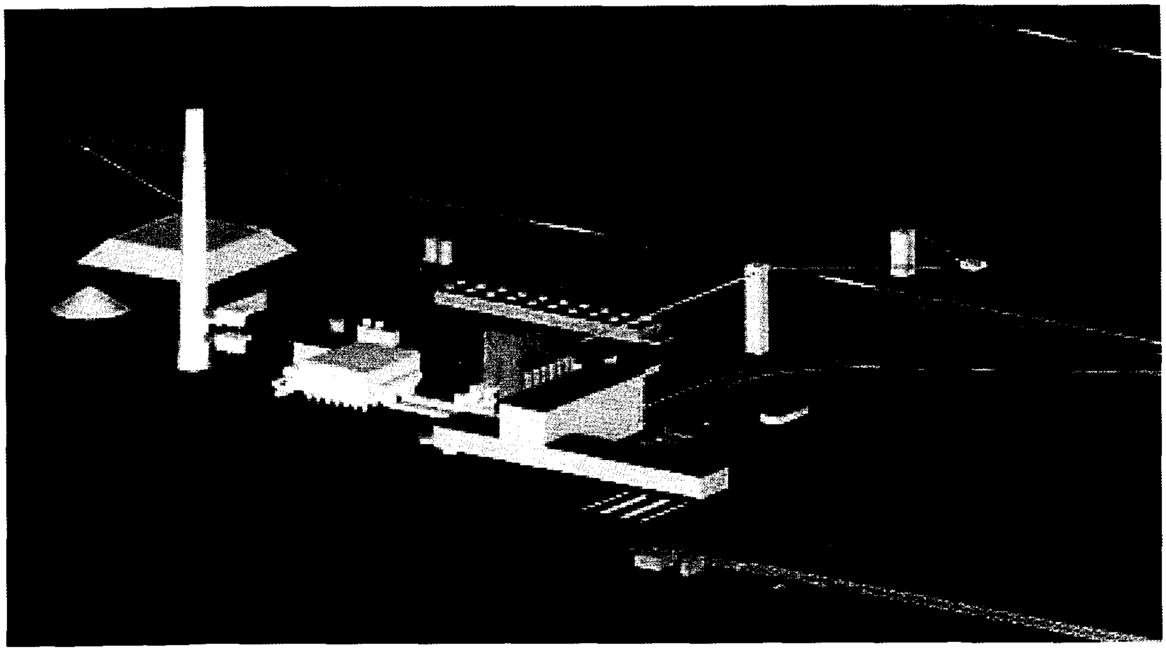
Florida Electrical Power Plant Siting Act
Need for Power Application

060635-EU

Taylor Energy Center



Submitted by:

Florida Municipal Power Agency
JEA
Reedy Creek Improvement District
City of Tallahassee
September 2006
Volume A

Florida Municipal Power Agency

REEDY CREEK IMPROVEMENT DISTRICT

City of Tallahassee
Your Own Utilities

Prepared by:
Black & Veatch Corporation

BLACK & VEATCH
building a world of difference

ENERGY WATER INFORMATION GOVERNMENT

DOCUMENT NO.
08611-06
9.19.06

Table of Contents

Table of Contents (Continued)

Table of Contents

Table of Contents (Continued)

Tables

Table of Contents (Continued)

Tables (Continued)

Table of Contents (Continued)

Tables (Continued)

Table of Contents (Continued)

Tables (Continued)

Table of Contents (Continued)

Tables (Continued)

Figures

Table of Contents (Continued)

Figures (Continued)

Abbreviations

AFUDC	Allowance for Funds Used During Construction
AN	Apalachicola Northern
ARP	Acid Rain Program
BART	Best Available Retrofit Technology
Beck	R.W. Beck, Inc.
BNSF	Burlington Northern Santa Fe
B&V	Black & Veatch
CAES	Compressed Air Energy Storage
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CaO	Calcium Oxide
CAPEX	Capital Expenditure
CAPP	Central Appalachia
CEP	Central Energy Plant
CFB	Circulating Fluidized Bed
CFR	Code of Federal Regulations
City	City of Tallahassee
CO	Carbon Monoxide
CO_2	Carbon Dioxide
COD	Commercial Operation Date
Conrail	Consolidated Rail Corporation
CONSOL	Consolidated Coal Company
CPWC	Cumulative Present Worth Cost
CSX	CSX Transportation
CTG	Combustion Turbine Generator
DCS	Distributed Control System
DCSS	Distillation Condensation Subsystem
DI	Diffuse Insolation
DNI	Direct Normal Insolation
Drummond	Drummond Coal Company
DSM	Demand-Side Management
EGUs	Electric Generating Units
EPA	Environmental Protection Agency
EPC	Engineer, Procure, and Construct
ESA	Electricity Storage Association

ESP	Electrostatic Precipitator
FBC	Fluidized Bed Combustion
FCR	Fixed Charge Rate
FDEP	Florida Department of Environmental Protection
FERC	Federal Energy Regulatory Commission
FF	Fabric Filter
FGD	Flue Gas Desulfurization
FGT	Florida Gas Transmission Company
FIP	Federal Implementation Plan
FIRE	Florida Integrated Resource Evaluator
FMPA	Florida Municipal Power Agency
FOB	Freight on Board
FPSC	Florida Public Service Commission
FPUA	Fort Pierce Utilities Authority
FPUC	Florida Public Utilities Company
FRCC	Florida Reliability Coordinating Council
FRP	Fiberglass Reinforced Plastic
G&A	General and Administrative
GC	Gulf Coast
GE	General Electric
GDP	Gross Domestic Product
GFRR	Georgia & Florida Railway, Inc.
GN	Georgia Northern
gpm	Gallons per Minute
HAT	Humid Air Turbine
Hellerworx	Hellerworx, Inc.
Hg	Mercury
HHV	Higher Heating Value
HP	High-Pressure
HPC	High-Pressure Compressor
HPT	High-Pressure Turbine
HRSG	Heat Recovery Steam Generator
HRVG	Heat Recovery Vapor Generator
ICT	International Coal Trade
IDC	Interest During Construction
IGCC	Integrated Gasification Combined Cycle
ILB	Illinois Basin

IP	Intermediate Pressure
IPP	Independent Power Producer
IRP	Integrated Resources Plan
ISO	Isometric
JPA	Jacksonville Port Authority
Kennedy	Kennedy Generating Station
Keystone	Keystone Industries, LLC
KUA	Kissimmee Utility Authority
kW	Kilowatt
lb/h	Pounds per Hour
LFG	Landfill Gas
LHV	Lower Heating Value
LNG	Liquefied Natural Gas
LP	Low Pressure
LPC	Low-Pressure Compressor
LPT	Low-Pressure Turbine
L&RP	Load and Resource Plan
LRDB	Load and Resource Database
LWU	Lake Worth Utilities
MBtu	Million British Thermal Units
MGA	Monongahela Railway
mgd	Million Gallons per Day
MOU	Memorandum of Understanding
MSHA	Mine Safety and Health Administration
MSW	Municipal Solid Waste
MTI	Materials Transfer, Inc.
MW	Megawatt
MWh	Megawatts per Hour
NAPP	Northern Appalachia
Na-S	Sodium-Sulfur
NERC	North American Electric Reliability Council
NFP	Need for Power
NH_3	Ammonia
NI	Nuclear Island
Northside	Northside Generation Station
NO_x	Nitrogen Oxide
NO_x	Oxides of Nitrogen

NPRB	Northern PRB
NRC	Nuclear Regulatory Commission
NS	Norfolk Southern
NSPS	New Source Performance Standard
NUG	Non-Utility Generator
NYMEX	New York Mercantile Exchange
O_2	Oxygen
O&M	Operating and Maintenance
OECD	Organization for Economic Cooperation and Development
OPEC	Organization of Petroleum Exporting Countries
OTEC	Ocean Thermal Energy Conversion
OUC	Orlando Utilities Commission
OWC	Oscillating Water Column
Pace Global	Pace Global Energy Services
PAFC	Phosphoric Acid Fuel Cell
PC	Pulverized Coal
PEF	Progress Energy Florida
petcoke	Petroleum Coke
PFBC	Pressurized Fluidized Bed Combustion
PM	Particulate Matter
PPA	Power Purchase Agreement
PPM	Part per Million
PRB	Powder River Basin
psig	Pounds per Square Inch Gauge
PTC	Production Tax Credit
PV	Photovoltaic
QFs	Qualifying Facilities
RCAF-U	Rail Cost Adjustment Factor Index Unadjusted for Productivity
RCID	Reedy Creek Improvement District
RDF	Refuse Derived Fuel
RFP	Request for Proposal
RH	Relative Humidity
RPM	Revolutions per Minute
SCA	Site Certification Application
scf	Square Cubic Feet
SCR	Selective Catalytic Reduction

SDA	Spray Dryer Absorber
SEC	Seminole Electric Cooperative
SEGS	Solar Electric Generating Station
SES	Stirling Energy Systems
SIPs	State Implementation Plans
SJRPP	St. Johns River Power Park
SNCR	Selective Noncatalytic Reduction
SNL	Sandia National Laboratories
SO_2	Sulfur Dioxide
Southern	Southern Power Company
SPRB	Southern PRB
SS	Stainless Steel
SSY	Simpson, Spence & Young Consultancy & Research Ltd.
TAPCHAN	Overtopping-Tapered Channel
TCEC	Treasure Coast Energy Center
TEA	The Energy Authority
TEC	Taylor Energy Center
TEC Fuels	Taylor Energy Center Fuels Committee
TI	Turbine Island
tpd	Tons per Day
TPT	TampaPlex Terminal
tpy	Tons per Year
TVA	Tennessee Valley Authority
ULSD	Ultra-Low Sulfur Diesel
UP	Union Pacific
VOC	Volatile Organic Compound
VTG	Vapor Turbine Generator
VWO	Valves Wide Open
WECS	Wave Energy Conversion System
WESP	Wet Electrostatic Precipitator
WS	Waynesburg Southern
WTE	Waste-to-Energy
WTI	West Texas Intermediate
ZLD	Zero Liquid Discharge

A.1.0 Introduction

This Need for Power (NFP) Application (Application) is submitted as part of the Site Certification Application (SCA) by the Florida Municipal Power Agency (FMPA), JEA, Reedy Creek Improvement District (RCID), and the City of Tallahassee (collectively referred to as the Participants) for the construction of the Taylor Energy Center (TEC) in accordance with the Florida Electrical Power Plant Siting Act. The TEC is proposed as a 765 MW (net) supercritical coal fired power plant that will be designed to burn a blend of petroleum coke (petcoke) and coal, with commercial operation on May 1, 2012. The TEC is proposed to be developed on a site consisting of approximately 3,000 acres to be located approximately 5 miles southeast of Perry, in Taylor County, Florida.

This Application is divided into subvolumes labeled A, B, C, D, and E and contains the following information:

- Volume A – NFP information common to all Participants.
- Volume B – NFP information specific to FMPA.
- Volume C – NFP information specific to JEA.
- Volume D – NFP information specific to RCID.
- Volume E – NFP information specific to the City of Tallahassee.

The determination of need for the proposed TEC is being sought under Section 403.519, Florida Statutes. The joint Application is based upon the collective needs of FMPA, JEA, RCID, and the City of Tallahassee. The proposed ownership percentages of TEC are as follows:

- FMPA – 38.9 percent.
- JEA – 31.5 percent.
- RCID – 9.3 percent.
- City of Tallahassee – 20.3 percent.

Applicants Official Names and Mailing Addresses

Florida Municipal Power Agency
8553 Commodity Circle
Orlando, Florida 32819-9002

JEA
21 West Church Street
Jacksonville, Florida 32202

Reedy Creek Improvement District
PO Box 10175
Lake Buena Vista, Florida 32830-3175

City of Tallahassee
400 E. Van Buren Street
Tallahassee, Florida 32301

A.2.0 Overview and Summary

A.2.1 Overview

The FMPA, JEA, RCID, and the City of Tallahassee (collectively referred to as the Participants) are jointly planning for the development, construction, and operation of the TEC to meet the forecast capacity requirements of each utility. The TEC is expected to be a 765 MW (net) supercritical coal fired power plant that will burn a blend of petcoke and coal, with commercial operation on May 1, 2012. The TEC will provide low cost, reliable baseload energy as well as diversify fuel use within Florida. A detailed description of the proposed TEC is presented in Section A.3.0.

A.2.2 Summary

FMPA is a wholesale supplier to 15 city-owned electric utilities throughout Florida. FMPA plans to maintain a 15 percent reserve margin in the winter season and an 18 percent reserve margin in the summer season. FMPA satisfies its member requirements through jointly owned and FMPA owned generating resources, as well as various power purchase agreements as summarized in Section B.2.0 Including resources under construction and not yet in service and other available resources, FMPA's available capacity will fall below its required 15 percent reserve margin during the winter of 2012/13. At that time, FMPA's reserve margin is projected to fall to 11.4 percent, or a shortfall of 52 MW. In the summer of 2011, FMPA's reserve margin is projected to decrease to 13.9 percent, or 59 MW below the required capacity, with a 230 MW need to maintain an 18 percent reserve margin by 2012. For purposes of this Application, it has been assumed that FMPA will satisfy the 2011 capacity requirement through installation of a simple cycle combustion turbine as described in Section B.5.0.

JEA is a retail supplier in Jacksonville, Florida, and in parts of three adjacent counties. JEA serves its retail load with owned resources, jointly owned resources, and power purchase agreements as summarized in Section C.2.0. JEA maintains a reserve margin of 15 percent. JEA's capacity will initially fall below its required 15 percent reserve margin during the winter of 2008/09. At that time, JEA's reserve margin is projected to fall to 14.8 percent, or a shortfall of 5 MW. Another small deficit will occur during the winter of 2011/2012. If these minor deficits materialize, JEA would likely enter into a short-term seasonal purchase agreement with The Energy Authority (TEA) to maintain its reserve margin. The capacity deficit will continue to increase and by the winter of 2012/13, the reserve margin is projected to be 11.5 percent, for a shortfall of 117 MW. JEA's reserve margin is also forecasted to fall below 15 percent during the summer of 2013. Thereafter, the deficit will continue. JEA currently supplies wholesale power to Florida Public Utilities Company (FPUC) with a contract that expires on December 31, 2007. If that contract is renewed, JEA's capacity needs will increase by approximately 100 MW.

RCID is a retail supplier in parts of Orange and Osceola counties. RCID meets its reserve requirements with existing generation resources, existing system purchases, and partial requirements purchases as described in Section D.2.0. RCID plans to maintain a 15 percent reserve margin for the summer and winter seasons. RCID is expected to encounter a capacity shortfall in 2011, at which time approximately 134 MW of additional capacity will be required. As described in Section D.5.0, for the purposes of this Application, it has been assumed that RCID will install a combined cycle unit and purchase short-term power to satisfy the 2011 capacity requirement.

The City of Tallahassee is the principal retail supplier in Tallahassee, Florida. It relies on existing and committed capacity resources (including purchased power) as described in Section E.2.0. The City of Tallahassee maintains a 17.0 percent reserve margin. The City of Tallahassee is expected to encounter a capacity shortfall in the summer of 2011, at which time approximately 22 MW of additional capacity will be required. The capacity shortfall is projected to increase to 34 MW in 2012. For purposes of this Application, it has been assumed that the City of Tallahassee will satisfy the 2011 capacity requirement either through a short-term capacity purchase agreement or through installation of a simple cycle combustion turbine as described in Section E.5.0.

TEC will be a 765 MW (net) supercritical coal unit that will be developed on a site consisting of approximately 3,000 acres to be located approximately 5 miles southeast of Perry, in Taylor County, Florida. The land is bordered by Highway 27 on the north and the Fenholloway River on the west. TEC will include one coal fired boiler, one steam turbine generator with efficient steam cycle, a cooling system, water and wastewater treatment systems, material handling systems, air quality control systems, electrical interconnections, and other balance-of-plant systems. TEC will burn a blend of petcoke and coal, with the ability to burn coal sourced from various regions including Latin America, the Powder River Basin (PRB), and the Central Appalachia region.

The Participants went through a multistage evaluation process to develop the most cost-effective generation expansion plan that would meet the corresponding need for capacity for each Participant. The first step involved developing detailed cost and performance estimates for TEC. The detailed description of the TEC project and the development of the cost and performance estimates are presented in Section A.3.0.

The second step involved the development of cost and performance estimates for numerous supply-side alternatives to TEC. Supply-side alternatives were developed in the following categories: renewable technologies, conventional technologies, advanced technologies, energy storage technologies, multi-fuel generation technologies (distributed generation), and emerging technologies. Supply-side alternatives also included units specific to each Participant, using available existing sites as well as other joint ownership alternatives.

The evaluation of supply-side alternatives was extensive. Eighteen renewable technologies were evaluated in the following areas:

- Solid biomass.
- Biogas.
- Waste-to-energy.
- Wind.
- Solar.
- Geothermal.
- Hydroelectric.
- Ocean.

The conventional alternatives evaluated included simple cycle, combined cycle, circulating fluidized bed (CFB), and TEC. The simple and combined cycle alternatives evaluated included aeroderivative, E-class, and F-class in order to consider the full range of performance and size. Emerging technologies including the GE LMS100 combustion turbine, integrated gasification combined cycle (IGCC) alternatives, and advanced design nuclear alternatives were also considered. Six advanced alternatives were evaluated in detail in the following categories:

- Advanced gas turbine technologies.
- Fuel cells.
- Advanced coal technologies.

Three energy storage and two multi-fuel or distributed generation technologies were also evaluated. All supply-side alternatives are discussed in Section A.6.0.

All supply-side alternatives were screened for economics, feasibility, and reliability for use in each Participant's system. The screening process resulted in a wide range of alternatives being selected for further detailed economic evaluations and sensitivity analyses, including simple cycle combustion turbines, combined cycle, pulverized coal (including participation in TEC), CFB, biomass, and an IGCC. Details of the evaluation of the supply-side alternatives and their screening are contained in Section 5.0 of Volumes B through E.

The third step in the evaluation process to determine the most cost-effective expansion plan for each Participant involved conducting a request for proposal (RFP) process for purchase power in lieu of the installation of TEC. An overview of the RFP process is included in Section A.7.0. JEA administered and issued the RFP on behalf of the Participants on November 28, 2005. The RFP requested purchase power bids from 100 to 750 MW for contract terms of 10 years or more (the RFP and the accompanying fuel prices are presented in Appendix A.1). The Participants received two bids (one from a coal fired power plant and one from a combined cycle plant) from one bidder (Southern Power Company, or Southern). Both bids were substantially higher in cost than TEC. A summary of the bid evaluation is presented in Section A.7.0.

The fourth step in the evaluation process was to conduct a detailed system evaluation of self-build and purchase power alternatives. Economic assumptions and fuel price forecasts were developed for base case and sensitivity analyses as discussed in Section A.4.0. A chronological optimal generation expansion model was used to determine the least-cost expansion plans for the self-build and purchase power alternatives. The evaluation was conducted over a 30 year planning period from 2006 through 2035. The least-cost expansion plans for each Participant determined by the optimal generation expansion model were modeled using a detailed chronological production cost model to obtain annual production costs. Fixed costs, including fixed charges on new unit additions, purchased power capacity costs, fixed operating and maintenance (O&M) costs, and natural gas transportation charges for firm delivery of natural gas (for any new combined cycle alternatives), were added to the production costs to obtain annual costs. In addition, environmental considerations were factored into the analyses, including the forecast cost of emissions allowances for current and future regulatory requirements as discussed in Section A.5.0. The cumulative present worth costs (CPWC) of all of these annual costs were determined and used as the basis to compare expansion plans. Section A.8.0 presents the methodology used for the detailed system evaluations.

Table A.2-1 indicates that participation in the TEC represents the least-cost capacity expansion plan for each Participant when compared to the most economical alternate self-build capacity expansion plans under base case assumptions. Additionally, Table A.2-1 indicates that participation in the TEC is lower in cost for each participant than either of Southern's purchase power proposals under these same base assumptions. Details of the system evaluation for the self-build and purchase power alternatives are presented in Sections 5.0 and 6.0 of Volumes B through E.

Numerous sensitivity analyses were performed for each Participant based upon variations of key assumptions related to fuel prices, load growth, capital cost, discount rate, emissions allowance prices, and the availability of supply-side alternatives. An expansion plan analysis was conducted for the sensitivity scenarios in the same manner as for the base case economic analysis. Details of the sensitivity analyses are presented in Section 6.0 of Volumes B through E.

Table A.2-1
CPWC Differential Summary for Each Participant – Base Case Economic Analysis

Participant	CPWC Differential ($000s)			
	TEC	Least-Cost Alternate Self-Build	Southern Coal Proposal	Southern Combined Cycle Proposal
FMPA	--	$403,534	$574,913	$691,166
JEA	--	$39,131	$487,096	$307,689
RCID	--	$270,814	$101,115	$202,527
City of Tallahassee	--	$152,585	$256,274	$414,251
Total		$866,064	$1,419,398	$1,615,633

The analyses of participation in the TEC also considered the potential cost-effectiveness of demand-side management (DSM) measures. Section A.9.0 describes the methodology used for each Participant in evaluating potential DSM measures to determine if there are cost-effective DSM alternatives that could mitigate the need for TEC. Section 7.0 of Volumes B through E discusses each Participant's DSM analysis in more detail and demonstrates that there are no available DSM measures that can cost-effectively mitigate the need for TEC for any of the Participants.

TEC is consistent with the needs of Peninsular Florida. TEC is needed to meet the increasing capacity requirements within Florida and to maintain adequate reserve margins within the state. Its high efficiency, supercritical pulverized coal generation will increase baseload generation and displace more costly oil and gas generation in the state. Its use of coal and petcoke will add to the diversification of fuels used for power generation within Florida. Details of the benefits to Peninsular Florida from the addition of TEC are presented in Section A.10.0.

Sections B.8.0, C.8.0, D.8.0, and E.8.0 discuss the strategic considerations associated with the addition of TEC for each Participant. The most important strategic considerations are the need for low cost baseload generating capacity and fuel diversity from coal and petcoke fuel.

Sections B.9.0, C.9.0, D.9.0, and E.9.0 discuss the consequences of delaying the installation of TEC. A 1 year delay in commercial operation of TEC would result in estimated increases in CPWC of $25.9 million for FMPA, $41.7 million for JEA, $25.5 million for RCID, and $4.4 million for the City of Tallahassee for a total of $97.5 million for the four Participants as compared to the May 1, 2012 commercial operation date of TEC.

Finally, Sections B.10.0, C.10.0, D.10.0, and E.10.0 demonstrate that each Participant is fully capable of financing the construction costs associated with TEC. All Participants currently have excellent bond credit ratings.

A.3.0 Project Overview

This section presents an overview of the proposed TEC, including a description of the Participants and an overview of the project site and technology, fuel supply, emissions control technologies, costs associated with the project, and project schedule.

A.3.1 Project Participants

The TEC is being proposed as a joint development project by four municipal utilities, including the FMPA, JEA, RCID, and the City of Tallahassee (the City, or Tallahassee). FMPA is a wholesale supplier to 15 city-owned electric utilities throughout Florida. JEA is a retail supplier in Jacksonville, Florida, and in parts of three adjacent counties. RCID is a retail supplier in parts of Orange and Osceola counties. Tallahassee is the principal retail supplier in Tallahassee, Florida. Collectively, the four utilities are referred to as the Participants throughout this Application.

The Participants are developing the proposed TEC to realize the benefits associated with the economies of scale inherent in constructing and operating a large power plant. Table A.3-1 presents each Participant's ownership percentage in TEC, with each Participant responsible for the costs associated with TEC in proportion to its individual ownership percentage.

Table A.3-1
Proposed TEC Ownership Percentages

Participant	Percent Ownership
FMPA	38.9
JEA	31.5
RCID	9.3
City of Tallahassee	20.3

A.3.2 Description of the Project Site

The TEC will be developed on a site consisting of approximately 3,000 acres to be located approximately 5 miles southeast of Perry, in Taylor County, Florida. The land is bordered by Highway 27 on the north and the Fenholloway River on the west. Though the TEC project consists of one unit, the site will be designed and constructed with consideration given to allowing the addition of a second unit. However, a second unit is not planned at this time.

Figure A.3-1 presents a conceptual site arrangement drawing, including the locations of the major equipment for TEC.

A.3.3 Overview of Project Technology

The TEC is proposed to be a 765 MW (net) supercritical pulverized coal unit. Coal is the most widely used fuel for the production of power in the United States, and most coal burning power plants use pulverized coal boilers. Pulverized coal units have the advantage of utilizing a proven technology with a very high reliability level and can utilize large domestic coal reserves as well as international sources of solid fuel. They can be sized very large, and the economies of scale can result in low busbar costs. Pulverized coal units are relatively easy to operate and maintain.

New generation pulverized coal boilers can be designed at supercritical steam pressures of 3,206 to 4,500 pounds per square inch gauge (psig), compared to the steam pressures of 2,400 psig for conventional subcritical boilers. This increase in pressure raises the overall efficiency. This increase in efficiency comes at a slightly higher capital cost, however, and the economics of the decision between subcritical and supercritical design depend on the cost of fuel, plant size, and other factors such as the expected capacity factor of the unit and the cost of capital.

The TEC will include one boiler, one steam turbine generator with efficient steam cycle, a cooling system, water and wastewater treatment systems, material handling systems, air quality control systems, electrical interconnections, and other balance-of-plant systems. TEC will consist of the following core technologies:

- 765 MW (net) supercritical coal fired boiler.
- Zero liquid discharge (ZLD) facility.
- Reverse air baghouse.
- Wet, forced oxidation flue gas desulfurization (FGD) system using limestone reagent.
- Wet electrostatic precipitator (WESP).
- Selective catalytic reduction (SCR) system.
- No. 2 oil fired auxiliary boiler and emergency generator.

Other considerations that will be incorporated into the design of TEC include the following:

- Enhanced distributed control system (DCS) with neural network, performance monitoring, and simulator.
- Initial construction that will include landfill area to store 8 years of combustion byproducts, with space reserved for 30 years.

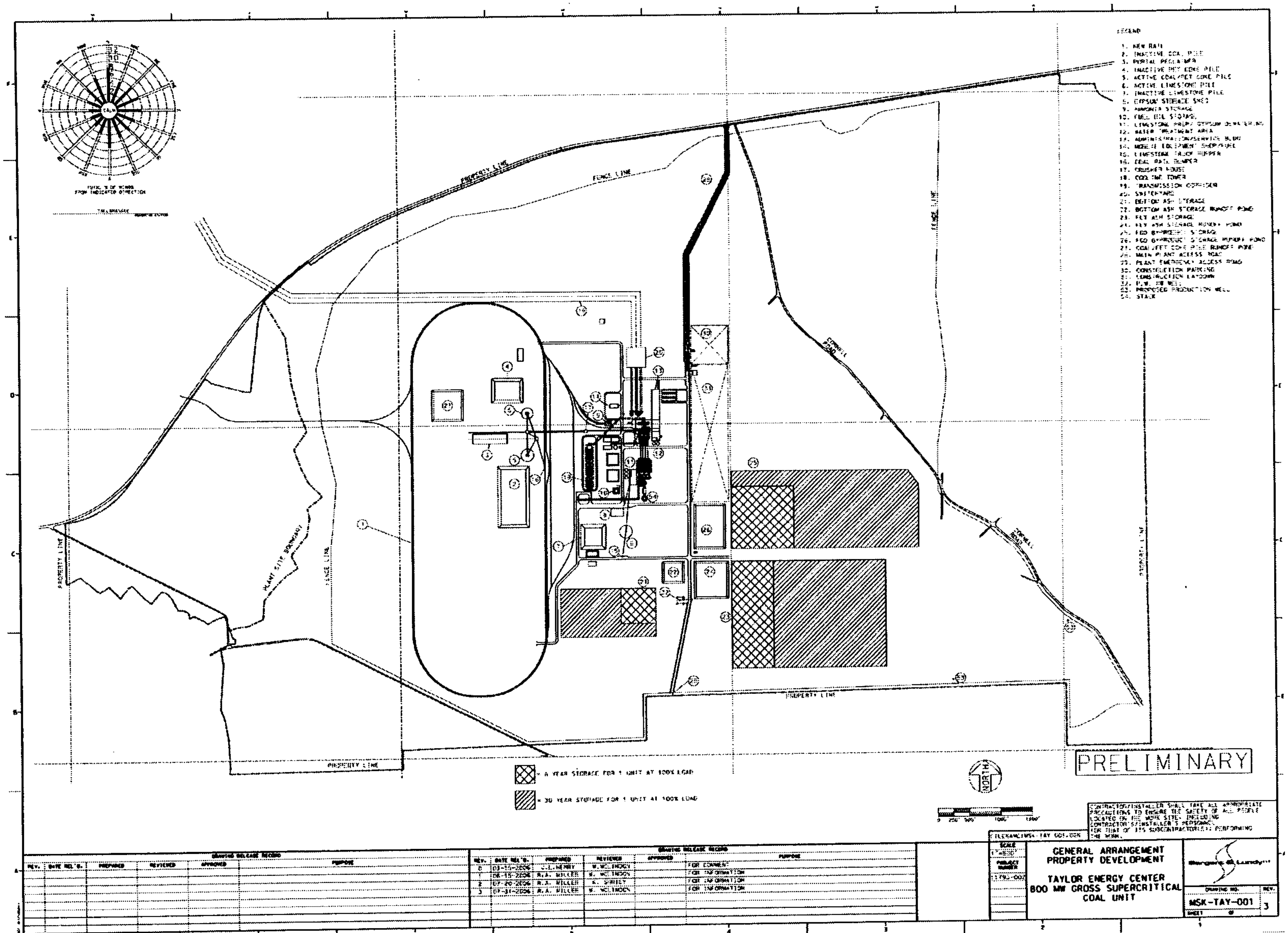


Figure A.3-1
Conceptual TEC Site Arrangement Drawing

- Additional 5 feet of fill and wetland mitigation.
- Foundation piles.
- 3.5 mile Georgia-Florida rail extension to the proposed site, including Route 27 and Fenholloway River crossings.
- Upgrades to plant access roads with acceleration and deceleration lanes.

TEC will have the best available control technologies for air quality control systems, including the following:

- SCR to limit nitrogen oxide (NO_x) emissions from the plant.
- A reverse air fabric filter baghouse to limit filterable PM_{10} particulate emissions.
- A single-tower wet FGD absorption system to remove approximately 97 percent of sulfur dioxide (SO_2) from the flue gas stream.
- A WESP to collect particulate, hazardous air pollutants in particulate form, and acid mists.

Mercury (Hg) emissions will be controlled through the co-benefits of the air quality control equipment mentioned above.

A.3.3.1 Boiler

The outdoor-type, supercritical boiler will be a once-through, balanced draft, single reheat unit capable of firing a blend of pulverized coal and up to 30 percent petcoke. The boiler will be designed for an outdoor installation and will be approximately 280 feet high. Design steam conditions will be 3,600 psig with 1,050° F main steam temperature and 1,100° F reheat steam temperature. The boiler will be the dry-bottom type with low NO_x burners and overfire air ports. Boiler draft will be provided by two 50 percent radial forced draft fans and one primary air fan per pulverizer mill.

A blend of crushed coal and petcoke will be delivered to the boiler building day bins. Fuel will be discharged to eight mills (with one as a spare) for pulverizing. Each mill will pulverize approximately 100,000 pounds per hour (lb/h) of fuel. Pulverized fuel will be blown into the boiler from the primary air fans. Low-sulfur No. 2 fuel oil or ultra low-sulfur diesel (ULSD), if available, will be utilized for startup fuel. Startup fuel oil will be provided to the boiler from a 300,000 gallon field erected fuel oil storage tank.

TEC will be designed with an auxiliary boiler burning low-sulfur No. 2 fuel oil, or ULSD, if available. The auxiliary boiler will be designed to provide steam during startup and low load operation. Auxiliary steam generated by the auxiliary boiler will also be used to support boiler hydrostatic testing and chemical cleaning during startup. Based on preliminary design criteria, one auxiliary boiler rated for 220,000 lb/h steam at 233 psig will be provided.

A.3.3.2 Steam Turbine and Thermal Cycle

TEC will include a single 765 MW (net) steam turbine generator. It will be located in an enclosed turbine building that will include a bridge crane for maintenance. The steam turbine is expected to include a high-pressure (HP) turbine, intermediate-pressure (IP) turbine, and a four-flow low-pressure (LP) turbine. Main steam from the boiler will flow through the main steam piping to the HP section of the steam turbine. Exhaust steam from the HP steam turbine will be returned to the boiler to be reheated before flowing to the IP turbine. Exhaust steam from the IP turbine will flow to the boiler feed pump turbine drives as well as the LP turbines.

Boiler feedwater will be provided to the boiler through two 50 percent turbine driven boiler feed pumps. A startup electric motor driven boiler feed pump with variable frequency drive will be used for startup and backup. This pump will also be 50 percent capacity. The cycle will include four stages of LP feedwater heating, a deaerator, and three HP feedwater heater stages. The feedwater heaters will utilize stainless steel tubes, 304SS tubes for LP feedwater heaters and 304N tubes for the HP heaters. LP Heaters 1 and 2 will be located in the condenser hood. LP exhaust steam will be condensed in a two-shell, two-pass condenser with titanium tubes. The thermal cycle would be conventional for large supercritical pulverized coal plants.

A.3.3.3 Cooling System

The circulating water system will consist of a surface condenser, a cooling tower, circulating water pumps, and supply and return circulating water piping. The heat dissipation system will include a mechanical draft wet cooling tower, which will use groundwater as makeup and will be a closed loop system. The cooling tower will be a conventional multi-cell, counterflow, back-to-back style mechanical draft, wet cooling tower. Circulating water and auxiliary water cooling pumps will take suction from the concrete cooling tower basin. The cooling tower will be capable of handling brackish type waters and will be equipped with non-clog fill and drift eliminators.

A.3.3.4 Water and Wastewater Systems

The water supply for TEC will be provided from a system of wells, including one well on standby. The system will handle, on average, approximately 8.1 million gallons per day (mgd), with a maximum use of approximately 9.1 mgd. The total depth of each well will be approximately 400 feet. Each well will be spaced approximately 2,000 feet apart and will have a pumping rate of 3,300 gallons per minute (gpm). Raw well water will be piped to the power plant water treatment system. The filtration and demineralizer systems will provide makeup water to the boiler. Water treatment equipment will include a cartridge filter, reverse osmosis, cation exchangers, anion exchangers, and a degasifier. The demineralizer will be sized for one unit, but there would be space for a second demineralizer.

Wastewater will be produced from process boiler blowdown, cooling tower blowdown, miscellaneous plant drains, byproduct storage area runoff, and sanitary wastes. Various ponds will collect uncontaminated (non-contact) storm water on the site prior to discharge. Sanitary wastes will be treated in an onsite treatment facility or piped to the City of Perry sanitary system. Process wastewaters will be recycled as appropriate to the wet FGD system or sent to a ZLD brine concentrator. After separation of the solid waste, the water will be returned to the filtration process. As a result, no process wastewaters will be discharged offsite. The solid waste will be disposed of in an approved landfill. Figure A.3-2 presents the conceptual water mass balance for TEC, showing the summer maximum case water and wastewater flows.

