended against using the supercritical cycle for a corrosive coals due to anticipated operating problems and potential reduced availability. However, on one project the boiler manufacturer indicated an availability equivalent to a subcritical unit could be achieved by increasing preventative maintenance and inspections in the water walls, superheaters, and reheaters. Alstom estimated this to require approximately $2 million per year more in boiler maintenance and inspection costs.

2.9 WATER CHEMISTRY

Operation of drum-type and once-through boilers requires that close attention be given to feedwater chemistry. Any condenser cooling water leaks or upset in the makeup water quality can result in contaminants entering the feedwater system. These contaminants and any corrosion products from the condensate and feedwater piping will be transported to the boiler. In the case of a drum-type boiler, a significant portion of these contaminants will be removed by boiler blowdown. However, in the case of a once-through supercritical unit, the boiler water and steam have the same density and the feedwater contaminants are carried directly to the turbine.

Full flow condensate polishing is required for a once-through unit, and is optional for a drum-type unit. For the drum-type unit, the condensate polisher may be either a partial flow side-stream or a full flow condensate polishing system. Since the drum-type unit has phase separation in the drum, it is not essential for every drum-type unit to have a condensate polisher. The drum steam separators will provide a relatively pure steam output and most of the dissolved solids and particulate in the liquid phase will be removed with the boiler blowdown. Once-through units do not have a drum; therefore, any solids in the boiler water will carry over with the steam. Once-through boilers must have full flow condensate polishers for removal of contaminants from the cycle.

Because the drum-type unit has two distinct water phases in the boiler drum, drum-type units have less stringent feed water chemistry than a once-through unit. Drum-type units can use sodium phosphate solutions to buffer the boiler water while maintaining a small amount of phosphate to react and condition any small amount of hardness that may enter the boiler through condenser tube leaks. Boiler conditioning chemicals such as sodium phosphate should not be fed into once-through boilers. All chemicals fed into a once-through unit must be volatile. The two main all volatile chemical treatment programs used to treat the condensate and feedwater are All Volatile Treatment (AVT) and Oxygenated Treatment (OT).

Either all-volatile treatment method may be used for drum-type and once-through units. However, the majority of new units are being designed based on implementing the Oxygenated Treatment program.

AVT uses an amine for condensate and feedwater pH adjustment with an oxygen scavenger to provide a reducing environment. The OT method feeds oxygen into the condensate and feedwater to maintain an oxidizing environment. The hematite iron oxides that form in the oxidizing environment are less soluble than magnetite formed in the reducing environment which results in reduced corrosion product and contaminant transport. The benefits for OT are lower condensate and feedwater corrosion and less iron transport to the boiler resulting in less frequent chemical cleanings. The cycle makeup water quality and condensate quality must be very high when using the OT method. Poor condensate quality will result in accelerated corrosion rates and excessive transport of corrosion products to the boiler. In addition, copper alloys cannot be used in the condensate and feedwater systems, especially with an OT program. Oxygen in the water reacts with the copper to attack the iron in the waterwall pipes. Since the water quality demand for OT is so pure, the unit generally must include a condensate polisher when using an OT program. Subcritical units, however, may use natural oxygenated treatment. Although in this treatment there is far less oxygen in the water, the small presence still leads to copper induced corrosion. When either OT program is used, it is recommended for both supercritical and subcritical units that the water is free of copper contaminants.

Table 2.4: Water Treatment Methods for Different Boiler Designs

Item	Once-through	Drum-type
Condensate Polisher	Required	Recommended
All Volatile Treatment (AVT)	Allowed	Allowed
Oxygenated Treatment (OT)	Recommended	Allowed w/Condensate Polisher
Phosphate Boiler Conditioning	None	Acceptable
Boiler Blowdown	None	Control Boiler Water Solids

2.10 STEAM TURBINE BYPASS

Steam turbine bypass systems allow steam production to bypass the steam turbine and flow directly to the condenser. Traditional bypass systems typically include two stages. The first stage is a bypass of main steam to the cold reheat and the second stage is bypass of hot reheat steam to the condenser. Turbine bypass systems are most commonly used in cycling fossil steam plants. The transient nature of cycling operation induces high stresses on the boiler, steam turbine, and balance of plant equipment. Additionally, frequent starts require expensive start-up fuel. A turbine bypass system alleviates these stresses and costs by:

- Allowing matching of steam temperatures to turbine metal temperatures during warm and hot starts.
- Allowing continued boiler operation after a steam turbine trip and rapid restart after fault resolution.
- Reducing solid particle transfer to the steam turbine during start-up or load changes.
- Reducing safety/relief valve operation with sudden load reductions.
- Reducing steam venting by redirecting steam production to the condenser saving demineralized water.
- Reducing start-up time and therefore saving start-up fuel.

In addition to reducing cycling operation stresses and costs, the bypass system also provides benefits during commissioning and restarting after extended shutdowns. These benefits include:

- Faster start-up after an extended shutdown.
- Faster cleanup of main steam and boiler water chemistry.
- Testing and commissioning of boiler equipment (pulverizers, gravimetric feeders, etc.) without the need for a functioning steam turbine.

For a 600 MW to 800 MW net supercritical unit, start-up fuel savings alone do not justify the capital cost of adding a turbine bypass system to the condenser when 100 percent base load operation is planned. Significant increases in the number of starts per year would have to occur to justify the addition of a turbine bypass system. This is especially true of once-through boiler designs, which include start-up bypasses within the boiler as standard design.

However, it is recommended for supercritical units that an HP bypass system be included to bypass main steam to the reheater of the boiler. The HP steam bypass provides steam flow through the reheaters to cool the reheater tubes and prevent overheating prior to steam flow being available from the cold reheat section of the steam turbine. Without this bypass, the ability of the boiler to produce steam at elevated temperatures during start-up is limited to around (700 °F to 800°F). These temperatures reflect the impact of typical recommended operating limits in boiler exhaust gas temperatures from boiler manufacturers prior to establishing flow in the reheaters (around 1000°F limit on furnace exit gas temperature). An HP bypass is needed to allow start up following a plant trip without incurring a significant hold period. This bypass would be in lieu of ignoring the steam turbine and boiler manufacturer's recommendations regarding boiler exhaust gas temperatures and temperature mismatches during a hot restart, as has typically been industry practice on existing plants that do not have steam turbine bypasses.

An HP bypass system costs approximately $7/kW for a 600 MW net plant, whereas the full cascading type turbine bypass system will cost approximately $13/kW. Fixed operating costs for a plant with a turbine bypass system are higher than for a plant without a turbine bypass system. Either arrangement requires the same number of operating personnel. However, the turbine bypass system will require bypass and temperature control valve maintenance. Additionally, insurance costs may increase with the bypass system because the cost of insurance is relative to the capital cost. Non-fuel variable operating and maintenance costs however, are identical with or without a turbine bypass system with the exception of start-up fuel cost. Start-up fuel costs typically drive the decision to add a turbine bypass system. However, in a base load plant with minimal starts per year, start-up fuel savings are minimal.

2.11 HEAT RATE BENEFITS

Conventional subcritical steam cycles are based on steam turbine throttle conditions of 2400 psig and 1000°F and 1000°F reheat steam temperature. Steam cycle efficiency improves as pressure and temperature is increased. For a single reheat cycle, increasing throttle pressure from 2400 psig to 4500 psig improves heat rate approximately 2.5 percent, while increasing steam temperatures from 1000°F/1000°F to 1100°F/1100°F improves the heat rate approximately 3 percent. Steam temperature increases produce greater improvements in efficiency than do increases in steam pressure. As steam pressure increases, the marginal improvement diminishes whereas temperature increases continue to pay steady dividends. Figure 2.4 below shows the estimated improvements in cycle efficiency possible with the supercritical steam cycle.