A.3.3.5 Material Handling Systems and Storage

All solid fuel supplies will be delivered to the site by bottom dump railcars via a new rail spur approximately 3.5 miles in length. Unit trains consisting of between 115 and 135 cars, each containing up to approximately 120 tons, will deliver coal to the site. Onsite fuel storage will allow for up to approximately 90 days. Two reclaim hoppers will also be available for reclaim and blending of fuel. The active coal storage area will be enclosed in a building capable of storing coal for approximately 5 days of operation. Two portal reclaimers will be used to move coal and petcoke from the active storage building to the crusher house. Crushed coal will be conveyed to coal storage silos within the enclosed boiler building.

Conventional mechanical conveying systems will be used to collect and store bottom ash, fly ash, and scrubber byproducts. A drag chain conveyor will remove bottom ash from the boiler to a concrete bunker for removal by front end loader and truck. Fly ash will be collected and stored in a 72 hour storage silo, with truck removal for disposal or sale. Onsite storage provisions will be included for FGD waste, which may also be sold as commercial grade gypsum. The plant property will have space available to accommodate 100 percent of the solid waste by-products from the facility for 30 years if necessary, with approximately 8 years of storage initially available at commercial operation.

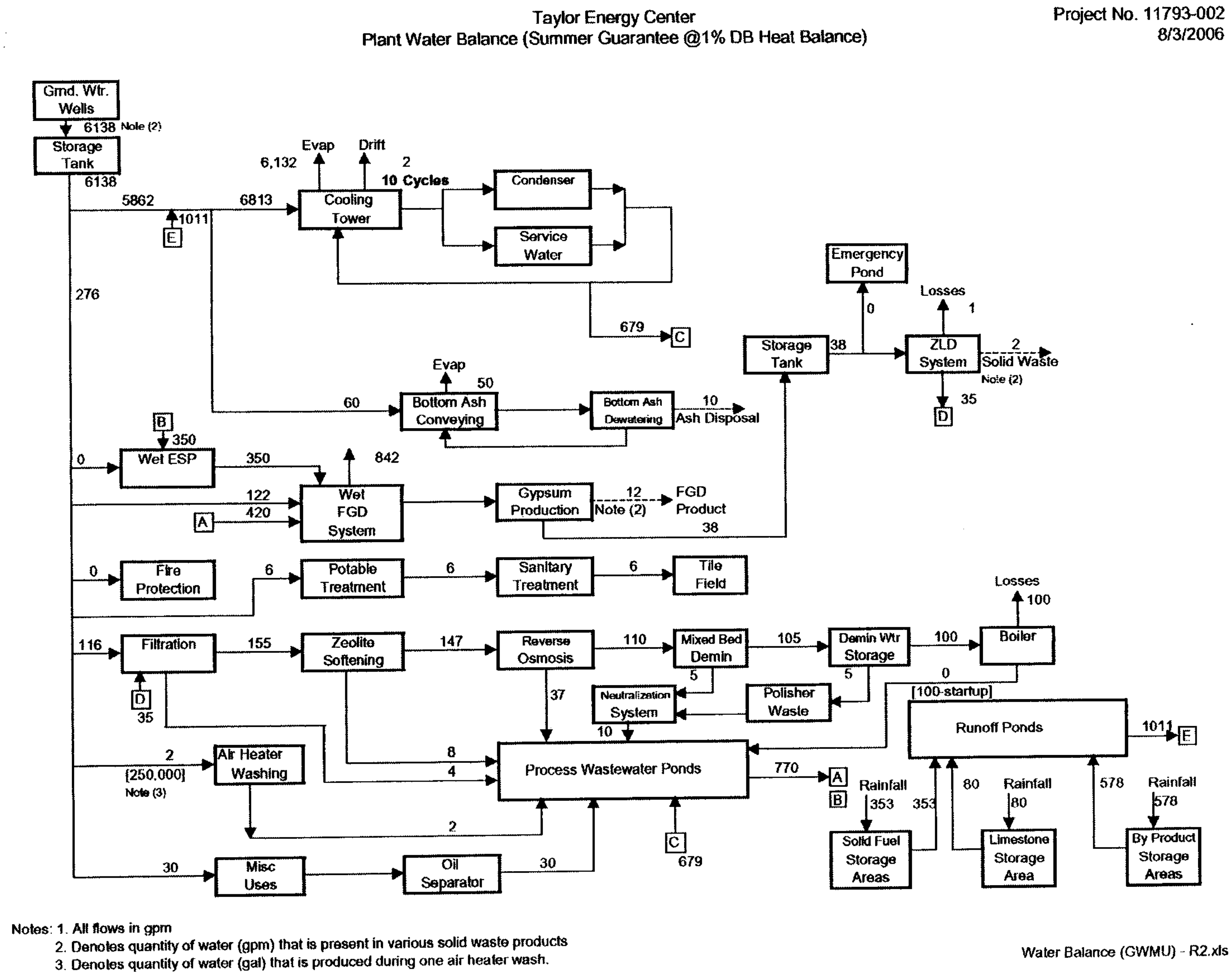


Figure A.3-2
Conceptual TEC Water Mass Balance

Limestone used as a reagent in the FGD system will be delivered to the site by 22 ton capacity haul trucks. TEC will have active and inactive limestone storage piles. The inactive limestone pile will contain about 90 days' supply of limestone. The active storage pile will be covered and will hold about a 10 day supply of limestone.

A.3.3.6 Air Quality Control Systems

TEC will have the best available control technologies for air quality control systems. SCR will be installed integral with the boiler and combustion controls to limit NO_x emissions from the plant. A reverse air fabric filter baghouse will be used to limit filterable PM_{10} particulate emissions. A single-tower wet FGD system will use limestone slurry absorption to remove approximately 97 percent of SO_2 from the flue gas stream. The FGD system will be designed to produce saleable gypsum byproduct. A WESP will be installed to collect particulate, hazardous air pollutants in particulate form, and acid mists. Treated flue gas will discharge from a concrete shell chimney. Hg emissions will be controlled through the co-benefits of the air quality control equipment mentioned above.

Four radial type induced draft fans connected in parallel will provide the draft to exhaust the flue gas from the boiler, SCR, and fabric filters and then force the gas through the FGD spray tower and WESP to the chimney. The chimney will have an outer concrete shell and an inner fiberglass reinforced plastic (FRP) liner.

Table A.3-2 summarizes the anticipated TEC emissions rates for three of the types of coal that TEC will be capable of burning, assuming each coal type is blended with 28 percent petcoke. The emission rates shown in Table A.3-2 are tentative pending air permitting.

A.3.3.7 Electrical Interconnection

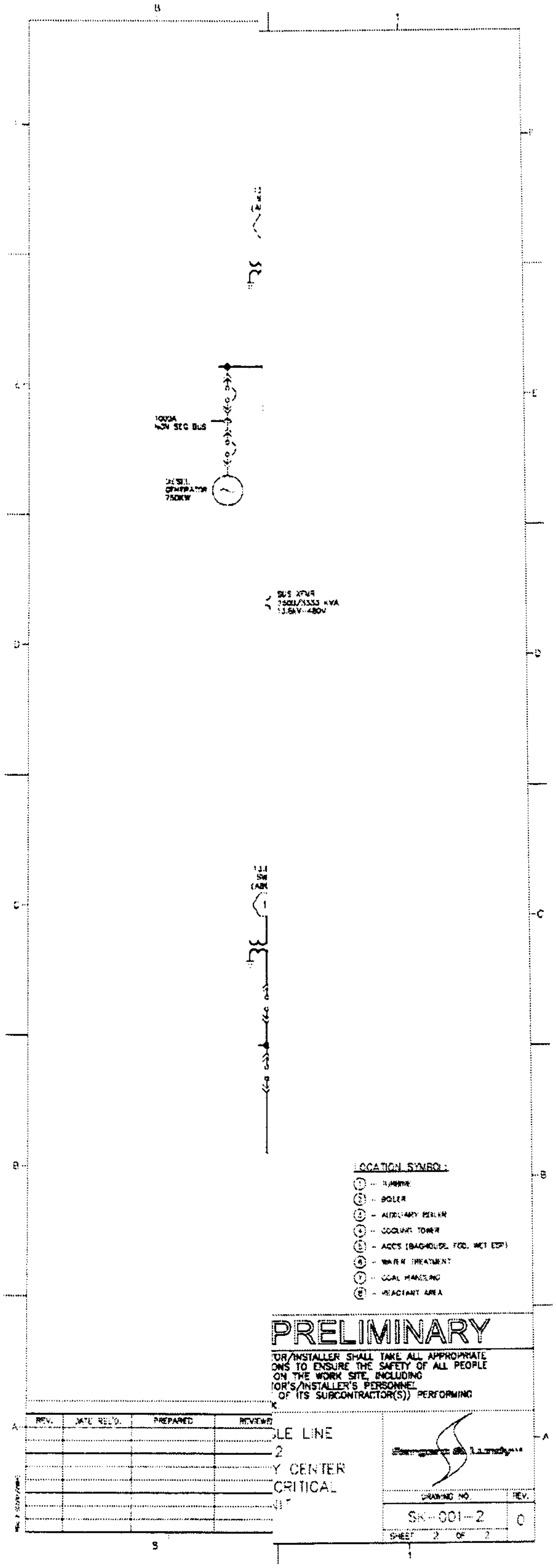
The proposed TEC site is located in the Progress Energy Florida (PEF) system and will connect to the PEF system at a 230 kV interconnection. Interconnecting the plant to the PEF system will be accomplished by PEF consistent with the requirements as set forth in Federal Energy Regulatory Commission (FERC) Docket RM02-1-000 and accompanying Order 2003. According to the FERC rule, PEF must complete a series of studies to determine the impact of the proposed TEC on the transmission grid and identify the new facilities and improvements that will be required to reliably integrate the plant into its system and deliver the output to the project owners. The overall purpose of those studies is the identification of any improvements needed to mitigate impacts on the transmission grid due to the TEC project. The identified improvements would be funded by the project Participants and installed by PEF before the project achieves its

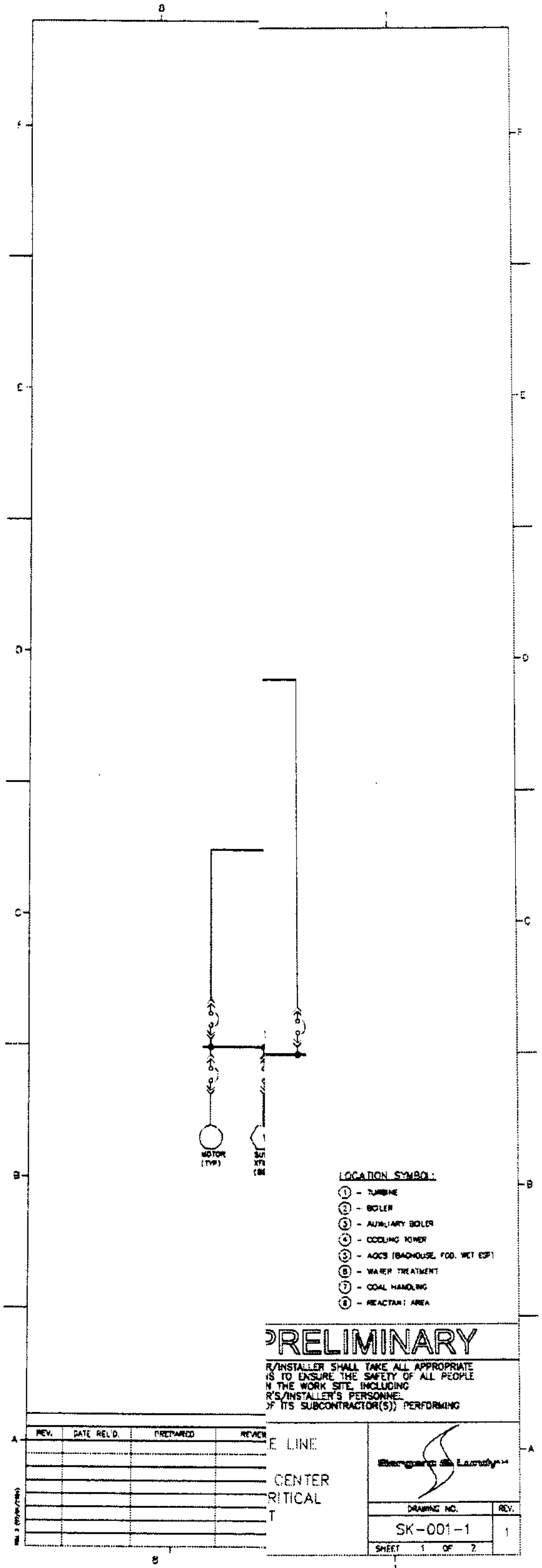
Table A.3-2 Anticipated TEC Emissions Rates by Coal Region (Assuming 28 Percent Petcoke Blend)			
	Coal Region		
Emission	Latin America	PRB	Central Appalachia
SO_2 (lb/MBtu)	0.09	0.09	0.09
NO_x (lb/MBtu)	0.07	0.07	0.07
Hg (lb/MBtu)	1.40×10^{-6}	1.90×10^{-6}	1.20×10^{-6}
CO_2 (lb/MBtu)	211	215	200
CO (lb/MBtu)	0.154	0.154	0.154
PM_{10} (lb/MBtu)	0.015	0.015	0.015
CO = Carbon monoxide. CO_2 = Carbon dioxide.			

commercial operation date (COD). The studies to be undertaken as part of the generator interconnection analysis are: (1) a feasibility study; (2) a system impact study; and (3) a facilities study. These studies are to be completed sequentially, and the total time for completion of all three studies is approximately 12 months.

The result of PEF's first study (the transmission feasibility assessment) indicated that under a variety of scenarios there is, in general, no major impediment to interconnecting the project to the transmission grid. As identified in that assessment, the simplest interconnection to implement would include 230 kV transmission lines from the site running 5.5 miles to the Perry substation (a PEF facility). The interconnection will most likely be designed, built, and operated by PEF. The switchyard onsite will be built for one unit, with space to expand for a second unit. Figures A.3-3 and A.3-4 show the arrangement of the TEC interconnection and auxiliary power systems.

The second step is a system impact study that will identify any impacts (overloads) on the PEF network associated with the plant and will recommend solutions that eliminate or mitigate those impacts. During this study, a preliminary interconnection plan (or plans) will be developed by PEF and shared with the project owners. This study is currently underway and is expected to be completed by September 2006. The objective of this study is to identify the impacts on the transmission system associated with the interconnection of the TEC project; those impacts will be fully mitigated through improvements identified by PEF in this study.


LOCATION SYMBOL:
2 - BOILER
4 - COOLING TOWER
8 - REACTANT AREA
PRELIMINARY
TOR/INSTALLER SHALL TAKE ALL APPROPRIATE
ONS TO ENSURE THE SAFETY OF ALL PEOPLE
ON THE WORK SITE, INCLUDING
TOR'S/INSTALLER'S PERSONNEL
OF ITS SUBCONTRACTOR(S)) PERFORMING
REV.
PREPARED
LE LINE
2
Y CENTER
CRITICAL
DRAWING NO.
REV.
SK-001-2
0
SHEET 2 OF 2


MOTOR (TYP)
LOCATION SYMBOL:
1 - TURBINE
2 - BOILER
3 - AUXILIARY BOILER
4 - COOLING TOWER
5 - AQCS (BAGHOUSE, FGD, WET ESP)
6 - WATER TREATMENT
7 - COAL HANDLING
8 - REACTANT AREA
PRELIMINARY
R/INSTALLER SHALL TAKE ALL APPROPRIATE
IS TO ENSURE THE SAFETY OF ALL PEOPLE
N THE WORK SITE, INCLUDING
R'S/INSTALLER'S PERSONNEL
OF ITS SUBCONTRACTOR(S)) PERFORMING
REV.
DATE REL'D.
PREPARED
REVIEW
E LINE
CENTER
RITICAL
T
DRAWING NO.
REV.
SK-001-1
1
SHEET 1 OF 2

The formal interconnection plan is to be developed as part of the third study and is not expected to be finished until early 2007. That plan may include other transmission corridors and facilities beyond the Perry substation to ensure grid reliability and full utilization of the TEC by the project owners. The result of this study is a list of the required facilities, the cost, and the anticipated time frame to interconnect the plant to the grid. Once that study is complete, the project owners would execute an agreement with PEF for funding of the facilities, and detailed design and engineering work would begin. It is anticipated that the PEF facilities and/or improvements will be ready by the time the plant is scheduled to be in service.

The costs for the interconnection and system improvements fall into one of two categories. The first involves direct interconnection costs, that is, costs directly associated with the interconnection of TEC that provide no benefit to the transmission network other than the interconnection of TEC to the network. The second cost category involves network upgrades and improvements that will benefit the transmission network. The categorization of the costs identified in the formal interconnection plan is determined as part of the formal interconnection plan. Since the formal interconnection plan has yet to be completed, the categorization of the costs and their magnitude is not known. For evaluation purposes, the direct interconnection costs were assumed to be those for the 5.5 mile 230 kV transmission lines to Perry substation. The estimated cost for these lines (developed by Sargent & Lundy) is included in the TEC capital cost in Table A.3-5. The cost for the network upgrades and improvements will not be known until the formal interconnection plan has been completed. These costs will be paid for by the project Participants, but their payments will be refunded through credits, including interest to their transmission service costs. Thus, only the transmission service costs have been included in the economic evaluations.

A.3.3.8 Emergency Diesel Generator

An emergency generator will be provided to supply power to the essential service motor control centers during an interruption of the electrical power supply to the site. Typical essential service loads include turbine and boiler feed pump turning gear motors, critical oil pumps, air preheater recirculating pumps, hydrogen side seal oil pumps, flame detector cooling air fans, air heaters, building heat and fuel supply systems, plant communication systems, and essential emergency lighting. Based on preliminary design criteria, the size of the emergency generator will be approximately 1,640 kW. The emergency generator will fire ultra low-sulfur diesel fuel (maximum sulfur content of 0.05 percent and a maximum ash content of 0.25 percent) and will be designed with advanced combustion modifications, including retard timing, to minimize potential NO_x emissions.

A.3.4 Fuel Supply

TEC will be capable of using a wide variety of coals, as well as coal and a coal/petcoke blend of up to approximately 30 percent petcoke. On an annual basis, the quantity of solid fuel used at TEC will be in the range of approximately 2.1 to 2.8 million tons, depending on the unit's annual capacity factor and the source of fuel. The solid fuel can be sourced from multiple locations with alternative transportation options, thus increasing the overall reliability of the fuel supply to TEC. Startup fuel will be low-sulfur fuel oil or ULSD, if available.

A.3.4.1 Fuel Procurement and Delivery

The Taylor Energy Center Fuels Committee (TEC Fuels Committee, or TEC Fuels), which consists of representatives of each of the Participants, is responsible for developing and implementing strategies for fuel procurement and delivery to TEC. Competitive bidding will be utilized to the extent possible to obtain fuel and transportation services. RFPs for fuel and transportation services will be issued after all necessary permits have been obtained for the project and sufficiently prior to commercial operation to ensure that a reliable fuel supply will be available to TEC. Details of the planned fuel procurement and delivery strategy are presented below.

The present strategy calls for maximum flexibilities in the sourcing of fuels from various US and foreign production regions to achieve maximum intra-supplier competition in future years. Similarly, planning calls for maximum flexibilities in the transport logistics for the movement of coals from source points to the TEC.

The TEC Fuels Committee recognizes that the narrow economic differences that currently exist for competing coal and petcoke alternatives indicate that no clear total energy cost alternative is likely to exist over the life of the TEC. Furthermore, the flexibility of the designs of the boiler and associated emissions control systems will allow opportunities for the switching of coal sourcing and transportation linkages in the future. This will allow increased leverage in future negotiations for both fuel supply and transport services.

The TEC Fuels Committee's strategy focuses on taking advantage of this opportunity for fuel flexibility by establishing a plan that creates and exploits competitive opportunities in the marketplace. Throughout the life of the project, TEC Fuels' objective will be to promote competition between supply source regions, between suppliers within each region, between transport modes, and between transport service providers within each mode. For example, when it is economical to do so, oceangoing vessels may be used to provide partial delivery of coal and petcoke to TEC as an alternative to complete reliance on rail transportation. In addition, the TEC Fuels

Committee will require multiple rail carriers to compete to supply service to TEC. Another key element of the fuel strategy is to use the competitive bidding process to evaluate all fuel options based on the "as-fired" cost to TEC so that a comparison can be made between fuels having different quality, combustion performance, and emissions potentials. This procurement process will offer supply opportunities to all viable suppliers, thus providing TEC with access to a full range of solid fuels from both international and domestic sources.

The TEC Fuels Committee's initial focus in the development and implementation of the fuel strategy is on the procurement and logistics to deliver solid fuels to TEC. These solid fuels (coal and petcoke) will constitute the overwhelming bulk of fuels – both in economic and performance/reliability terms – over the life of TEC. Other items will ultimately be addressed, including the procurement and delivery of limestone and No. 2 fuel oil for startup, and consideration of railcars to support the fuel plan. The delivered fuel costs presented in Section A.4.0 are based on and include costs for carrier-owned cars. Ultimately, TEC may purchase some or all of the railcars necessary to deliver fuel to TEC, leveraging low cost tax exempt municipal financing to further lower costs.

This fuel strategy provides reasonable flexibility to periodically change fuel sources and delivery modes to maintain competitive pricing and take full advantage of the capability of the TEC unit design to burn a wide range of solid fuels.

A.3.4.2 Identification of Potential Fuels and Sourcing Regions

The following coal/petcoke production regions have been identified as potential sourcing points for the TEC and are more fully discussed in Section A.4.6. Based on the delivered fuel cost projections in Section A.4.0, a blend of Latin American coal and petcoke would result in the lowest production costs for TEC. The next lowest production costs for TEC result from a blend of PRB coal and petcoke:

- Latin American Coals. Principal sourcing identified at this time includes South America (Colombia and Venezuela). Bituminous coal produced in these regions has low-cost linkages to deep water port facilities for ocean vessel delivery to rail-served ports in Florida or adjacent states. Sourcing is projected to expand in the future as new production areas become available.
- Petcoke. Principal sourcing identified includes production from both domestic (Gulf Coast) and foreign (primarily Caribbean) refining regions with ocean vessel deliveries to rail-served ports in Florida or adjacent states.

- PRB Coals. Principal sourcing identified is the subbituminous coal region, with primary production centered in two counties of eastern Wyoming, with secondary production areas located in southeastern Montana.
- Central Appalachia Coals. Principal sourcing identified is the bituminous coal production region of eastern Kentucky, southern West Virginia, the western counties of Virginia, and portions of central Tennessee.

These coal and petcoke production regions, along with a summary description of transport linkages to the TEC, are further described in the following subsections.

A.3.4.3 Rail Service to the TEC Site

Rail service to the TEC site will be provided by a spur-line extension from an existing rail line – the Georgia & Florida Railroad (GFRR). The GFRR is a Class III short line operating over approximately 84 miles of trackage extending between Adel, Georgia (north end) and a paper mill complex at Foley (southeast of Perry), Florida[1]. The GFRR interconnects with the two major eastern Class I railroads – CSX Transportation (CSXT) and Norfolk Southern (NS) Railway at the following locations:

- NS at Albany and Adel, Georgia.
- CSXT at Quitman, Georgia and Greenville, Florida.[2]

CSXT has trackage rights over the GFRR between Quitman, Georgia and Perry, Florida.

Rail movements to the TEC site will entail the utilization of high efficiency unit trains comprised of aluminum body, steel carriage air-door hopper railcars designed for up to approximately 120 tons of coal per car, in trains ranging between 115 and 135 cars

[1] The GFRR is currently owned and operated by OmniTRAX, Inc., an affiliate of the Broc Companies, Inc., which operates a number of short-line railroads across the United States and Canada. The GFRR is comprised of two segments – the former Georgia Northern Railway (GN) line between Albany and Adel, GA and the former Live Oak, Perry and South Georgia Railroad between Adel, GA and Perry-Foley, FL. The GN was merged into the Georgia Southern and Florida Railroad in late 1993, and became part of the Georgia and Florida Railway shortly thereafter. Up until 1994, the Adel, GA to Perry-Foley, FL line was the Live Oak, Perry and South Georgia Railroad. It was the Georgia & Florida Railroad for a short period (1994-95) then resold to North American Rail Net, Inc. (1995-2005) until North American RailNet was merged into OmniTRAX. The current name is the Georgia & Florida Railway; however, in this Application, it is called by its better known name - the Georgia and Florida Railroad - and acronym "GFRR."

[2] The east-west CSXT Thomasville-to-Waycross/Savannah, GA mainline crosses the north-south GFRR at grade at the southeast corner of Quitman, GA. Wye connection legs are in place for southbound to west and eastbound train movements. Loaded train movements from Thomasville or Valdosta interchanging to GFRR will require the construction of new southbound wye trackage legs to accommodate direct run-through train operations. Similarly, the east-west CSXT Tallahassee-to-Jacksonville mainline crosses the north-south GFRR line at grade in downtown Greenville without interconnection. An interconnection between the carriers would require the construction of new east-to-southbound and west-to-southbound connector wye legs.

in length. Unloading of the unit trains will utilize a high-capacity railcar receiving system. This system will have a nominal rated capability of approximately 4,000 tons per hour. The projected unloading time for a unit train will be about 5 hours.

The following subsections demonstrate the reliability of coal supply at the mines and the ability of the rail transportation infrastructure to reliably deliver coal to the TEC.

A.3.4.4 Latin America Coals and Petcoke

The coal would move by deep-draft ocean vessel to a US Gulf or Atlantic Coast port for terminaling and forwarding by rail to the TEC site. The petcoke would move by deep-draft ocean vessel or barge to a US Gulf or Atlantic Coast port for terminaling and forwarding by rail to the TEC site. The current preferred purchase strategy is to contract for Latin American coal and petcoke delivered to a US port by the fuel supplier(s). This arrangement eliminates the need for international shipping contracts and the associated risks, while preserving pricing competition. It is in the best interest of prospective suppliers to provide fuel deliveries to a US port location designated by TEC at the lowest possible cost. Contractual arrangements may range from single-shipment vessel charters to multi-year term contracts, depending upon future market conditions.

Colombian and Venezuelan source regions have been identified as the most likely international supplies of coal. Deliveries of coals destined for TEC will require that the product first be delivered to a port facility located in the southeastern United States. Movements from the foreign ship loading ports will be by Handymax or Panamax Class vessels moving directly to deep-draft US port locations. At these ports, the vessels will be off-loaded and the coals stored onsite (in-transit storage) for subsequent reloading into railcars for forwarding in unit train service directly to TEC.

Colombia and Venezuela are the largest sources of imported steam coals into the United States in recent years. These are relatively high quality coals with as-received high heat contents and low sulfur contents. These coals are the fuels of choice for eastern US and Gulf Coast utilities and plants that have steam generation and flue gas cleanup systems designed for Central Appalachian coals, because the coals can be burned with minimal impacts on steam-raising equipment and operations.

Colombia and Venezuela collectively produce about 80 million short tons (2005) of coal, with in-place recoverable reserves exceeding 6 billion tons. Production is rapidly ramping up to meet world demand for this coal. These coals are projected as being the import coals of choice in future years because of their high quality and short ocean-transport distances to US Gulf and Atlantic Coast ports. Demand for the coals will be especially strong from Mid-Atlantic and New England utilities that have older generating facilities without cleanup systems, these utilities are facing increasing restrictions on flue gas emissions.

Historically, the primary markets for Colombian and Venezuelan coals have been European utilities. Movement into the United States has peaked when European pricing and demands have slackened. However, starting in late 2003 with the recent dramatic increases in the pricing of eastern US sourced coals, utilities started looking in depth at alternative sourcing, including imported South American coals. The increase in demand for export coals (both metallurgical and steam grades) is being driven by increased procurements by expanding third-world economies (primarily China and India) and has resulted in an interesting and unprecedented phenomenon of simultaneous increases in both exports of US-produced coals and imports of foreign coals – often through the same port.

Petcoke is a waste or byproduct of the oil-refining process. As such, it has no meaningful "cost of production" by which to gauge value. Historically, the bulk of petcoke (approximately 59 percent in 2005) produced in the United States has been sold overseas (primarily in European markets) to domestic industrial users. This has been a fuel of opportunity, depending upon locations of the supply and use points and the connecting transport linkages. For these and other reasons, petcoke prices have historically been quite variable, but usually low cost on a dollar/MBtu basis compared to other fuels such as coal and natural gas.

Potential sourcing of petcoke for supply to TEC will include existing and future refinery/coker facilities that have direct or short-haul rail access to deep water ports located on the US Gulf Coast (Louisiana and Texas), in the Caribbean, and on the Atlantic Coast of Mexico and South America. Projections call for about 35 million metric tonnes per year of new coke-making capacity to be installed worldwide in the period between 2006 and 2010. This rate of addition to petcoke production capacity is approximately six times the growth rate between 1995 and 2000. Approximately 60 percent (21 million tonnes) is forecasted to be installed in the period between 2006 and 2008

Other sources of foreign coals and possibly petcoke for TEC are likely to appear in future years. These may include Russia, South Africa, and Indonesia. While imports to the United States from these regions are relatively limited at the present time, the establishment of expanded in-place port and terminaling facilities for the receipt and rail forwarding of imported coals offers maximum fuel procurement flexibility for TEC in the future.

A.3.4.5 Port and Terminal Facilities for Imported Coals and Petcoke

The size and loaded draft of the ocean vessels delivering coal or coke to US ports will be limited by the physical size and draft limitations of each facility. Potential port locations and limiting conditions are presented in Table A.3-3.

Table A.3-3
Potential Port Locations and Limiting Conditions

Location	Limiting Draft (feet below MLW)	Limiting Deadweight Tonnage (metric tonnes)	Railroad Carrier
Jacksonville, FL Port Authority (JPA)	38	70,000	CSXT, NS
St. Johns River Northside Generating Station	38	70,000	CSXT
Mobile, AL McDuffie Coal Terminal	45	170,000	CN, BNSF, CSXT
Tampa Bay, FL TampaPlex Terminal (TPT)	40	100,000	CSXT
Lower Mississippi River International Marine Terminal	48	170,000	None
Lower Mississippi River TECO Bulk Terminal, LLC	48	170,000	None
Port St. Joe, FL	12	3,300	AN

The coal port at Jacksonville, Florida is prospective at this time. The Jacksonville Port Authority (JPA) has expressed an interest in the development of a bulk terminal facility at the site of a former Jefferson Smurfit paperboard mill, located along the St. Johns River near Talleyrand Avenue and to the north of the existing Talleyrand Marine Port. The 91 acre property is owned by Jax Maritime Partners. Under current JPA plans, the site would be acquired by JPA through eminent domain processes. JPA has indicated that the acquisition is part of a long-term expansion of the Talleyrand port facilities to accommodate its future needs for additional container, general cargo, and import automobile landside facilities, as well as for a new bulk materials terminal. JPA has revealed a memorandum of understanding (MOU) calling for Drummond Coal Company (Drummond) to be the operator of the bulk terminal portion of the new facilities. NS has been reported to be the preferred rail carrier to transport coal from the facility.

As a competing project, a 61-acre parcel of the site has reportedly been purchased from Jax Maritime Partners by Keystone Industries, LLC (Keystone), a subsidiary of Keystone Coal Company. Keystone has disclosed plans to develop the property as a 6 million tons per year throughput bulk terminal, independent from the JPA arrangements. Under Keystone's plan, both NS and CSXT (via interchange from NS as the carrier serving the port facilities) would have rights to originate rail coal shipments from the terminal facilities.

The Northside Generating Station terminal facility located on the St. John's River in Jacksonville, Florida is an existing pier and terminaling facility that is owned and operated by JEA. This facility includes a rail-mounted ship-unloader capable of efficiently unloading Panamax class vessels and an overland conveyor linkage to the fuels stockyard of JEA's Northside Generating Station. The terminal facilities are employed by JEA to deliver petcoke, coals and limestone for the Northside Station.

There is presently only limited rail capability and no handling and railcar loadout systems in place for rail forwarding of coals from the Northside Station. There is space at the adjacent SJRPP Station for the development of coal storage and rail loading facilities. These facilities would take advantage of coal yard area space and the existing rail spur line from the CSXT branch line serving the SJRPP Station. The Northside Generating Station is solely owned by JEA, and the SJRPP Station is jointly owned by JEA and Florida Power & Light. As such, JEA, one of the TEC Participants, has ownership interests such that the existing port facilities could be used for supplying TEC. It is anticipated, however, that one or more of the above alternative port facilities will be developed and available for TEC. The delivered fuel cost projections in Section A.4.0 are based on the use of a port in Jacksonville. Other ports available to serve TEC are described below.

The McDuffie Terminal on Mobile Bay is owned and operated by the Alabama State Docks Department – Port of Mobile, Alabama and is a long-established facility for the export of coals. In recent years, it has expanded to accommodate the inbound movement of bulk commodities, with the addition of two rail-mounted gantry crane type ship unloaders rated at 2,500 tons per hour. At present, inbound coal moves only to barges for transshipment on the Tennessee-Tomhigbee-Warrior River and Intra-Coastal Waterway Systems. Facilities for the efficient loadout of railcars in unit train shipments will require new development.

The TampaPlex Terminal on Tampa Bay, Florida has limitations in its ability to transload from vessels to railcars in terms of both ground areas for interim storage and sufficient space for the development of both trackage and railcar-loading facilities for originating unit train movements. This port location will require major upgrading of facilities to accommodate the throughput tonnage levels required by TEC.

The International Marine Terminal located on the Lower Mississippi River at MP 57 near Myrtle Grove, Louisiana is a terminal of long-standing, handling both export and inbound coal and other bulk commodities movements. The terminal has existing facilities for the unloading of large ocean vessels at both dockside and mid-stream locations. The unloading of vessels in the mid-stream of the river employs multiple cranes (Clyde-Whirley type units with clamshell buckets) mounted on barges. These units transfer the coals directly to barges for either upriver, intra-coastal, or cross-gulf movements. Alternatively, the barges move to adjacent barge docks for unloading and transfer of coal to ground storage for blending and subsequent reloading to cross-gulf or intra-coastal barges. The terminal has an advertised throughput capability of 12 million tons per year with capacity for expansion. The facility has provided transshipment services for the movement of coal to the Progress Energy Florida's Crystal River Station for more than 40 years.

Similarly, the TECO Bulk Terminal (Electro-Coal Transfer) located on the Lower Mississippi River at MP55 near Davant, Louisiana employs almost identical facilities and operations for terminaling of both inbound and outbound movements of coals and other bulk commodities. This terminal has an announced annual capability of 25 million tons and has been in service for more than 35 years, to transship imported coals in cross-gulf barge units to utility destinations in the Tampa Bay area of Florida.

Either or both of the Lower Mississippi terminals could be employed to transfer foreign-sourced coals from deep-draft ships to shallow-draft barges for forwarding to Peninsular Florida terminals, for reloading to railcars and forwarding to TEC.

The terminaling facilities at Port St. Joe, Florida were developed in the early-1980s to serve the Seminole Station, which is owned and operated by Seminole Electric Cooperative, Inc. at Palatka, Florida. The facility was designed as a water-to-rail transfer for Illinois Basin coals (White County, Illinois) moving by barging down the Ohio-Mississippi Rivers (via Intra-Coastal Waterway movements) to Port St. Joe, Florida. The terminal facilities were originally owned and operated by Materials Transfer, Inc., a subsidiary of International Shipholdings Corporation. Installed facilities include a barge unloading system and ground area for pile storage of up to 200,000 tons of coal. The terminal also includes railcar loadout facilities to load unit coal trains for forwarding over Apalachicola Northern (AN) and CSXT to destinations in Georgia and Florida.

The Port St. Joe facility operated between 1982 and early 1999, when it was shut down due to economic considerations (i.e., lower delivered basis costs for Central Appalachian origin coals moving in all-rail CSXT movements). The port and terminaling facilities are under new ownership and retain the original name – Materials Transfer, Inc. (MTI). The installed facilities and equipment are in place, but are currently inactive except for sporadic movements of petcoke.

Under certain scenarios of future fuel sourcing for TEC, the Port St. Joe facilities could be a component in logistics movements for coals originating in the Illinois Basin (Ohio and Mississippi River movements) and for Intra-Coastal transshipments of imported coals and petcoke from deep-draft terminals located on the Lower Mississippi River on the Port of Mobile, Alabama.

A.3.4.6 Rail Linkages – Ports to TEC

Rail movements from the Jacksonville area port and terminaling facilities would employ CSXT as the originating carrier, with CSXT routing from Jacksonville via Baldwin, Lake City, and Live Oak, Florida to an interconnection with GFRR at Greenville, Florida. Continuation from Greenville, Florida to the TEC site would be over the GFRR.

Rail movements from the McDuffie Coal Terminal at Mobile, Alabama would utilize CSXT as the originating carrier, with unit trains routed eastward via Flomaton, Alabama, Pensacola, and Tallahassee to Greenville, Florida with GFRR continuation to TEC.

Rail movements from ports and terminals in the Tampa Bay area would employ CSXT routings via Plant City, Vitis, Ocala, and Starke to Baldwin, Florida then westward to an interconnection with the GFRR at Greenville, Florida.

Rail movement from the former MTI Terminal at Port St. Joe, Florida would employ the short-line Apalachicola Northern Railroad (AN) as the originating carrier, with movements interchanging to CSXT at Chattahoochee, Florida. CSXT would continue the movements via Tallahassee to Greenville, Florida, with forwarding by the GFRR to TEC.

The projected approximate one-way rail haulage distances for unit train movements of coals and petcoke from the alternative port locations to the TEC site are presented in Table A.3-4. The train movements assume the routings as outlined above, with ranges in mileages dependent upon alternatives in routings. The delivered fuel cost projections in Section A.4.0 assume water-borne delivery to Jacksonville with rail delivery to TEC.

Table A.3-4 Approximate Projected One-Way Haulage Distances to TEC	
Port Location	Approximate One-Way Distance
Jacksonville, FL - JPA Terminal	156.3 miles
St. Johns River – Northside Station	170.6 miles
Mobile, AL – McDuffie Coal Terminal	385.2 miles
Tampa Bay, FL – TampaPlex Terminal	333.6 miles to 404.0 miles
Port St. Joe, FL – MTI Terminal	220.0 miles

A.3.4.7 Powder River Basin

The next lowest cost as-fired source of fuel for TEC is subbituminous rank coal from the PRB of Wyoming and Montana blended with petcoke. The PRB is divided into two distinct subregions. The Northern Powder River Basin (NPRB) is comprised of mines located in Big Horn and Rosebud Counties of southeastern Montana. The four current mines are large-scale surface mining operations that produced about 37.8 million tons of coal in calendar year 2005. All mines are served by the Burlington Northern Santa Fe (BNSF) railroad as the originating carrier for rail movements. NPRB coals generally have a higher heating value than coals in the Southern Powder River Basin (SPRB), making them generally more desirable for rail hauls to destinations located in the upper Midwest. However, because of longer rail haul distances, higher sodium content and captive rail service from the BNSF, the NPRB coals generally do not compete with coals from the SPRB for movements to the southeastern United States.

The SPRB is centered in two counties (Campbell and Converse Counties of eastern Wyoming). Large-scale surface mines in these two counties produced approximately 390.3 million tons in calendar year 2005, which represents in excess of one third (on a tonnage basis) of all coals produced in the United States. This region is the "Saudi Arabia of coal" because the enormous availability of reserves, thickness of coal seams (which lie relatively close to the surface), and highly efficient mining practices contribute to economics of extraction that are unmatched in the world. Current production is from 15 very large mining operations (ranging up to 90 million tons per year from a single mine), which are owned or controlled by six companies or ownership combinations. Mines located in the southern portion of the basin are competitively served by the BNSF and Union Pacific (UP) railroads by means of the "Joint Line" (owned and maintained by both carriers with day-to-day operations and dispatch functions performed by BNSF). Six mines located within the northern portion of the region are served only by (and are captive to) the BNSF railroad.

The sizes of the individual surface mines located within the SPRB are enormous when compared to other mining operations throughout the United States and indeed throughout the world. The nine largest mine complexes produced between 19.5 and 88 million tons per operation in 2005. The three remaining small mines individually produced between 4 and 12.5 million tons in 2005. All 12 mines (together with three mines that are reopening) are ramping up production in 2006 to meet the projected increases in demand for SPRB coals. Given the enormous reserves and low costs of mining in the region, the expanded production discussed in Appendix A.2 is readily achievable.

Several issues associated with the BNSF-UP "Joint Line" limited rail transportation from the PRB in 2005. The completion of the triple tracking from Walker to Shawnee Junction and other improvements have resulted in significant improvements in rail capacity from the PRB to the point where unit train movements are relatively fluid (as of the third quarter of 2006) and are projected to continue to improve in the future.

With BNSF as the originating rail carrier in the PRB, the routing of unit train movements will be BNSF-direct to Birmingham, Alabama via Lincoln, Nebraska; Kansas City and Springfield, Missouri; and Memphis, Tennessee. At Birmingham, the trains will be interchanged to either CSXT or NS for continuation to TEC via one of the alternative routings described below:

- CSXT – Birmingham, Alabama to an interconnection with GFRR at Quitman, Georgia via Montgomery, Troy and Dothan, Alabama and Bainbridge and Thomasville, Georgia. Continuation over GFRR to TEC.
- CSXT – Bainbridge, Georgia via Tallahassee to an interconnection with GFRR at Greenville, Florida. Continuation over GFRR to TEC.
- NS – Birmingham, Alabama to an interconnection with GFRR at Adel, Georgia via Atlanta, Macon, and Cordele, Georgia. Continuation over GFRR to TEC.
- NS – Leeds, Alabama via Opelika, Alabama and Columbus, Americas, and Albany, Georgia to an interconnection with GFRR at Albany or Adel, Georgia. Continuation over GFRR to TEC.

The projected one-way haul mileage for the above BNSF-originated rail routings will range between 1,962 and 2,062 miles, depending on the locations of individual mines within the PRB and the CSXT/NS routing alternatives between Birmingham, Alabama and Adel/Albany and Quitman, Georgia or Greenville, Florida to the TEC site.

Assuming that UP is the originating rail carrier, the routing of unit train movements will be UP-direct to an interchange to CSXT or NS at either East St. Louis, Illinois or Memphis, Tennessee. The UP routing will be via Joyce, O'Fallons, Gibbon, and Hastings, Nebraska; Marysville and Topeka, Kansas; and Kansas City and St. Louis, Missouri. CSXT continuations from East St. Louis would incorporate a routing via Mt. Vernon, Illinois and Evansville, Indiana or, alternatively Vincennes, Indiana, then move south via Henderson, Kentucky, Nashville and Chattanooga, Tennessee to Atlanta, Georgia. From an interchange at Memphis, the CSXT routing continuation would move northwest to join the above route at Nashville, Tennessee and then move south and east to Atlanta, Georgia. From Atlanta, Georgia, the routing would follow the present-day Florida coal traffic unit train routing via Cordele and Waycross, Georgia.

NS movements from St. Louis would continue eastward via Mt. Vernon, Illinois and Princeton, Indiana to Louisville, Kentucky, then turn south to Atlanta, Georgia via Chattanooga, Tennessee, and a continuation to Adel, Georgia via Macon, Georgia. Routing over NS from Memphis, Tennessee would move eastward to Corinth, Mississippi, then either turn southeast to Birmingham, Alabama and Columbus, Georgia to an interchange with the GFRR at Albany, Georgia or, alternatively, continue eastward to join the above routing at Chattanooga, Tennessee.

The projected one-way haul mileages for the above UP-originated rail routings will range between 1,978 and 2,222 miles, depending on mine locations within the SPRB, the location of the point of interchange between UP and either CSXT/NS and the CSXT or NS routing alternatives via Columbus or Atlanta, Georgia to the GFRR interchange points and continuation to TEC.

As indicated, the NPRB and SPRB coals have enormous reserve and mining capabilities and the BNSF, UP, CSXT and NS rail systems provide multiple routing alternatives. The combination of very large-scale and low-cost mining coupled with competitive rail transportation over a multiple route rail network ensures a reliable and economical coal supply from the PRB coal region for TEC.

A.3.4.8 Central Appalachia

The Central Appalachia (CAPP) coal region has been the premier US coal production region since the late 19th century. It produces both high quality metallurgical grade coals for domestic and export markets and steam grade coals for a broad range of utility and industrial customers throughout the eastern United States. It has historically been the source for the overwhelming majority of domestic coal tonnages used by Florida utilities.

The CAPP is the most intensively mined coal region in the United States, with more than 750 mines listed in the federal Mine Safety and Health Administration

(MSHA) database. Many of the mine listings represent inactive operations. The remaining mines range in size from small-scale operations to large-scale mining complexes. The small-scale operations generally rely on third-parties or larger coal companies to aggregate and market the coals and, in many cases, to wash and tipple the coals through "fast-load" railcar loadout facilities capable of meeting the carrier railroad's requirements for unit train originations.

Mining operations are split between surface mining and underground mining technologies. Deep mines produce roughly 55 percent of total tonnages, with most individual deep mines producing less than 1.0 million tons per year. Surface mines are also relatively small, with larger tonnage operations ranging between 400,000 and 1.5 million tons per year with the largest operations in the 5 million ton per year range.

Production of CAPP coals is declining, with total tonnages of about 235.2 million tons in 2005. As discussed in Appendix A.2, a continuing drop in annual tonnages is forecast due to myriad factors, including a declining reserve base, more difficult and costly mining conditions, increasing environmental and permitting barriers to opening new mines, and shortages of skilled labor.

Both CSXT and NS provide rail service from numerous mines located within the CAPP coal region. Because of the mountainous nature of the region, each railroad serves a separate slate of mines – even though, in some cases, the rail lines may be in proximity as the "crow flies." Very few mining operations can offer rail originations on both carriers.

The CSXT railroad moves coal to Florida destinations by means of two rail corridors. Coal shipments originating in eastern Kentucky move westward over a network of branchlines to intercept the Cincinnati to Atlanta north-south spine corridor at Winchester and Corbin, Kentucky. From these points, shipments move south via Knoxville, Tennessee through Atlanta, Cordele, and Waycross, Georgia and Callahan, Florida to join the CSXT Savannah to Thomasville, Georgia rail corridor at Waycross, Georgia or, alternatively, continue southeastward to intercept the CSXT Jacksonville to Tallahassee east-west rail corridor at Baldwin, Florida. Unit train movements will then move west from Waycross via Valdosta, Georgia to interconnect to the GFRR at Quitman, Georgia. Alternatively, the trains would move west from Baldwin, Florida via Lake City and Live Oak, Florida to interconnect to the GFRR at Greenville, Florida. Unit trains would continue from either interchange point over the GFRR to TEC.

Alternatively, coals originating at CSXT-served mines in West Virginia, extreme eastern Kentucky, and the western counties of Virginia would move southward over the former Clinchfield mainline corridor between Ashland and Elkhorn City, Kentucky; St. Paul and Speers Ferry, Virginia; and Johnson City, Tennessee to join the above described

CSXT mainline at either Knoxville, Tennessee (via NS trackage rights over Johnson City to Knoxville) or alternatively at Atlanta, Georgia.

The above corridors located north of Baldwin, Florida are long-established routings for the movements of large tonnages of CAPP-sourced coals to CSXT-served utility plants in Florida. The Waycross-to-Quitman, Georgia and Baldwin to Greenville, Florida rail corridors historically have not carried any unit train coal traffic; however, the lines appear to be capable of supporting heavy-haul train operations with minimal upgrading. The rail lines are therefore fully capable of supporting the heavy-haul movements of loaded coal unit trains and have sufficient basic capacity to support any additional traffic imposed by TEC.

The projected one-way haul distance for the above CSXT routings will range between 690 and 1,235 miles, depending on mine locations within the CAPP coal region, alternatives in movement routings, and the point of interchange to the GFRR. Haulage distances from the most likely sourcing points located in eastern Kentucky will range from about 690 miles up to about 1,035 miles.

The NS railroad originates limited volumes of coals in central Kentucky and Tennessee over branchlines radiating from the NS Cincinnati, Ohio to Chattanooga, Tennessee north-south mainline corridor. Movements from mines with higher production tonnages located in eastern Kentucky, southern West Virginia, the western portion of Virginia, and east-central Tennessee move south and west over a second mainline corridor via Knoxville, Tennessee to Chattanooga, Tennessee. Movements from both originating corridors would continue south from Chattanooga via Macon and Cordele, Georgia to interconnect with the GFRR at Adel, Georgia. The GFRR would forward the unit train shipments southward to TEC.

One-way rail haulage distances for NS-sourced loadout points range from about 635 miles for central Tennessee mines up to 845 miles for mines located in West Virginia. As with CSXT movements, the haul mileages from individual origin points will vary depending on locations within the CAPP, alternative route corridors, and the point of interchange (Albany or Adel, Georgia) to the GFRR.

The NS rail corridors have historically (and at present) carried significant tonnages of coal in unit train service to several Southern Company (Georgia Power Company) power plants located in south-central and southwestern Georgia. The rail properties are fully capable of supporting heavy-haul unit train movements between mine load points and the Adel, Georgia interchange point without major upgrading or reinforcement of existing trackage or signaling systems. The NS rail corridors would appear to have sufficient transport capacity to adequately accommodate the additional traffic imposed by TEC.

Multiple existing rail routes exist to reliably provide coal from CAPP to TEC if it becomes economical to do so.

A.3.4.9 Fuel Procurement and Delivery Summary

Domestic sourcing of coals for TEC will be able to access major coal supply areas presently producing over 75 percent of all coals mined in the United States. Coupled with the ability to access the world of foreign-sourced coals, these arrangements will provide a high degree of competition in fuel supply for the TEC.

Similarly, the ability to employ multiple sourcing points and logistics systems (competing multiple Class I rail carriers and ports) affords a very high degree of flexibility and intra-modal competition for the transport of fuels to TEC.

The combination of abundant supply options and multiple transportation sources ensures that TEC will be reliably supplied with competitively priced fuel.

A.3.5 Project Capital Costs

The TEC capital cost estimate is based on constructing a nominal 765 MW (net) supercritical coal fired power station on a greenfield site located in Taylor County, near Perry, Florida. The cost estimate is based on a multiple engineer, procure, and construct (EPC) approach, with multiple contracts for the turbine island, boiler island, back-end pollution control island, yard material handling, and other balance-of-plant contracts. Table A.3-5 summarizes the capital cost estimate for the TEC. All costs are escalated to the anticipated May 2012 COD.

The base estimate of approximately $1.421 billion includes one supercritical, coal fired unit with well water makeup, ZLD, No. 2 fuel oil igniters, mechanical draft cooling tower, reverse air baghouse and wet, forced oxidation FGD system using limestone reagent, SCR, and WESP. The base estimate also includes costs for external training, contractor general and administrative (G&A) amounts, and contingency. Adjustments that have been added to and included in the base estimate are as follows:

- Labor per diem applied to 100 percent of the workforce.
- Differential cost to work five 10 hour days per week.
- 5.5 mile transmission interconnect to the Perry substation.
- Spare parts.
- Sacrificial coal bed.
- Commissioning consumables and initial fills.

The owner's costs of approximately $117 million include staffing, construction management, consultants, travel, insurance, services, supplies, rentals, one-time setup costs, and energy and fuel for startup/commissioning.

The allowance for funds used during construction (AFUDC) is approximately $135 million and is based on a 5.0 percent interest during construction rate.

A.3.6 Project O&M Costs

O&M costs include fixed and nonfuel variable costs. Fixed costs are independent of plant operation, while nonfuel variable costs are directly related to plant operation.

Table A.3-5
Capital Cost Estimate Summary

Description	
Base Estimate	$1,420,892,000
Owner's Costs	$116,994,000
Land	$20,100,000
Community Contribution Lump Sum	$20,000,000
Owner's AFUDC (1)	$135,413,000
Total Installed Cost – May 2012 COD	$1,713,399,000

(1)AFUDC calculated based on all components of capital cost estimate, including the base estimate, owner's costs, land, and community contribution.

A.3.6.1 Fixed O&M Costs

Fixed O&M costs include labor, payroll burden, fixed routine maintenance, and administrative costs. For TEC, annual fixed O&M costs in 2005 dollars are estimated to be $17,710,227. This includes an estimated staff of 149 employees with an annual payroll of $11.36 million and contracted annual fixed O&M expenses of $6.35 million. Ongoing capitalized expenditures are an additional aspect of fixed O&M expenses and have been estimated to be $2.50/kW-yr in 2005 dollars. The escalation rate for ongoing capital expenditures is estimated to be 2.0 percent per year over the assumed inflation rate to account for increasing capital expenditures as the unit ages.

A.3.6.1.1 Community Contribution Costs. In addition to the base fixed O&M value is an amount for contribution to the community. In the initial year of construction (2008), the contribution amounts to $20 million, as presented in Table A.3-5. The annual community contribution coinciding with commercial operation of TEC is estimated to be $2.5 million.

A.3.6.2 Nonfuel Variable O&M Costs

Nonfuel variable O&M costs vary as a function of plant generation. FGD reagent (or limestone), water treatment chemicals, ammonia, SCR replacement, fabric filter replacement, and other maintenance are included in the nonfuel variable O&M estimate. The nonfuel variable O&M estimates for TEC (in 2005 dollars) are presented in Table A.3-6 for operation on coals from each region that TEC would be able to utilize, assuming a fuel blend including 28 percent petcoke. Emissions allowance costs are not included in the nonfuel variable O&M estimates in Table A.3-6, since these costs will be accounted for separately in the economic analyses presented in Volumes B through E of this Application.

Table A.3-6
Nonfuel Variable O&M Estimates – Real 2005 $
(Assuming 28 Percent Petcoke Blend)

	Latin American Coal	PRB Coal	Central Appalachian Coal
Nonfuel Variable O&M	$1.36/MWh	$1.37/MWh	$1.15/MWh

A.3.7 Net Project Output and Heat Rate

Table A.3-7 presents net output and net plant heat rate estimates for TEC at summer, winter, and average ambient temperature conditions for coals from each region that TEC will be able to utilize, assuming a fuel blend including 28 percent petcoke. The net plant heat rate estimates include a degradation allowance of 1.5 percent.

Table A.3-7
Estimated TEC Performance[(1)]

	Latin American Coal		PRB Coal		Central Appalachian Coal	
Performance Point[(2)]	Net Output (MW)[(3)]	Net Plant Heat Rate (Btu/kWh)[(3)]	Net Output (MW)[(3)]	Net Plant Heat Rate (Btu/kWh)[(3)]	Net Output (MW)[(3)]	Net Plant Heat Rate (Btu/kWh)[(3)]
Summer Full Load	754.1	9,377	752.0	9,582	757.1	9,299
Winter Full Load	755.1	8,990	752.7	9,190	758.1	8,916,
Full Load (VWO)[(4)]	765.5	9,238	764.0	9,432	769.2	9,153
75% VWO Steam Flow	592.6	9,428	589.7	9,654	595.4	9,343

Table A.3-7
Estimated TEC Performance[1]

Performance Point[2]	Latin American Coal Net Output (MW)[3]	Latin American Coal Net Plant Heat Rate (Btu/kWh)[3]	PRB Coal Net Output (MW)[3]	PRB Coal Net Plant Heat Rate (Btu/kWh)[3]	Central Appalachian Coal Net Output (MW)[3]	Central Appalachian Coal Net Plant Heat Rate (Btu/kWh)[3]
50% Min Flow Generation	392.7	9,933	390.6	10,176	395.2	9,829
35% Min Flow Generation	272.5	10,535	271.6	10,805	274.7	10,424

(1)Performance based on 72 percent coal and 28 percent petcoke blend.
(2)Summer performance at 94° F, winter performance at 27° F, and average performance at 68.6° F.
(3)Transmission losses are not reflected but will be accounted for in the economic analyses.
(4)VWO = Valves wide open.

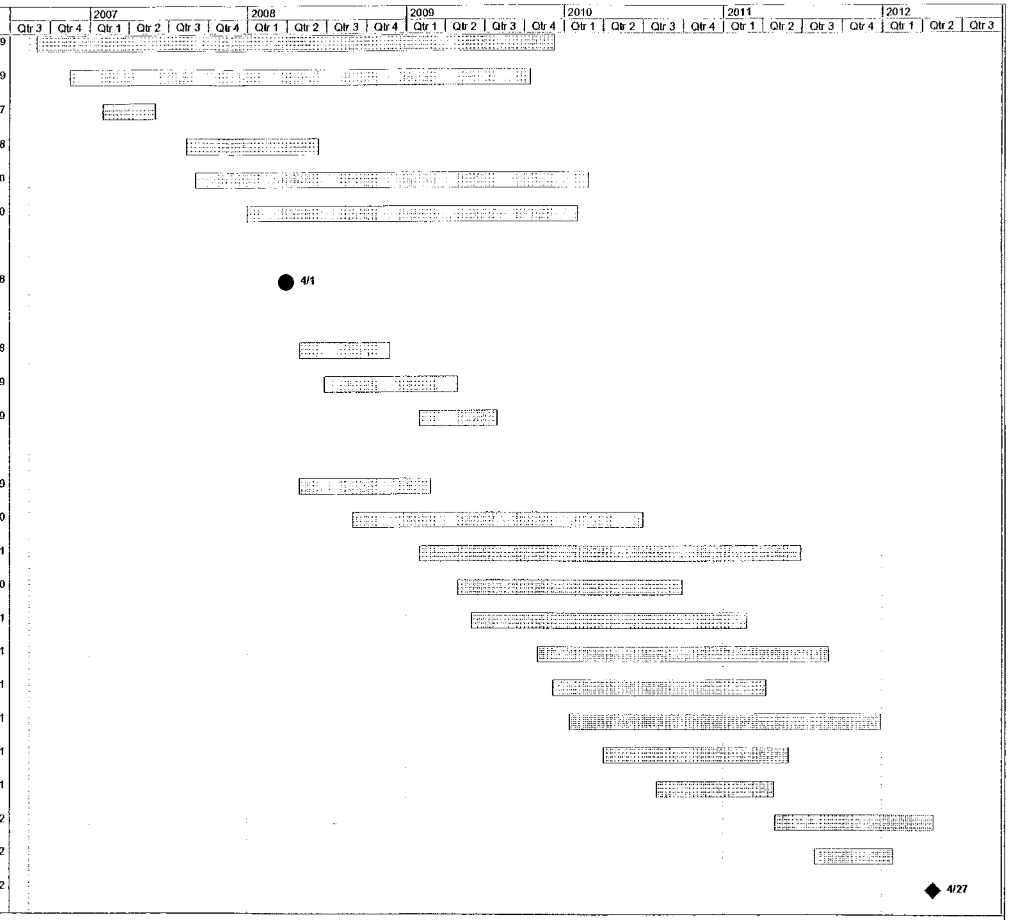
A.3.8 Project Forced Outages and Scheduled Maintenance

TEC is expected to have an annual forced outage rate of 5.23 percent. During overhaul years, which occur about every 7 years, the annual scheduled maintenance requirements will be higher than in non-overhaul years; however, the overall average annual scheduled maintenance requirement is expected to be approximately 16 days per year over an overhaul cycle, or 4.38 percent.

A.3.9 Project Schedule

A preliminary schedule has been planned for TEC. Specifications and contract negotiations for long-lead equipment and components such as the turbine generator and supercritical boiler will commence prior to the end of 2006, and negotiation of the contract for the concrete stack is planned in early 2007. Early contracting for this equipment and components is required to support the COD. Detailed plant design will commence during the fall of 2007 and will continue into early 2010. The air permit will be required to start construction and is anticipated to be received by April 1, 2008. Project construction is planned to commence in spring 2008, after all required permits have been obtained. Commissioning and startup is planned to commence in May 2011, and the TEC project is scheduled to begin commercial operation by May 1, 2012. Figure A.3-5 reflects the project schedule.

ID	Task Name	Duration	Start	Finish
1	Turbine Generator Procurement/Fabrication	854 days	Fri 9/1/06	Wed 12/9/09
2	Steam Generator Procurement/Fabrication	760 days	Fri 11/17/06	Thu 10/15/09
3	Stack EPC Contract	87 days	Thu 2/1/07	Fri 6/1/07
4	Boiler Island EPC Contract	220 days	Mon 8/13/07	Fri 6/13/08
5	Civil/Structural Design	650 days	Mon 9/3/07	Fri 2/26/10
6	BOP Engineering/Procurement/Design	544 days	Wed 1/2/08	Mon 2/1/10
7				
8	Issue Air Permit	0 days	Tue 4/1/08	Tue 4/1/08
9				
10	Cooling Tower EPC Contract	148 days	Fri 5/2/08	Tue 11/25/08
11	AQCS EPC Contract	220 days	Fri 6/27/08	Thu 4/30/09
12	Material Handling System EPC Contract	130 days	Mon 2/2/09	Fri 7/31/09
13				
14	Site Development Work	217 days	Thu 5/1/08	Fri 2/27/09
15	Substructures/Foundations Work	479 days	Mon 9/1/08	Thu 7/1/10
16	Boiler Island Erection	629 days	Mon 2/2/09	Thu 6/30/11
17	Cooling Tower Erection	370 days	Fri 5/1/09	Thu 9/30/10
18	Stack Erection	454 days	Tue 6/2/09	Fri 2/25/11
19	Mechanical Erection Work	479 days	Mon 11/2/09	Thu 9/1/11
20	Turbine-Generator Erection	351 days	Mon 12/7/09	Mon 4/11/11
21	Electrical Work	511 days	Fri 1/15/10	Fri 12/30/11
22	AQCS Erection	305 days	Thu 4/1/10	Wed 6/1/11
23	Material Handling Erection	195 days	Mon 8/2/10	Fri 4/29/11
24	Commissioning/Startup	260 days	Mon 5/2/11	Fri 4/27/12
25	Final Site Work	130 days	Mon 8/1/11	Fri 1/27/12
26	Commercial Operation	0 days	Fri 4/27/12	Fri 4/27/12



Project: TEC Level 1 Schedule
Date: Mon 8/14/06

April 27, 2012 Commercial Operation

Task
Split
Progress
Milestone
Summary
Project Summary
External Tasks
External Milestone
Deadline

Page 1

Figure A.3-5
Project Schedule

A.4.0 Economic Evaluation Criteria

This section presents the economic evaluation criteria and methodology used to demonstrate that the TEC is part of each Participant's least-cost capacity expansion plan to satisfy its forecast of respective capacity requirements throughout the 30 year evaluation period.

A.4.1 Inflation and Escalation Rates

The general inflation rate, construction cost escalation rate, fixed O&M escalation rate, and nonfuel variable O&M escalation rate are each assumed to be 2.5 percent.

A.4.2 Municipal Bond Interest Rate

The tax exempt municipal bond interest rate is assumed to be 5.0 percent.

A.4.3 Present Worth Discount Rate

The present worth discount rate is assumed to be equal to the tax exempt municipal bond interest rate of 5.0 percent.

A.4.4 Interest During Construction Interest Rate

The interest during construction rate, or IDC, is assumed to be 5.0 percent.

A.4.5 Levelized Fixed Charge Rate

The fixed charge rate, or FCR, represents the sum of a project's fixed charges as a percent of the initial investment cost. When the FCR is applied to the initial investment, the product equals the revenue requirements needed to offset the fixed charges during a given year. A separate FCR can be calculated and applied to each year of an economic analysis, but it is common practice to use a single, levelized FCR that has the same present value as the year-by-year fixed charge rate.

Different generating technologies are assumed to have different economic lives and therefore different financing terms. Simple cycle combustion turbines are assumed to have a 20 year financing term, while natural gas fired combined cycle units are assumed to be financed over 25 years. Solid fuel generating unit alternatives are assumed to have a 30 year financing term. Given the various economic lives and corresponding financing terms, different levelized fixed charge rates were developed. All levelized fixed charge rate calculations assume the 5.0 percent tax exempt municipal bond interest rate, a

2.0 percent bond issuance fee, an assumed 0.50 percent annual property insurance cost, and a debt service reserve fund equal to 100 percent of the average annual debt service requirement earning interest at an interest rate equal to the bond interest rate of 5.0 percent. The resulting 20 year fixed charge rate is 8.972 percent, the 25 year fixed charge rate is 7.915 percent, and the 30 year fixed charge rate is 7.254 percent.

A.4.6 Fuel Price Forecast Methodology

Fuel price projections for coal, petcoke, natural gas, and fuel oil were provided for use in this Application by Hill & Associates. The fuel price projections were provided for 2006 through 2030 for fuels currently being used by each of the Participants, as well as for fuels that might be used by future units considered in the economic analysis (described in Section A.6.0), including the TEC.

The fuel price forecasts provided by Hill & Associates were developed based in part on the expertise of several companies. Forecasts for coal and petcoke were developed by Hill & Associates, while natural gas and fuel oil price forecasts were provided by Pace Global Energy Services (Pace Global). Rail transportation rates were provided by Hellerworx, Inc. (Hellerworx), and ocean vessel rates were provided by Simpson, Spence & Young Consultancy & Research Ltd. (SSY). The overall delivered fuel price forecasts were developed with the input of the Taylor Energy Center Fuels Committee (TEC Fuels), which consists of representatives from each of the Participants.

Developing long-range estimates requires consideration of volatile energy markets, such as those recently experienced. To address fuel price uncertainty, high and low fuel price sensitivities and a fuel sensitivity that considers the potential impact of the regulation of CO_2 emissions in the United States were provided. These forecasts, along with Hill & Associates' base case forecast, are presented in this section. Volumes B through E of this Application provide economic analyses for each Participant using both the base case fuel forecasts and the sensitivity scenarios provided by Hill & Associates.

A.4.6.1 Coal Supply, Demand, and Price Forecast Methodology

Hill & Associates provided forecast commodity prices for a variety of coals and coal types consisting of coals from every major commercial region in the United States plus imported coals, each with various heating values and sulfur contents, including the following:

- Central Appalachia.
- Northern Appalachia.
- Illinois Basin.

- Powder River Basin.
- Latin America (Colombia and Venezuela).

Hill & Associates utilized its proprietary PRISM™ forecasting model, which integrates aspects of all fossil fuel markets as they relate to electricity demand, to develop the coal price forecasts. This model perspective is particularly important, since 92 percent of domestic coal production is consumed for electricity generation. The price projections for Colombian and Venezuelan coals were based on Hill & Associates' International Coal Trade (ICT) model and research. The coal price projections provided by Hill & Associates incorporated natural gas and oil price projections provided by Pace Global. Projections of electricity demand growth were based on the Energy Information Administration's Annual Energy Outlook 2005.

Hill & Associates not only considered the relationship between coal, natural gas, oil, and electricity markets, it also incorporated the requirement that generating facilities maintain compliance with local and national air emissions standards. The primary objective was to satisfy US electricity demand at the lowest possible cost while remaining within the emissions limits. Several alternatives to do so are possible, including fuel switching, running one plant instead of another, and/or adding cleanup equipment or new generation capacity. Hill & Associates simultaneously considered the impact that all of these potential decisions would have on fossil fuel supply, demand, and price.

The projection of coal demand for electrical generation combines a top-down approach with a bottom-up analysis. The initial point in the bottom-up analysis of demand was to list all existing power generation facilities and develop data on their present coal utilization, specifications, emissions control processes, regulatory limits, and future plans, along with other information. This information is updated annually by Hill & Associates and includes all known plants from any source, regardless of plant size.

Fundamental assumptions used by Hill & Associates include specific coal supply curves, Clean Air Interstate Rule (CAIR)/Clean Air Mercury Rule (CAMR) environmental regulations, natural gas and oil price forecasts, and electricity demand growth rates. Hill & Associates' coal supply curves were developed based on detailed review of mining operations in all of the major basins. The modeling process included mine cost, capacity, and reserve estimates for every operating coal mine in the contiguous 48 states and Colombia and Venezuela. Mine cost and reserve estimates were also included for undeveloped reserves. Projections were provided for a relatively broad selection of coal qualities from the major producing basins as well as for various qualities of petcoke, allowing for a comprehensive basis from which to interpolate projected prices for any coals not directly represented from these basins.

Hill & Associates expects that CAIR and CAMR will be implemented as promulgated in 2005. Although the operation of all generating units will have to include consideration of local attainment issues and State Implementation Plans (SIPs), Hill & Associates believes that CAIR/CAMR will generally be the regulation that drives fossil fuel decisions through the forecast period. In fact, as a result of CAIR/CAMR regulations, a significant number of new emissions cleanup equipment projects (scrubbers and SCR) have been announced and were taken into account in the forecast. The allowance price forecasts provided by Hill & Associates for SO_2, NO_x, and Hg, the emissions regulated under CAIR and CAMR, are discussed in Section A.5.0.

Hill & Associates did not forecast natural gas or oil prices directly. Instead, projections of these prices, and in the case of natural gas the demand/price relationship, were inputs to the PRISM™ model. Hill & Associates combined these prices with the coal supply curves through the solution of electricity dispatch to provide an integrated solution that takes into account the interrelationship of costs across all fuel types.

The Energy Information Administration's Annual Energy Outlook 2005 was used as the basis for the electricity demand growth rate. Baseline electricity demand data was taken from EIA Form 714.

A.4.6.1.1 Central Appalachia Coal Supply. The Central Appalachia (CAPP) region provides high quality coal for use in steam and metallurgical markets. Production in the CAPP region reached its peak in 1990, when 350 million tons were produced. Since that time, production has decreased to 230 million tons per year (tpy) because of the depletion of economical reserves, and this trend is likely to continue through the forecast period. Overall, CAPP is the most intensively mined basin in the United States, with more than 750 mines listed by the Mine Safety and Health Administration (MSHA). The vast majority of these mines produce less than 100,000 tpy, but comprise only a small fraction of total CAPP production.