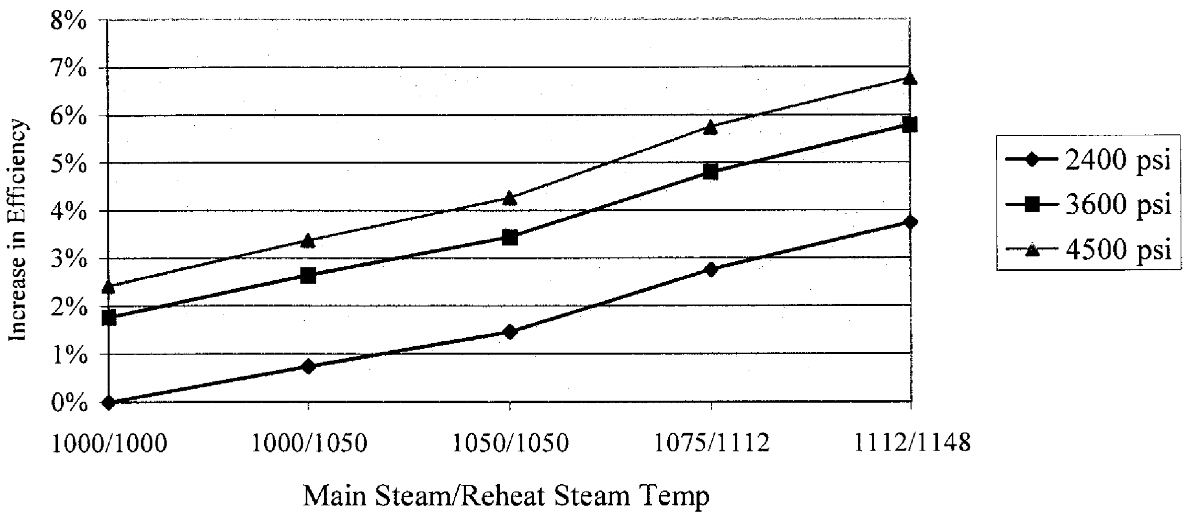


Figure 2.4: Impact of Steam Conditions on Efficiency

Even owners who decide against supercritical units are considering increasing steam temperatures beyond 1000°F. Analysis of recent boiler and steam turbine bids received by Burns & McDonnell concluded that a 2400psig/1050°F/1050°F subcritical steam cycle using single or double reheat is more cost-effective than a 2400 psig/1000°F/1000°F subcritical cycle.

Additional efficiency improvements can be realized by utilizing a double reheat cycle. The double reheat cycle at 1000°F /1000°F /1000°F and 3600 psig has a 2 percent boiler efficiency advantage over the single reheat cycle at the same pressure. The double reheat cycle at 4500 psig with steam conditions of 1000°F /1025°F /1050°F has an estimated heat rate that is 6 percent better than the 2400 psig /1000°F /1000°F subcritical steam cycle. However, there is limited experience with double reheat cycles and the double reheat configurations are generally cost prohibitive and have higher operational complexities.

2.12 EMISSION BENEFITS

Supercritical units have lower annual emissions than subcritical units. Although the stated emission rate in pounds per million Btu of fuel burned is the same for both units, the reduced fuel consumption for a supercritical unit will result in lower total annual emissions for the same net annual output of power. Therefore, some utilities are considering supercritical units primarily due to their environmental benefits. It may be easier to gain public support for a project if the owner shows they are using proven technology with the lowest annual emissions.

Recent PSD permit applications have been submitted with the BACT emission limits shown in Table 2.5.

Table 2.5: Emission Limits for New Plants

Facility	MW	Steam Cycle	Fuel	SO_2	NO_x	PM_{10}	CO	Hg
Weston 4	500 MW	Supercritical	PRB	0.12	0.08	0.02	0.15	7.50e-6
Longview Power	600 MW	Supercritical	WV Bit. 2.5% Sulfur	0.12	0.08	0.018	0.11	2.39e-6
OPPD	600 MW	Subcritical	PRB	0.10	0.08	0.027	0.16	3.85e-6
Prairie State	2 @ 750 MW	Supercritical	S IL Bit.	0.182	0.08	0.015	0.12	2.00e-6
Santee Cooper	2 @ 600 MW	Subcritical	Bit./Pet Coke	0.25	0.08	0.018	0.17	3.60e-6
MidAmerican	750 MW	Supercritical	PRB	0.10	0.07	0.025	0.154	1.70e-6

*All limits shown in lb/MMBtu

2.13 OPERATIONAL FLEXIBILITY

A common misconception is supercritical units do not operate well at part load conditions and are not suitable for cycling service. In reality, new supercritical units operating with sliding pressure have demonstrated good part load efficiencies.

2.13.1 Startup Times

In cycling service, the boiler is limited with regard to how rapid the temperature of certain components may change. Drum-type subcritical units are limited by thick-walled components like the steam drum and the superheater outlet headers. The drum on a natural circulation boiler is typically 1.2 to 1.3 times larger than that of a forced circulation boiler. The larger drum allows larger volumes of water storage to help minimize level change under rapid downward load and pressure ramping. Because the forced circulation drum is smaller, the wall thickness is smaller and faster load changes are achievable.

Supercritical units do not have drums and, therefore, do not have the same magnitude of load ramp delays associated with component temperature differentials. Integral separators located downstream of the furnace in the supercritical cycle can be relatively thick-walled components. Manufacturers, however, have typically utilized multiple separators in their design, thus reducing the size and required wall thickness.

Supercritical units are typically designed for forced circulation, requiring the use of boiler circulating pumps. During start-up, shutdown, and low load operation (up to 35 percent unit capacity) a boiler circulating water pump (BCP) is used to maintain mass flow in the furnace wall tubes to avoid overheating. Discharge from the furnace walls is directed through one or more separators at all loads, but at low loads (less than 35 percent), the water that is removed from the steam/water mixture exiting the furnace walls is re-circulated by the BCPs. The steam is directed to the superheater and then to the steam turbine.

At about 35-40 percent load the steam separators dry out and the BCPs are removed from service. Water level controls on the separator automatically control when the BCPs are removed from service. The turbine-generator load is raised by increasing the boiler pressure, and supercritical pressures are achieved at about 60 to 70 percent load.

Alstom provided information on hot, warm, and cold startup times for once-through and drum units, which are summarized in Table 2.6. The startup times are based on units with a bypass system. Startup times for units without a bypass system will be considerably longer. The Alstom data is representative of other boiler vendors.

Table 2.6: Startup Times for Alstom Boilers

First Fire to Turbine Synch	Once-Through Minutes	Drum Unit Minutes
Hot Startup, After 2 Hour Shutdown	30	30
Warm Startup, After 8 Hour Shutdown	45	45-70
Cold Startup, After 36 Hour Shutdown	90	140-220

2.13.2 Ramp Rates

Alstom provided expected steam temperature swings for different ramp rates for both drum type and once-through units. The following table assumes the units are operating in sliding pressure mode and with a five minute load ramp. The data is similar to that received from other vendors.

Table 2.7: Steam Temperature Variances at Different Ramp Rates

	Main Steam Temperature	Reheat Steam Temperature
Drum Type		
3% per minute (30-100% load)	±10 F°	±15 F°
5% per minute (50-100% load)	±35 F°	±40 F°
Once-Through		
3% per minute (30-100% load)	±10 F°	±10 F°
5% per minute (50-100% load)	±10 F°	±12 F°

2.14 ECONOMICS

Burns & McDonnell performed a number of analyses of supercritical vs. subcritical cycles for projects in recent years. The economic comparison of supercritical vs. subcritical units typically represents a trade-off of higher capital cost versus reduced operating costs. The economic analyses for a new subcritical and supercritical unit at the Seminole Generating Station are reflected in the study "Seminole Generating Station 650 MW Solid Fuel Fired Unit Feasibility Study".

Certain components of a coal-fired unit have a higher initial capital cost for a supercritical unit in comparison to a subcritical unit. The following components are typically more costly in a supercritical unit:

- Boiler
- Steam Turbine
- Boiler feed pumps and startup boiler feed pump
- Feedwater heaters and feedwater piping

- Steam piping
- Condensate polishing equipment, full flow instead of a side-stream partial flow

The steam turbine and steam piping capital cost is typically slightly higher for supercritical than subcritical units. Increases in the steam temperature will have a greater impact on cost than increases in the steam pressure.

The following components are less costly for a supercritical unit since a supercritical unit will burn less fuel and will have less heat rejection from the steam cycle:

- Condenser/cooling water system
- Fuel handling equipment
- Ash handling equipment
- Air pollution control equipment and systems
- Water treatment equipment and systems

In our analyses, typical results show supercritical units compared with subcritical units have a slightly higher capital cost, better efficiency that reduces fuel consumption, lower emissions and sorbent costs, more consumables for the condensate polisher, and comparable operating and maintenance costs. The previously issued report "Seminole Generating Station 650 MW Solid Fuel Fired Unit Feasibility Study" contains the O&M estimates for supercritical and subcritical units operating at SGS. Due to the high value of ash and gypsum sales, O&M costs are slightly higher for the supercritical unit.