The most significant factor affecting the future of coal production in the CAPP region is the increasing difficulty and expense to develop new mines. As low cost reserves are depleted, their replacements will have higher mine costs. The barriers to developing new mines in the CAPP region include permitting, bonding, labor shortages, and trucking laws. As a result, Hill & Associates projects that CAPP production is likely to drop over the next 20 years from 230 million tpy to between 100 and 130 million tpy. Coal production in the CAPP region in the near term is projected to remain at current levels due to the current high prices caused by the international coal supply and demand situation and the inability of domestic utilities to switch to lower cost alternatives. Over time, utilities will switch to lower cost alternatives including higher sulfur coals as the scrubber market continues to develop. Despite the factors discussed previously, there continues to be new mine activity in the CAPP region, offsetting depletion of reserves in existing mines.

A.4.6.1.2 Northern Appalachia Coal Supply. The Northern Appalachia (NAPP) region is generally conducive to two mining approaches. The first approach includes large underground mining complexes in the Pittsburgh Seam. Nearly two thirds of the annual NAPP production comes from the relatively few operations in the Pittsburgh Seam, each operation producing well over 1 million tpy. Pittsburgh Seam production is highly valued by utilities for its high heat content, relatively low sulfur content (compared to the Illinois Basin), and good combustibility and handling characteristics. Mining companies value the Pittsburgh Seam because of the mining conditions that are conducive to large mines and mining complexes with low operating costs. The second approach includes small underground and surface mining operations, with most producing less than 200,000 tons annually.

Overall, Hill & Associates believes that NAPP coal production will reach a peak in about 10 years as reserves in the Pittsburgh Seam begin to deplete, and the remaining reserve base is unable to compensate for the loss of Pittsburgh Seam production. Demand for NAPP coal is expected to remain high due to load growth and the increased scrubbing that will allow for use of eastern US coals with higher sulfur content than the low sulfur PRB Coal. From 2004 to 2015, Hill & Associates projects that demand will increase from 130 million tpy to 190 millions tpy.

A.4.6.1.3 Illinois Basin Coal Supply. The Illinois Basin (ILB) region contains abundant, relatively low cost reserves. The passage of the 1990 Clean Air Act Amendments resulted in utilities switching to low sulfur alternatives. As a result, production of the relatively higher sulfur ILB coals has declined from a high of 158 million tpy in 1988 to a low of 88 million tpy during the mid-1990s. Hill & Associates expects ILB coal production to recover as scrubbers are added to more plants as a result of CAIR and CAMR, allowing for the use of higher sulfur coals.

ILB mines consist of both small and large operations. Most surface operations are small, with production averaging less than 1 million tpy. The deep mine operations tend to be fairly large, with most averaging production in excess of 1 million tpy. The majority of the economically mineable surface reserves have been depleted in the ILB, and Hill & Associates predicts that 90 percent of the production in the ILB will be from underground mines by 2015. The underground reserves in the ILB are estimated to be between five to ten times larger than the reserve base in the NAPP.

A.4.6.1.4 PRB Coal Supply. The PRB region contains large reserves of low sulfur coal, with all production coming from surface mining operations. The PRB region comprises the Southern PRB (SPRB) and the Northern PRB (NPRB). The SPRB is the portion of the region located in Wyoming, and the NPRB is the portion of the region located in Montana. The SPRB is the largest producing region in the PRB, accounting for approximately 90 percent of the total production. In 2004, SPRB production totaled 382 million tons, while the NPRB produced 39 million tons. The total production in 2004 (420 million tons) represented a 17 percent increase from production during 2003. PRB coal production is expected to continue to steadily increase and will be capable of satisfying the forecasted demand of 700 million tpy by 2023.

A.4.6.1.5 Latin America Coal Supply. Colombia and Venezuela were the largest sources of imported steam coal to the United States in 2005, providing a total of 21.9 million tons. Coals from Latin America tend to be imported to the United States because of comparable quality to eastern US bituminous coals and also because the relative proximity of these countries allows for transportation rates that make these coals competitive with domestic coals. Imports of Venezuelan coal are expected to increase in the next few years, because utilities in the northeastern US (where emissions regulations are stricter than national standards) will be looking for low sulfur coals with high heating values to replace domestic coals. Colombia and Venezuela collectively produce about 72 million tons of coal per year (93 percent of which is exported from Latin America), with active reserves exceeding 6 billion tons.

A.4.6.1.6 Coal Demand and Price Forecasts. In developing the coal price forecasts, Hill & Associates reviewed the recent history of coal demand and prices. During 2003 and 2004, numerous events occurred that resulted in increased coal prices in the eastern United States. Overall demand for coal in the United States increased due to a strengthening US economy, which resulted in increased electricity demand and increased domestic steel production. At the same time, the recent trend of steadily decreasing coal exports was reversed in response to the increased demand for all commodities to feed the growing economies of India and China, including metallurgical coal from the United States. The expanding economies of India and China also led to a shortage in shipping vessels, resulting in extremely high ocean freight rates. The increased ocean freight rates forced European buyers to turn from Asia to the United States for swing supply, resulting in increased demand for coal in the Atlantic Basin (and contributing to the reversal of the declining thermal coal export trend).

During this same time period, excess domestic coal production capacity fell to an all-time low in the major coal producing regions. The problem was especially acute in the CAPP region due to the bankruptcies of several major mines and declining average productivity due to shifts in mining methods. Production costs increased because of increased costs for oil, natural gas, and steel (which led to higher mine operating costs). An aging workforce coupled with an acute shortage of trained workers to meet the growing demand resulted in increased labor costs as producers were forced to raise wages to attract and/or retain workers.

Delivery capacity for coal in the United States was adversely affected by a shortage of locomotives, cars, experienced train operators, and dispatchers, all occurring while coal demand was increasing. Rail carriers responded to this increased demand for coal shipments by significantly raising rates, which further disrupted normal shipping patterns. Additionally, transportation capability was further impacted by the shortage of barge capacity.

While all of the factors discussed previously led to a substantial increase in the delivered cost of coal in the United States, Hill & Associates expects that these factors will be short-lived, which will allow the current sellers' market for coal to once again revert to a buyers' market for a variety of reasons, including the expectation that the US economic growth will slow, partly due to higher energy costs. Worldwide supply of raw materials will begin to catch up with the demands of the Indian and Chinese economies, leading to stable or declining incremental shifts of US thermal coals to metallurgical coals. Additionally, investments in shipping will reduce ocean freight rates, and the decreased rates will reopen Asian coal sources to Europe, leading to a decrease in demand for US coals. Domestically, investment in railroad and river transportation infrastructure, as well as management practices, will ease the constrained coal transportation system and the rates of increase in rail and barge transportation costs will ease as well.

An additional factor expected to influence coal pricing in the future is the projected erosion of sulfur premiums because of an increase in the use of FGD technology at US power plants in order to achieve compliance with environmental regulations under CAIR, which is expected to decrease the overall demand for low sulfur CAPP coal. The SO_2 emissions limitations under CAIR will preclude most US coals from being considered "compliance" coals, or coals that can be burned without emissions offsets over and above the original allowance allocation. This factor, coupled with an implementation plan that will reward early SO_2 reductions, has resulted in the announcement of a large number of plans for FGD additions to existing power plants across the United States.

A.4.6.2 Petcoke Supply, Demand, and Price Forecast Methodology

Petcoke is a byproduct of oil refining processes and, as such, it has no meaningful "cost of production" by which to gauge future prices. Further complicating the petcoke forecasting process is the fact that only a fraction of the total US and Caribbean production is consumed by US power generators. The majority of petcoke is sold overseas or to industrial markets. As a result, petcoke prices have been quite variable, but usually low cost on a dollar/MBtu basis compared to other fuels such as coal and natural gas. Ultimately, Hill & Associates provided a forecast based on the historical average price of petcoke.

A.4.6.3 Natural Gas Supply, Demand, and Price Forecast

Pace Global provided annual price projections through 2030 for natural gas at the Henry Hub trading point for Hill & Associates. Pace Global believes that the era of low cost natural gas in North America came to an end in 2000, after demand for natural gas in North America rose permanently above the North American supply of natural gas available at prices under $3.00/MBtu. Since 1994, increasing rates of drilling have been necessary to maintain the existing level of US natural gas production. Productivity is declining, and prospects for new conventional production are limited. Substantial natural gas resources remain for unconventional production, but these resources are more costly to develop.

From the 1980s through 1999, rising imports of pipeline natural gas from Canada enabled the United States to increase natural gas consumption at stable prices. However, in 2000, the supply of Canadian natural gas to the United States leveled out and subsequently peaked in 2002. Since then, natural gas prices have surged on rising demand in the United States and declining supplies in North America. Production of natural gas in North America has not increased, despite much higher rates of drilling in response to the high prices.

In the future, North American natural gas prices will have to be high enough to cover the increased costs of incremental North American exploration and production, including unconventional technologies, and the cost of importing liquefied natural gas (LNG). It is forecast that price levels will decline as increasing amounts of LNG enter the US market between 2008 and 2011 and then rise over time. While incremental North American natural gas and substantial amounts of LNG from worldwide natural gas reserves will be available, the volume and pricing will be affected by strong world competition for limited resources and the trade-weighted value of the US dollar.

Because of the currently limited supply of natural gas in North America, increasing demand is resulting in significantly higher prices rather than higher consumption. Damage to oil, natural gas, and power facilities in the US Gulf Coast area from recent hurricanes has temporarily reduced industrial and power sector natural gas demand, and industrial natural gas consumption is currently below normal as a result of the loss of oil refining, gas processing, and pipeline operations. Power demand from these facilities and from damaged housing is also below normal. The high spot market prices currently being realized have caused some manufacturing activity to be reduced. As increased amounts of LNG become available over the 2006 through 2010 period, US natural gas prices are expected to decline and consumption is expected to rise. Demand in the power and industrial sectors is expected to be the most responsive to changes in natural gas prices. The Pace Global US natural gas market model takes this response into account in its forecast of natural gas consumption. Over the 2004 through 2010 period, annual consumption is projected to increase by 0.9 percent in the residential/commercial sectors, to decline by 0.4 percent in the industrial sector, and to increase by 4.3 percent in the power sector. Although high natural gas prices result in relatively expensive natural gas fired power generation, the growing US electricity demand will not be able to be met over the next 6 years without increased utilization of existing natural gas combined cycle generating units. Pace Global forecasts particularly strong growth in natural gas consumption in the power sector later in the decade, when more natural gas becomes available from LNG imports and natural gas prices decline to more attractive levels.

Between 2010 and 2015, Pace Global expects that a large share of incremental US power generation will be natural gas fired, with natural gas consumption in the power industry greatly outpacing consumption growth in the other sectors. After 2015, natural gas consumption is expected to grow very slowly, because the majority of incremental power generation will come from new baseload generating units that are not likely to be natural gas fired. Energy intensive industrial activity will tend to be located outside the United States, and high natural gas prices in the residential/commercial sector are expected to encourage more energy conservation and greater reliance on electricity for space heating.

High natural gas spot market prices have encouraged an increase in North American drilling since 2002, but little net incremental natural gas has been produced as a result, with natural gas producers reporting more rapid production declines in old wells and less production from new wells than historically experienced. The results of incremental drilling over the last year and a half are difficult to assess because of the disruptions associated with recent hurricane activity. Between 2004 and 2015, Pace Global forecasts a decline of 2.0 percent (0.2 percent annually) in natural gas production in the contiguous United States, as increasing production in the Rockies is offset by declining production elsewhere.

Although affecting natural gas production and consumption in recent years, Pace Global expects that hurricanes will not consistently disrupt operations over the next few years. If producing regions are affected by hurricanes, natural gas prices will increase beyond the prices projected by Pace Global. Production of natural gas in Canada is expected to increase in the near term, but net imports into the United States from Canada are forecasted to remain constant as Canadian consumption increases along with production. Net North American pipeline imports to the United States are forecasted to decline in the near term, as pipeline exports to Mexico increase to meet that country's growing demand for power generation. However, when new LNG terminals begin operating in Mexico in 2008 and 2009, US net pipeline exports to Mexico are expected to decrease.

Increased utilization of the combined cycle power plants that have been installed in the United States over the last 5 years will require increasing supplies of imported LNG. Natural gas is available worldwide to meet the US requirements, but construction of liquefaction facilities, regasification terminals, and LNG tankers must occur before significant incremental supplies can be delivered. More than 40 LNG regasification terminal projects have been announced by developers for various North American locations, which are more projects than necessary to meet US requirements through 2020. Most of the new LNG terminals are proposed to be constructed in the Gulf of Mexico, but terminals are also proposed in the northeastern US, the Bahamas, and on the West Coast.

Pace Global forecasts that the United States will become increasingly dependent on LNG imports to meet consumption over time, with 11 percent of the natural gas demand being met by LNG by 2010, increasing to 17 percent by 2015. This level of LNG imports is feasible if current plans for new facilities overseas remain on schedule. The current capacity of regasification facilities, combined with the construction of additional terminals, is projected to be sufficient to accommodate LNG imports. Any limitations on LNG imports into the United States would more likely be the result of a lack of LNG supplies available for shipment to the United States. Should such limitations occur, natural gas prices will be higher than the forecast prices provided by Pace Global.

A.4.6.4 Fuel Oil Supply, Demand, and Price Forecast

Pace Global provided annual price projections through 2030 for distillate and residual fuel oils in the Gulf Coast market region for Hill & Associates. Forecasts were developed for No. 2 distillate fuel oil (0.5 percent sulfur), low sulfur No. 2 distillate fuel oil (0.05 percent sulfur), ultra-low sulfur No. 2 distillate fuel oil (0.0015 percent sulfur), and No. 6 residual fuel oil (1 percent and 3 percent sulfur grades).

Forecasted petroleum prices were developed by Pace Global for products used by power generating facilities in the Gulf Coast market region. When world refinery capacity is matched to the demand for products and the available crudes, product prices are largely determined by world crude oil prices. When this is not the case, product prices are affected by the supply and demand balance for each product. The principal US crude oil marker is West Texas Intermediate (WTI) crude oil, located in Cushing, Oklahoma. WTI is the crude oil listed on the New York Mercantile Exchange (NYMEX). Pace Global forecasts the price of WTI and uses this price as the basis for forecasting US and world petroleum product prices.

The world has sufficient low cost oil resources to meet world demand for decades, but access to most of the world's petroleum resources is restricted by governments. As a result, government decisions in the Organization of Petroleum Exporting Countries (OPEC) and political/economic developments in non-OPEC countries will be the main drivers of short-run oil price behavior. Unexpectedly rapid growth in world demand for oil, combined with OPEC's inability to increase its production of light crudes and the damage caused by recent hurricanes in the US Gulf Coast, is causing oil prices to increase well above world production costs. Pace Global expects that there is an underlying long-run upward trend in oil production costs caused by world resource depletion among the world's market-responsive producers and OPEC's reluctance to substantially increase production. The world's marginal cost of crude oil production was under $10 per barrel (in 2005 dollars) in 1950 and is now over $20 per barrel (in 2005 dollars).

The rapid growth in world oil demand is likely to continue. The effect of resource depletion on oil prices is expected to continue, if not accelerate. Pace Global's forecast incorporates its belief that government production policies and political events will prevent the increase in world production required to meet rising world demand at the normal price levels experienced in the past. Under this scenario, OPEC would limit its production to maximize income, causing prices to remain substantially above average world production costs.

Oil consumption per capita in China and India is a small fraction of US consumption, and at the low level of gross domestic product (GDP) per capita in these countries, petroleum consumption typically grows at almost the same rate as the GDP. Over the next 20 years, Chinese and Indian consumers are expected to place a large amount of demand pressure on the oil market, unless their economic growth rates slow.

High crude oil prices since 2002 have led to an increase in world oil exploration and development. Pace Global expects that non-OPEC countries will increase their oil production over the next decade, but not in sufficient amounts to meet the rapid growth in world oil demand. Over the 2005 through 2010 time frame, non-OPEC production is forecasted to provide 70 percent of the increase in world oil supply. The non-OPEC country expected to provide the greatest increase in supply over this period is Russia, but there is uncertainty about the size of this increase due to political struggles between private oil producers and the Russian government over who will control the oil resources and who will benefit from the profits associated with production. Additionally, the oil pipeline system in Russia is capacity constrained. If Russia's production does not materialize as forecasted, prices will rise or OPEC will have to make up the difference.

Between 2010 and 2020, non-OPEC production is projected to meet 75 percent of the increased world oil requirements. However, the uncertainty surrounding the level of non-OPEC production over time is considerable, because most of the production must come from countries that are not members of the Organization for Economic Co-operation and Development (OECD), where political conditions are uncertain. Recently, many non-OPEC governments outside of the OECD have increased their taxation of oil revenues to capture a larger share of profits, which reduces the incentive for producers to respond to higher prices. If non-OPEC production does not materialize at the forecast rates, OPEC will have to increase production or limited world supplies will lead to price rationing and higher prices. Pace Global expects that OPEC will not increase production, but instead will continue to keep production levels low and oil prices high.

A.4.6.5 Fuel Price Forecasts

The following subsections present the annual commodity fuel price projections for coal, petcoke, natural gas, and fuel oil by Hill & Associates and Pace Global, provided for use in this Application.

A.4.6.5.1 Coal Price Forecasts. As discussed previously, Hill & Associates provided commodity price forecasts for various coals from every major commercial region in the United States as well as imported coals (freight on board [FOB] at the mine for domestic coals, and FOB Bolivar, Colombia for imported coals). Forecasts for CAPP coal, NAPP coal, ILB coal, PRB coal, and Latin American coals (Colombia and Venezuela) are presented in Tables A.4-1 through A.4-5, respectively.

A.4.6.5.2 Petcoke Price Forecasts. As discussed previously, Hill & Associates provided the commodity price forecasts for petcoke, which are presented in Table A.4-6.

A.4.6.5.3 Natural Gas Price Forecasts. As discussed previously, Pace Global provided the Henry Hub natural gas price forecasts, which are shown in Table A.4-7.

A.4.6.5.4 Fuel Oil Price Forecasts. As discussed previously, Pace Global provided forecasts for No. 2 distillate fuel oil with three different sulfur contents and No. 6 residual fuel oil with two different sulfur contents. The forecasts are presented in Table A.4-8.

Table A.4-1
Central Appalachia Coal Price Forecasts
(Commodity, Real 2005 $/ton)

Year	S. WV-Hi Btu Super-Compliance 13,150 Btu/lb 0.62 % Sulfur	S. WV-Hi Btu Super-Compliance 13,100 Btu/lb 0.65 % Sulfur	S. WV-Mid Btu Compliance 12,200 Btu/lb 0.67 % Sulfur	S. WV-Mid Btu Compliance 12,350 Btu/lb 0.67 % Sulfur	S. WV-Mid Btu Near-Compliance 12,200 Btu/lb 0.82 % Sulfur	S. WV-Mid Btu Near-Compliance 12,250 Btu/lb 0.98 % Sulfur	S. WV-Mid Btu Mid-Sulfur 12,500 Btu/lb 1.67 % Sulfur	S. WV-Mid Btu Mid-Sulfur 12,800 Btu/lb 1.67 % Sulfur
2006	$71.96	$70.93	$66.09	$68.17	$59.67	$62.83	$56.21	$41.87
2007	$60.60	$62.14	$58.63	$57.25	$48.69	$50.68	$47.92	$38.96
2008	$46.62	$49.59	$46.69	$46.33	$42.38	$44.46	$42.03	$37.39
2009	$40.44	$40.18	$36.04	$37.00	$34.14	$34.74	$35.14	$37.27
2010	$39.81	$40.46	$35.31	$37.29	$33.50	$34.65	$34.99	$36.95
2011	$39.74	$40.19	$34.99	$36.53	$33.21	$34.86	$34.85	$37.57
2012	$40.19	$40.83	$35.57	$37.17	$33.71	$35.28	$34.82	$37.44
2013	$40.53	$41.47	$35.95	$37.68	$34.05	$36.06	$35.39	$38.31
2014	$40.68	$40.87	$35.94	$37.24	$33.93	$35.62	$35.40	$37.80
2015	$41.00	$40.69	$36.35	$37.15	$34.23	$35.38	$35.73	$37.62
2016	$41.90	$42.30	$36.56	$38.02	$35.09	$36.37	$36.30	$38.61
2017	$42.02	$42.35	$36.55	$37.87	$35.11	$36.27	$36.20	$38.62
2018	$42.87	$42.76	$37.18	$38.32	$35.81	$36.71	$36.96	$39.35
2019	$42.41	$42.22	$37.35	$38.32	$35.91	$36.67	$37.05	$39.30
2020	$42.85	$42.80	$37.12	$38.07	$35.70	$36.42	$36.71	$38.96
2021	$43.95	$43.71	$37.90	$39.21	$36.37	$37.52	$37.38	$40.06
2022	$43.77	$43.68	$37.84	$39.38	$36.31	$37.68	$37.33	$40.25
2023	$44.90	$44.52	$38.82	$40.53	$37.26	$38.79	$38.48	$41.42
2024	$44.58	$45.02	$38.98	$41.39	$37.41	$39.55	$39.29	$42.26
2025	$45.89	$45.29	$39.19	$41.60	$37.60	$39.74	$39.43	$42.40
2026	$45.83	$45.49	$39.19	$41.62	$37.49	$39.64	$39.32	$42.29
2027	$46.53	$46.12	$39.73	$42.57	$38.02	$40.54	$40.25	$43.24
2028	$47.04	$46.56	$40.04	$43.12	$38.29	$41.03	$40.74	$43.75
2029	$47.55	$47.00	$40.34	$43.67	$38.56	$41.52	$41.24	$44.25
2030	$48.06	$47.43	$40.65	$44.23	$38.82	$42.00	$41.73	$44.76

Table A.4-1 (Continued)
Central Appalachia Coal Price Forecasts
(Commodity, Real 2005 $/ton)

Year	E. KY-Hi Btu Super-Compliance 13,100 Btu/lb 0.57 % Sulfur	E. KY-Hi Btu Super-Compliance 13,150 Btu/lb 0.65 % Sulfur	E. KY-Mid Btu Compliance 12,700 Btu/lb 0.67 % Sulfur	E. KY-Mid Btu Compliance 12,500 Btu/lb 0.69 % Sulfur	E. KY-Mid Btu Near-Compliance 12,300 Btu/lb 1.00 % Sulfur	E. KY-Mid Btu Near-Compliance 12,600 Btu/lb 1.12 % Sulfur	E. KY-Mid Btu Mid-Sulfur 12,100 Btu/lb 1.74 % Sulfur	E. KY-Mid Btu Mid-Sulfur 12,300 Btu/lb 1.75 % Sulfur
2006	$72.50	$55.64	$66.04	$69.04	$59.22	$62.72	$42.13	$42.12
2007	$62.53	$50.66	$56.64	$55.27	$47.72	$50.35	$38.60	$38.86
2008	$48.56	$51.80	$45.23	$45.19	$40.09	$44.46	$35.65	$36.42
2009	$40.53	$40.43	$36.84	$37.54	$34.25	$34.76	$34.82	$34.46
2010	$40.00	$40.88	$36.08	$37.70	$34.10	$34.68	$34.66	$34.23
2011	$39.93	$40.46	$35.71	$37.01	$34.16	$34.99	$34.67	$34.41
2012	$40.29	$41.08	$36.05	$37.65	$34.55	$35.40	$35.07	$34.83
2013	$40.73	$41.79	$36.41	$38.28	$35.07	$36.17	$35.60	$35.61
2014	$40.80	$41.17	$36.48	$37.71	$35.12	$35.74	$35.64	$35.21
2015	$41.13	$41.22	$36.86	$37.67	$35.37	$35.47	$35.88	$34.96
2016	$41.69	$42.65	$37.11	$38.51	$36.14	$36.50	$36.52	$36.19
2017	$41.62	$42.65	$37.05	$38.33	$35.93	$36.36	$36.32	$36.15
2018	$42.69	$43.06	$37.68	$38.70	$36.69	$36.79	$37.07	$36.83
2019	$42.42	$42.52	$37.87	$38.74	$36.82	$36.81	$37.27	$36.93
2020	$42.44	$43.10	$37.66	$38.48	$36.55	$36.57	$36.90	$36.56
2021	$43.34	$44.01	$38.30	$39.62	$36.83	$37.66	$37.10	$37.58
2022	$43.20	$43.98	$38.27	$39.89	$36.92	$37.82	$37.24	$37.79
2023	$44.30	$44.82	$39.23	$41.05	$37.79	$38.95	$38.11	$38.90
2024	$44.54	$45.32	$39.51	$41.88	$38.30	$39.79	$38.57	$39.51
2025	$45.17	$45.59	$40.18	$42.07	$38.59	$39.99	$38.82	$39.63
2026	$45.18	$45.79	$39.85	$42.19	$38.43	$40.01	$38.71	$39.58
2027	$45.93	$46.42	$40.64	$43.10	$39.15	$40.94	$39.39	$40.38
2028	$46.41	$46.86	$41.05	$43.67	$39.53	$41.48	$39.75	$40.81
2029	$46.89	$47.30	$41.46	$44.23	$39.91	$42.02	$40.12	$41.24
2030	$47.38	$47.73	$41.87	$44.79	$40.29	$42.56	$40.48	$41.67

Table A.4-2
Northern Appalachia Coal Price Forecasts
(Commodity, Real 2005 $/ton)

Year	W. PA Mid-Sulfur 13,000 Btu/lb 1.95 % Sulfur	W. PA High-Sulfur 12,200 Btu/lb 3.34 % Sulfur	OH Mid-Sulfur 12,150 Btu/lb 2.20 % Sulfur	OH High-Sulfur 11,750 Btu/lb 3.60 % Sulfur	N. WV Mid-Sulfur 12,900 Btu/lb 2.10 % Sulfur	N. WV High-Sulfur 12,350 Btu/lb 3.60 % Sulfur
2006	$52.38	$50.47	$45.58	$40.51	$54.17	$50.78
2007	$44.52	$44.33	$37.93	$33.79	$46.77	$43.07
2008	$37.75	$33.21	$32.50	$32.92	$39.15	$36.90
2009	$38.27	$34.32	$34.72	$32.88	$37.16	$36.41
2010	$37.45	$33.49	$34.56	$32.12	$36.54	$35.68
2011	$37.11	$32.78	$34.01	$31.73	$36.14	$35.38
2012	$37.70	$33.57	$34.74	$32.40	$36.69	$35.91
2013	$37.75	$33.62	$35.15	$32.74	$37.20	$35.87
2014	$37.43	$33.50	$34.71	$32.20	$37.22	$35.55
2015	$37.11	$33.41	$34.68	$32.06	$36.60	$35.22
2016	$37.58	$33.65	$35.58	$32.71	$37.67	$35.37
2017	$37.61	$33.72	$35.87	$32.94	$38.05	$35.33
2018	$39.37	$35.68	$39.17	$36.27	$39.47	$36.64
2019	$39.99	$36.39	$39.45	$36.50	$39.83	$37.46
2020	$39.32	$35.60	$38.98	$38.56	$39.36	$36.64
2021	$40.22	$36.20	$39.78	$38.50	$40.12	$37.46
2022	$40.24	$36.24	$39.63	$38.60	$39.97	$37.57
2023	$41.55	$37.41	$41.00	$40.00	$41.43	$38.33
2024	$41.70	$37.81	$42.05	$41.00	$41.69	$38.22
2025	$42.01	$37.96	$42.73	$41.00	$42.06	$38.24
2026	$42.00	$38.52	$42.54	$41.00	$41.76	$38.40
2027	$42.70	$39.12	$43.86	$42.06	$42.65	$38.62
2028	$43.10	$39.63	$44.61	$42.64	$43.07	$38.78
2029	$43.49	$40.14	$45.36	$43.22	$43.49	$38.94
2030	$43.89	$40.65	$46.12	$43.80	$43.91	$39.09

Table A.4-3
Illinois Basin Coal Price Forecasts
(Commodity, Real 2005 $/ton)

Year	IN Compliance 11,100 Btu/lb 0.58 % Sulfur	IN Near-Compliance 10,950 Btu/lb 1.10 % Sulfur	IN Mid-Sulfur 11,000 Btu/lb 1.70 % Sulfur	IN High-Sulfur 11,100 Btu/lb 3.05 % Sulfur	IL Near-Compliance 11,800 Btu/lb 1.30 % Sulfur	IL Mid-Sulfur 11,550 Btu/lb 1.70 5 Sulfur	IL High-Sulfur 11,150 Btu/lb 3.00 % Sulfur	W. KY Near-Compliance 11,900 Btu/lb 0.98 % Sulfur	W. KY High-Sulfur 11,600 Btu/lb 3.19 % Sulfur
2006	$63.98	$46.18	$44.69	$37.72	$45.51	$44.47	$40.00	$46.30	$37.46
2007	$54.20	$37.32	$37.49	$32.21	$37.97	$36.82	$32.34	$41.64	$28.67
2008	$44.90	$32.93	$31.38	$28.33	$33.40	$31.64	$28.91	$40.00	$27.76
2009	$32.24	$28.82	$28.82	$28.21	$29.36	$29.97	$27.93	$35.45	$28.10
2010	$32.03	$28.20	$28.36	$27.45	$29.00	$29.19	$27.28	$33.26	$27.71
2011	$31.60	$28.19	$28.84	$27.71	$28.72	$29.18	$27.33	$33.32	$27.61
2012	$31.05	$27.97	$29.38	$27.50	$28.73	$28.96	$27.16	$33.55	$27.52
2013	$31.71	$28.20	$29.28	$27.49	$28.92	$29.17	$27.04	$33.10	$27.41
2014	$31.58	$28.06	$28.50	$27.34	$28.91	$29.01	$26.43	$32.36	$27.32
2015	$31.45	$28.13	$28.31	$26.85	$29.07	$29.01	$26.55	$32.32	$27.22
2016	$31.31	$28.89	$28.98	$27.32	$29.80	$29.61	$26.73	$32.52	$27.12
2017	$30.90	$28.54	$29.15	$27.14	$29.63	$29.19	$26.23	$32.33	$26.97
2018	$30.95	$29.12	$29.52	$28.07	$30.78	$29.74	$26.56	$32.47	$27.00
2019	$30.91	$30.67	$30.28	$28.73	$30.83	$29.86	$26.92	$32.52	$27.48
2020	$30.78	$30.92	$30.11	$27.96	$30.37	$29.39	$26.18	$32.23	$26.72
2021	$30.85	$30.91	$29.79	$28.17	$30.82	$29.64	$26.32	$32.94	$26.93
2022	$30.51	$30.25	$29.25	$27.84	$30.81	$29.51	$26.30	$32.32	$26.60
2023	$31.12	$30.93	$30.03	$28.61	$31.73	$30.41	$27.10	$33.24	$27.39
2024	$31.32	$31.30	$30.20	$28.71	$31.93	$30.72	$27.47	$33.48	$27.40
2025	$31.07	$30.85	$30.21	$28.59	$32.16	$30.79	$28.30	$33.55	$27.28
2026	$30.67	$30.41	$30.04	$28.45	$31.97	$30.70	$27.55	$33.10	$27.06
2027	$31.02	$30.82	$30.47	$28.80	$32.55	$31.25	$28.46	$33.70	$27.39
2028	$31.05	$30.84	$30.65	$28.92	$32.82	$31.53	$28.83	$33.89	$27.48
2029	$31.07	$30.87	$30.83	$29.04	$33.10	$31.81	$29.20	$34.07	$27.56
2030	$31.10	$30.89	$31.00	$29.16	$33.37	$32.08	$29.57	$34.26	$27.64

Table A.4-4
PRB Coal Price Forecasts
(Commodity, Real 2005 $/ton)

Year	N. Gillette Compliance 8,350 Btu/lb 0.44 % Sulfur	S. Gillette Super-Compliance 8,400 Btu/lb 0.36 % Sulfur	N. Wright Super-Compliance 8,800 Btu/lb 0.35 % Sulfur	S. Wright Ultra-Compliance 8,800 Btu/lb 0.24 % Sulfur
2006	$13.68	$15.12	$16.98	$19.12
2007	$11.92	$13.10	$14.90	$17.23
2008	$5.36	$6.75	$8.17	$10.26
2009	$4.92	$5.57	$6.69	$7.50
2010	$5.14	$5.55	$6.65	$7.55
2011	$4.74	$5.14	$6.18	$6.93
2012	$4.58	$4.98	$6.02	$6.76
2013	$4.78	$5.07	$6.12	$6.96
2014	$4.47	$4.75	$5.79	$6.63
2015	$4.45	$4.73	$5.78	$6.84
2016	$5.11	$5.41	$6.50	$7.95
2017	$5.13	$5.39	$6.50	$7.98
2018	$5.11	$5.37	$6.43	$7.83
2019	$5.11	$5.34	$6.41	$7.36
2020	$5.06	$5.32	$6.39	$7.69
2021	$6.53	$6.82	$7.95	$8.38
2022	$6.58	$6.85	$7.99	$8.36
2023	$8.66	$8.90	$10.14	$10.37
2024	$8.64	$8.89	$10.14	$10.31
2025	$8.78	$9.06	$10.30	$10.48
2026	$8.60	$8.86	$10.09	$10.24
2027	$9.50	$9.77	$11.04	$11.11
2028	$9.92	$10.18	$11.48	$11.50
2029	$10.33	$10.60	$11.91	$11.89
2030	$10.75	$11.02	$12.35	$12.27

Table A.4-5
Latin America Coal Price Forecasts
(Commodity, Real 2005 $/ton)[1]

Year	Latin America High Btu 13,000 Btu/lb 0.60 % Sulfur	Latin America Mid Btu 12,000 Btu/lb 1.17 % Sulfur
2006	$50.74	$43.75
2007	$53.32	$48.17
2008	$52.52	$47.45
2009	$52.15	$47.12
2010	$51.67	$46.87
2011	$50.54	$46.51
2012	$48.66	$44.99
2013	$46.92	$43.07
2014	$46.73	$43.06
2015	$44.90	$41.56
2016	$42.76	$39.58
2017	$40.73	$37.71
2018	$38.10	$35.27
2019	$37.13	$34.38
2020	$36.74	$34.01
2021	$36.14	$33.45
2022	$35.74	$33.08
2023	$34.99	$32.39
2024	$34.10	$31.56
2025	$33.07	$30.61
2026	$33.07	$30.61
2027	$32.02	$29.64
2028	$31.29	$28.97
2029	$30.57	$28.30
2030	$29.84	$27.62

[1] Commodity price forecasts are for FOB Bolivar, Colombia.