2.15 FUTURE TRENDS

Boiler manufacturers are working with materials suppliers to investigate and develop new materials that would allow supercritical steam cycles to increase to 5400 psig and 1300°F or greater steam temperature.

2.16 CONCLUSIONS

Modern supercritical units have significant advantages in efficiency and reduced emissions per kilowatt-hour of energy produced. They also have better plant cycling and load ramping than conventional drum type units. Advances in supercritical technology should allow new units to have availability rates similar to subcritical units. Experience worldwide has shown availability can be comparable to subcritical units of the same vintage.

Subcritical units have the advantages of being familiar to U.S. operators and less complex to operate. Control systems on subcritical units are less complex and require less equipment and fewer instruments. Water quality is less critical, and "upsets" in treatment or condenser tube leaks are more easily managed. Drum-type units tend to use materials that are more conventional and the vertical tube configuration in the furnace will be less costly to repair than spiral wound furnaces commonly used for supercritical units.

For projects using low to moderate priced fuels, the life cycle economics of supercritical vs. subcritical units are approximately equal. The results for a specific project will depend on the delivered fuel cost at the specific plant location and the cost of capital for the project. However, as new environmental regulations are passed and limiting emissions becomes more critical, it is anticipated that more owners will select supercritical units.

Table 2.8 summarizes the advantages of supercritical units compared to subcritical units.

Table 2.8: Steam Cycle Evaluation

Criteria	Supercritical	Subcritical
Plant Efficiency	✓	
Simpler Controls		✓
Capital Cost		✓
Fuel Consumption	✓	
Fixed O&M	=	=
Variable O&M	✓	
Fuel Flexibility	=	=
Lower Design Pressure		✓
Startup Time	✓	
Ramp Rates	✓	
Emissions	✓	
Feedwater Quality Requirements		✓
Plant Availability	=	=

2.17 REFERENCES

1. Supercritical Power Plants Evaluation of Design Parameters, The World Bank Group, at http://www.worldbank.org/html/fpd/em/supercritical/ppt_supercritical/index.htm
2. Refurbishment of Yaomeng Power Plant, DTI Publication URN 03/1065 at http://www.dti.gov.uk/energy/coal/cfft/cct/pub/bpb005.pdf

3.0 STEAM CYCLE AND UNIT SIZE ASSESSMENT

3.1 INTRODUCTION

Seminole Electric Cooperative, Inc. is evaluating the feasibility of adding Unit 3 at the Seminole Generating Station with a capacity between 600 to 800 MW net. A previous evaluation was performed by Burns & McDonnell titled "Seminole Generating Station 650 MW Solid Fuel Fired Unit Feasibility Study" which defined the performance, capital costs, O&M costs and levelized busbar costs for a 600 MW net subcritical and supercritical unit. This assessment evaluates the performance, capital costs, and operating costs associated with an incremental increase in net plant output up to 800 MW net.

3.2 STEAM CYCLE ASSESSMENT

This section evaluates the effect of steam parameters, turbine last stage blade length, and feedwater heater configuration on the performance and economics for both subcritical and supercritical units.

3.2.1 Steam Parameters

As discussed in the supercritical assessment, the improvement in heat rate when comparing 1000°F/1000°F steam conditions to 1050°F/1050°F steam conditions will be around 1.5 percent for subcritical and supercritical units. Table 3.1 shows that there is a small capital cost difference for this temperature increase relative to the gain in efficiency. However, as the heat rate improves with steam temperatures over 1050°F/1050°F, the capital cost increases by approximately 0.4 percent for subcritical and supercritical units. With the commercial introduction of new steel alloys with higher allowable stresses and longer life at elevated temperatures, a number of power plants with steam parameters above 1075°F/1100°F have been built in Japan and Europe. New materials have recently emerged commercially that will allow steam parameters to exceed 1100°F/1100°F. However, there is currently no domestic experience with pulverized coal plants operating at these steam parameters. At these higher steam temperatures, high sulfur coal or pet coke may lead to liquid phase corrosion in the boiler.

Table 3.1: Percent Increase in Capital Costs at Different Steam Conditions

Steam Cycle	1000°F/1000°F	1000°F/1050°F	1050°F/1050°F	1075°F/1100°F
Subcritical	BASE	~ 0%	0.12%	0.5%
Supercritical	2.0%	2.0%	2.1%	2.5%

3.2.2 Turbine Last Stage Blades

The critical component of the steam turbine that affects heat rate is the last stage blade (LSB) selection and number of low-pressure steam turbine flow paths. Plants in the 600 MW to 800 MW size range will utilize a four-flow low-pressure steam turbine. The last stage blade selection, however, is not as simple because LSB availability and performance varies significantly by steam turbine manufacturer. The largest last stage blades with any significant operating experience are between 40 inches and 42 inches in length. Smaller blades are also available between 32 inches and 34 inches in length. This evaluation compares GEs 33.5 inch and 40 inch blades.

The economic benefit of using larger last stage blades is dependent on plant output and steam turbine backpressure. For units in the range of 600 MW to 800 MW, economics typically dictate that longer last stage blades are justified. A 600 MW steam turbine capital cost increases approximately $4 million dollars when 40 inch LSBs are used instead of 33.5 inch LSBs. Depending on operating backpressure, the 40 inch LSBs result in an efficiency gain of up to 2%.

The largest last stage blades with any significant operating experience are between 40 inches and 42 inches in length. This range of last stage blade lengths provides a viable option for 600 MW to 800 MW units.

Nearly all steam turbine manufacturers are currently developing longer last stage blades (up to 46 inches). However, there are no units in commercial operation with these longer last stage blades. Several manufacturers have progressed to the point that they are testing or will soon be testing a full scale version of the blades in a test stand. Utilization of these larger last stage blades could result in a significant improvement in plant heat rate and an associated reduction in plant emissions.

3.2.3 Feedwater Heater Configuration

The configuration of feedwater heaters in a steam cycle affects the cycle efficiency. The higher the feedwater temperature entering the boiler the less heat input from the boiler required to heat it to its saturation temperature prior to vaporizing it. The resulting savings from the reduced boiler heat input more than offset the output lost as a result of extracting the steam from the steam turbine. This is because nearly all the energy in the extracted steam heats the water through a series of cascading feedwater heaters. If not used for feedwater heating, nearly 30 – 40 percent of the energy in the steam is lost in the heat rejection system after the steam exhausts from the steam turbine. The addition of a feedwater heater above the reheat point (HARP) offers a substantial increase in efficiency with minimal capital investment, maintenance costs, and risk. In the 600 MW to 800 MW net range, the eighth feedwater heater improves the plant heat rate by approximately 1.0 percent for supercritical units and 0.8 percent for subcritical units. The addition of the HARP feedwater heater usually is economically justified as the operating savings more than offset the additional capital costs. Adding an eighth feedwater heater to both a subcritical and supercritical units increases the total capital cost by approximately $2 - 4/kW. Along with the economic benefits, the eight feedwater heater cycle offers risk mitigation in regards to increases in fuel costs, sorbent costs, and for future emissions legislation.

The addition of a high pressure feedwater heater to the cycle requires no special operating and maintenance considerations. Maintenance requirements are the same as those required for the other high pressure feedwater heaters and are minimal with application of proper materials of construction and proper water treatment practices.

In order to provide steam to the eighth feedwater heater, the steam turbine requires an extraction connection in the high pressure section of the steam turbine. Manufacturers indicate the capital cost is minimal to add the HP turbine extraction for units in this size range. The increased steam flow for the HARP feedwater heater configuration requires increased boiler feedwater flow rates and therefore, larger feedwater pumps and drives which increases the capital cost. Due to increased efficiency, an eight feedwater heater cycle results in lower fuel consumption than a seven feedwater heater cycle. This reduced fuel consumption results in lower exhaust gas flow rates and lower annual emissions. Therefore, the air pollution control system will be smaller by a proportional amount. The improved heat rate of the eight feedwater heater cycle compared to a seven feedwater heater cycle also reduces the size of the cycle heat rejection system. The result of this is that a smaller cooling tower and condenser can achieve the same backpressure.