Table A.4-6
Petcoke Price Forecasts
(Commodity, Real 2005 $/ton)

Year	Gulf Region 14,000 Btu/lb Low Sulfur High Grind	Gulf Region 14,000 Btu/lb Low Sulfur Low Grind	Gulf Region 14,000 Btu/lb High Sulfur High Grind	Gulf Region 14,000 Btu/lb High Sulfur Low Grind
2006	$20.35	$18.99	$15.45	$14.09
2007	$20.35	$18.99	$15.45	$14.09
2008	$20.35	$18.99	$15.45	$14.09
2009	$20.35	$18.99	$15.45	$14.09
2010	$20.35	$18.99	$15.45	$14.09
2011	$20.35	$18.99	$15.45	$14.09
2012	$20.35	$18.99	$15.45	$14.09
2013	$20.35	$18.99	$15.45	$14.09
2014	$20.35	$18.99	$15.45	$14.09
2015	$20.35	$18.99	$15.45	$14.09
2016	$20.35	$18.99	$15.45	$14.09
2017	$20.35	$18.99	$15.45	$14.09
2018	$20.35	$18.99	$15.45	$14.09
2019	$20.35	$18.99	$15.45	$14.09
2020	$20.35	$18.99	$15.45	$14.09
2021	$20.35	$18.99	$15.45	$14.09
2022	$20.35	$18.99	$15.45	$14.09
2023	$20.35	$18.99	$15.45	$14.09
2024	$20.35	$18.99	$15.45	$14.09
2025	$20.35	$18.99	$15.45	$14.09
2026	$20.35	$18.99	$15.45	$14.09
2027	$20.35	$18.99	$15.45	$14.09
2028	$20.35	$18.99	$15.45	$14.09
2029	$20.35	$18.99	$15.45	$14.09
2030	$20.35	$18.99	$15.45	$14.09

Table A.4-7
Natural Gas Price Forecasts
(Real 2005 $/MBtu)

Year	Henry Hub
2006	$9.02
2007	$8.35
2008	$7.20
2009	$6.12
2010	$5.36
2011	$5.10
2012	$5.20
2013	$5.31
2014	$5.41
2015	$5.52
2016	$5.63
2017	$5.74
2018	$5.86
2019	$5.98
2020	$6.09
2021	$6.22
2022	$6.34
2023	$6.47
2024	$6.60
2025	$6.73
2026	$6.86
2027	$7.00
2028	$7.14
2029	$7.28
2030	$7.43

Table A.4-8
Gulf Coast Fuel Oil Price Forecasts
(Commodity, Real 2005 $/bbl)

Year	No. 2 Distillate 0.5 % Sulfur	No. 2 Distillate 0.05 % Sulfur	No. 2 Distillate 0.0015 % Sulfur	No. 6 Residual 1 % Sulfur	No. 6 Residual 3 % Sulfur
2006	$73.31	$74.63	$77.15	$45.32	$37.32
2007	$63.90	$64.95	$69.13	$41.79	$34.80
2008	$60.75	$61.71	$65.69	$40.26	$33.65
2009	$57.83	$58.71	$62.69	$38.79	$32.54
2010	$54.48	$55.25	$59.33	$37.03	$31.17
2011	$52.12	$52.83	$57.90	$35.74	$30.17
2012	$51.66	$52.36	$56.89	$35.50	$29.98
2013	$51.64	$52.34	$56.38	$35.48	$29.97
2014	$51.64	$52.34	$55.94	$35.48	$29.97
2015	$51.72	$52.42	$55.64	$35.53	$30.00
2016	$52.38	$53.09	$56.31	$35.88	$30.28
2017	$53.15	$53.89	$57.11	$36.31	$30.62
2018	$53.95	$54.70	$57.93	$36.74	$30.96
2019	$54.76	$55.53	$58.75	$37.18	$31.28
2020	$55.56	$56.38	$59.59	$37.61	$31.62
2021	$56.40	$57.22	$60.45	$38.05	$31.96
2022	$57.23	$58.09	$61.31	$38.48	$32.29
2023	$58.08	$58.97	$62.19	$38.92	$32.63
2024	$58.95	$59.85	$63.08	$39.36	$32.97
2025	$59.82	$60.75	$63.97	$40.25	$33.64
2026	$60.71	$61.67	$64.89	$40.25	$33.64
2027	$61.62	$62.61	$65.83	$40.69	$33.98
2028	$62.54	$63.55	$66.77	$41.14	$34.31
2029	$63.46	$64.50	$67.73	$41.59	$34.65
2030	$64.40	$65.47	$68.70	$42.03	$34.98

A.4.6.6 Rail Transportation Rate Forecasts

Forecasted rail rates through 2030 were provided by Hellerworx for rail transportation of coal from selected origins to the proposed TEC site and are presented in Table A.4-9. The TEC site will be served by the Georgia & Florida Railway, Inc. (GFRR), which means that the site will have access to competitive rail service. The GFRR connects with CSX Transportation (CSXT) at Quitman, Georgia (approximately 49 rail miles north of Perry, Florida) and with Norfolk Southern (NS) at Adel, Georgia (approximately 77 rail miles north of Perry, Florida). CSXT has trackage rights over the GFRR line between Quitman and Perry, so CSXT can provide "run-through" transportation service over the line, at rates projected to be essentially equivalent to CSXT-direct service. NS can provide transportation competition for almost all of the coals transported by CSXT via its interchange with GFRR at Adel, Georgia.

Since late 2003, railroads have been much more aggressive in seeking rate increases from coal shippers, often seeking double-digit rate increases upon expiration of existing contracts. Rate increases applicable to competitively served coal shippers within the State of Florida (which are estimated to have totaled approximately 25 percent over the past 2 years) are included in the base rate assumptions. Rate increases of this magnitude are not expected to be applied to base rates for competitive movements in the future. A portion of the recent rail rate increases can be attributed to the fuel surcharges that railroads began to impose as world oil prices began to increase sharply. The base rates forecasted incorporate the current diesel fuel prices. However, these surcharges are not treated explicitly in the forecast, since the surcharges generally average only 2 to 3 percent of the overall rate over a fairly wide range of oil prices.

Rail transportation rates were forecasted based on a model of bidding behavior known as "next best" pricing. On any route where there is competition between railroads, the rail rate is expected to be determined by the lowest amount the railroad with the second best route is willing to bid. The railroad with the best route would generally be expected to bid just below its estimate of the "second best" railroad's bid, in order to maximize the value of its superior route. Forecasts were developed for 2005, which reflect recent rail price increases, and were then escalated assuming a decline of 1 percent per year in real terms. The real decline in rates is consistent with experience with major railroads' past pricing practices for competitive rail movements, which are usually a percentage of the standard Rail Cost Adjustment Factor Index Unadjusted for Productivity (known as RCAF-U). Competitive movements generally receive more favorable contract escalation terms than movements captive to a single railroad.

Table A.4-9
Rail Rate Forecasts
(Real 2005 $/ton)

Year	CAPP 12,400 Btu/lb 0.70 % Sulfur	CAPP 12,000 Btu/lb 1.00 % Sulfur	NAPP 13,115 Btu/lb 1.60 % Sulfur	NAPP 13,115 Btu/lb 2.50 % Sulfur
2006	$18.91	$19.50	$26.33	$26.33
2007	$18.72	$19.31	$26.07	$26.07
2008	$18.53	$19.11	$25.81	$25.81
2009	$18.35	$18.92	$25.55	$25.55
2010	$18.16	$18.73	$25.30	$25.30
2011	$17.98	$18.55	$25.04	$25.04
2012	$17.80	$18.36	$24.79	$24.79
2013	$17.62	$18.18	$24.55	$24.55
2014	$17.45	$18.00	$24.30	$24.30
2015	$17.27	$17.82	$24.06	$24.06
2016	$17.10	$17.64	$23.82	$23.82
2017	$16.93	$17.46	$23.58	$23.58
2018	$16.76	$17.29	$23.34	$23.34
2019	$16.59	$17.11	$23.11	$23.11
2020	$16.43	$16.94	$22.88	$22.88
2021	$16.26	$16.77	$22.65	$22.65
2022	$16.10	$16.61	$22.42	$22.42
2023	$15.94	$16.44	$22.20	$22.20
2024	$15.78	$16.28	$21.98	$21.98
2025	$15.62	$16.11	$21.76	$21.76
2026	$15.47	$15.95	$21.54	$21.54
2027	$15.31	$15.79	$21.32	$21.32
2028	$15.16	$15.63	$21.11	$21.11
2029	$15.01	$15.48	$20.90	$20.90
2030	$14.86	$15.32	$20.69	$20.69

Table A.4-9 (Continued)
Rail Rate Forecasts
(Real 2005 $/ton)

Year	ILB 11,000 Btu/lb 3.00 % Sulfur	ILB 11,000 Btu/lb 3.00 % Sulfur	PRB 8,800 Btu/lb 0.35 % Sulfur	PRB 8,400 Btu/lb 0.35 % Sulfur	South America 11,000 - 11,800 Btu/lb 1.00 % Sulfur
2006	$25.84	$25.84	$33.07	$33.07	$8.51
2007	$25.58	$25.58	$32.74	$32.74	$8.43
2008	$25.32	$25.32	$32.41	$32.41	$8.34
2009	$25.07	$25.07	$32.08	$32.08	$8.26
2010	$24.82	$24.82	$31.76	$31.76	$8.18
2011	$24.57	$24.57	$31.45	$31.45	$8.10
2012	$24.33	$24.33	$31.13	$31.13	$8.02
2013	$24.08	$24.08	$30.82	$30.82	$7.94
2014	$23.84	$23.84	$30.51	$30.51	$7.86
2015	$23.60	$23.60	$30.21	$30.21	$7.78
2016	$23.37	$23.37	$29.90	$29.90	$7.70
2017	$23.13	$23.13	$29.61	$29.61	$7.62
2018	$22.90	$22.90	$29.31	$29.31	$7.55
2019	$22.67	$22.67	$29.02	$29.02	$7.47
2020	$22.45	$22.45	$28.73	$28.73	$7.40
2021	$22.22	$22.22	$28.44	$28.44	$7.32
2022	$22.00	$22.00	$28.15	$28.15	$7.25
2023	$21.78	$21.78	$27.87	$27.87	$7.18
2024	$21.56	$21.56	$27.59	$27.59	$7.11
2025	$21.35	$21.35	$27.32	$27.32	$7.03
2026	$21.13	$21.13	$27.04	$27.04	$6.96
2027	$20.92	$20.92	$26.77	$26.77	$6.89
2028	$20.71	$20.71	$26.51	$26.51	$6.83
2029	$20.51	$20.51	$26.24	$26.24	$6.76
2030	$20.30	$20.30	$25.98	$25.98	$6.69

A.4.6.7 Ocean Vessel and Ocean Barge Rate Forecasts

SSY provided dry bulk carrier freight rate projections through 2030 for coal imports into Florida. The forecasts, shown in Table A.4-10, were developed on a spot charter basis for Handymax (modern vessels lifting approximately 43,000 tons) deliveries from Bolivar, Colombia to Jacksonville and from Bolivar, Colombia to Tampa and for Panamax (modern vessels lifting approximately 60,000 tons) deliveries from Bolivar, Colombia to Jacksonville.

Dry bulk freight rates surged to unprecedented levels in 2004 and into 2005, primarily as a result of record Chinese-led increases in seaborne dry bulk trade. The rapid acceleration in cargo volumes overwhelmed increases in fleet supply, putting enormous pressure on the rail and port infrastructure serving global dry bulk trade. As a result, incidences of port delays increased, which in turn tied up a significant number of ships.

The growth in Chinese dry cargo imports in 2004 resulted in the country's port and rail infrastructure having difficulty in handling the volume. Together with the economic slowdown measures introduced by the Chinese government at the end of April 2004, growth in China's imports of raw materials was temporarily moderated. Further measures were introduced in 2005, signaling the Chinese government's determination to prevent certain sectors of the economy from growing at an unsustainable rate. Nonetheless, China is expected to remain a strong influence in the growth of dry bulk trade.

Outside of China, world trade in key industrial cargoes is expected to increase. Factored into this is the prospect of increased Asian steam coal imports from the introduction of new coal fired power generating capacity, plus expansion in the steel industry of India and upside potential for China's grain imports. Combined, these factors will likely ensure that the dry bulk trade over the balance of the decade remains above historical averages. Beyond 2010, SSY expects that the rate of demand growth will slow with a gradual return toward the long-term annual growth rate of 2.5 to 3.0 percent compared to the 6.0 to 8.0 percent annual growth rate experienced over the past few years.

The trend in previous bulk shipping cycles has been the undermining of freight rates by the rising supply of new building activities. Capacity additions increased during 2005, and a record volume of new vessels entered service; however, potential growth nonetheless was constrained by the high number of vessels on order at the world's leading shipyards. Consequently, between 2006 and 2007, SSY does not believe deliveries will significantly exceed 2005 levels. However, the new capacity going into service in China over the mid- to long-term is expected to raise the underlying rate of dry bulk carrier new building additions.

Table A.4-10
Vessel Rate Forecasts
(Real 2005 $/ton)

Year	Handymax Bolivar/Jacksonville	Handymax Bolivar/Tampa	Panamax Bolivar/Jacksonville
2006	$11.34	$12.02	$7.26
2007	$9.07	$9.53	$6.35
2008	$11.79	$12.47	$8.62
2009	$13.15	$14.29	$8.85
2010	$12.25	$13.15	$8.71
2011	$11.34	$12.02	$7.26
2012	$8.85	$9.30	$5.90
2013	$8.39	$8.85	$5.22
2014	$9.07	$9.53	$6.35
2015	$11.34	$12.02	$7.26
2016	$11.61	$12.38	$8.39
2017	$11.34	$12.02	$7.26
2018	$10.21	$10.89	$6.71
2019	$11.34	$12.02	$7.26
2020	$11.79	$12.70	$8.62
2021	$12.25	$13.15	$8.71
2022	$11.57	$12.25	$7.44
2023	$10.43	$11.11	$6.80
2024	$12.25	$13.15	$8.71
2025	$13.15	$14.29	$8.85
2026	$12.47	$13.38	$8.75
2027	$11.34	$12.02	$7.26
2028	$11.79	$12.70	$8.62
2029	$12.93	$13.83	$8.85
2030	$13.38	$14.29	$8.94

After 2010, the potential for a prolonged period of dry bulk carrier oversupply increases, since regulatory requirements for the replacement of single-hulled oil tankers will be complete, adequate fleet supply will be available, and as a consequence there is likely to be surplus shipbuilding capacity. However, another consequence of the heightened freight market has been the deferral of vessel demolition. The rate of vessel demolition is extremely responsive to the freight market cycle, although typically dry bulk carriers are scrapped after 25 to 30 years of service. Currently, even the oldest vessels are in demand and profitable. However, more than 10 percent of the dry bulk vessels are older than 25 years, and an additional 20 percent are between 20 to 24 years old, providing a significant potential for accelerated demolition once the freight markets enter a period of severe downsizing.

A.4.6.8 Delivered Fuel Price Methodology and Forecasts

TEC Fuels developed delivered price forecasts for various grades of coals, petcoke, natural gas, and fuel oils (distillate and residual) based on the commodity price forecasts provided by Hill & Associates and Pace Global, the rail transportation rates provided by Hellerworx, and the vessel rates provided by SSY. The delivered fuel forecasts, in nominal (current year) $/MBtu, are presented in Tables A.4-11 through A.4-18 at the end of this subsection, while the remainder of this subsection outlines the procedures used by TEC Fuels to estimate the delivered cost of fuel to the TEC.

A.4.6.8.1 Delivered Coal Price Methodology. Coal price forecasts were provided by Hill & Associates for various qualities and grades in all the major coal producing regions in the United States, along with forecasts for coals mined in Venezuela and Colombia. Commodity, or FOB, forecasts were provided through 2030 in real 2005 $/ton. Hellerworx provided the forecast of rail transportation rates from the various coal producing regions in the United States to the TEC site assuming a competitive rail environment between CSXT and NS. For PRB coals, Hellerworx based its forecast on a competitive environment between the Union Pacific (UP) and Burlington Northern Santa Fe (BNSF) railroads for deliveries to interconnections with both CSXT and NS. Hellerworx also provided a rate forecast for a short haul from a potential water terminal to be constructed in the Jacksonville, Florida area to the TEC (to accommodate delivery of imported coals). The rail transportation rate forecasts were provided in real 2005 $/ton.

SSY provided the forecasted shipping rates from a common point in Bolivar, Colombia to Jacksonville, Florida for two different sized vessels (Handymax and Panamax). Freight rates were provided by SSY in real 2005 $/ton. TEC Fuels estimated a transloading rate for coals delivered to a water based terminal, which was intended to cover the cost of moving products from the ship to the land and then from the land to railcars.

To develop the forecast of delivered coal prices, TEC Fuels combined the commodity and rail and vessel transportation cost components, in real 2005 $/ton. For domestic coals, the Hellerworx rail forecasts were added to the Hill & Associates coal price forecasts. For Latin American coals (Colombian and Venezuelan), the commodity price forecasts from Hill & Associates were added to the shipping rates from Bolivar to Jacksonville provided by SSY, which were then combined with the transloading rates developed by TEC Fuels and the short haul rates from Jacksonville to the TEC site provided by Hellerworx. The resulting delivered coal price forecasts were converted from a real 2005 $/ton basis to a real 2005 $/MBtu basis using the heating content of each coal type, and the real 2005 $/MBtu forecasts were then converted to nominal (current year) $/MBtu, based on an annual inflation rate of 2.5 percent.

A.4.6.8.2 Delivered Petcoke Price Methodology. Petcoke price forecasts were provided by Hill & Associates for various qualities (high and low sulfur and high and low grind quality specifications) for purchase along the US Gulf Coast in real 2005 $/ton. TEC Fuels estimated a barge freight rate from the US Gulf Coast region to the Jacksonville, Florida area in real 2005 $/ton.

To develop the forecast of delivered petcoke prices, TEC Fuels combined the commodity and barge transportation cost components in real 2005 $/ton. The transloading rates projected by TEC Fuels and the short haul rates from Jacksonville to the TEC site provided by Hellerworx were then added. The resulting delivered coal price forecasts were converted from a real 2005 $/ton basis to a real 2005 $/MBtu basis using the heating content of the petcoke, and the real 2005 $/MBtu forecasts were then converted to nominal (current year) $/MBtu, based on an annual inflation rate of 2.5 percent.

A.4.6.8.3 Delivered Natural Gas Price Methodology. Pace Global provided the forecasted natural gas prices at the Henry Hub in Louisiana through 2030 in real 2005 $/MBtu. TEC Fuels estimated a long-term variable charge for delivery of natural gas from Louisiana to the TEC site, which was added to the Henry Hub forecasts provided by Pace Global. The variable charge developed consists of two components: a transportation fuel rate equal to 3.0 percent of the annual Henry Hub natural gas forecast and a variable usage fee for the delivery pipeline of $0.05/MBtu. Fixed costs for pipeline demand charges were not included in the forecasted natural gas prices. The variable delivered natural gas cost in real 2005 $/MBtu were then converted to nominal (current year) $/MBtu, based on an annual inflation rate of 2.5 percent.

A.4.6.8.4 Delivered Fuel Oil Price Methodology. Pace Global provided TEC Fuels with forecasted distillate and residual fuel oil prices in the Gulf Coast market region through 2030 in real 2005 $/barrel. TEC Fuels added $5/barrel (in real 2005 dollars) to the distillate fuel oil forecast provided by Pace Global to arrive at a delivered cost to the TEC site. No surcharge was added to the residual fuel oil forecast, based on historical ability to purchase residual oil below typical Gulf Coast pricing. The resulting delivered fuel oil price forecasts were converted from a real 2005 $/barrel basis to a real 2005 $/MBtu basis using the heating contents of No. 2 distillate fuel oil and No. 6 residual fuel oil, and the real 2005 $/MBtu forecasts were then converted to nominal (current year) $/MBtu, based on an annual inflation rate of 2.5 percent.

A.4.7 Fuel Price Sensitivity Cases

The fuel price forecasts discussed throughout Section A.4.6 represent the base case fuel price forecasts, which will be considered in the base case economic evaluations presented in Section 6.0 of Volumes B through E and several of the sensitivity cases considered in Section 7.0 of Volumes B through E. In addition to the base case fuel forecasts, Hill & Associates and TEC Fuels developed fuel price projections for three separate sensitivity scenarios including a high fuel price scenario, a low fuel price scenario, and a scenario that considers the potential effect on fuel prices resulting from CO_2 regulations in the United States. Each of these sensitivity cases is described in the remainder of this section, with the corresponding delivered fuel prices presented as well. These delivered fuel price projections will subsequently be analyzed in Section 7.0 of Volumes B through E. Similar to the base case, the emissions allowance price forecasts for each of the fuel sensitivity cases are presented in Section A.5.0.

A.4.7.1 High Fuel Price Forecast

The high commodity fuel price projections for coal, natural gas, and fuel oil were developed by Hill & Associates by changing fundamental coal and natural gas market drivers. The annual base case commodity natural gas and fuel oil projections were increased by 20 percent, and coal prices were increased by discouraging investment in new mine capacity through increasing investment hurdles relative to the base case. The high fuel price scenario also increases the base case electricity demand growth by 0.2 percent year-to-year (i.e., if the base case growth rate between 2006 and 2007 was 2.3 percent, it was increased to 2.5 percent for the high case).

Table A.4-11
Central Appalachia Coal Price Forecasts
(Delivered, Nominal $/MBtu)

Year	S. WV-Hi Btu Super-Compliance 13,150 Btu/lb 0.62 % Sulfur	S. WV-Hi Btu Super-Compliance 13,100 Btu/lb 0.65 % Sulfur	S. WV-Mid Btu Compliance 12,200 Btu/lb 0.67 % Sulfur	S. WV-Mid Btu Compliance 12,350 Btu/lb 0.67 % Sulfur	S. WV-Mid Btu Near-Compliance 12,200 Btu/lb 0.82 % Sulfur	S. WV-Mid Btu Near-Compliance 12,250 Btu/lb 0.98 % Sulfur	S. WV-Mid Btu Mid-Sulfur 12,500 Btu/lb 1.67 % Sulfur	S. WV-Mid Btu Mid-Sulfur 12,800 Btu/lb 1.67 % Sulfur
2006	$3.56	$3.54	$3.60	$3.64	$3.33	$3.44	$3.10	$2.46
2007	$3.19	$3.27	$3.36	$3.26	$2.93	$3.00	$2.83	$2.39
2008	$2.69	$2.82	$2.90	$2.85	$2.71	$2.79	$2.63	$2.38
2009	$2.49	$2.49	$2.49	$2.50	$2.40	$2.42	$2.39	$2.42
2010	$2.52	$2.56	$2.51	$2.57	$2.42	$2.47	$2.43	$2.46
2011	$2.57	$2.60	$2.54	$2.59	$2.46	$2.53	$2.48	$2.54
2012	$2.65	$2.69	$2.63	$2.67	$2.54	$2.60	$2.53	$2.59
2013	$2.72	$2.77	$2.70	$2.76	$2.61	$2.70	$2.61	$2.69
2014	$2.79	$2.81	$2.76	$2.79	$2.66	$2.73	$2.67	$2.72
2015	$2.86	$2.86	$2.84	$2.85	$2.73	$2.78	$2.74	$2.77
2016	$2.97	$3.00	$2.91	$2.96	$2.84	$2.89	$2.83	$2.88
2017	$3.04	$3.07	$2.98	$3.01	$2.90	$2.95	$2.89	$2.95
2018	$3.15	$3.16	$3.08	$3.10	$3.00	$3.04	$2.99	$3.05
2019	$3.20	$3.20	$3.15	$3.17	$3.07	$3.10	$3.06	$3.11
2020	$3.29	$3.30	$3.21	$3.23	$3.13	$3.15	$3.11	$3.16
2021	$3.43	$3.43	$3.33	$3.36	$3.23	$3.29	$3.22	$3.30
2022	$3.49	$3.50	$3.40	$3.45	$3.30	$3.37	$3.28	$3.38
2023	$3.64	$3.63	$3.53	$3.60	$3.43	$3.52	$3.43	$3.53
2024	$3.70	$3.74	$3.62	$3.73	$3.52	$3.64	$3.55	$3.66
2025	$3.86	$3.84	$3.71	$3.83	$3.61	$3.74	$3.64	$3.75
2026	$3.95	$3.94	$3.80	$3.91	$3.68	$3.81	$3.71	$3.82
2027	$4.08	$4.07	$3.92	$4.07	$3.80	$3.96	$3.86	$3.97
2028	$4.21	$4.19	$4.03	$4.20	$3.90	$4.08	$3.98	$4.09
2029	$4.33	$4.31	$4.14	$4.33	$4.01	$4.21	$4.10	$4.22
2030	$4.47	$4.44	$4.25	$4.47	$4.11	$4.34	$4.23	$4.35

Table A.4-11 (Continued)
Central Appalachia Coal Price Forecasts
(Delivered, Nominal $/MBtu)

Year	E. KY-Hi Btu Super-Compliance 13,100 Btu/lb 0.57 % Sulfur	E. KY-Hi Btu Super-Compliance 13,150 Btu/lb 0.65 % Sulfur	E. KY-Mid Btu Compliance 12,700 Btu/lb 0.67 % Sulfur	E. KY-Mid Btu Compliance 12,500 Btu/lb 0.69 % Sulfur	E. KY-Mid Btu Near-Compliance 12,300 Btu/lb 1.00 % Sulfur	E. KY-Mid Btu Near-Compliance 12,600 Btu/lb 1.12 % Sulfur	E. KY-Mid Btu Mid-Sulfur 12,100 Btu/lb 1.74 % Sulfur	E. KY-Mid Btu Mid-Sulfur 12,300 Btu/lb 1.75 % Sulfur
2006	$3.58	$2.91	$3.43	$3.61	$3.26	$3.32	$2.59	$2.54
2007	$3.26	$2.77	$3.12	$3.11	$2.84	$2.88	$2.49	$2.46
2008	$2.76	$2.88	$2.70	$2.74	$2.57	$2.69	$2.41	$2.41
2009	$2.48	$2.47	$2.40	$2.47	$2.36	$2.33	$2.43	$2.37
2010	$2.51	$2.54	$2.42	$2.53	$2.40	$2.37	$2.47	$2.41
2011	$2.56	$2.58	$2.45	$2.55	$2.46	$2.44	$2.52	$2.47
2012	$2.64	$2.66	$2.52	$2.64	$2.53	$2.51	$2.60	$2.54
2013	$2.71	$2.75	$2.59	$2.72	$2.61	$2.60	$2.68	$2.64
2014	$2.78	$2.78	$2.65	$2.76	$2.67	$2.64	$2.74	$2.67
2015	$2.85	$2.85	$2.73	$2.81	$2.74	$2.68	$2.81	$2.72
2016	$2.94	$2.98	$2.80	$2.92	$2.84	$2.79	$2.91	$2.84
2017	$3.01	$3.05	$2.86	$2.97	$2.89	$2.84	$2.96	$2.90
2018	$3.13	$3.14	$2.95	$3.06	$2.99	$2.93	$3.07	$3.00
2019	$3.18	$3.18	$3.03	$3.13	$3.07	$2.99	$3.14	$3.07
2020	$3.25	$3.28	$3.08	$3.18	$3.12	$3.05	$3.19	$3.12
2021	$3.38	$3.40	$3.19	$3.32	$3.20	$3.18	$3.27	$3.25
2022	$3.44	$3.48	$3.26	$3.41	$3.28	$3.26	$3.35	$3.33
2023	$3.59	$3.60	$3.39	$3.56	$3.41	$3.40	$3.48	$3.48
2024	$3.68	$3.71	$3.48	$3.69	$3.51	$3.52	$3.59	$3.59
2025	$3.80	$3.81	$3.60	$3.78	$3.61	$3.62	$3.69	$3.68
2026	$3.89	$3.91	$3.66	$3.87	$3.68	$3.70	$3.76	$3.76
2027	$4.02	$4.04	$3.79	$4.02	$3.81	$3.84	$3.89	$3.90
2028	$4.15	$4.16	$3.90	$4.15	$3.92	$3.97	$4.00	$4.01
2029	$4.27	$4.28	$4.02	$4.29	$4.04	$4.09	$4.12	$4.14
2030	$4.40	$4.41	$4.14	$4.42	$4.16	$4.22	$4.24	$4.26

Table A.4-12
Northern Appalachia Coal Price Forecasts
(Delivered, Nominal $/MBtu)

Year	W. PA Mid-Sulfur 13,000 Btu/lb 1.95 % Sulfur	W. PA High-Sulfur 12,200 Btu/lb 3.34 % Sulfur	OH Mid-Sulfur 12,150 Btu/lb 2.20 % Sulfur	OH High-Sulfur 11,750 Btu/lb 3.60 % Sulfur	N. WV Mid-Sulfur 12,900 Btu/lb 2.10 % Sulfur	N. WV High-Sulfur 12,350 Btu/lb 3.60 % Sulfur
2006	$3.10	$3.23	$3.03	$2.92	$3.20	$3.20
2007	$2.85	$3.03	$2.77	$2.68	$2.97	$2.94
2008	$2.63	$2.60	$2.58	$2.69	$2.71	$2.73
2009	$2.71	$2.71	$2.74	$2.74	$2.68	$2.77
2010	$2.73	$2.73	$2.79	$2.76	$2.71	$2.79
2011	$2.77	$2.75	$2.82	$2.80	$2.75	$2.84
2012	$2.86	$2.84	$2.91	$2.89	$2.83	$2.92
2013	$2.92	$2.90	$2.99	$2.97	$2.92	$2.98
2014	$2.97	$2.96	$3.03	$3.00	$2.98	$3.03
2015	$3.01	$3.01	$3.09	$3.06	$3.01	$3.07
2016	$3.10	$3.09	$3.21	$3.16	$3.13	$3.14
2017	$3.17	$3.16	$3.29	$3.23	$3.21	$3.21
2018	$3.33	$3.33	$3.55	$3.50	$3.36	$3.35
2019	$3.43	$3.45	$3.64	$3.58	$3.45	$3.46
2020	$3.46	$3.47	$3.69	$3.79	$3.49	$3.49
2021	$3.59	$3.58	$3.81	$3.86	$3.61	$3.61
2022	$3.67	$3.66	$3.89	$3.95	$3.68	$3.70
2023	$3.82	$3.81	$4.06	$4.13	$3.85	$3.82
2024	$3.92	$3.92	$4.21	$4.28	$3.94	$3.90
2025	$4.02	$4.01	$4.35	$4.38	$4.05	$3.98
2026	$4.10	$4.13	$4.43	$4.47	$4.12	$4.08
2027	$4.24	$4.26	$4.62	$4.64	$4.27	$4.18
2028	$4.36	$4.39	$4.77	$4.79	$4.39	$4.28
2029	$4.48	$4.52	$4.93	$4.94	$4.51	$4.38
2030	$4.61	$4.66	$5.10	$5.09	$4.64	$4.49

Table A.4-13
Illinois Basin Coal Price Forecasts
(Delivered, Nominal $/MBtu)

Year	IN Compliance 11,100 Btu/lb 0.58 % Sulfur	IN Near-Compliance 10,950 Btu/lb 1.10 % Sulfur	IN Mid-Sulfur 11,000 Btu/lb 1.70 % Sulfur	IN High-Sulfur 11,100 Btu/lb 3.05 % Sulfur	IL Near-Compliance 11,800 Btu/lb 1.30 % Sulfur	IL Mid-Sulfur 11,550 Btu/lb 1.70 5 Sulfur	IL High-Sulfur 11,150 Btu/lb 3.00 % Sulfur	W. KY Near-Compliance 11,900 Btu/lb 0.98 % Sulfur	W. KY High-Sulfur 11,600 Btu/lb 3.19 % Sulfur
2006	$4.15	$3.37	$3.29	$2.93	$3.10	$3.12	$3.03	$3.11	$2.80
2007	$3.78	$3.02	$3.01	$2.73	$2.83	$2.84	$2.73	$2.97	$2.46
2008	$3.41	$2.86	$2.78	$2.60	$2.68	$2.66	$2.62	$2.96	$2.46
2009	$2.85	$2.72	$2.70	$2.65	$2.55	$2.63	$2.62	$2.81	$2.53
2010	$2.90	$2.74	$2.73	$2.66	$2.58	$2.65	$2.64	$2.76	$2.56
2011	$2.93	$2.79	$2.82	$2.73	$2.62	$2.70	$2.70	$2.82	$2.61
2012	$2.97	$2.84	$2.90	$2.78	$2.67	$2.74	$2.74	$2.89	$2.66
2013	$3.06	$2.91	$2.96	$2.83	$2.74	$2.81	$2.79	$2.93	$2.70
2014	$3.12	$2.96	$2.97	$2.88	$2.79	$2.86	$2.82	$2.95	$2.75
2015	$3.17	$3.02	$3.02	$2.91	$2.86	$2.92	$2.88	$3.01	$2.80
2016	$3.23	$3.13	$3.12	$3.00	$2.96	$3.01	$2.95	$3.08	$2.86
2017	$3.27	$3.17	$3.20	$3.05	$3.01	$3.05	$2.98	$3.13	$2.90
2018	$3.34	$3.27	$3.28	$3.17	$3.14	$3.14	$3.06	$3.21	$2.97
2019	$3.41	$3.44	$3.40	$3.27	$3.20	$3.21	$3.14	$3.28	$3.05
2020	$3.47	$3.53	$3.46	$3.29	$3.24	$3.25	$3.16	$3.33	$3.07
2021	$3.55	$3.60	$3.51	$3.37	$3.34	$3.33	$3.23	$3.44	$3.15
2022	$3.60	$3.63	$3.54	$3.42	$3.40	$3.39	$3.30	$3.47	$3.19
2023	$3.72	$3.75	$3.67	$3.54	$3.54	$3.52	$3.42	$3.61	$3.31
2024	$3.81	$3.86	$3.76	$3.62	$3.62	$3.62	$3.51	$3.70	$3.37
2025	$3.87	$3.91	$3.84	$3.69	$3.72	$3.70	$3.65	$3.78	$3.43
2026	$3.92	$3.95	$3.91	$3.75	$3.78	$3.77	$3.67	$3.83	$3.49
2027	$4.03	$4.07	$4.02	$3.86	$3.90	$3.89	$3.81	$3.95	$3.59
2028	$4.11	$4.15	$4.12	$3.95	$4.00	$3.99	$3.92	$4.05	$3.67
2029	$4.20	$4.24	$4.22	$4.04	$4.11	$4.10	$4.03	$4.15	$3.75
2030	$4.29	$4.33	$4.32	$4.13	$4.22	$4.20	$4.15	$4.25	$3.83

Table A.4-14
PRB Coal Price Forecasts
(Delivered, Nominal $/MBtu)

Year	N. Gillette Compliance 8,350 Btu/lb 0.44 % Sulfur	S. Gillette Super-Compliance 8,400 Btu/lb 0.36 % Sulfur	N. Wright Super-Compliance 8,800 Btu/lb 0.35 % Sulfur	S. Wright Ultra-Compliance 8,800 Btu/lb 0.24 % Sulfur
2006	$2.87	$2.94	$2.91	$3.04
2007	$2.81	$2.87	$2.84	$2.98
2008	$2.44	$2.51	$2.48	$2.61
2009	$2.45	$2.47	$2.43	$2.48
2010	$2.50	$2.51	$2.47	$2.53
2011	$2.51	$2.53	$2.48	$2.53
2012	$2.54	$2.56	$2.51	$2.56
2013	$2.60	$2.60	$2.56	$2.62
2014	$2.62	$2.62	$2.58	$2.64
2015	$2.66	$2.66	$2.62	$2.69
2016	$2.75	$2.76	$2.71	$2.82
2017	$2.80	$2.80	$2.76	$2.87
2018	$2.84	$2.85	$2.80	$2.91
2019	$2.89	$2.89	$2.84	$2.92
2020	$2.93	$2.94	$2.89	$3.00
2021	$3.11	$3.12	$3.07	$3.11
2022	$3.16	$3.17	$3.12	$3.16
2023	$3.41	$3.41	$3.37	$3.39
2024	$3.47	$3.47	$3.43	$3.44
2025	$3.54	$3.55	$3.50	$3.52
2026	$3.58	$3.59	$3.54	$3.56
2027	$3.74	$3.74	$3.70	$3.71
2028	$3.85	$3.85	$3.81	$3.81
2029	$3.96	$3.97	$3.92	$3.92
2030	$4.08	$4.08	$4.04	$4.03