3.3 UNIT SIZE ASSESSMENT

This section evaluates the capital cost and performance of 600 MW to 800 MW net pulverized coal units with a single reheat steam turbine on a brownfield site. Performance and capital costs identified in this section are based on the following:

- The unit is designed for a 70/30 blend of bituminous coal and pet coke.
- The pulverized coal fired boiler will utilize balanced-draft combustion with single reheat.
- Emission controls include selective catalytic reduction (SCR) for NO_x reduction, activated carbon injection for mercury control, an electrostatic precipitator (ESP) for particulate collection, a wet flue gas desulfurization system (FGD) for sulfur dioxide (SO_2) reduction and a wet ESP for sulfuric acid (H_2SO_4) reduction.
- A circulating water system that includes a natural draft cooling tower and circulating pumps that supply cooling water to a water-cooled surface condenser.
- A 1050°F/1050°F steam cycle with 40 inch steam turbine last stage blades.
- An eight feedwater heater configuration for a supercritical unit and a seven feedwater heater configuration for a subcritical unit.

The estimated performance and cost estimates are based on in-house data and information from similar projects. The basis for the assumptions and scope of supply is identified in the "Feasibility Study for a 600MW Solid Fuel Fired Power Plant" study.

The estimates and projections prepared by Burns & McDonnell relating to construction costs and schedules are based on our experience, qualifications and judgment as a professional consultant. Since Burns & McDonnell has no control over weather, cost and availability of labor, material and equipment, labor productivity, construction contractor's procedures and methods, unavoidable delays, construction contractor's method of determining prices, economic conditions, government regulations and laws (including interpretation thereof), competitive bidding and market conditions or other factors affecting such estimates or projections, Burns & McDonnell does not guarantee that actual rates, costs, performance, schedules, etc., will not vary from the estimates and projections prepared by Burns & McDonnell.

Due to the capital intensive nature of solid fuel generation projects resources and length of construction period, there is capital cost risk due to interest costs, labor availability and costs, and general inflation. Other risk factors associated with the construction of new solid fuel generation plants include the fact several US boiler manufacturers are currently under financial duress, and the skilled workforce that constructed a number of coal units in the 1970's and 1980's have aged without a significant influx of younger construction workers with similar specialized skills and experience. If a number of new coal units initiate construction within the next decade, the supply of skilled construction workers could be strained. The primary tradeoff for these higher capital risks with a solid fuel generation resource is the long-term stability of coal and other solid fuel alternatives, which have few competing uses relative to natural gas that is used by almost all economic sectors including residential heating.

3.3.1 Performance

Estimated performance was developed for 600 MW to 800 MW net subcritical and supercritical pulverized coal units at SGS. Figure 3.1 shows that as plant size increases from 600 MW to 800 MW net, the net plant heat rate increases slightly, assuming constant condenser pressure.

The heat rate advantage of a supercritical unit over a subcritical unit varies slightly with plant size. The velocity exiting the last stage of a 800 MW net steam turbine is higher than a 600 MW net steam turbine. This results in higher losses in the back end of the turbine because the units use the same last stage blades and therefore share a fixed annulus area for the steam to flow. Supercritical cycles require less steam flow than subcritical cycles resulting in overall lower steam turbine exhaust losses. Since the supercritical steam cycle unloads the back end of the steam turbine, the performance benefit for the 800 MW net option will be greater than for the 600 MW net option. The net plant heat rate increases about 0.7% for a subcritical unit compared to a 0.3% increase for a supercritical unit over the 600 MW to 800 MW net size range.

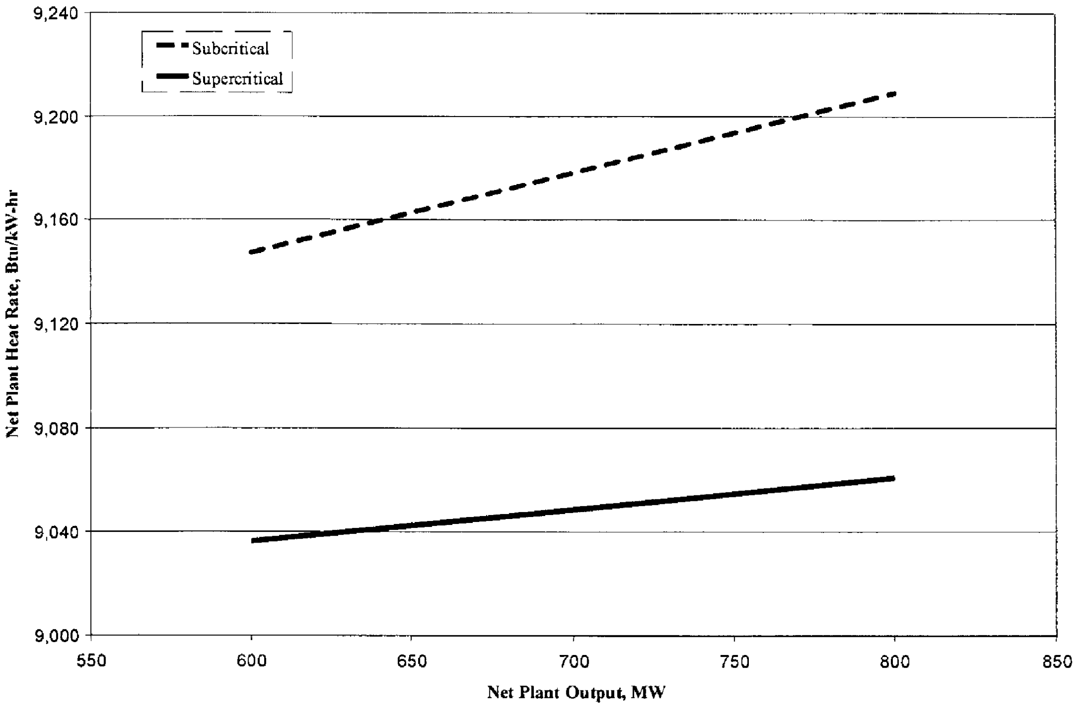


Figure 3.1: Net Plant Heat Rate vs. Net Plant Output

3.3.2 Emissions

A preliminary assessment of the anticipated Best Available Control Technology (BACT) and the anticipated emissions requirements for a new 600 MW net pulverized coal unit at SGS were discussed in the previous study "Feasibility Study for a 600MW Solid Fuel Fired Power Plant." BACT emission levels change with time, unit type, and fuel type. The emission rates are based on Burns & McDonnell's best estimated BACT levels taking into account technology limitations and current expected guaranteed performance levels.

The air pollution control equipment required to accommodate the 70% bituminous coal and 30% pet coke blend is as follows:

- SCR for NO_x control.
- Activated Carbon Injection System for mercury (Hg) control.
- ESP for particulate (PM) control.
- Wet FGD for SO_2 control.
- Wet ESP for sulfuric acid mist (H_2SO_4) control.

The BACT emission limits shown in Table 3.2 are not expected to change between 600 MW and 800 MW net units. The PM emission rate is filterable particulate matter only. The mercury emission limit specified is based on recent test data and does not represent a typical vendor guarantee. In addition, the CO limit is based on the expected byproducts from the combustion process in the boiler and is not a controlled pollutant.

Table 3.2: Preliminary BACT Emission Limits for 600 MW - 800 MW Units

Pollutant	Emission Limit
NO_x	0.07 lb/MMBtu
SO_2	0.18 lb/MMBtu
PM	0.015 lb/MMBtu
Hg	6×10^{-6} lb/MW-hr
CO	0.15 lb/MMBtu
H_2SO_4	0.005 lb/MMBtu

3.3.3 Capital Costs

The capital costs summarized in this section are based on previous screening-level cost estimates used in evaluating the installation of a 600 MW net pulverized coal unit adjacent to the existing units at the Seminole Generating Station. Burns & McDonnell did not solicit bids from equipment manufacturers or contractors for equipment or construction services.

The capital cost estimates for 600 MW to 800 MW net subcritical and supercritical pulverized coal units are included in Figure 3.2 below. It is shown that as unit size increases from 600 MW to 800 MW net, the capital cost decreases by 9 percent on a $/kW basis. Therefore, there are economies of scale with increases in plant size.