Table A.4-15
Latin America Coal Price Forecasts
(Delivered, Nominal $/MBtu)

Year	Latin America High Btu 13,000 Btu/lb 0.60 % Sulfur	Latin America Mid Btu 12,000 Btu/lb 1.17 % Sulfur
2006	$2.73	$2.66
2007	$2.86	$2.88
2008	$2.99	$3.01
2009	$3.06	$3.08
2010	$3.10	$3.14
2011	$3.06	$3.12
2012	$2.99	$3.05
2013	$2.94	$2.99
2014	$3.06	$3.12
2015	$3.09	$3.17
2016	$3.11	$3.19
2017	$3.02	$3.10
2018	$2.92	$3.00
2019	$2.97	$3.05
2020	$3.09	$3.18
2021	$3.14	$3.23
2022	$3.11	$3.20
2023	$3.10	$3.19
2024	$3.24	$3.34
2025	$3.26	$3.36
2026	$3.33	$3.43
2027	$3.24	$3.34
2028	$3.36	$3.47
2029	$3.40	$3.52
2030	$3.44	$3.55

Table A.4-16
Petcoke Price Forecasts
(Delivered, Nominal $/MBtu)

Year	Gulf Region 14,000 Btu/lb Low Sulfur High Grind	Gulf Region 14,000 Btu/lb Low Sulfur Low Grind	Gulf Region 14,000 Btu/lb High Sulfur High Grind	Gulf Region 14,000 Btu/lb High Sulfur Low Grind
2006	$1.56	$1.51	$1.38	$1.33
2007	$1.51	$1.46	$1.33	$1.28
2008	$1.65	$1.60	$1.46	$1.41
2009	$1.74	$1.69	$1.55	$1.49
2010	$1.74	$1.69	$1.55	$1.49
2011	$1.75	$1.69	$1.54	$1.49
2012	$1.68	$1.63	$1.48	$1.42
2013	$1.70	$1.65	$1.49	$1.43
2014	$1.77	$1.71	$1.55	$1.49
2015	$1.91	$1.85	$1.69	$1.63
2016	$1.97	$1.91	$1.74	$1.68
2017	$2.00	$1.94	$1.77	$1.70
2018	$2.00	$1.93	$1.75	$1.69
2019	$2.10	$2.03	$1.85	$1.78
2020	$2.17	$2.10	$1.91	$1.84
2021	$2.24	$2.17	$1.98	$1.91
2022	$2.26	$2.18	$1.99	$1.92
2023	$2.25	$2.17	$1.98	$1.90
2024	$2.40	$2.32	$2.12	$2.04
2025	$2.51	$2.43	$2.22	$2.14
2026	$2.53	$2.45	$2.23	$2.15
2027	$2.52	$2.44	$2.22	$2.13
2028	$2.61	$2.52	$2.30	$2.21
2029	$2.74	$2.65	$2.42	$2.33
2030	$2.83	$2.74	$2.51	$2.42

Table A.4-17
Natural Gas Price Forecasts
(Delivered, Nominal $/MBtu)

Year	Henry Hub + Variable Charges
2006	$9.58
2007	$9.10
2008	$8.05
2009	$7.02
2010	$6.31
2011	$6.16
2012	$6.43
2013	$6.73
2014	$7.03
2015	$7.35
2016	$7.68
2017	$8.03
2018	$8.40
2019	$8.78
2020	$9.17
2021	$9.59
2022	$10.02
2023	$10.48
2024	$10.96
2025	$11.45
2026	$11.96
2027	$12.51
2028	$13.08
2029	$13.67
2030	$14.29

Table A.4-18
Gulf Coast Fuel Oil Price Forecasts
(Delivered, Nominal $/MBtu)

Year	No. 2 Distillate 0.5 % Sulfur	No. 2 Distillate 0.05 % Sulfur	No. 2 Distillate 0.0015 % Sulfur	No. 6 Residual 1 % Sulfur	No. 6 Residual 3 % Sulfur
2006	$13.96	$14.19	$14.64	$7.42	$6.11
2007	$12.59	$12.78	$13.54	$7.02	$5.84
2008	$12.31	$12.49	$13.24	$6.93	$5.79
2009	$12.06	$12.23	$12.99	$6.84	$5.74
2010	$11.70	$11.86	$12.66	$6.69	$5.64
2011	$11.52	$11.66	$12.69	$6.62	$5.59
2012	$11.71	$11.86	$12.79	$6.74	$5.69
2013	$12.00	$12.15	$13.01	$6.91	$5.84
2014	$12.30	$12.45	$13.24	$7.08	$5.98
2015	$12.63	$12.78	$13.50	$7.27	$6.14
2016	$13.09	$13.26	$13.99	$7.52	$6.35
2017	$13.60	$13.77	$14.53	$7.80	$6.58
2018	$14.13	$14.31	$15.09	$8.09	$6.82
2019	$14.68	$14.87	$15.67	$8.39	$7.06
2020	$15.25	$15.46	$16.27	$8.70	$7.32
2021	$15.85	$16.06	$16.90	$9.03	$7.58
2022	$16.47	$16.70	$17.55	$9.36	$7.85
2023	$17.11	$17.35	$18.22	$9.70	$8.13
2024	$17.78	$18.03	$18.93	$10.05	$8.42
2025	$18.47	$18.74	$19.65	$10.54	$8.81
2026	$19.19	$19.47	$20.41	$10.80	$9.03
2027	$19.95	$20.24	$21.21	$11.19	$9.35
2028	$20.73	$21.04	$22.03	$11.60	$9.67
2029	$21.53	$21.86	$22.88	$12.02	$10.01
2030	$22.38	$22.72	$23.76	$12.45	$10.36

A.4.7.2 Low Fuel Price Forecast

The low commodity fuel price projections for coal, natural gas, and fuel oil were developed by Hill & Associates by changing fundamental coal and natural gas market drivers. The annual base case commodity natural gas and fuel oil projections were decreased 20 percent, and coal prices were decreased by encouraging investment in new mine capacity through lowering investment hurdles relative to the base case. The low fuel price scenario also decreases the base case electricity demand growth by 0.1 percent year-to-year (i.e., if the base case growth rate between 2006 and 2007 was 2.3 percent, it was decreased to 2.2 percent for the low case).

A.4.7.3 Consideration of Potential Effects of CO_2 Regulations

Although there has been proposed federal legislation designed to limit emissions of CO_2, a "greenhouse gas," there currently is no national or Florida legislation or regulation that either limits or assigns a cost to CO_2 emissions. Even though there are no regulatory programs in place for CO_2 emissions, the Participants evaluated the potential impact on the cost-effectiveness of the Taylor Energy Center if such a regulatory program were adopted. Information about this analysis based on a hypothetical future regulation is presented for information purposes only.

Hill & Associates has developed fuel price projections based on assumptions regarding the regulation of CO_2 emissions generally analogous to the proposed unadopted McCain/Liebermann *Climate Stewardship Act of 2005* (S.342). The *Climate Stewardship Act of 2005* calls for imposing a cap and trade program for CO_2 (and other greenhouse gases) across all segments of the economy.

More specifically, the following aspects of S.342 were adopted by Hill & Associates to develop the regulated-CO_2 fuel price analysis:

- Emissions levels would be capped at year 2000 levels, with no second phase.
- CO_2 emissions allowances would be created.
- CO_2 emissions allowances would be fungible, for both inter- and intra-industries.
- CO_2 emissions offsets could be created from domestic and international sources.

In developing the regulated-CO_2 fuel price analysis, a CO_2 emissions cap had to be designed for just the electric generating units (EGUs), notwithstanding the likelihood of a much more economy-wide national standard as proposed in the *Climate Stewardship Act of 2005*. Hill & Associates developed such a cap based on CO_2 emissions from EGUs as reported by the US Environmental Protection Agency (EPA) for the year 2000 in the preliminary *Summary Emissions Report (Quarter 4: Year-To-Date Values)* as presented at http://www.epa.gov/airmarkets/emissions/prelimarp/index.html.

The preliminary *Summary Emissions Report (Quarter 4: Year-To-Date Values)* reported year 2000 EGU CO_2 emissions as 2.45 billion tons. An additional 10 percent was added to this emissions level to create the actual initial CO_2 emissions cap for the years 2010 through 2014 used by Hill & Associates in developing the CO_2 fuel price sensitivity. Beyond 2014, the CO_2 emissions cap was increased an additional 0.5 percent per year, based on the following:

- The potential for relatively low cost CO_2 reductions by power plants (limiting emissions of other "greenhouse gases," improving station service efficiency, re-forestation on company-owned property, methane capture at coal mines, etc.).
- The potential for low cost CO_2 emissions offsets from other industries.
- Additional CO_2 emissions offsets/credits assigned to EGUs as a result of political expediency in an effort to buffer electricity customers from higher electricity costs.

The regulated-CO_2 fuel price analysis also anticipates other changes in fundamental factors, when compared to the base case forecast, in response to a carbon-constrained economy, including the following:

- A reduction in electricity demand growth. In the regulated-CO_2 fuel price analysis, electricity demand growth was limited to 1.0 percent in any area of the country that had exceeded 1.0 percent in the base case fuel price forecast.
- An increase in the amount of energy produced by renewables or other non-emitting sources (except nuclear). The renewable standards promulgated by regulation/legislation were used in states where such laws exist (as of year end 2005). States with no current renewable standards were projected to have an average of 12.0 percent of their energy produced by non-emitting sources by 2009 (including current non-emitting sources), with a 0.5 percent growth in renewable energy production every year until a maximum of 20 percent was achieved.
- An increase in the amount of nuclear capacity. The regulated-CO_2 fuel price analysis includes 12 new nuclear units coming on line between 2016 and 2020. The base case forecast includes no new nuclear additions throughout the forecast time horizon.

A.4.7.4 Fuel Sensitivity Cases – Delivered Price Methodology

Hill & Associates provided commodity fuel price projections, in real 2005 dollars, for the high fuel price sensitivity case, the low fuel price sensitivity case, and the regulated-CO_2 fuel price analysis. TEC Fuels utilized the same methodology to convert each fuel from real 2005 commodity projections to nominal (current year) $/MBtu as was used in the base case. The delivered fuel price projections for the high fuel price sensitivity case are presented in Tables A.4-19 through A.4-26. The delivered fuel price projections for the low fuel price sensitivity case are presented in Tables A.4-27 through A.4-34. The delivered fuel price projections for the regulated-CO_2 fuel price analysis are presented in Tables A.4-35 through A.4-42.

Table A.4-19
Central Appalachia Coal Price Forecasts – High Fuel Price Sensitivity
(Delivered, Nominal $/MBtu)

Year	S. WV-Hi Btu Super-Compliance 13,150 Btu/lb 0.62 % Sulfur	S. WV-Hi Btu Super-Compliance 13,100 Btu/lb 0.65 % Sulfur	S. WV-Mid Btu Compliance 12,200 Btu/lb 0.67 % Sulfur	S. WV-Mid Btu Compliance 12,350 Btu/lb 0.67 % Sulfur	S. WV-Mid Btu Near-Compliance 12,200 Btu/lb 0.82 % Sulfur	S. WV-Mid Btu Near-Compliance 12,250 Btu/lb 0.98 % Sulfur	S. WV-Mid Btu Mid-Sulfur 12,500 Btu/lb 1.67 % Sulfur	S. WV-Mid Btu Mid-Sulfur 12,800 Btu/lb 1.67 % Sulfur
2006	$3.70	$3.65	$3.74	$3.67	$3.35	$3.42	$3.13	$2.48
2007	$3.33	$3.39	$3.45	$3.36	$2.99	$3.03	$2.83	$2.41
2008	$2.80	$2.91	$3.00	$2.93	$2.78	$2.84	$2.63	$2.40
2009	$2.56	$2.54	$2.55	$2.56	$2.46	$2.46	$2.44	$2.47
2010	$2.59	$2.60	$2.58	$2.61	$2.49	$2.51	$2.47	$2.50
2011	$2.67	$2.69	$2.64	$2.68	$2.55	$2.62	$2.55	$2.61
2012	$2.76	$2.78	$2.75	$2.76	$2.65	$2.69	$2.64	$2.68
2013	$2.84	$2.86	$2.82	$2.85	$2.71	$2.76	$2.70	$2.75
2014	$2.86	$2.90	$2.84	$2.89	$2.74	$2.80	$2.74	$2.79
2015	$2.99	$2.99	$2.96	$2.97	$2.85	$2.90	$2.86	$2.89
2016	$3.12	$3.26	$3.05	$3.09	$2.95	$3.02	$2.94	$3.01
2017	$3.19	$3.17	$3.11	$3.13	$3.01	$3.06	$3.00	$3.07
2018	$3.30	$3.38	$3.23	$3.21	$3.14	$3.14	$3.13	$3.16
2019	$3.36	$3.35	$3.31	$3.30	$3.22	$3.23	$3.20	$3.24
2020	$3.47	$3.45	$3.38	$3.38	$3.29	$3.30	$3.27	$3.31
2021	$3.62	$3.63	$3.54	$3.58	$3.44	$3.50	$3.43	$3.50
2022	$3.77	$3.70	$3.66	$3.69	$3.56	$3.61	$3.54	$3.62
2023	$3.83	$3.86	$3.75	$3.86	$3.65	$3.77	$3.64	$3.77
2024	$3.93	$3.99	$3.86	$3.98	$3.75	$3.89	$3.75	$3.88
2025	$4.06	$4.10	$4.00	$4.15	$3.89	$4.05	$3.89	$4.04
2026	$4.18	$4.23	$4.13	$4.31	$4.01	$4.21	$4.02	$4.19
2027	$4.31	$4.37	$4.27	$4.48	$4.15	$4.37	$4.16	$4.35
2028	$4.44	$4.51	$4.41	$4.66	$4.28	$4.54	$4.30	$4.51
2029	$4.57	$4.65	$4.55	$4.84	$4.42	$4.72	$4.45	$4.68
2030	$4.71	$4.80	$4.70	$5.03	$4.57	$4.90	$4.60	$4.86

Table A.4-19 (Continued)
Central Appalachia Coal Price Forecasts – High Fuel Price Sensitivity
(Delivered, Nominal $/MBtu)

Year	E. KY-Hi Btu Super-Compliance 13,100 Btu/lb 0.57 % Sulfur	E. KY-Hi Btu Super-Compliance 13,150 Btu/lb 0.65 % Sulfur	E. KY-Mid Btu Compliance 12,700 Btu/lb 0.67 % Sulfur	E. KY-Mid Btu Compliance 12,500 Btu/lb 0.69 % Sulfur	E. KY-Mid Btu Near-Compliance 12,300 Btu/lb 1.00 % Sulfur	E. KY-Mid Btu Near-Compliance 12,600 Btu/lb 1.12 % Sulfur	E. KY-Mid Btu Mid-Sulfur 12,100 Btu/lb 1.74 % Sulfur	E. KY-Mid Btu Mid-Sulfur 12,300 Btu/lb 1.75 % Sulfur
2006	$3.70	$3.05	$3.50	$3.65	$3.15	$3.29	$2.59	$2.57
2007	$3.38	$2.93	$3.21	$3.22	$2.84	$2.90	$2.49	$2.48
2008	$2.86	$2.98	$2.80	$2.83	$2.58	$2.72	$2.42	$2.43
2009	$2.53	$2.53	$2.44	$2.52	$2.41	$2.37	$2.48	$2.42
2010	$2.57	$2.58	$2.47	$2.57	$2.46	$2.41	$2.52	$2.45
2011	$2.65	$2.67	$2.54	$2.64	$2.53	$2.52	$2.59	$2.56
2012	$2.74	$2.75	$2.62	$2.72	$2.62	$2.60	$2.69	$2.63
2013	$2.81	$2.83	$2.69	$2.81	$2.68	$2.66	$2.75	$2.70
2014	$2.84	$2.87	$2.71	$2.85	$2.72	$2.70	$2.79	$2.74
2015	$2.98	$2.96	$2.83	$2.93	$2.84	$2.79	$2.92	$2.84
2016	$3.08	$3.10	$2.93	$3.04	$2.94	$2.91	$3.01	$2.97
2017	$3.15	$3.15	$2.99	$3.09	$3.00	$2.95	$3.07	$3.03
2018	$3.26	$3.25	$3.10	$3.17	$3.10	$3.03	$3.18	$3.11
2019	$3.35	$3.32	$3.18	$3.26	$3.19	$3.12	$3.27	$3.19
2020	$3.43	$3.42	$3.25	$3.33	$3.25	$3.19	$3.32	$3.27
2021	$3.57	$3.64	$3.39	$3.53	$3.40	$3.38	$3.48	$3.45
2022	$3.71	$3.68	$3.51	$3.65	$3.54	$3.49	$3.62	$3.57
2023	$3.78	$3.88	$3.61	$3.81	$3.64	$3.65	$3.72	$3.71
2024	$3.88	$3.99	$3.73	$3.94	$3.76	$3.76	$3.84	$3.82
2025	$4.00	$4.11	$3.86	$4.10	$3.89	$3.92	$3.98	$3.97
2026	$4.13	$4.25	$3.99	$4.27	$4.02	$4.08	$4.11	$4.12
2027	$4.25	$4.39	$4.12	$4.44	$4.16	$4.24	$4.26	$4.27
2028	$4.38	$4.54	$4.26	$4.61	$4.30	$4.40	$4.40	$4.43
2029	$4.51	$4.70	$4.41	$4.79	$4.45	$4.58	$4.55	$4.60
2030	$4.65	$4.86	$4.56	$4.98	$4.60	$4.76	$4.71	$4.77

Table A.4-20
Northern Appalachia Coal Price Forecasts – High Fuel Price Sensitivity
(Delivered, Nominal $/MBtu)

Year	W. PA Mid-Sulfur 13,000 Btu/lb 1.95 % Sulfur	W. PA High-Sulfur 12,200 Btu/lb 3.34 % Sulfur	OH Mid-Sulfur 12,150 Btu/lb 2.20 % Sulfur	OH High-Sulfur 11,750 Btu/lb 3.60 % Sulfur	N. WV Mid-Sulfur 12,900 Btu/lb 2.10 % Sulfur	N. WV High-Sulfur 12,350 Btu/lb 3.60 % Sulfur
2006	$3.18	$3.28	$3.11	$2.98	$3.28	$3.26
2007	$2.89	$3.03	$2.80	$2.70	$3.01	$2.97
2008	$2.64	$2.60	$2.58	$2.69	$2.72	$2.74
2009	$2.84	$2.83	$2.87	$2.87	$2.81	$2.89
2010	$2.82	$2.81	$2.88	$2.85	$2.80	$2.88
2011	$2.88	$2.85	$2.93	$2.92	$2.86	$2.94
2012	$3.00	$2.98	$3.05	$3.03	$2.97	$3.05
2013	$3.05	$3.03	$3.12	$3.10	$3.04	$3.11
2014	$3.09	$3.07	$3.17	$3.14	$3.07	$3.14
2015	$3.18	$3.16	$3.26	$3.22	$3.18	$3.23
2016	$3.28	$3.26	$3.38	$3.33	$3.30	$3.32
2017	$3.35	$3.34	$3.47	$3.41	$3.37	$3.38
2018	$3.50	$3.50	$3.71	$3.65	$3.53	$3.53
2019	$3.57	$3.58	$3.79	$3.88	$3.59	$3.60
2020	$3.64	$3.64	$3.86	$3.95	$3.66	$3.67
2021	$3.80	$3.78	$4.01	$4.04	$3.81	$3.83
2022	$3.90	$3.87	$4.12	$4.13	$3.91	$3.93
2023	$4.01	$3.97	$4.27	$4.31	$4.02	$4.01
2024	$4.14	$4.13	$4.41	$4.47	$4.16	$4.14
2025	$4.33	$4.24	$4.53	$4.57	$4.28	$4.26
2026	$4.47	$4.37	$4.68	$4.67	$4.41	$4.38
2027	$4.62	$4.51	$4.83	$4.92	$4.55	$4.51
2028	$4.77	$4.65	$4.99	$5.08	$4.69	$4.65
2029	$4.93	$4.79	$5.15	$5.25	$4.84	$4.78
2030	$5.09	$4.94	$5.32	$5.43	$4.99	$4.93

Table A.4-21
Illinois Basin Coal Price Forecasts – High Fuel Price Sensitivity
(Delivered, Nominal $/MBtu)

Year	IN Compliance 11,100 Btu/lb 0.58 % Sulfur	IN Near-Compliance 10,950 Btu/lb 1.10 % Sulfur	IN Mid-Sulfur 11,000 Btu/lb 1.70 % Sulfur	IN High-Sulfur 11,100 Btu/lb 3.05 % Sulfur	IL Near-Compliance 11,800 Btu/lb 1.30 % Sulfur	IL Mid-Sulfur 11,550 Btu/lb 1.70 5 Sulfur	IL High-Sulfur 11,150 Btu/lb 3.00 % Sulfur	W. KY Near-Compliance 11,900 Btu/lb 0.98 % Sulfur	W. KY High-Sulfur 11,600 Btu/lb 3.19 % Sulfur
2006	$4.30	$3.39	$3.40	$3.00	$3.09	$3.17	$3.07	$3.13	$2.86
2007	$3.90	$3.10	$3.11	$2.78	$2.83	$2.90	$2.88	$3.01	$2.51
2008	$3.55	$2.98	$2.82	$2.61	$2.67	$2.71	$2.66	$3.00	$2.51
2009	$2.98	$2.88	$2.87	$2.80	$2.70	$2.79	$2.78	$2.97	$2.69
2010	$2.95	$2.86	$2.85	$2.78	$2.67	$2.77	$2.76	$2.85	$2.68
2011	$3.02	$2.95	$2.96	$2.87	$2.76	$2.86	$2.85	$2.94	$2.76
2012	$3.11	$3.05	$3.04	$2.96	$2.85	$2.95	$2.93	$3.04	$2.85
2013	$3.21	$3.12	$3.13	$3.03	$2.95	$3.02	$3.00	$3.11	$2.91
2014	$3.23	$3.18	$3.17	$3.08	$2.98	$3.07	$3.02	$3.15	$2.96
2015	$3.33	$3.26	$3.25	$3.15	$3.08	$3.15	$3.09	$3.24	$3.01
2016	$3.38	$3.36	$3.48	$3.21	$3.17	$3.24	$3.17	$3.31	$3.07
2017	$3.43	$3.40	$3.56	$3.27	$3.23	$3.27	$3.20	$3.36	$3.12
2018	$3.55	$3.52	$3.67	$3.38	$3.35	$3.37	$3.29	$3.45	$3.19
2019	$3.59	$3.57	$3.78	$3.43	$3.40	$3.40	$3.31	$3.51	$3.25
2020	$3.67	$3.62	$3.77	$3.49	$3.46	$3.46	$3.37	$3.58	$3.31
2021	$3.84	$3.77	$3.84	$3.62	$3.60	$3.61	$3.50	$3.75	$3.43
2022	$3.96	$3.97	$3.95	$3.72	$3.76	$3.75	$3.63	$3.84	$3.50
2023	$4.07	$4.11	$3.99	$3.79	$3.83	$3.81	$3.69	$3.91	$3.56
2024	$4.15	$4.20	$4.09	$3.89	$3.91	$3.89	$3.77	$3.98	$3.64
2025	$4.32	$4.40	$4.18	$3.99	$4.05	$4.03	$3.91	$4.10	$3.74
2026	$4.46	$4.57	$4.27	$4.10	$4.16	$4.15	$4.03	$4.21	$3.83
2027	$4.60	$4.75	$4.36	$4.21	$4.29	$4.27	$4.15	$4.32	$3.93
2028	$4.74	$4.93	$4.45	$4.33	$4.41	$4.40	$4.27	$4.43	$4.03
2029	$4.90	$5.12	$4.55	$4.44	$4.54	$4.53	$4.39	$4.54	$4.13
2030	$5.05	$5.31	$4.64	$4.56	$4.67	$4.66	$4.52	$4.66	$4.23

Table A.4-22
PRB Coal Price Forecasts – High Fuel Price Sensitivity
(Delivered, Nominal $/MBtu)

Year	N. Gillette Compliance 8,350 Btu/lb 0.44 % Sulfur	S. Gillette Super-Compliance 8,400 Btu/lb 0.36 % Sulfur	N. Wright Super-Compliance 8,800 Btu/lb 0.35 % Sulfur	S. Wright Ultra-Compliance 8,800 Btu/lb 0.24 % Sulfur
2006	$3.00	$3.08	$3.06	$3.22
2007	$2.91	$2.96	$2.95	$3.10
2008	$2.55	$2.64	$2.62	$2.78
2009	$2.50	$2.51	$2.47	$2.52
2010	$2.51	$2.51	$2.47	$2.53
2011	$2.55	$2.55	$2.51	$2.56
2012	$2.59	$2.59	$2.55	$2.61
2013	$2.63	$2.63	$2.59	$2.65
2014	$2.67	$2.67	$2.63	$2.70
2015	$2.71	$2.72	$2.67	$2.76
2016	$2.77	$2.78	$2.73	$2.85
2017	$2.83	$2.83	$2.79	$2.90
2018	$2.88	$2.88	$2.84	$2.95
2019	$3.01	$3.01	$2.97	$3.04
2020	$3.24	$3.25	$3.21	$3.24
2021	$3.49	$3.50	$3.45	$3.48
2022	$3.56	$3.57	$3.52	$3.54
2023	$3.62	$3.63	$3.59	$3.60
2024	$3.68	$3.69	$3.65	$3.66
2025	$3.86	$3.87	$3.83	$3.83
2026	$3.98	$3.99	$3.95	$3.95
2027	$4.11	$4.12	$4.08	$4.07
2028	$4.24	$4.25	$4.21	$4.20
2029	$4.38	$4.39	$4.35	$4.33
2030	$4.52	$4.53	$4.49	$4.46

Table A.4-23
Latin America Coal Price Forecasts – High Fuel Price Sensitivity
(Delivered, Nominal $/MBtu)

Year	Latin America High Btu 13,000 Btu/lb 0.60 % Sulfur	Latin America Mid Btu 12,000 Btu/lb 1.17 % Sulfur
2006	$2.80	$2.70
2007	$2.91	$2.90
2008	$3.02	$3.03
2009	$3.08	$3.09
2010	$3.14	$3.16
2011	$3.08	$3.13
2012	$3.01	$3.07
2013	$2.99	$3.10
2014	$3.13	$3.25
2015	$3.26	$3.39
2016	$3.41	$3.54
2017	$3.44	$3.57
2018	$3.51	$3.64
2019	$3.64	$3.77
2020	$3.81	$3.96
2021	$3.92	$4.07
2022	$3.96	$4.11
2023	$4.03	$4.18
2024	$4.26	$4.42
2025	$4.39	$4.55
2026	$4.50	$4.67
2027	$4.53	$4.69
2028	$4.74	$4.92
2029	$4.89	$5.08
2030	$5.04	$5.22

Table A.4-24
Petcoke Price Forecasts – High Fuel Price Sensitivity
(Delivered, Nominal $/MBtu)

Year	Gulf Region 14,000 Btu/lb Low Sulfur High Grind	Gulf Region 14,000 Btu/lb Low Sulfur Low Grind	Gulf Region 14,000 Btu/lb High Sulfur High Grind	Gulf Region 14,000 Btu/lb High Sulfur Low Grind
2006	$1.68	$1.63	$1.49	$1.45
2007	$1.64	$1.59	$1.44	$1.40
2008	$1.78	$1.73	$1.58	$1.53
2009	$1.87	$1.82	$1.67	$1.62
2010	$1.88	$1.82	$1.67	$1.62
2011	$1.89	$1.83	$1.67	$1.62
2012	$1.83	$1.77	$1.61	$1.55
2013	$1.85	$1.79	$1.62	$1.57
2014	$1.92	$1.86	$1.69	$1.64
2015	$2.07	$2.01	$1.83	$1.77
2016	$2.13	$2.06	$1.88	$1.83
2017	$2.16	$2.10	$1.91	$1.86
2018	$2.16	$2.09	$1.90	$1.84
2019	$2.27	$2.20	$2.00	$1.94
2020	$2.34	$2.27	$2.07	$2.01
2021	$2.42	$2.35	$2.14	$2.08
2022	$2.44	$2.37	$2.16	$2.09
2023	$2.44	$2.36	$2.15	$2.08
2024	$2.59	$2.52	$2.30	$2.23
2025	$2.71	$2.63	$2.40	$2.33
2026	$2.73	$2.65	$2.42	$2.34
2027	$2.73	$2.64	$2.41	$2.33
2028	$2.82	$2.73	$2.49	$2.41
2029	$2.95	$2.87	$2.62	$2.54
2030	$3.05	$2.96	$2.71	$2.63

Table A.4-25
Natural Gas Price Forecasts – High Fuel Price Sensitivity
(Delivered, Nominal $/MBtu)

Year	Henry Hub + Variable Charges
2006	$11.49
2007	$9.97
2008	$9.65
2009	$8.41
2010	$7.56
2011	$7.37
2012	$7.71
2013	$8.06
2014	$8.42
2015	$8.81
2016	$9.20
2017	$9.62
2018	$10.06
2019	$10.52
2020	$10.98
2021	$11.50
2022	$12.01
2023	$12.56
2024	$13.13
2025	$13.72
2026	$14.34
2027	$14.99
2028	$15.68
2029	$16.38
2030	$17.13

Table A.4-26
Gulf Coast Fuel Oil Price Forecasts – High Fuel Price Sensitivity
(Delivered, Nominal $/MBtu)

Year	No. 2 Distillate 0.5 % Sulfur	No. 2 Distillate 0.05 % Sulfur	No. 2 Distillate 0.0015 % Sulfur	No. 6 Residual 1 % Sulfur	No. 6 Residual 3 % Sulfur
2006	$16.57	$16.86	$17.39	$8.91	$7.34
2007	$14.92	$15.15	$16.07	$8.42	$7.01
2008	$14.59	$14.81	$15.70	$8.31	$6.95
2009	$14.28	$14.48	$15.40	$8.21	$6.89
2010	$13.85	$14.03	$14.99	$8.03	$6.76
2011	$13.62	$13.79	$15.02	$7.95	$6.71
2012	$13.85	$14.02	$15.15	$8.09	$6.83
2013	$14.19	$14.37	$15.40	$8.29	$7.00
2014	$14.55	$14.73	$15.67	$8.50	$7.18
2015	$14.93	$15.12	$15.98	$8.72	$7.36
2016	$15.48	$15.68	$16.56	$9.03	$7.62
2017	$16.09	$16.29	$17.20	$9.36	$7.90
2018	$16.72	$16.94	$17.86	$9.71	$8.18
2019	$17.37	$17.60	$18.55	$10.07	$8.48
2020	$18.05	$18.30	$19.27	$10.44	$8.78
2021	$18.76	$19.02	$20.02	$10.83	$9.10
2022	$19.50	$19.77	$20.79	$11.23	$9.42
2023	$20.26	$20.55	$21.60	$11.64	$9.76
2024	$21.06	$21.36	$22.44	$12.07	$10.11
2025	$21.88	$22.20	$23.30	$12.65	$10.57
2026	$22.74	$23.08	$24.21	$12.96	$10.83
2027	$23.64	$23.99	$25.15	$13.43	$11.22
2028	$24.57	$24.94	$26.12	$13.92	$11.61
2029	$25.53	$25.92	$27.14	$14.42	$12.02
2030	$26.53	$26.94	$28.19	$14.94	$12.44

Table A.4-27
Central Appalachia Coal Price Forecasts – Low Fuel Price Sensitivity
(Delivered, Nominal $/MBtu)

Year	S. WV-Hi Btu Super-Compliance 13,150 Btu/lb 0.62 % Sulfur	S. WV-Hi Btu Super-Compliance 13,100 Btu/lb 0.65 % Sulfur	S. WV-Mid Btu Compliance 12,200 Btu/lb 0.67 % Sulfur	S. WV-Mid Btu Compliance 12,350 Btu/lb 0.67 % Sulfur	S. WV-Mid Btu Near-Compliance 12,200 Btu/lb 0.82 % Sulfur	S. WV-Mid Btu Near-Compliance 12,250 Btu/lb 0.98 % Sulfur	S. WV-Mid Btu Mid-Sulfur 12,500 Btu/lb 1.67 % Sulfur	S. WV-Mid Btu Mid-Sulfur 12,800 Btu/lb 1.67 % Sulfur
2006	$3.42	$3.41	$3.56	$3.63	$3.23	$3.37	$3.10	$2.46
2007	$3.09	$3.18	$3.29	$3.18	$2.89	$2.99	$2.83	$2.38
2008	$2.66	$2.79	$2.87	$2.82	$2.69	$2.79	$2.63	$2.37
2009	$2.48	$2.49	$2.48	$2.50	$2.39	$2.41	$2.38	$2.42
2010	$2.48	$2.53	$2.48	$2.54	$2.40	$2.45	$2.40	$2.45
2011	$2.53	$2.59	$2.52	$2.58	$2.43	$2.52	$2.47	$2.54
2012	$2.59	$2.64	$2.57	$2.63	$2.49	$2.57	$2.52	$2.59
2013	$2.67	$2.72	$2.66	$2.72	$2.56	$2.63	$2.57	$2.64
2014	$2.74	$2.78	$2.72	$2.77	$2.62	$2.68	$2.63	$2.69
2015	$2.82	$2.83	$2.81	$2.83	$2.70	$2.75	$2.71	$2.74
2016	$2.92	$2.96	$2.87	$2.91	$2.78	$2.84	$2.78	$2.83
2017	$3.01	$2.96	$2.95	$2.97	$2.85	$2.91	$2.84	$2.90
2018	$3.11	$3.11	$3.04	$3.05	$2.96	$2.99	$2.95	$3.00
2019	$3.15	$3.15	$3.10	$3.11	$3.01	$3.04	$3.00	$3.05
2020	$3.23	$3.23	$3.16	$3.17	$3.07	$3.10	$3.06	$3.11
2021	$3.29	$3.38	$3.22	$3.24	$3.13	$3.17	$3.12	$3.19
2022	$3.40	$3.40	$3.31	$3.34	$3.21	$3.27	$3.20	$3.28
2023	$3.51	$3.58	$3.43	$3.47	$3.33	$3.39	$3.31	$3.40
2024	$3.59	$3.63	$3.50	$3.57	$3.40	$3.49	$3.41	$3.49
2025	$3.69	$3.76	$3.57	$3.65	$3.47	$3.56	$3.47	$3.58
2026	$3.78	$3.93	$3.65	$3.71	$3.54	$3.62	$3.53	$3.64
2027	$3.87	$4.03	$3.74	$3.82	$3.63	$3.72	$3.63	$3.75
2028	$3.97	$4.16	$3.82	$3.92	$3.71	$3.81	$3.73	$3.85
2029	$4.07	$4.30	$3.91	$4.02	$3.80	$3.91	$3.82	$3.95
2030	$4.17	$4.44	$4.00	$4.13	$3.89	$4.01	$3.92	$4.05