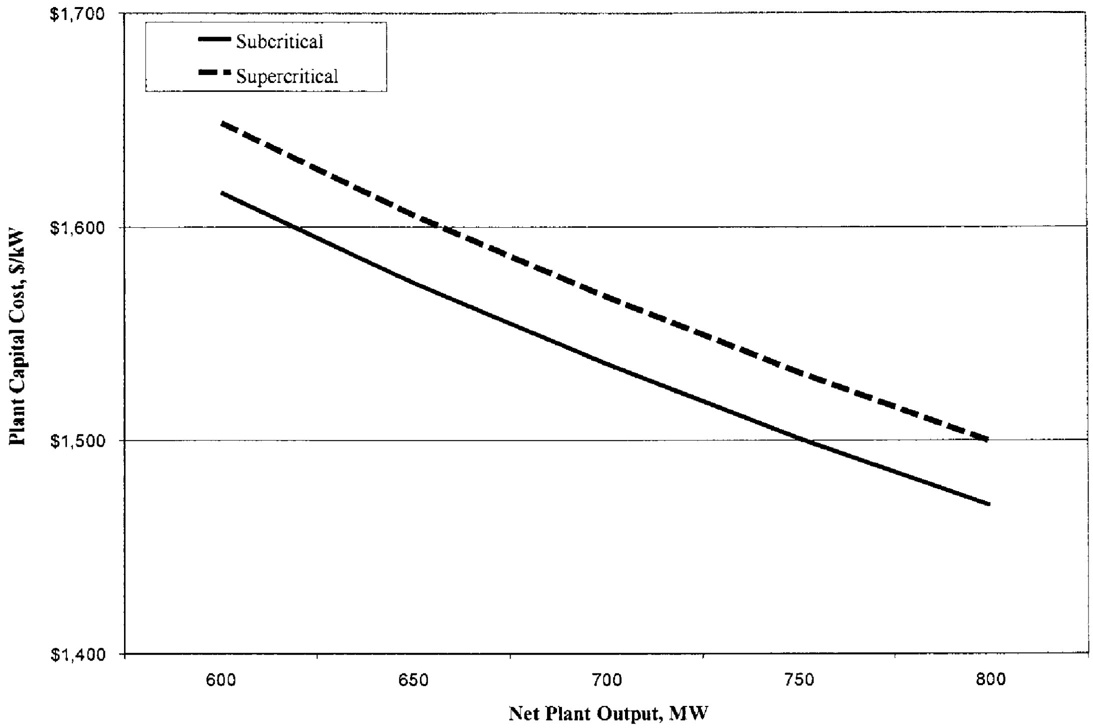


Figure 3.2: Plant Capital Cost vs. Net Plant Output

3.3.4 O&M Costs

A summary of the calculated variable and fixed O&M costs for subcritical and supercritical units between 600 MW to 800 MW net are included in Figures 3.3 and 3.4. These O&M costs were estimated based on the assumptions discussed in the previous study "650 MW Solid Fuel Fired Unit Feasibility Study."

Fixed O&M Cost Basis:

- Subcritical and supercritical plants require an additional staff of 46 people.
- Fixed employee costs include office and administration, contract labor, safety, and training expenses.
- Buildings, grounds, and supply costs are included.
- Steam turbine, boiler, and air pollution control equipment are inspected annually.
- Major annual maintenance costs include steam turbine and boiler tube replacements and overhaul, baghouse bag replacements, SCR catalyst replacements, and water treatment system replacements.
- Property taxes, insurance, and interest during construction are not included.

Variable (Non-Fuel) O&M Cost Basis:

- Water consumption, treatment chemicals, and consumables are included.
- Maintenance costs include SCR, scrubber, water treatment, cooling tower, brine concentrator and spray dryer system general maintenance (material handling, electrical, DCS, etc).
- Emissions controls costs include limestone and ammonia consumption. Gypsum, bottom ash and fly ash are saleable by-products.

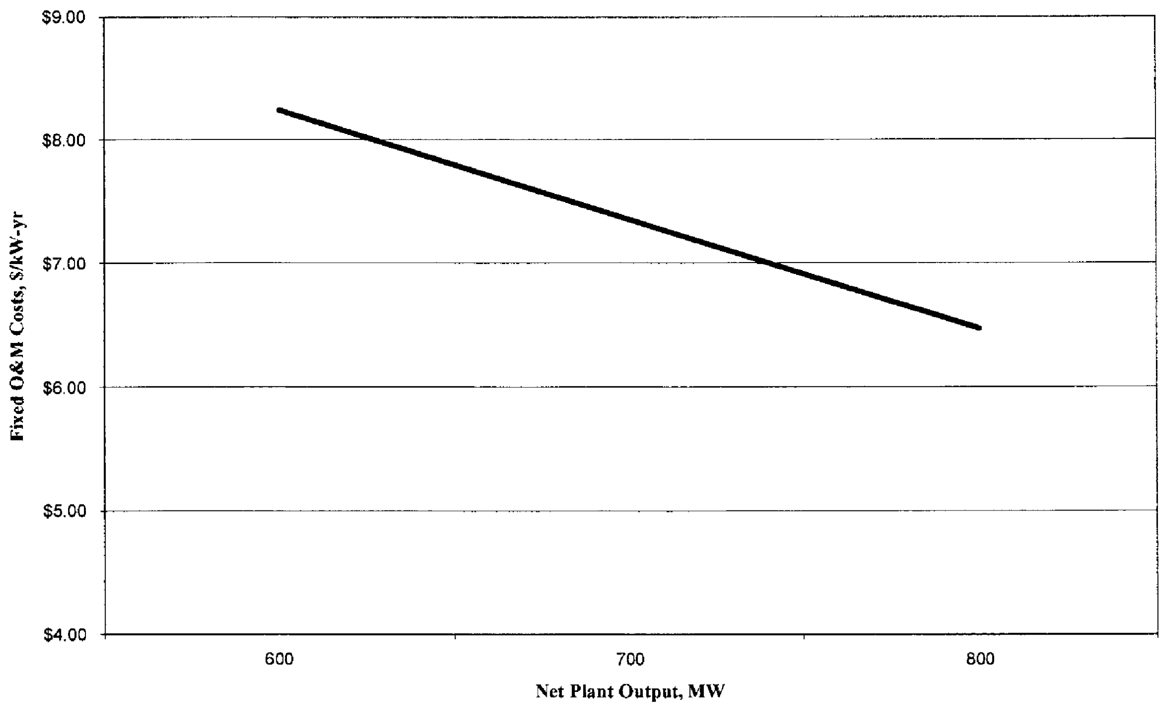


Figure 3.3: Fixed O&M Costs vs. Net Plant Output

As shown in Figure 3.3, the total fixed O&M costs per kW-yr decreases as unit size increases from 600 MW to 800 MW. Equipment inspection costs and staffing requirements remain fairly constant with plants in this size range. Fixed O&M costs do not change between subcritical and supercritical units, assuming property taxes and insurance are not included. Staffing requirements and annual inspection fees are expected to be the same for both subcritical and supercritical units.

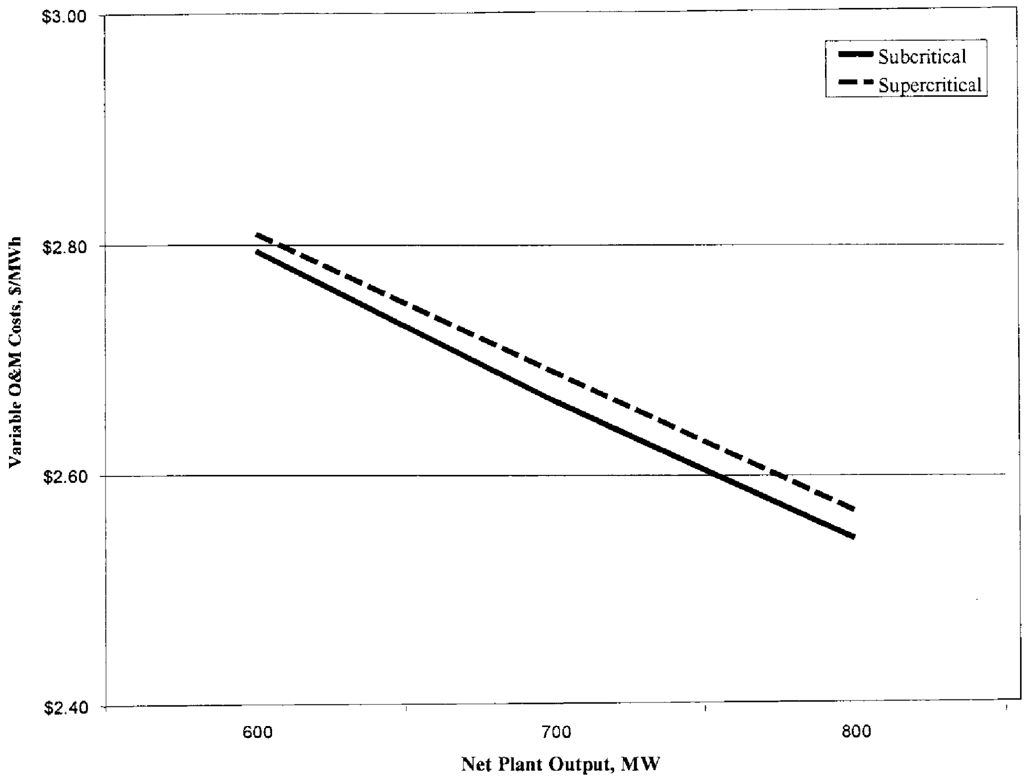


Figure 3.4: Variable O&M Costs vs. Net Plant Output

Variable O&M costs decrease almost linearly as unit size increases. Between 600 MW and 800 MW, the variable O&M cost decreases by $0.23/MWh for both supercritical and subcritical units. The value of gypsum and ash sales at the Seminole Generating Station causes variable O&M costs to be greater for supercritical units. Major maintenance and equipment overhaul expenses only increases slightly as unit size increases. Scrubber and SCR consumable costs increase as fuel consumption increases. However, these cost increases are relatively minor and therefore as plant output increases, variable O&M costs on a $/MWh basis decrease.

3.4 CONCLUSIONS

Domestic operating experience for pulverized coal units is limited to steam cycle conditions of 1050°F/1050°F. High sulfur coals present a greater problem with boiler tube corrosion at elevated temperatures, and there is currently no operating experience with 30% pet coke at steam temperatures above 1050°F. Boiler manufacturers recommend appropriate design and material considerations be made for high sulfur fuels similarly for subcritical and supercritical boilers. There is potentially a greater O&M costs for corrosive coals in supercritical units due to more frequent boiler inspections and material replacements.

In addition to increasing steam temperatures, regenerative feedwater heating is a common method for improving steam power plant efficiency. The addition of a heater above reheat the reheat point offers a substantial increase in efficiency with minimal capital investment, maintenance costs, and risk. Along with the economic benefits, the eight feedwater heater cycle does offer risk mitigation in regards to fuel consumption, sorbent consumption, waste disposal costs, and increased emissions allowance costs when compared to a seven feedwater heater cycle.

Turbine last stage blade selection affects plant performance. SECI should consider the use of 40 to 42 inch last stage blades based upon the improvement in performance and operating experience with this blade size. Longer LSBs are available from several of the large steam turbine manufacturers. However, these longer blades have limited experience in commercial operation between 600 MW and 800 MW.

Between 600 MW and 800 MW net, unit size has a small impact on net plant heat rate. Other design conditions, such as the condenser pressure and feedwater heater configuration have a greater effect on the net plant heat rate than does unit size. Supercritical units require less steam flow than subcritical units and therefore the loss through the back end of the steam turbine is less. Between 600 MW and 800 MW net, this causes the heat rate degradation to be less for supercritical units.

Overall capital cost decreases nearly 9 percent on a $/kW basis for both supercritical and subcritical steam cycles as unit size increases from 600 MW to 800 MW net. Fixed O&M costs are nearly the same for both subcritical and supercritical units. Variable O&M costs for a supercritical unit between 600 MW to 800 MW net are around 0.4 percent higher compared to a subcritical unit due to the high value of ash and gypsum sales at SGS.

4.0 INTEGRATED GASIFICATION COMBINED CYCLE

4.1 GENERAL DESCRIPTION

Integrated Gasification Combined Cycle (IGCC) technology produces a low calorific value syngas from coal or solid waste, to be fired in a conventional combined cycle plant. The gasification process in itself is a proven technology utilized extensively for production of chemical products such as ammonia for use in fertilizer. Utilizing coal as a solid feedstock in a gasifier is currently under development for projects jointly funded by the Department of Energy (DOE) at several power plant facilities throughout the United States. The gasification process represents a link between solid fossil fuels such as coal and existing gas turbine technology. The IGCC process is shown in Figure 4.1 below.

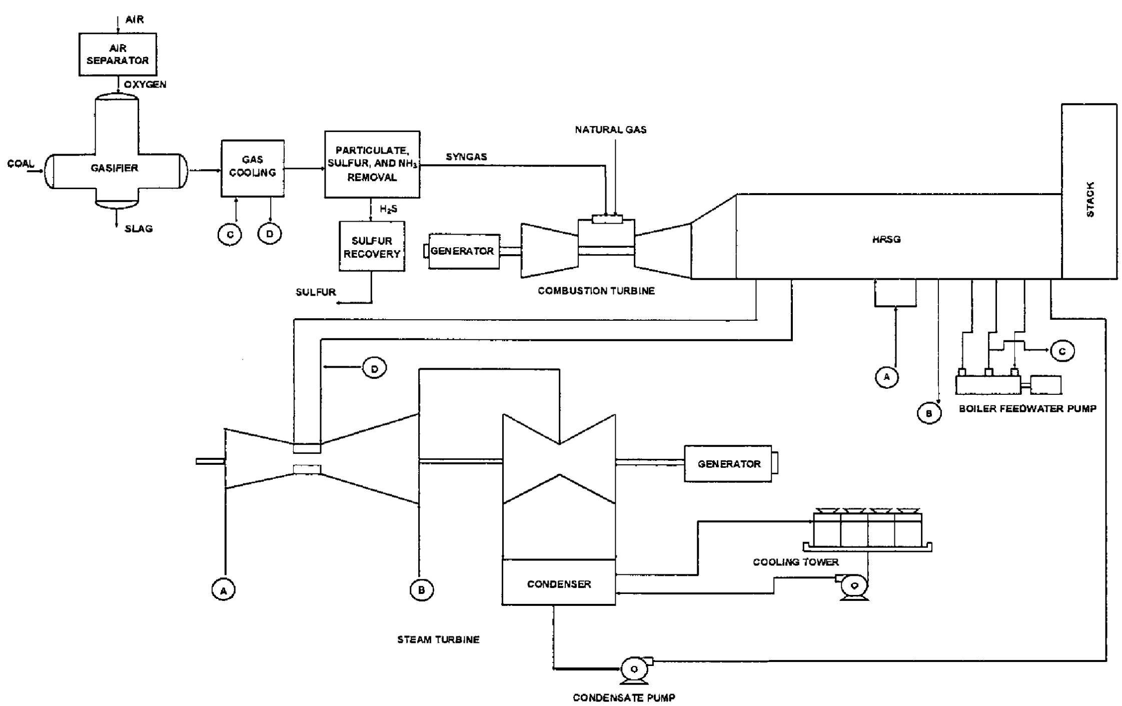


Figure 4.1: IGCC Process Diagram

A 600 MW net IGCC plant would typically be composed of two coal gasifiers, a coal handling system, an air separation unit, a gas conditioning system to remove sulfur and particulate, two gas turbines, two heat recovery steam generators with supplemental duct firing and a single steam turbine. Cooling water for the steam turbine would be based on a mechanical draft cooling tower.

Integrating proven gasifier technology with proven gas turbine combined cycle technology is a recent development, and continues to be improved at the existing DOE jointly funded power plants. Because gasification-based power generation is a relatively new technology with few operating plants, its unique operating features and its environmental performance capability are not well known.

Gasifiers designed to accept coal as a solid fuel generally fall into three categories: entrained flow, fluidized bed, and moving bed.

Entrained Flow

The entrained flow gasifier reactor design converts coal into molten slag. This gasifier design utilizes high temperatures with short residence time and will accept either liquid or solid fuel. General Electric (Chevron Texaco), Conoco Phillips (E-Gas), Prenflo, and Shell produce gasifiers of this design.

Fluidized Bed

Fluidized-bed reactors are highly back-mixed and efficiently mix feed coal particles with coal particles already undergoing gasification. Fluidized bed gasifiers accept a wide range of solid fuels, but are not suitable for liquid fuels. The KRW and High Temperature Winkler designs use this technology.