Table A.4-27 (Continued)
Central Appalachia Coal Price Forecasts – Low Fuel Price Sensitivity
(Delivered, Nominal $/MBtu)

Year	E. KY-Hi Btu Super-Compliance 13,100 Btu/lb 0.57 % Sulfur	E. KY-Hi Btu Super-Compliance 13,150 Btu/lb 0.65 % Sulfur	E. KY-Mid Btu Compliance 12,700 Btu/lb 0.67 % Sulfur	E. KY-Mid Btu Compliance 12,500 Btu/lb 0.69 % Sulfur	E. KY-Mid Btu Near-Compliance 12,300 Btu/lb 1.00 % Sulfur	E. KY-Mid Btu Near-Compliance 12,600 Btu/lb 1.12 % Sulfur	E. KY-Mid Btu Mid-Sulfur 12,100 Btu/lb 1.74 % Sulfur	E. KY-Mid Btu Mid-Sulfur 12,300 Btu/lb 1.75 % Sulfur
2006	$3.45	$2.75	$3.34	$3.43	$3.13	$3.24	$2.58	$2.54
2007	$3.17	$2.66	$3.05	$3.03	$2.84	$2.87	$2.49	$2.45
2008	$2.72	$2.84	$2.67	$2.71	$2.56	$2.69	$2.41	$2.40
2009	$2.47	$2.47	$2.39	$2.47	$2.36	$2.32	$2.42	$2.37
2010	$2.48	$2.51	$2.39	$2.51	$2.39	$2.36	$2.46	$2.39
2011	$2.54	$2.57	$2.43	$2.54	$2.44	$2.43	$2.50	$2.46
2012	$2.59	$2.62	$2.47	$2.60	$2.50	$2.48	$2.56	$2.51
2013	$2.67	$2.70	$2.55	$2.68	$2.57	$2.53	$2.64	$2.57
2014	$2.73	$2.75	$2.61	$2.73	$2.63	$2.58	$2.70	$2.62
2015	$2.83	$2.81	$2.71	$2.79	$2.71	$2.65	$2.78	$2.69
2016	$2.92	$2.91	$2.78	$2.87	$2.79	$2.74	$2.85	$2.78
2017	$2.97	$2.98	$2.83	$2.93	$2.85	$2.80	$2.92	$2.86
2018	$3.09	$3.08	$2.92	$3.01	$2.95	$2.88	$3.02	$2.96
2019	$3.13	$3.13	$2.97	$3.08	$3.01	$2.94	$3.08	$3.01
2020	$3.20	$3.20	$3.04	$3.13	$3.07	$2.99	$3.14	$3.07
2021	$3.28	$3.29	$3.12	$3.21	$3.13	$3.06	$3.20	$3.14
2022	$3.39	$3.39	$3.22	$3.31	$3.21	$3.16	$3.29	$3.24
2023	$3.50	$3.51	$3.33	$3.43	$3.30	$3.27	$3.38	$3.36
2024	$3.59	$3.62	$3.40	$3.53	$3.37	$3.37	$3.44	$3.42
2025	$3.68	$3.70	$3.48	$3.61	$3.43	$3.44	$3.50	$3.52
2026	$3.77	$3.79	$3.56	$3.68	$3.52	$3.51	$3.59	$3.58
2027	$3.86	$3.89	$3.64	$3.79	$3.60	$3.61	$3.66	$3.68
2028	$3.96	$3.99	$3.73	$3.89	$3.68	$3.70	$3.74	$3.78
2029	$4.06	$4.10	$3.82	$3.99	$3.76	$3.80	$3.82	$3.87
2030	$4.16	$4.21	$3.91	$4.10	$3.85	$3.90	$3.90	$3.97

Table A.4-28
Northern Appalachia Coal Price Forecasts – Low Fuel Price Sensitivity
(Delivered, Nominal $/MBtu)

Year	W. PA Mid-Sulfur 13,000 Btu/lb 1.95 % Sulfur	W. PA High-Sulfur 12,200 Btu/lb 3.34 % Sulfur	OH Mid-Sulfur 12,150 Btu/lb 2.20 % Sulfur	OH High-Sulfur 11,750 Btu/lb 3.60 % Sulfur	N. WV Mid-Sulfur 12,900 Btu/lb 2.10 % Sulfur	N. WV High-Sulfur 12,350 Btu/lb 3.60 % Sulfur
2006	$3.15	$3.27	$3.08	$2.95	$3.22	$3.23
2007	$2.85	$3.03	$2.77	$2.69	$2.96	$2.95
2008	$2.63	$2.61	$2.59	$2.70	$2.71	$2.73
2009	$2.70	$2.70	$2.73	$2.74	$2.67	$2.76
2010	$2.70	$2.70	$2.78	$2.75	$2.68	$2.77
2011	$2.72	$2.70	$2.78	$2.77	$2.70	$2.79
2012	$2.76	$2.76	$2.83	$2.82	$2.74	$2.83
2013	$2.84	$2.84	$2.93	$2.90	$2.83	$2.90
2014	$2.88	$2.88	$2.98	$2.95	$2.91	$2.94
2015	$2.93	$2.93	$3.04	$3.00	$2.98	$2.99
2016	$3.03	$3.02	$3.13	$3.09	$3.05	$3.09
2017	$3.10	$3.10	$3.23	$3.17	$3.14	$3.15
2018	$3.26	$3.27	$3.48	$3.43	$3.30	$3.30
2019	$3.37	$3.38	$3.58	$3.55	$3.39	$3.40
2020	$3.43	$3.44	$3.64	$3.75	$3.44	$3.48
2021	$3.49	$3.49	$3.70	$3.82	$3.49	$3.54
2022	$3.56	$3.55	$3.75	$3.91	$3.55	$3.61
2023	$3.70	$3.69	$3.97	$4.09	$3.71	$3.71
2024	$3.76	$3.77	$4.05	$4.24	$3.78	$3.76
2025	$3.86	$3.86	$4.16	$4.33	$3.89	$3.85
2026	$3.93	$3.94	$4.21	$4.43	$3.94	$3.93
2027	$4.13	$4.06	$4.38	$4.60	$4.06	$4.00
2028	$4.24	$4.16	$4.50	$4.74	$4.17	$4.09
2029	$4.36	$4.27	$4.63	$4.89	$4.28	$4.17
2030	$4.49	$4.38	$4.76	$5.04	$4.39	$4.26

Table A.4-29
Illinois Basin Coal Price Forecasts – Low Fuel Price Sensitivity
(Delivered, Nominal $/MBtu)

Year	IN Compliance 11,100 Btu/lb 0.58 % Sulfur	IN Near-Compliance 10,950 Btu/lb 1.10 % Sulfur	IN Mid-Sulfur 11,000 Btu/lb 1.70 % Sulfur	IN High-Sulfur 11,100 Btu/lb 3.05 % Sulfur	IL Near-Compliance 11,800 Btu/lb 1.30 % Sulfur	IL Mid-Sulfur 11,550 Btu/lb 1.70 5 Sulfur	IL High-Sulfur 11,150 Btu/lb 3.00 % Sulfur	W. KY Near-Compliance 11,900 Btu/lb 0.98 % Sulfur	W. KY High-Sulfur 11,600 Btu/lb 3.19 % Sulfur
2006	$4.03	$3.35	$3.26	$2.95	$3.10	$3.11	$2.98	$3.08	$2.81
2007	$3.68	$3.03	$2.99	$2.74	$2.82	$2.82	$2.70	$2.93	$2.43
2008	$3.37	$2.86	$2.77	$2.60	$2.67	$2.65	$2.62	$2.94	$2.46
2009	$2.84	$2.71	$2.70	$2.65	$2.55	$2.62	$2.62	$2.81	$2.53
2010	$2.85	$2.70	$2.70	$2.63	$2.53	$2.61	$2.61	$2.75	$2.53
2011	$2.85	$2.73	$2.76	$2.68	$2.59	$2.64	$2.64	$2.80	$2.55
2012	$2.89	$2.78	$2.81	$2.73	$2.63	$2.69	$2.69	$2.84	$2.63
2013	$3.00	$2.86	$2.92	$2.79	$2.69	$2.76	$2.73	$2.91	$2.67
2014	$3.06	$2.91	$2.93	$2.84	$2.75	$2.81	$2.77	$3.02	$2.72
2015	$3.14	$2.97	$2.97	$2.88	$2.83	$2.87	$2.82	$3.06	$2.77
2016	$3.23	$3.07	$3.06	$2.95	$2.89	$2.95	$2.89	$3.05	$2.82
2017	$3.26	$3.12	$3.11	$3.01	$2.96	$2.99	$2.93	$3.09	$2.87
2018	$3.29	$3.22	$3.23	$3.12	$3.08	$3.09	$3.01	$3.16	$2.93
2019	$3.38	$3.41	$3.36	$3.23	$3.14	$3.15	$3.07	$3.24	$3.01
2020	$3.40	$3.47	$3.41	$3.27	$3.18	$3.19	$3.11	$3.30	$3.05
2021	$3.44	$3.48	$3.43	$3.31	$3.25	$3.24	$3.17	$3.33	$3.09
2022	$3.54	$3.55	$3.49	$3.37	$3.32	$3.31	$3.23	$3.39	$3.15
2023	$3.64	$3.62	$3.56	$3.44	$3.40	$3.39	$3.31	$3.46	$3.21
2024	$3.69	$3.70	$3.63	$3.50	$3.46	$3.48	$3.40	$3.54	$3.26
2025	$3.75	$3.79	$3.72	$3.56	$3.52	$3.53	$3.50	$3.60	$3.32
2026	$3.85	$3.86	$3.78	$3.63	$3.62	$3.60	$3.52	$3.66	$3.37
2027	$3.92	$3.95	$3.87	$3.69	$3.69	$3.69	$3.64	$3.74	$3.44
2028	$4.00	$4.03	$3.94	$3.76	$3.77	$3.77	$3.73	$3.81	$3.50
2029	$4.08	$4.12	$4.03	$3.83	$3.85	$3.85	$3.82	$3.89	$3.56
2030	$4.16	$4.21	$4.11	$3.90	$3.93	$3.93	$3.91	$3.97	$3.62

Table A.4-30
PRB Coal Price Forecasts – Low Fuel Price Sensitivity
(Delivered, Nominal $/MBtu)

Year	N. Gillette Compliance 8,350 Btu/lb 0.44 % Sulfur	S. Gillette Super-Compliance 8,400 Btu/lb 0.36 % Sulfur	N. Wright Super-Compliance 8,800 Btu/lb 0.35 % Sulfur	S. Wright Ultra-Compliance 8,800 Btu/lb 0.24 % Sulfur
2006	$2.78	$2.83	$2.80	$2.90
2007	$2.48	$2.80	$2.77	$2.62
2008	$2.39	$2.47	$2.44	$2.56
2009	$2.45	$2.47	$2.43	$2.48
2010	$2.47	$2.49	$2.45	$2.50
2011	$2.49	$2.50	$2.46	$2.50
2012	$2.53	$2.54	$2.49	$2.54
2013	$2.57	$2.58	$2.53	$2.59
2014	$2.61	$2.62	$2.57	$2.62
2015	$2.65	$2.66	$2.62	$2.68
2016	$2.70	$2.71	$2.66	$2.76
2017	$2.74	$2.75	$2.70	$2.81
2018	$2.79	$2.79	$2.74	$2.86
2019	$2.83	$2.83	$2.79	$2.89
2020	$2.88	$2.88	$2.84	$2.95
2021	$2.98	$2.98	$2.94	$3.05
2022	$3.10	$3.10	$3.06	$3.18
2023	$3.15	$3.15	$3.11	$3.22
2024	$3.21	$3.21	$3.17	$3.27
2025	$3.23	$3.23	$3.19	$3.28
2026	$3.31	$3.31	$3.27	$3.29
2027	$3.34	$3.34	$3.30	$3.32
2028	$3.39	$3.39	$3.35	$3.34
2029	$3.44	$3.44	$3.40	$3.37
2030	$3.49	$3.49	$3.45	$3.40

Table A.4-31
Latin America Coal Price Forecasts – Low Fuel Price Sensitivity
(Delivered, Nominal $/MBtu)

Year	Latin America High Btu 13,000 Btu/lb 0.60 % Sulfur	Latin America Mid Btu 12,000 Btu/lb 1.17 % Sulfur
2006	$2.70	$2.64
2007	$2.58	$2.56
2008	$2.72	$2.66
2009	$2.49	$2.47
2010	$2.48	$2.45
2011	$2.47	$2.45
2012	$2.53	$2.51
2013	$2.67	$2.65
2014	$2.84	$2.83
2015	$2.88	$2.85
2016	$2.98	$2.96
2017	$2.99	$2.88
2018	$2.90	$2.97
2019	$2.94	$3.02
2020	$3.06	$3.15
2021	$3.11	$3.20
2022	$3.08	$3.17
2023	$3.07	$3.16
2024	$3.21	$3.31
2025	$3.23	$3.33
2026	$3.30	$3.40
2027	$3.21	$3.30
2028	$3.32	$3.43
2029	$3.37	$3.48
2030	$3.40	$3.51

Table A.4-32
Petcoke Price Forecasts – Low Fuel Price Sensitivity
(Delivered, Nominal $/MBtu)

Year	Gulf Region 14,000 Btu/lb Low Sulfur High Grind	Gulf Region 14,000 Btu/lb Low Sulfur Low Grind	Gulf Region 14,000 Btu/lb High Sulfur High Grind	Gulf Region 14,000 Btu/lb High Sulfur Low Grind
2006	$1.44	$1.39	$1.27	$1.21
2007	$1.39	$1.34	$1.21	$1.16
2008	$1.52	$1.47	$1.34	$1.29
2009	$1.61	$1.55	$1.43	$1.37
2010	$1.61	$1.55	$1.42	$1.36
2011	$1.61	$1.55	$1.42	$1.36
2012	$1.54	$1.48	$1.35	$1.28
2013	$1.56	$1.50	$1.36	$1.29
2014	$1.62	$1.56	$1.42	$1.35
2015	$1.76	$1.70	$1.55	$1.48
2016	$1.81	$1.75	$1.60	$1.53
2017	$1.84	$1.78	$1.62	$1.55
2018	$1.83	$1.76	$1.60	$1.53
2019	$1.93	$1.86	$1.70	$1.62
2020	$1.99	$1.92	$1.76	$1.68
2021	$2.06	$1.99	$1.82	$1.74
2022	$2.08	$2.00	$1.83	$1.75
2023	$2.06	$1.99	$1.81	$1.72
2024	$2.21	$2.13	$1.95	$1.86
2025	$2.31	$2.23	$2.04	$1.96
2026	$2.33	$2.25	$2.05	$1.96
2027	$2.31	$2.23	$2.03	$1.94
2028	$2.39	$2.31	$2.11	$2.01
2029	$2.52	$2.43	$2.22	$2.13
2030	$2.61	$2.52	$2.30	$2.21

Table A.4-33
Natural Gas Price Forecasts – Low Fuel Price Sensitivity
(Delivered, Nominal $/MBtu)

Year	Henry Hub + Variable Charges
2006	$7.68
2007	$6.66
2008	$6.45
2009	$5.63
2010	$5.06
2011	$4.94
2012	$5.16
2013	$5.40
2014	$5.63
2015	$5.89
2016	$6.16
2017	$6.43
2018	$6.73
2019	$7.04
2020	$7.35
2021	$7.69
2022	$8.03
2023	$8.40
2024	$8.78
2025	$9.18
2026	$9.59
2027	$10.03
2028	$10.48
2029	$10.95
2030	$11.45

Table A.4-34
Gulf Coast Fuel Oil Price Forecasts – Low Fuel Price Sensitivity
(Delivered, Nominal $/MBtu)

Year	No. 2 Distillate 0.5 % Sulfur	No. 2 Distillate 0.05 % Sulfur	No. 2 Distillate 0.0015 % Sulfur	No. 6 Residual 1 % Sulfur	No. 6 Residual 3 % Sulfur
2006	$11.35	$11.53	$11.89	$5.94	$4.89
2007	$10.25	$10.41	$11.02	$5.61	$4.67
2008	$10.04	$10.18	$10.78	$5.54	$4.63
2009	$9.84	$9.98	$10.59	$5.47	$4.59
2010	$9.56	$9.68	$10.32	$5.36	$4.51
2011	$9.42	$9.53	$10.35	$5.30	$4.47
2012	$9.58	$9.69	$10.44	$5.39	$4.56
2013	$9.81	$9.93	$10.62	$5.53	$4.67
2014	$10.06	$10.18	$10.81	$5.66	$4.78
2015	$10.32	$10.45	$11.02	$5.81	$4.91
2016	$10.70	$10.83	$11.42	$6.02	$5.08
2017	$11.11	$11.25	$11.86	$6.24	$5.26
2018	$11.55	$11.69	$12.31	$6.47	$5.46
2019	$11.99	$12.15	$12.78	$6.72	$5.65
2020	$12.45	$12.62	$13.27	$6.96	$5.85
2021	$12.94	$13.11	$13.78	$7.22	$6.07
2022	$13.44	$13.62	$14.30	$7.49	$6.28
2023	$13.96	$14.15	$14.85	$7.76	$6.51
2024	$14.50	$14.70	$15.42	$8.04	$6.74
2025	$15.06	$15.27	$16.01	$8.43	$7.05
2026	$15.65	$15.87	$16.62	$8.64	$7.22
2027	$16.26	$16.49	$17.26	$8.96	$7.48
2028	$16.89	$17.14	$17.93	$9.28	$7.74
2029	$17.54	$17.80	$18.62	$9.62	$8.01
2030	$18.22	$18.50	$19.33	$9.96	$8.29

Table A.4-35
Central Appalachia Coal Price Forecasts – Regulated-CO_2 Scenario
(Delivered, Nominal $/MBtu)

Year	S. WV-Hi Btu Super-Compliance 13,150 Btu/lb 0.62 % Sulfur	S. WV-Hi Btu Super-Compliance 13,100 Btu/lb 0.65 % Sulfur	S. WV-Mid Btu Compliance 12,200 Btu/lb 0.67 % Sulfur	S. WV-Mid Btu Compliance 12,350 Btu/lb 0.67 % Sulfur	S. WV-Mid Btu Near-Compliance 12,200 Btu/lb 0.82 % Sulfur	S. WV-Mid Btu Near-Compliance 12,250 Btu/lb 0.98 % Sulfur	S. WV-Mid Btu Mid-Sulfur 12,500 Btu/lb 1.67 % Sulfur	S. WV-Mid Btu Mid-Sulfur 12,800 Btu/lb 1.67 % Sulfur
2006	$3.56	$3.54	$3.64	$3.64	$3.28	$3.39	$3.10	$2.46
2007	$3.19	$3.27	$3.36	$3.26	$2.93	$3.00	$2.83	$2.39
2008	$2.69	$2.82	$2.90	$2.85	$2.71	$2.79	$2.63	$2.38
2009	$2.49	$2.49	$2.49	$2.50	$2.40	$2.42	$2.39	$2.42
2010	$2.41	$2.42	$2.40	$2.43	$2.33	$2.36	$2.35	$2.35
2011	$2.48	$2.49	$2.46	$2.48	$2.38	$2.42	$2.40	$2.43
2012	$2.55	$2.59	$2.53	$2.57	$2.45	$2.51	$2.44	$2.50
2013	$2.58	$2.64	$2.58	$2.62	$2.50	$2.57	$2.49	$2.56
2014	$2.67	$2.69	$2.65	$2.68	$2.56	$2.62	$2.56	$2.61
2015	$2.72	$2.74	$2.73	$2.73	$2.63	$2.67	$2.63	$2.66
2016	$2.73	$2.83	$2.74	$2.79	$2.67	$2.73	$2.66	$2.72
2017	$2.82	$2.89	$2.80	$2.84	$2.72	$2.78	$2.71	$2.77
2018	$2.95	$2.97	$2.91	$2.92	$2.81	$2.86	$2.81	$2.86
2019	$2.97	$2.97	$2.94	$2.95	$2.85	$2.88	$2.83	$2.92
2020	$3.05	$3.05	$3.02	$3.00	$2.90	$2.94	$2.85	$2.96
2021	$3.18	$3.21	$3.14	$3.15	$3.02	$3.09	$2.99	$3.09
2022	$3.23	$3.29	$3.20	$3.25	$3.08	$3.16	$3.06	$3.16
2023	$3.09	$3.39	$3.28	$3.38	$3.19	$3.28	$3.18	$3.30
2024	$3.18	$3.38	$3.31	$3.39	$3.19	$3.29	$3.22	$3.42
2025	$3.30	$3.32	$3.22	$3.32	$3.10	$3.22	$3.11	$3.50
2026	$3.22	$3.25	$3.15	$3.24	$3.03	$3.14	$3.03	$3.57
2027	$3.33	$3.35	$3.24	$3.36	$3.12	$3.26	$3.15	$3.71
2028	$3.43	$3.45	$3.33	$3.46	$3.20	$3.35	$3.24	$3.82
2029	$3.53	$3.55	$3.42	$3.57	$3.29	$3.45	$3.34	$3.94
2030	$3.63	$3.65	$3.51	$3.68	$3.37	$3.56	$3.44	$4.06

Table A.4-35 (Continued)
Central Appalachia Coal Price Forecasts – Regulated-CO_2 Scenario
(Delivered, Nominal $/MBtu)

Year	E. KY-Hi Btu Super-Compliance 13,100 Btu/lb 0.57 % Sulfur	E. KY-Hi Btu Super-Compliance 13,150 Btu/lb 0.65 % Sulfur	E. KY-Mid Btu Compliance 12,700 Btu/lb 0.67 % Sulfur	E. KY-Mid Btu Compliance 12,500 Btu/lb 0.69 % Sulfur	E. KY-Mid Btu Near-Compliance 12,300 Btu/lb 1.00 % Sulfur	E. KY-Mid Btu Near-Compliance 12,600 Btu/lb 1.12 % Sulfur	E. KY-Mid Btu Mid-Sulfur 12,100 Btu/lb 1.74 % Sulfur	E. KY-Mid Btu Mid-Sulfur 12,300 Btu/lb 1.75 % Sulfur
2006	$3.58	$2.91	$3.41	$3.54	$3.14	$3.26	$2.59	$2.54
2007	$3.26	$2.77	$3.12	$3.11	$2.84	$2.88	$2.49	$2.46
2008	$2.76	$2.88	$2.70	$2.74	$2.57	$2.69	$2.41	$2.41
2009	$2.48	$2.47	$2.40	$2.47	$2.36	$2.33	$2.43	$2.37
2010	$2.41	$2.40	$2.32	$2.40	$2.34	$2.27	$2.41	$2.30
2011	$2.48	$2.47	$2.37	$2.45	$2.39	$2.34	$2.46	$2.36
2012	$2.55	$2.57	$2.43	$2.54	$2.45	$2.42	$2.53	$2.45
2013	$2.58	$2.62	$2.47	$2.59	$2.50	$2.48	$2.57	$2.51
2014	$2.65	$2.66	$2.53	$2.64	$2.55	$2.53	$2.62	$2.56
2015	$2.70	$2.70	$2.60	$2.70	$2.62	$2.57	$2.69	$2.61
2016	$2.72	$2.77	$2.60	$2.75	$2.66	$2.63	$2.73	$2.68
2017	$2.79	$2.84	$2.66	$2.80	$2.71	$2.68	$2.78	$2.73
2018	$2.90	$2.93	$2.74	$2.88	$2.79	$2.75	$2.86	$2.82
2019	$2.93	$2.95	$2.79	$2.91	$2.82	$2.78	$2.89	$2.85
2020	$2.96	$3.01	$2.82	$2.94	$2.87	$2.83	$2.94	$2.89
2021	$3.12	$3.16	$2.97	$3.11	$2.97	$2.98	$3.03	$3.04
2022	$3.17	$3.24	$3.02	$3.19	$3.06	$3.05	$3.13	$3.12
2023	$3.28	$3.34	$3.11	$3.32	$3.14	$3.16	$3.21	$3.24
2024	$3.32	$3.34	$3.16	$3.45	$3.16	$3.22	$3.23	$3.22
2025	$3.25	$3.29	$3.08	$3.53	$3.07	$3.23	$3.13	$3.16
2026	$3.16	$3.21	$2.99	$3.62	$3.01	$3.27	$3.06	$3.09
2027	$3.27	$3.31	$3.09	$3.76	$3.11	$3.40	$3.16	$3.20
2028	$3.36	$3.41	$3.18	$3.87	$3.20	$3.50	$3.25	$3.29
2029	$3.46	$3.51	$3.27	$4.00	$3.29	$3.61	$3.34	$3.38
2030	$3.56	$3.61	$3.36	$4.12	$3.38	$3.72	$3.43	$3.48

Table A.4-36
Northern Appalachia Coal Price Forecasts – Regulated-CO_2 Scenario
(Delivered, Nominal $/MBtu)

Year	W. PA Mid-Sulfur 13,000 Btu/lb 1.95 % Sulfur	W. PA High-Sulfur 12,200 Btu/lb 3.34 % Sulfur	OH Mid-Sulfur 12,150 Btu/lb 2.20 % Sulfur	OH High-Sulfur 11,750 Btu/lb 3.60 % Sulfur	N. WV Mid-Sulfur 12,900 Btu/lb 2.10 % Sulfur	N. WV High-Sulfur 12,350 Btu/lb 3.60 % Sulfur
2006	$3.10	$3.23	$3.03	$2.92	$3.20	$3.20
2007	$2.85	$3.03	$2.77	$2.68	$2.97	$2.94
2008	$2.63	$2.60	$2.58	$2.69	$2.71	$2.73
2009	$2.71	$2.71	$2.74	$2.74	$2.68	$2.77
2010	$2.68	$2.66	$2.72	$2.70	$2.69	$2.72
2011	$2.74	$2.72	$2.79	$2.77	$2.71	$2.80
2012	$2.83	$2.82	$2.87	$2.87	$2.80	$2.89
2013	$2.90	$2.89	$2.97	$2.95	$2.90	$2.96
2014	$2.90	$2.91	$2.98	$2.95	$2.93	$2.98
2015	$2.86	$2.88	$2.98	$2.92	$2.87	$3.00
2016	$2.87	$2.89	$3.02	$2.96	$2.90	$3.01
2017	$2.92	$2.94	$3.10	$3.05	$2.96	$3.05
2018	$3.08	$3.11	$3.35	$3.31	$3.12	$3.16
2019	$3.17	$3.19	$3.41	$3.35	$3.19	$3.23
2020	$3.19	$3.22	$3.46	$3.54	$3.22	$3.27
2021	$3.32	$3.33	$3.59	$3.62	$3.35	$3.40
2022	$3.40	$3.41	$3.67	$3.71	$3.42	$3.49
2023	$3.48	$3.49	$3.76	$3.80	$3.52	$3.54
2024	$3.50	$3.51	$3.83	$3.87	$3.54	$3.54
2025	$3.39	$3.39	$3.72	$3.71	$3.43	$3.40
2026	$3.31	$3.34	$3.61	$3.62	$3.34	$3.34
2027	$3.41	$3.44	$3.76	$3.75	$3.45	$3.42
2028	$3.50	$3.54	$3.87	$3.86	$3.55	$3.50
2029	$3.59	$3.64	$4.00	$3.97	$3.64	$3.58
2030	$3.68	$3.74	$4.12	$4.08	$3.74	$3.67

Table A.4-37
Illinois Basin Coal Price Forecasts – Regulated-CO_2 Scenario
(Delivered, Nominal $/MBtu)

Year	IN Compliance 11,100 Btu/lb 0.58 % Sulfur	IN Near-Compliance 10,950 Btu/lb 1.10 % Sulfur	IN Mid-Sulfur 11,000 Btu/lb 1.70 % Sulfur	IN High-Sulfur 11,100 Btu/lb 3.05 % Sulfur	IL Near-Compliance 11,800 Btu/lb 1.30 % Sulfur	IL Mid-Sulfur 11,550 Btu/lb 1.70 5 Sulfur	IL High-Sulfur 11,150 Btu/lb 3.00 % Sulfur	W. KY Near-Compliance 11,900 Btu/lb 0.98 % Sulfur	W. KY High-Sulfur 11,600 Btu/lb 3.19 % Sulfur
2006	$4.15	$3.37	$3.29	$2.93	$3.10	$3.12	$3.03	$3.11	$2.80
2007	$3.78	$3.02	$3.01	$2.73	$2.83	$2.84	$2.73	$2.97	$2.46
2008	$3.41	$2.86	$2.78	$2.60	$2.68	$2.66	$2.62	$2.96	$2.46
2009	$2.85	$2.72	$2.70	$2.65	$2.55	$2.63	$2.62	$2.81	$2.53
2010	$2.79	$2.64	$2.63	$2.61	$2.46	$2.54	$2.58	$2.61	$2.50
2011	$2.85	$2.72	$2.75	$2.70	$2.57	$2.64	$2.62	$2.72	$2.57
2012	$2.83	$2.78	$2.85	$2.75	$2.62	$2.69	$2.67	$2.84	$2.65
2013	$2.93	$2.83	$2.89	$2.80	$2.67	$2.75	$2.71	$2.84	$2.68
2014	$3.01	$2.87	$2.90	$2.84	$2.73	$2.80	$2.73	$2.87	$2.70
2015	$3.05	$2.91	$2.92	$2.85	$2.75	$2.80	$2.76	$2.97	$2.74
2016	$3.08	$2.95	$2.98	$2.87	$2.79	$2.85	$2.77	$2.98	$2.73
2017	$3.16	$2.98	$3.04	$2.91	$2.83	$2.88	$2.79	$2.96	$2.77
2018	$3.24	$3.08	$3.08	$2.98	$2.94	$2.95	$2.85	$3.01	$2.80
2019	$3.29	$3.21	$3.17	$3.05	$2.98	$2.99	$2.90	$3.08	$2.84
2020	$3.29	$3.24	$3.23	$3.07	$2.99	$3.01	$2.91	$3.11	$2.85
2021	$3.38	$3.32	$3.29	$3.17	$3.10	$3.09	$3.00	$3.21	$2.95
2022	$3.43	$3.35	$3.33	$3.22	$3.17	$3.16	$3.05	$3.26	$2.98
2023	$3.49	$3.44	$3.39	$3.28	$3.25	$3.24	$3.15	$3.33	$3.04
2024	$3.50	$3.47	$3.40	$3.28	$3.26	$3.26	$3.16	$3.35	$3.04
2025	$3.37	$3.32	$3.30	$3.16	$3.16	$3.15	$3.11	$3.43	$2.94
2026	$3.26	$3.24	$3.23	$3.10	$3.09	$3.09	$3.02	$3.48	$2.88
2027	$3.34	$3.33	$3.32	$3.18	$3.18	$3.18	$3.12	$3.59	$2.95
2028	$3.41	$3.40	$3.40	$3.25	$3.26	$3.26	$3.21	$3.67	$3.01
2029	$3.48	$3.47	$3.47	$3.33	$3.34	$3.34	$3.29	$3.76	$3.08
2030	$3.55	$3.54	$3.55	$3.40	$3.42	$3.42	$3.38	$3.85	$3.14

Table A.4-38
PRB Coal Price Forecasts – Regulated-CO_2 Scenario
(Delivered, Nominal $/MBtu)

Year	N. Gillette Compliance 8,350 Btu/lb 0.44 % Sulfur	S. Gillette Super-Compliance 8,400 Btu/lb 0.36 % Sulfur	N. Wright Super-Compliance 8,800 Btu/lb 0.35 % Sulfur	S. Wright Ultra-Compliance 8,800 Btu/lb 0.24 % Sulfur
2006	$2.87	$2.94	$2.91	$3.04
2007	$2.81	$2.87	$2.84	$2.98
2008	$2.44	$2.51	$2.48	$2.61
2009	$2.45	$2.47	$2.43	$2.48
2010	$2.44	$2.44	$2.40	$2.44
2011	$2.44	$2.46	$2.41	$2.45
2012	$2.50	$2.51	$2.46	$2.51
2013	$2.55	$2.55	$2.50	$2.54
2014	$2.57	$2.58	$2.53	$2.58
2015	$2.61	$2.63	$2.57	$2.61
2016	$2.66	$2.70	$2.62	$2.68
2017	$2.69	$2.73	$2.66	$2.72
2018	$2.75	$2.79	$2.71	$2.79
2019	$2.78	$2.78	$2.72	$2.78
2020	$2.82	$2.82	$2.76	$2.84
2021	$2.96	$2.96	$2.90	$2.93
2022	$3.01	$3.02	$2.95	$2.98
2023	$3.21	$3.21	$3.14	$3.16
2024	$3.26	$3.26	$3.20	$3.21
2025	$3.33	$3.33	$3.26	$3.28
2026	$3.37	$3.37	$3.30	$3.31
2027	$3.49	$3.49	$3.43	$3.43
2028	$3.59	$3.59	$3.52	$3.52
2029	$3.68	$3.68	$3.61	$3.61
2030	$3.78	$3.78	$3.71	$3.71

Table A.4-39
Latin America Coal Price Forecasts – Regulated-CO_2 Scenario
(Delivered, Nominal $/MBtu)

Year	Latin America High Btu 13,000 Btu/lb 0.60 % Sulfur	Latin America Mid Btu 12,000 Btu/lb 1.17 % Sulfur
2006	$2.73	$2.66
2007	$2.86	$2.88
2008	$2.99	$3.01
2009	$3.06	$3.08
2010	$2.93	$2.96
2011	$2.92	$2.99
2012	$2.84	$2.89
2013	$2.74	$2.80
2014	$2.91	$2.98
2015	$2.93	$3.01
2016	$2.89	$2.97
2017	$2.82	$2.88
2018	$2.72	$2.77
2019	$2.74	$2.80
2020	$2.82	$2.90
2021	$2.89	$2.95
2022	$2.87	$2.91
2023	$2.81	$2.85
2024	$2.88	$2.93
2025	$2.76	$2.81
2026	$2.67	$2.72
2027	$2.58	$2.63
2028	$2.70	$2.76
2029	$2.74	$2.81
2030	$2.78	$2.85

Table A.4-40
Petcoke Price Forecasts – Regulated-CO_2 Scenario
(Delivered, Nominal $/MBtu)

Year	Gulf Region 14,000 Btu/lb Low Sulfur High Grind	Gulf Region 14,000 Btu/lb Low Sulfur Low Grind	Gulf Region 14,000 Btu/lb High Sulfur High Grind	Gulf Region 14,000 Btu/lb High Sulfur Low Grind
2006	$1.56	$1.51	$1.38	$1.33
2007	$1.51	$1.46	$1.33	$1.28
2008	$1.65	$1.60	$1.46	$1.41
2009	$1.74	$1.69	$1.55	$1.49
2010	$1.74	$1.69	$1.55	$1.49
2011	$1.75	$1.69	$1.54	$1.49
2012	$1.68	$1.63	$1.48	$1.42
2013	$1.70	$1.65	$1.49	$1.43
2014	$1.77	$1.71	$1.55	$1.49
2015	$1.91	$1.85	$1.69	$1.63
2016	$1.97	$1.91	$1.74	$1.68
2017	$2.00	$1.94	$1.77	$1.70
2018	$2.00	$1.93	$1.75	$1.69
2019	$2.10	$2.03	$1.85	$1.78
2020	$2.17	$2.10	$1.91	$1.84
2021	$2.24	$2.17	$1.98	$1.91
2022	$2.26	$2.18	$1.99	$1.92
2023	$2.25	$2.17	$1.98	$1.90
2024	$2.40	$2.32	$2.12	$2.04
2025	$2.51	$2.43	$2.22	$2.14
2026	$2.53	$2.45	$2.23	$2.15
2027	$2.52	$2.44	$2.22	$2.13
2028	$2.61	$2.52	$2.30	$2.21
2029	$2.74	$2.65	$2.42	$2.33
2030	$2.83	$2.74	$2.51	$2.42

Table A.4-41
Natural Gas Price Forecasts – Regulated-CO_2 Scenario
(Delivered, Nominal $/MBtu)

Year	Henry Hub + Variable Charges
2006	$9.58
2007	$8.32
2008	$8.05
2009	$7.02
2010	$6.31
2011	$6.16
2012	$6.43
2013	$6.73
2014	$7.03
2015	$7.35
2016	$7.68
2017	$8.03
2018	$8.40
2019	$8.78
2020	$9.17
2021	$9.59
2022	$10.02
2023	$10.48
2024	$10.96
2025	$11.45
2026	$11.96
2027	$12.51
2028	$13.08
2029	$13.67
2030	$14.29

Table A.4-42
Gulf Coast Fuel Oil Price Forecasts – Regulated-CO_2 Scenario
(Delivered, Nominal $/MBtu)

Year	No. 2 Distillate 0.5 % Sulfur	No. 2 Distillate 0.05 % Sulfur	No. 2 Distillate 0.0015 % Sulfur	No. 6 Residual 1 % Sulfur	No. 6 Residual 3 % Sulfur
2006	$13.96	$14.19	$14.64	$7.42	$6.11
2007	$12.59	$12.78	$13.54	$7.02	$5.84
2008	$12.31	$12.49	$13.24	$6.93	$5.79
2009	$12.06	$12.23	$12.99	$6.84	$5.74
2010	$11.70	$11.86	$12.66	$6.69	$5.64
2011	$11.52	$11.66	$12.69	$6.62	$5.59
2012	$11.71	$11.86	$12.79	$6.74	$5.69
2013	$12.00	$12.15	$13.01	$6.91	$5.84
2014	$12.30	$12.45	$13.24	$7.08	$5.98
2015	$12.63	$12.78	$13.50	$7.27	$6.14
2016	$13.09	$13.26	$13.99	$7.52	$6.35
2017	$13.60	$13.77	$14.53	$7.80	$6.58
2018	$14.13	$14.31	$15.09	$8.09	$6.82
2019	$14.68	$14.87	$15.67	$8.39	$7.06
2020	$15.25	$15.46	$16.27	$8.70	$7.32
2021	$15.85	$16.06	$16.90	$9.03	$7.58
2022	$16.47	$16.70	$17.55	$9.36	$7.85
2023	$17.11	$17.35	$18.22	$9.70	$8.13
2024	$17.78	$18.03	$18.93	$10.05	$8.42
2025	$18.47	$18.74	$19.65	$10.54	$8.81
2026	$19.19	$19.47	$20.41	$10.80	$9.03
2027	$19.95	$20.24	$21.21	$11.19	$9.35
2028	$20.73	$21.04	$22.03	$11.60	$9.67
2029	$21.53	$21.86	$22.88	$12.02	$10.01
2030	$22.38	$22.72	$23.76	$12.45	$10.36

A.5.0 Environmental Considerations

In May 2005, the federal EPA published as final its Clean Air Interstate Rule (CAIR) and Clean Air Mercury Rule (CAMR), establishing new regulatory programs that impose reductions of SO_2, NO_x, and Hg emissions on the electric utility industry beginning in the next 3 to 4 years. This section provides an overview of the new CAIR and CAMR programs, outlines the EPA model rule and Florida Department of Environmental Protection (FDEP) proposed approach for adopting and allocating allowances under these programs, and discusses the EPA's Regional Haze Rule as well as potential greenhouse gas legislation. This section also presents the emissions allowance price forecasts developed by Hill & Associates and presents a brief description of how the forecast emissions allowance prices were considered in the economic analyses performed in this Application.