Moving Bed

In moving-bed reactors, large particles of coal move slowly down through the bed while reacting with gases moving up through the bed. Moving-bed gasifiers are not suitable for liquid fuels. The Lurgi Dry Ash gasification process is a moving bed design and has been utilized both at the Dakota Gasification plant for production of SNG and the South Africa Sasol plant for production of liquid fuels. BGL is another manufacturer of the moving bed design.

The majority of the DOE test facilities utilize the entrained flow gasification design with coal as feedstock. Pulverized coal is fed in conjunction with water and oxygen from an air separation unit (ASU) into the gasifier at around 450 psig where the partial oxidation of the coal occurs. The raw syngas produced by the reaction in the gasifier exits at around 2400 °F and is cooled to less than 400 °F in a gas cooler, which produces additional steam for both the steam turbine and gasification process. Scrubbers then remove particulate, ammonia (NH_3), hydrogen chloride and sulfur from the raw syngas stream. The cooled syngas then feeds into a modified combustion chamber of a gas turbine specifically designed to accept the low calorific syngas. Exhaust heat from the gas turbine then generates steam in a heat recovery steam generator (HRSG) to power a steam turbine. Reliability issues associated with fouling and/or tube leaks within the syngas cooler have challenged the existing IGCC installations. The syngas cooler greatly improves thermal efficiencies when compared to a quench cooler system typical to those utilized in chemical production gasifiers.

4.2 CURRENT STATUS

The following table identifies the DOE jointly funded test facilities constructed in the United States, with various gasification system designs.

Table 4.1: IGCC Test Facilities

Facility	Owner	Capacity (MW)	Commercial Operation Date	Gasifier Manufacturer	Status
Polk County	Tampa Electric	252	1996	Chevron Texaco	Operating
Wabash River	PSI Energy	262	1995	Conoco Phillips	Operating
Pinon Pine	Sierra Pacific	99	1997	KRW	Decommissioned
LGTI	Dow Chemical	160	1987	Conoco Phillips	Decommissioned
Cool Water	Texaco	125	1984	Chevron Texaco	Decommissioned

There are several IGCC projects currently in the development phase, including the 540 MW power station for Global Energy, Inc. located in Lima, OH, and Excelsior Energy's 530 MW Mesaba Energy Project located in Minnesota.

4.3 PLANT CHARACTERISTICS

4.3.1 Performance

Cold start-up times for IGCC plants have typically ranged from 40-50 hours compared to a conventional PC boiler start-up time of 4-6 hours. Hot restart procedures are in testing at several of these facilities, and Eastman Chemical Company has developed a proprietary process that allows a fairly rapid startup. However, the startup process requires flaring the syngas produced until it is adequate quality for introduction into the gas turbine. The gasification plant requires stable operation in order to maintain syngas quality and the technology to support load following continues to be developed.

A performance estimate was supplied by GE for a typical 550 MW IGCC unit firing 100% Illinois coal. The GE performance estimate is at 90°F dry-bulb temperature, 60%RH, and 0 ft. elevation. The estimated performance for a 550 MW IGCC unit is shown in Table 4.2.

Table 4.2: IGCC Expected Performance

IGCC Performance at 90 F, 60% RH, 0 ft. elevation	
Gross Gas Turbine Output, kW	394,000
Gross Steam Turbine Output, kW	282,800
Gross Plant Output, kW	676,800
Total Auxiliary Loads, kW	123,678
Net Plant Output, kW	**553,122**
Net Plant Heat Rate, Btu/kWh (HHV)	**9,106**

Significant design issues have prevented coal gasification units from achieving industry acceptable availability levels. These design issues include fouling within the syngas cooler, design of the pressurized coal feeding system, molten slag removal from the pressurized gasifier, durability of gas clean-up equipment and solid particulate carryover resulting in erosion within the gas turbine. The complexity of the combined cycle unit in conjunction with the reliability of numerous systems, including the gasifier, O_2 generator, air separation unit and multiple scrubbers have contributed to reduced plant availability.

Unit availability at the DOE jointly funded plants has been improving due to design modifications intended to improve equipment life and reliability. Polk County was able to achieve 83% availability for 2003 and Wabash River achieved 83.7% availability for 2003. All of these coal gasification plants have experienced down-time for design modifications and replacement of equipment. Polk County and

Wabash River are the only two coal IGCC plants in the United States that have achieved extended periods of commercial operation. The current generation of IGCC plants should be capable of operation with an availability of around 85 percent compared to around 90 percent for conventional steam electric plants.

4.3.2 Emissions Controls

The IGCC facility includes the following emissions controls equipment:

- Nitrous oxide (NO_x) emission control is achieved by injecting either nitrogen or steam into the gas turbine combustors during syngas operation. During natural gas operation, steam injection is utilized for NO_x control. Selective catalytic reduction (SCR) is not included at this time.
- Sulfur dioxide (SO_2) emission control is achieved through sulfur removal in the syngas. Sulfur removal is accomplished by using an amine scrubber that utilizes a methyldiethanolamine (MDEA) solution to absorb Hydrogen Sulfide (H_2S) from the syngas stream prior to combustion. High levels of sulfur removal are accomplished by first passing the syngas through a carbonyl sulfide (COS) hydrolysis reactor prior to the amine scrubber to convert small amounts of COS in the syngas to H_2S.
- Mercury removal is achieved by passing the syngas through a carbon filter bed prior to combustion.
- The syngas is scrubbed prior to combustion to remove particulate. Post-combustion particulate control is not required due to the inherently low emissions of this pollutant.

GEs proposed emission rates for an IGCC unit firing 100% Illinois bituminous coal are shown in Table 4.3. These emission rates are compared to a 600 MW pulverized coal unit firing a 70/30 bituminous coal and pet coke blend using BACT control technology.

Table 4.3: Pulverized Coal vs. IGCC Emission Rates

Pollutant	600 MW Pulverized Coal Emission Rate	550 MW IGCC Emission Rate
NOx, lb/MMBtu Coal	0.07	0.055
SO2, lb/MMBtu Coal	0.18	0.09
CO, lb/MMBtu Coal	0.15	0.03
Particulate, lb/MMBtu Coal	0.018	0.008

Note: Particulate does not include ambient air or corrosion products.

4.3.3 Waste Disposal

The syngas sulfur removal process can result in 99.9 percent pure sulfur, which is a saleable by-product. The gasifier converts coal ash to a low-carbon vitreous slag and flyash. The slag has beneficial use and can be utilized as grit for abrasives, roofing materials, or as an aggregate in construction. Fly ash entrained in the syngas is recovered in the particulate removal system and is either recycled to the gasifier or combined with other solids in the water treatment system and shipped off site for reuse or to be landfilled.

4.3.4 Water Requirements

An IGCC plant uses approximately one third the cooling water for condensing steam compared to a conventional steam electric plant. However, a large cooling water supply is required for coal gasification and for the air separation unit used to produce pure oxygen and when combined with the steam condensing requirements, the amount of water is comparable to a conventional steam electric plant.

4.3.5 Project Schedule

The permitting process for a greenfield 600 MW net IGCC takes approximately 18 months. The design and construction duration is approximately 48 months. In most cases, the permitting phase and design/construction phase will partially overlap to decrease the overall implementation period; however, this schedule does expose the Owner to some risk if the permit is not approved. Total implementation time for a 600 MW net IGCC including permitting, design, and construction is approximately 52 – 64 months.

4.3.6 Capital Cost Estimates

GE has estimated the capital cost of a typical IGCC plant based on a 550 MW "greenfield" site firing 100% Illinois coal to be approximately $1,640/kW excluding Owner's costs. This capital cost is for the three major blocks (gasification block, air separation unit block, and power block) and EPC contractor costs (including indirect costs, engineering costs, construction management, EPC fee, EPC contingency).

B&McD estimated Owner's costs (excluding interest during construction, financing fees, and escalation) for a typical 550 MW IGCC plant to be $230/kW. The total project cost incorporating GE costs and Owner's costs is estimated to be $1,870/kW based on a 550 MW facility.

4.3.7 Operations and Maintenance

Note that there has not been a long operating history for IGCC units. Scheduled maintenance consists of an outage of approximately 3 weeks/year and 4-5 weeks every five years. Tampa Electric's 250 MW IGCC demonstration facility estimates fixed and variable O&M costs are $32.80/kW-yr and $5.91/MWh, respectively. The plant is staffed by five 10-man O&M teams, and 28 additional support personnel.

4.3.8 Long Term Development

Much of future technology development will be supported through government funding support of Clean Coal Technology within the power industry. A few large scale (550 MW and greater) IGCC power plants are currently in the preliminary project development and/or permitting stage in the United States, however, commercial operation of these plants is at least 4 to 5 years in the future.

4.4 IGCC AT SEMINOLE GENERATING STATION

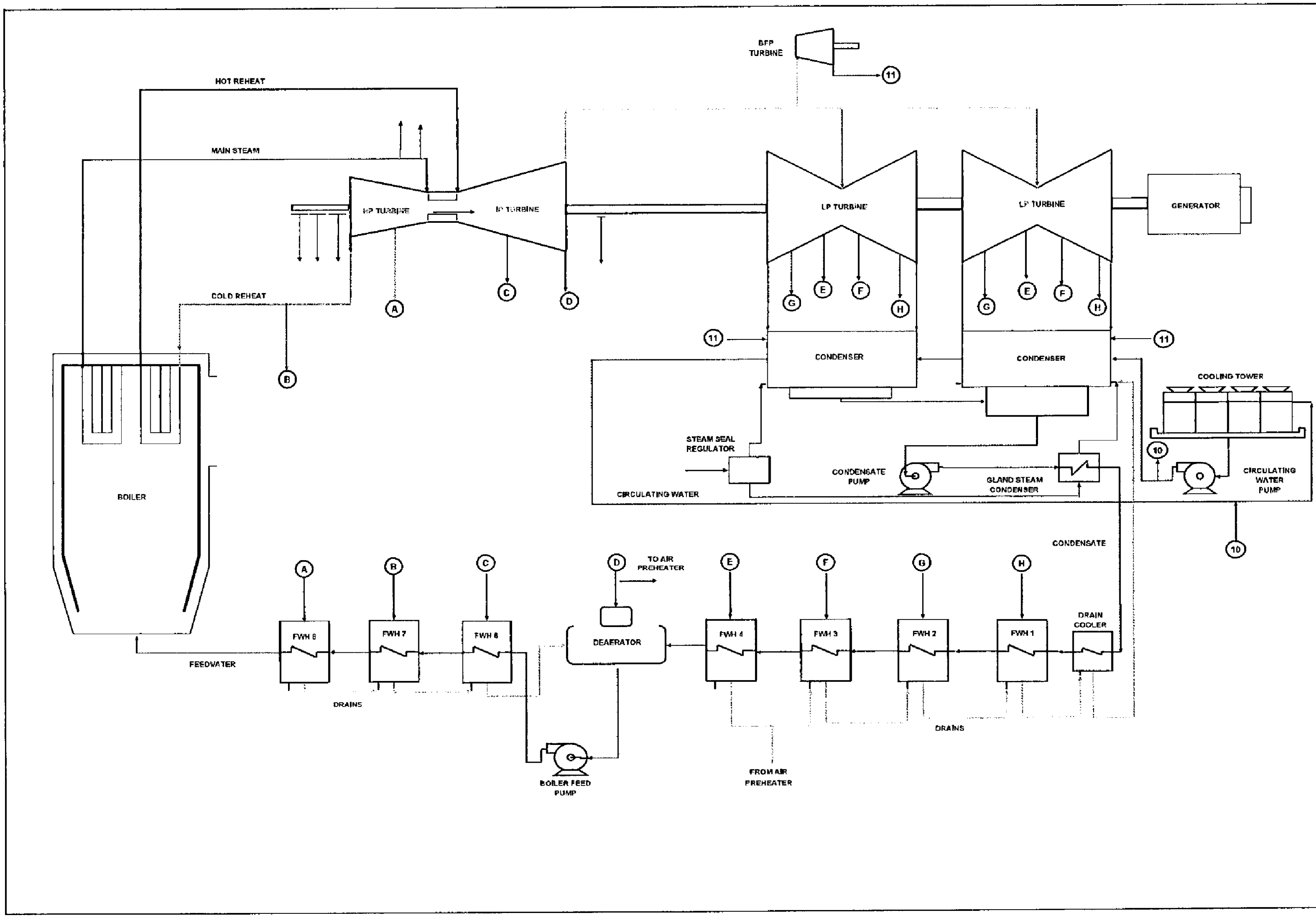
A greenfield 600 MW net IGCC plant requires approximately 120 acres which includes areas for coal handling, construction laydown and parking. The Seminole Generating Station site has existing coal handling infrastructure to support an IGCC plant. The space required for the IGCC power block is approximately 45 acres. The existing site is capable of accommodating an IGCC plant however, some of the remaining permitted landfill area to the east of the existing units may have to be utilized which would reduce the life of that landfill.

The slag from an IGCC plant could be sold similar to the bottom ash from the existing units. In addition, the sulfur byproduct could also be sold if a market exits. Therefore, the potential landfill requirements would be less than a conventional steam electric plant.

The availability and reliability of the current IGCC plants is improving but is not comparable with conventional steam electric plants. The penalty for higher availability is with more redundancy and therefore higher capital costs.

Much of future IGCC technology development will be supported through government funding of clean coal technology in the power industry. Operational flexibility for rapid start-up and load following remains to be demonstrated and may be required for an IGCC plant to compete effectively within the current U.S. power market.

Acceptance of coal within the power industry and the relative price of natural gas will also influence the future development and commercialization of IGCC in the United States. The technical barriers to commercialization remain to be addressed through future generations of government jointly funded coal IGCC facilities. Once the development effort has been successfully completed, coal fueled IGCC technology has the potential to be a reliable clean-coal generation technology.



PERFORMANCE SUMMARY

Seminole Electric Cooperative
Seminole Unit 3
750 MW PC SUPERCRITICAL
BMCD PROJECT 39736

STEAM CYCLE DIAGRAM

DESIGNED BY: ____________

CHECKED BY: ____________

STATUS: ____________

DATE	MODEL REV.
12-Oct-05	

Exhibit RAK-6

EXHIBIT RAK-7

SEMINOLE ELECTRIC COOPERATIVE, INC.
SEMINOLE GENERATING STATION

SGS UNIT 3 FACT SHEET

Plant Design

Megawatt (net) .... 750 MW
Net Plant Heat Rate (71°F/80% RH) .... 9,000 Btu/kWh
Steam Cycle Conditions .... 3700 PSI/1,050 F/1,050 F

Water Supply

Cooling Tower Makeup .... St. Johns River
Boiler Makeup .... Ground Water
Potable Water .... Well System
Average Annual Makeup from St. John's River .... 33 MGD

Fuels

Type .... Eastern Bituminous Coal/Petcoke
Blend .... Up to 30% Petcoke
Delivery .... Rail
Startup Fuel .... Fuel Oil

Air Quality Control Systems

SO_2 .... Wet FGD
NO_x .... Low NO_x Burners/Overfire Air/SCR
PM .... ESP
Sulfuric Acid Mist .... Wet ESP

Reagent

Wet FGD .... Limestone
Limestone Delivery .... Truck
SCR .... Urea
Urea Delivery .... Truck/Rail

Waste Disposal

Gypsum .... Lafarge
Gypsum Transport .... Conveyor
Fly Ash .... Sold/Landfilled
Bottom Ash .... Sold/Landfilled
Ash Transport .... Truck
Landfill Location .... On-site

SGS UNIT 3 FACT SHEET Continued

Major Equipment

Boiler	Supercritical Pulverized Coal
Steam Turbine	Tandem Compound/Four Flow/Single Reheat
Cooling Tower	Mechanical Draft
Wet Flue Gas Desulfurization (FGD)	Single Module
Wastewater Treatment System	Brine Concentrator/Spray Dryer
Stack	675 Ft
Selective Catalytic Reduction Unit (SCR)	Dual Train
Electrostatic Precipitator (ESP)	Dual Train
Wet Electrostatic Precipitator (Wet ESP)	Single Train

Exhibit RAK-8
SGS Unit 3 Construction Milestones

Milestone	Date
Start Procurement of Boiler	Aug 2007
Start Procurement of Steam Turbine	Aug 2007
Receive Approvals to Start Construction	Oct 2007
Award of Boiler and Steam Turbine	Nov 2007
Mobilize/Start Site Work	Oct 2008
Start Foundations	Dec 2008
Start Boiler Steel Erection	Jun 2009
Boiler Hydro	Feb 2011
Initial Synchronization	Oct 2011
First Fire on Coal	Oct 2011
Commercial Operation	May 2012