A.5.1 Clean Air Interstate Rule Overview

On May 12, 2005, the EPA published the final CAIR, mandating reductions in SO_2 and NO_x emissions in 28 states and the District of Columbia. The EPA structured the CAIR to compel emissions reductions from EGUs and to encourage participation in an interstate cap-and-trade market to address the interstate transport of precursor emissions that significantly contribute to downwind nonattainment areas for the new 8 hour ozone and $PM_{2.5}$ national ambient air quality standards. Regulated EGUs are defined in CAIR as stationary fossil fuel fired boilers, or stationary fossil fuel fired combustion turbines, serving (at any time) a generator with a nameplate capacity of more than 25 MW producing electricity for sale. While modeling was performed to determine the geographical extent of individual sources contributing to these downwind nonattainment areas, the EPA designated entire states (and thereby all EGUs situated within these states) as being subject to regulation under CAIR. Thus, while it is debatable whether some or all of their emissions significantly contribute to downwind ozone and $PM_{2.5}$ nonattainment areas, all individual EGUs located within the State of Florida have been included in and are subject to CAIR.

The CAIR program seeks to achieve emissions reductions by establishing permanent cumulative EGU emission caps to be implemented in two phases under three separate programs: an annual SO_2 emissions program, an annual NO_x emissions program, and a seasonal NO_x emissions program, as shown in Table A.5-1.

CAIR seeks to maintain SO_2 and NO_x emissions within the program caps through the establishment of emissions "budgets." Each affected state will receive a proportional distribution of the overall cap for each phase of each program. States may individually choose which sources to regulate, as well as whether to mandate controls or allow participation in EPA's recommended model cap-and-trade program. States that choose to participate in the proposed interstate cap-and-trade program will also decide how to allocate allowances from their respective NO_x annual and seasonal budgets. States will ultimately set forth their chosen measures for achieving compliance with the emissions budgets in State Implementation Plans (SIPs) to be submitted to the EPA for approval by September 2006. Florida is subject to regulation under all three CAIR programs and has been provided with the emissions budgets listed in Table A.5-2.

Table A.5-1
CAIR Program Emissions Caps

	2009	2010	2015
SO_2 Annual		3.6 million tons	2.5 million tons
NO_x Annual	1.5 million tons		1.3 million tons
NO_x Seasonal	0.58 million tons		0.48 million tons

Table A.5-2
CAIR Emissions Budgets for Florida

	2009	2010	2015
SO_2 Annual		253,450 tons	177,415 tons
NO_x Annual	99,445 tons[(1)]		82,871 tons
NO_x Seasonal	47,912 tons		39,926 tons

(1) While it is not shown in the above total, CAIR also apportions to Florida an additional 8,335 tons of annual NO_x emissions from the Supplemental Compliance Pool for control year 2009 only.

Although the EPA originally proposed apportioning the regionwide NO_x annual and seasonal budgets based on each state's cumulative EGUs' share of recent historic heat input, the final CAIR apportioned these budgets on a fuel-adjusted heat input basis, in which gas and oil fired EGU heat input data is reduced compared to coal fired EGUs. These fuel adjustment factors (0.4 for gas and 0.6 for oil) have resulted in enhanced budgets for states with significant coal fired capacity, such as Ohio, as compared to states that have predominantly gas and oil fired generation, such as Florida. Several Florida utilities petitioned the EPA to reconsider application of these fuel adjustment factors when establishing state NO_x budgets, as well as the basis for including the entire State of Florida in the CAIR program. EPA granted this petition and published a notice on December 2, 2005, seeking additional comments on these issues. In a March 15, 2006 decision, EPA determined that for all issues under reconsideration, they considered their original CAIR determinations to be reasonable and that no changes will be made.

Until Florida officially submits its proposed SIP to the EPA, it cannot be conclusively determined which EGUs will be regulated, as well as whether they must meet strict emissions limits or may participate in the interstate emissions trading program. Preliminary indications from the FDEP are that Florida will choose to allow participation in the CAIR SO_2 annual, NO_x annual, and NO_x seasonal trading programs, and will likely adopt an allowance allocation methodology similar to what is proposed in the EPA's model rule. However, Florida is proposing to adopt a NO_x allocation scheme (described in Subsection A.5.1.1) that would differ from the EPA's model rule in several respects. Ultimately, the EPA must approve Florida's SIP for it to become effective. But if this SIP is not approved, Florida would have to implement the trading program proposed in the Federal Implementation Plan (FIP) published by the EPA on August 24, 2005.

The emissions trading option, if adopted, would provide the TEC Participants with some flexibility in choosing TEC's compliance options. Since allowances are fully transferable, entities owning multiple regulated sources may aggregate their allowances and then choose the most cost-effective units to control to achieve compliance across and amongst their collective generation portfolio. An entity can choose to reduce hours of operation and buy wholesale power, switch fuels, and/or install emissions control equipment to reduce its total emissions to either meet its allowance allocation or achieve further reductions to free up allowances for sale or future use. Alternatively, it may be more cost effective to purchase allowances to authorize emissions above their allocated level. Ultimately, an entity's sole compliance requirement is to possess sufficient allowances in its CAIR program accounts to cover its total emissions of SO_2 and NO_x (in tons) for each program at the end of each compliance period.

With regard to how CAIR will be incorporated into other ongoing SO_2 and NO_x emissions trading programs, it is important to understand that although CAIR will utilize the same allowances allocated under the Title IV Acid Rain Program for its annual SO_2 trading program, both programs (CAIR and Acid Rain) will continue in force and effect. Thus, all Title IV affected units will have to comply with the requirements of both the Acid Rain and CAIR programs for annual SO_2 emissions. Alternatively, the CAIR seasonal NO_x emissions trading program will replace the current NO_x SIP Call trading programs when it takes effect in May 2009. Though none of the Florida units are currently subject to the NO_x SIP Call program, it is important to note that allowances banked from this program will be able to be used for compliance purposes in the CAIR program.

A.5.1.1 Allocations of Allowances Under CAIR

The allocation of allowances to regulated EGUs under the CAIR proposed NO_x and SO_2 cap-and-trade programs will ultimately be determined by each regulated state. CAIR established a deadline of September 11, 2006, by which all regulated states must submit their SIPs. Collectively, these SIPs, once approved by the EPA, will establish the structure of the overall CAIR trading program. Preliminary indications from the FDEP are that Florida will opt to allow participation in the various trading programs and will likely adopt an allowance allocation methodology somewhat different from what is proposed in EPA's model rule and proposed FIP. The following discussions on CAIR implementation and allowance allocation methodologies are based on information presented by the FDEP at its April 13, 2006 rulemaking workshop in Tallahassee.

A.5.1.1.1 Allowance Allocations Under the CAIR Annual SO_2 Program. The CAIR SO_2 model trading program incorporates and runs concurrently with the Clean Air Act Title IV Acid Rain Program (ARP). Most sources governed by CAIR already receive allocations of SO_2 allowances under the Title IV ARP, and the very same ARP allowances are to be used to comply with CAIR. Affected sources must comply with both the ARP and the CAIR.

To calculate equivalent CAIR annual SO_2 allowance allocations, one must first determine the number of ARP allowances allocated to each regulated CAIR SO_2 unit. ARP allowance allocations can be found in 40 CFR §73.10, Table 2. Since CAIR does not begin until 2010, the ARP 2010 allocations would be used to determine the equivalent number of annual allowances to be allocated under CAIR.

While the ARP SO_2 allowances will be used under the CAIR cap-and-trade program, their value will be less than their relative value for compliance with the ARP. Under ARP, each allowance permits the holder to emit 1 ton of SO_2, regardless of when the allowance was originally allocated or acquired. However, the CAIR reductions require sources to annually retire (submit) multiple allowances for each ton of SO_2 emitted. The value of an allowance under CAIR will vary depending upon its vintage year (year of initial allocation or issuance) and the location of the emitting source. Table A.5-3 outlines the value of allowances for emissions from sources within the 28 states and the District of Columbia (identified in CAIR), based upon the retirement scheme under the CAIR SO_2 model trading program.

The CAIR SO_2 model rule is designed to satisfy the requirements of both the Title IV ARP and the CAIR annual SO_2 cap-and-trade program sequentially. This is accomplished by conducting the year-end retirement accounting by first deducting all requisite ARP deductions, and then making the additional deductions required to comply with CAIR. Practically speaking, compliance with CAIR will ensure a source's compliance with ARP; however, compliance with ARP will not ensure compliance with the CAIR annual SO_2 program.

Table A.5-3
Value of the CAIR SO_2 Allowances

Vintage Year	Value of Allowance (in tons)
Pre-2010	1
2010 to 2014	0.5
2015 +	0.35

A.5.1.1.2 Calculation of Allowances Under the CAIR Annual NO_x Program. The EPA's model cap-and-trade program for annual NO_x emissions recommends that each state establish set-aside accounts of allowances for new units to use under each phase of the program. It then recommends that states allocate the remaining allowances to their regulated EGUs proportionately, using historical baseline heat input rates for each regulated EGU, adjusted for the primary fuel. The allowance allocation to regulated EGUs is based on the ratio of each individual regulated EGU's baseline fuel-adjusted heat input to an established overall state baseline fuel-adjusted heat input for all regulated EGUs in the state. The model rule differentiates between units that commenced operation before January 1, 2001 (which use fuel-adjusted heat input data), and those that started after that date (which use modified heat output data, i.e., converted heat input based on a unit's energy output adjusted by a Btu/kWh multiplier). The fuel-adjusted heat input is simply the unit heat input multiplied by a fuel adjustment factor of 1.0 for coal, 0.6 for oil, and 0.4 for natural gas. The converted heat input or modified heat output is the gross electrical heat output converted to heat input using factors of 7,900 Btu/kWh for coal fired units and 6,675 Btu/kWh for oil and gas fired units.

The FDEP's proposed allocation scheme would differ from the EPA model rule in several respects. Similar to the EPA model rule, FDEP is proposing to allocate NO_x allowances to existing units using the fuel-adjusted heat input methodology and a modified output-based standard for new units for Phases I and II. However, the FDEP redefines a new unit as one commencing operation during or after 2007. The EPA model rule defined a new unit as one commencing operation during or after 2001. Furthermore, the FDEP proposes a new unit set-aside of 5 percent for both CAIR Phases I and II. Under the preliminary FDEP plan, new units may be brought into the general allocation pool with as little as 1 year of operating data and may be required to rely on either set-aside allowances or the allowance market for the first 5 to 8 years of operation. This is because FDEP is planning on allocating allowances every 3 years for three control years. The allocations will be made at least 4 years prior to the associated control year, and it is anticipated that there will be a 1 year lag for data gathering and verification. Also, unlike the EPA model rule in which retired units continue to get allowances, under the proposed FDEP approach, retired units will no longer receive allowances once an allocation year is reached in which the unit did not operate during the most recent 5 years of available data used in allocating allowances.

Specifically, FDEP's proposed allocation methodology is summarized as follows:

- Phase I state budget of 99,445 tons:
  - 2009 to 2012--Set aside 5 percent (4,972 tons) of the state budget for distribution to new units (those that began commercial operation after 2003) based on their prior year emissions. The remaining 94,473 allowances will be distributed proportionately between existing (pre-2004) units on a fuel-adjusted heat input basis. The baseline for pre-2000 existing units will equal the average of the three highest years of fuel-adjusted heat input during 2000 to 2004. Pre-2000 existing units will maintain this baseline heat input, unless they are retired. The baseline for existing units commencing operation between 2000 and 2006 will equal the average of the three highest years of fuel-adjusted heat input during their first 5 full years of operation. If in 2006, an existing unit has less than 5 full years of operating data available, its initial baseline will be (1) its highest annual fuel-adjusted heat input if 1 to 3 years of data is available or (2) the average of the two highest annual fuel-adjusted heat input if 4 years of data is available. If one full year of operating data is not available at the time the allocations are made, the existing unit will need to obtain allowances from the new unit set-aside pool. Allocations to existing units will be made by October 31, 2006. Allocations to new units from the set-aside pool will be made as soon as possible after July 1 of each control year for that control year.
  - 2013 to 2014--Set aside 5 percent (4,972 tons) of the budget for distribution to new units (those that began commercial operation after 2006) based on their prior year emissions. Allocate the remaining 94,473 allowances proportionately between existing (began pre-2007) units on a fuel-adjusted heat input basis. The baseline for pre-2000 existing units will be the same baseline used for the years 2009 to 2012. The baseline for existing units commencing operation between 2000 and 2006 will equal the average of the three highest years of fuel-adjusted heat input

during their first 5 full years of operation. If in 2009, an existing unit has less than 5 full years of operating data available, its initial baseline will be (1) its highest annual fuel-adjusted heat input if 1 to 3 years of data is available or (2) the average of the two highest annual fuel-adjusted heat input if 4 years of data is available. If one full year of operating data is not available at the time allocations are made, the existing unit will need to obtain allowances from the new unit set-aside pool. All existing units will be allocated their allowances for these control periods in 2009. Allocations to new units from the set-aside pool will be made as soon as possible after July 1 of each control year for that control year.

- Phase II state budget of 82,871 tons:
  - 2015 onward--Set aside 5 percent (4,144 tons) of the budget for distribution to new units based on their emissions in the year immediately preceding the control year. Allocate the remaining 78,727 allowances proportionately between all existing units and new units joining the existing unit pool. Allowances will be allocated based on an existing unit's fuel-adjusted heat input baseline (same basis as used in Phase I) and on a new unit's converted input (modified output) baseline (three highest years of first 5 full years of operation). FDEP will allocate allowances in 3 year blocks, 4 years in advance, based on data available at the time of allocation. If in the allocation year, an existing unit has less than 5 full years of operating data available, its initial baseline will be (1) its highest annual converted heat input if 1 to 3 years of data is available or (2) the average of the two highest annual converted heat input if 4 years of data is available. If one full year of operating data is not available at the time allocations are made, the unit will need to obtain allowances from the new unit set-aside pool. Allocations to new units from the set-aside pool will be made as soon as possible after July 1 of each control year for that control year. Units will continue to get allowance allocations based on the established baseline heat input until the unit is retired.

Pursuant to the FDEP proposed methodology, each existing (began operation before January 1, 2007) unit's baseline is calculated by averaging the three highest annual heat inputs during either the 2000 to 2004 control period for units that commenced operation prior to 2001 or the unit's first 5 full years of operation for units commencing operation after 2000, which are adjusted by a multiplier based on fuel used (100 percent for coal, 60 percent for oil, and 40 percent for all other fuels).

New units will be allocated allowances from the set-aside pool based on their proportionate contribution of NO_x emissions to the total emissions from all new units in the state during the year immediately preceding the compliance year. These allowances would be allocated by July 1 of the compliance year. The FDEP has released a projection of NO_x emissions from the new units. Table A.5-4 presents these new unit emissions projections and the ratio of allowances that would be available in the new unit pool, based on a 5 percent set-aside during Phases I and II.

Table A.5-4
Phase I New Unit Set-Aside Allowance Pool(1)

Compliance Year	Projected New Units NO_x Emissions from the Previous Year (tpy)	Allowances Set-Aside (tons)	Ratio Allowances to Emissions
2009	1,298	4,972	3.83
2010	1,651	4,972	3.01
2011	2,505	4,972	1.99
2012	3,600	4,972	1.38
2013	6,162	4,972	0.81
2014	8,648	4,972	0.57
2015	10,149	4,144	0.41

(1)Data taken from an FDEP worksheet titled "CAIR_NOx_Allocations_4-13-06_workshop.xls."

A.5.1.1.3 Calculation of Allowances Under the CAIR Seasonal NO_x Program. CAIR's seasonal NO_x trading program only applies to emissions from regulated EGUs occurring between May 1 and September 30 of each year. Other than this different compliance time period, the administration and allocation of allowances under this seasonal program is essentially the same as provided under the annual program. It should be noted that emissions of NO_x from affected units during this seasonal period are regulated under both the CAIR annual and seasonal NO_x programs, meaning that separate allowances must be secured under each individual program for each ton of NO_x emitted during the May through September ozone season. However, as noted earlier, the CAIR seasonal program is intended to replace and supersede the current NO_x SIP Call trading program, and banked allowances originally allocated under the existing NO_x SIP Call program can be used for compliance in the upcoming CAIR seasonal NO_x program.

A.5.2 Clean Air Mercury Rule Overview

On March 15, 2005, the EPA issued the final CAMR. The rule is intended to limit the emissions of Hg from affected coal fired utility units (greater than 25 MW) located in all 50 states from current levels of 48 tons per year (tpy) eventually to 15 tpy. Like the various CAIR programs, CAMR is a two-phase emissions reduction program with the first phase (effective in 2010) capping nationwide Hg emissions to 38 tpy, and the second phase (effective in 2018) capping total nationwide Hg emissions at 15 tpy.

Similar to the framework of CAIR, each state is assigned an Hg emissions budget under CAMR and must submit a SIP detailing the control programs that will be implemented to meet its specified state budget for coal fired utility units. Collectively, the budgets for all 50 states establish the "cap" for each phase of the emissions trading program. The initial Phase I cap of 38 tons scheduled to take effect in 2010 was based on the maximum reduction in Hg emissions that could be achieved through installation of FGD and SCR, otherwise known as the "co-benefit" of Hg reduction achieved through control of SO_2 and NO_x emissions under the proposed CAIR rulemaking. The Phase II cap of 15 tons of Hg emissions per year scheduled to take effect in 2018 is based on additional controls being installed, and allows for commercial development of emerging Hg control technologies. The state budget for Florida is 1.233 tons in 2010, and 0.487 tons in 2018.

CAMR also establishes standards of performance for Hg emissions from new coal fired utility units constructed, modified, or reconstructed after January 30, 2004. These standards differ according to categorization of the unit's coal rank and process type: bituminous, subbituminous, lignite, coal refuse, and IGCC. These new source limits are intended to serve as the "backstop" for the model trading program by setting the minimum control levels that must be achieved by new coal fired units, as a prerequisite to participation in the CAMR trading program.

EPA received several petitions to reconsider its final CAMR and, in response to petitions filed by a group of states, environmental groups, and Indian nations, agreed to reopen several issues for additional public comment. As part of its reconsideration notice, EPA also proposed to revise most of its New Source Performance Standard (NSPS) Subpart Da standards (40 Code of Federal Regulations (CFR) Part 60 Subpart Da) for Hg emissions from utility units. The current final CAMR Subpart Da and subsequent proposed revised standards are listed in Table A.5-5.

Table A.5-5
CAMR New Unit Performance Standards

Coal Rank/ Process Type	Current Final Rule Limit (as of 8/28/06)	Best Demonstrated Technology
Bituminous	20×10^{-6} lb/MWh	Fabric filter (FF) + FGD (wet or dry)
Subbituminous - In areas with county-level precipitation greater than 25 in./yr mean annual precipitation	66×10^{-6} lb/MWh	FF + wet FGD
Subbituminous - In areas with county-level precipitation less than 25 in./yr mean annual precipitation	97×10^{-6} lb/MWh	FF + spray dryer absorber (SDA), or ESP + SDA
Lignite	175×10^{-6} lb/MWh	FF + SDA, or ESP + wet FGD, or fluidized bed combustor (FBC) + ESP
Coal Refuse	16×10^{-6} lb/MWh	FBC + FF
IGCC	20×10^{-6} lb/MWh	

CAMR faces multiple legal challenges and is bound for review in the courts. Thirteen states and numerous environmental interest groups have filed lawsuits seeking to have the courts invalidate CAMR. Some of the major issues to be litigated include (1) whether the EPA has authority to regulate Hg emissions under a cap-and-trade program, (2) EPA's basis for revoking the December 2000 regulatory determination, (3) whether EPA followed the proper delisting petition process for an air toxin, and (4) whether proven technologies do widely exist to lower Hg pollution to levels beyond those established in the rule. Recently, the DC Circuit Court denied a petition to stay (suspend) the rule and, as a result, CAMR remains in effect until these pending legal issues are resolved. Accordingly, utilities should proceed with development of Hg control compliance strategies based on the final CAMR requirements and schedule.

A.5.2.1 Allocations of Allowances Under CAMR Using the FDEP Methodology

CAMR sets forth a model trading rule for states to use in implementing the cap-and-trade program. States are not required to adopt this model trading rule and may choose to achieve the mandated reductions by using another approach, such as imposing strict limits on individual units, or even requiring reductions beyond what is established in their budget. Based on the FDEP rule amendments with an effective date of September 6, 2006 (posted by the FDEP), Florida is planning on participating in the EPA-administered Hg cap-and-trade program for both Phase I and Phase II. A primary difference in the Florida implementation of the Phase I portion of the cap-and-trade program is that for compliance years 2012 through 2017, Florida is proposing to only allocate 70 percent of the state Hg budget to existing units and have a 5 percent set-aside for new units. For this period where only 70 percent of the state budget is allocated, there are provisions in the proposed regulations whereby a unit may receive more allocations (up to what it would have been allocated if the state would have allocated the entire state budget) if the unit's actual Hg emissions exceed the quantity of allocations received and the unit had full operation of specific control equipment for that year. For the first two years of Phase I (2010 and 2011), Florida is planning on allocating 95 percent of the state Hg budget to existing units and have a 5 percent new-unit set-aside. Under the proposed rules, in Phase II (beginning in control year 2018), Florida would allocate 95 percent of the state Hg budget to existing units and have a 5 percent set-aside for new units. Much of the Hg allowance allocation methodology will follow the general allowance allocation methodology used for CAIR, including the use of the 5 year period 2000 through 2004 as the fixed baseline period for Hg budget units that commence operation prior to 2001. As with CAIR, the baseline period for new units will be based on the first 5 full years of operation. As with Florida's proposed CAIR allowance allocation methodology, the proposed rules would define existing units as those that commenced operation prior to 2007, bringing more units into the initial existing unit pool than under the EPA model rule. Also, under the proposed Florida rule, new units would be brought into the main allowance pool more quickly than under the EPA model rule, decreasing the time that new units will have to rely on allowances from the new-unit set-aside pool.

Specifically, FDEP's proposed allocation methodology is summarized as follows:

- Phase I state budget of 1.233 tons:
  - 2010 to 2017--Set aside 5 percent (0.06165 ton or 1,973 ounces/allowances) of the state budget for distribution to new units based on their prior year emissions. For control years 2010 and 2011, the remaining 37,483 ounces (1.17135 tons) of annual Hg allowances will be distributed proportionately between existing (pre-2004) units on a fuel-adjusted heat input basis. For control years 2012 through 2017, only 70 percent of the state budget, or 27,619 ounces (0.8631 tons) will be allocated to units with an established baseline heat input. The heat input will be adjusted for the types of coal used in each unit (multiplied by 3.0 for lignite, multiplied by 1.25 for subbituminous, and multiplied by 1.0 for other solid fuel types). The baseline for pre-2000 existing units will equal the average of the three highest years of fuel-adjusted

heat input during 2000 to 2004. The baseline for existing units commencing operation between 2000 and 2006 will equal the average of the three highest years of fuel-adjusted heat input during their first 5 full years of operation. If, in the allocation year, an existing unit has less than 5 full years of operating data available, its initial baseline will be (1) its highest annual fuel-adjusted heat input if 1 to 3 years of data is available or (2) the average of the two highest annual fuel-adjusted heat input amounts, if 4 years of data is available. If one full year of operating data is not available at the time the allocations are made, the existing unit will need to obtain allowances from the new unit set-aside pool. Allocations to existing units will be made by October 31, 2006 for control years 2010, 2011, and 2012. Thereafter, allocations will be made every 3 years for a 3 year control period. Allocations to new units from the set-aside pool will be made based on the unit's previous year Hg emissions. New units must submit their requests for allowances from the new unit set-aside on or before May 1 of the control year.

- Phase II state budget of 0.487 tons:
  - 2018 onward--Set aside 5 percent (0.0243 ton or 778 ounces/allowances) of the budget for distribution to new units based on their emissions in the year immediately preceding the control year. Allocate the remaining 0.46265 ton or 14,805 ounces/allowances proportionately between all existing units and new units joining the existing unit pool. Allowances will be allocated based on an existing unit's fuel-adjusted heat input baseline (same basis as used in Phase I) and on a new unit's (commenced operation on or after January 1, 2007) converted input (modified output) baseline (three highest years of first 5 full years of operation). FDEP will allocate allowances in 3 year blocks, 4 years in advance, based on data available at the time of allocation. If in the allocation year, an existing unit has less than 5 full years of operating data available, its initial baseline will be (1) its highest annual converted heat input if 1 to 3 years of data is available or (2) the average of the two highest annual converted heat input amounts, if 4 years of data is available. If one full year of operating data is not available at the time the allocations are made, the unit will need to obtain allowances from the new unit set-aside pool. Allocations to new

units from the set-aside pool will be made based on the unit's previous year Hg emissions. New units must submit their requests for allowances from the new unit set-aside on or before May 1 of the control year. Units will continue to get allowance allocations based on the established baseline heat input until the unit is retired.

A.5.2.2 Allocations of Allowances Under CAMR Using the EPA Model Rule Methodology

EPA's model trading rule sets forth a recommended approach for allocating allowances that states may adopt - where existing units receive allocations based on a historical heat input basis adjusted for the type of coal used, and new units will be allocated allowances on a modified output basis as part of the periodic updating of total annual allocations in future years. Similar to the model CAIR annual NO_x trading program described above, the CAMR model cap-and-trade program recommends that each state establish set-aside accounts of allowances for new units to use under each phase of the program (5 percent in Phase I and 3 percent in Phase II), and then recommends that states allocate the remaining allowances to their regulated EGUs proportionately using historical baseline heat input rates for each regulated EGU. The model CAMR rule differentiates between units that commenced operation before January 1, 2001 (which use heat input data), and those that started after that date (which use "converted" heat input data, calculated by multiplying the unit's gross energy output by a heat rate conversion factor of 7,900 Btu/kWh).

Allocations for the first 5 compliance years (2010 through 2014) are recommended by the EPA to be based on historic heat inputs for existing sources. Allowances for 2015 and later will be allocated from the state's Hg budget annually, 6 years in advance, taking into account output data from new units with established baselines. Thus, allowances allocated to existing units will slowly decline as their share of total heat input decreases with the entry of new units.

As the distributors of allowances, states may alternatively choose to establish their own allocation methods regarding cost (free or auction), frequency (permanent or periodic), basis (heat input or power output), and the use and size of set-asides (for new units, incentives or relief purposes). However, CAMR does require that allowances be allocated to existing units no less than 3 years prior to the allowance vintage year (first year that it can be used for compliance) to provide sources sufficient time to plan for compliance.

As previously indicated, Florida is planning on entering the EPA administered cap-and-trade program in both Phase I and Phase II, although the allowance allocation methodology will differ in some regards from the EPA model methodology. If Florida abandons its current planned allocation methodology, and/or the EPA does not approve Florida's SIP, the following is a summary of EPA's recommended CAMR model rule methodology:

- Phase I state budget of 1.233 tons:
  - 2010 to 2017--Five percent of the budget (0.06165 ton or 1,973 ounces/allowances) would be set aside for new units. The remaining allocation budget of 1.17135 tons would yield 37,483 ounces of annual Hg allowances for allocation to existing units (those that commenced operation before January 1, 2001) based on baseline heat input rates for each unit from 2000 to 2004, adjusted for the types of coal fired in each unit (multiplied by 1.0 for bituminous, 1.25 for subbituminous, and 3.0 for lignite coals). New units (those that commenced operation after January 1, 2001) would be added to the baseline beginning with compliance year 2015, using "converted" heat input data (calculated by multiplying the unit's gross energy output by a heat rate conversion factor of 7,900 Btu/kWh).
  - 2015 to 2017--Three percent of the budget (0.03699 ton or 1,184 ounces/allowances) would be set aside for annual allocation to new units. The remaining budget of 1.19601 tons would yield 38,272 ounces of annual Hg allowances for allocation to existing units and new units added to the baseline.
- Phase II state budget of 0.487 ton:
  - 2018 onward--Three percent of the budget (0.01461 ton or 568 ounces/allowances) would be set aside for annual allocation to new units. The remaining budget of 0.47239 ton would yield 15,116 ounces of annual Hg allowances for allocation to existing units and new units added to the baseline.

New units that commence commercial operation after January 1, 2001, will be allocated allowances from the set-aside pool based on their proportionate contribution of Hg emissions to the total emissions from all new coal fired EGUs in the state during the year immediately preceding the compliance year. As new units enter into service and establish a baseline, they will be allocated allowances in proportion to their share of the total calculated heat input (existing unit heat input plus new units' modified heat input). Because retired units will continue to receive allowances indefinitely under the EPA model rule, allowances allocated to existing units will slowly decline as their share of total calculated heat input decreases with the entry of new units.

A.5.3 Regional Haze Rule

EPA finalized its original Regional Haze Rule in 1999, and more recently revised this rule in July 2005. The Regional Haze Rule calls on states to set periodic goals for improving visibility in 156 natural areas over the next 60 years. To reach these goals, states must develop "implementation plans" every 10 years that set forth enforceable measures and strategies for reducing visibility-impairing pollution, which include identification of specific facilities that will have to install best available retrofit technology (BART) controls. The BART requirements are given in 40 CFR 51.308(e). The BART rule applies to facilities that meet the following criteria:

(1) The facility contains emissions units in any of 26 listed categories in the rule. Fossil fuel fired steam electric plants of more than 250 mmBtu/h heat input is one of the 26 listed categories.

(2) The facility contains one or more emissions units that began operation after August 7, 1962 and were in existence on August 7, 1977.

(3) Of these units, the sum of potential emissions from any visibility-impairing pollutant is equal to or greater than 250 tons per year.

The pollutants addressed by BART are all visibility-impairing pollutants emitted at a greater than de minimis level. These BART pollutants will include NO_x, SO_2, and particulate matter (PM). It is expected that volatile organic compounds (VOC) and ammonia (NH_3) will not be included as BART pollutants in the final Florida BART rulemaking. It is also expected that Florida will consider CAIR equal to BART for EGUs. As such, no BART determination would be required for CAIR pollutants NO_x and SO_2. However, a BART determination would still be needed for PM. The following issues will need to be addressed as part of the BART determination:

- The available retrofit control options.
- Existing pollution control equipment in use at the facility.
- Compliance costs associated with each available control option.
- The remaining useful life of the unit.
- The energy and non-air impacts associated with implementing a control option.
- The control options impact on visibility (as determined through modeling).

A.5.4 Potential Greenhouse Gas Legislation (Provided for Information Only)

Cap-and-trade type programs are also being considered as a means to regulate greenhouse gases. One measure proposed in the Senate is the *Climate Stewardship Act of 2005* (S.342) introduced by Senators McCain and Lieberman. Though on June 22, 2005, the Senate voted 38 to 60 against an amendment to add the *Climate Stewardship Act of 2005* to the Senate Energy Bill, it is discussed here as an example of a proposed cap-and-trade program that would include regulation of CO_2 emissions from utility generating units. A May 26, 2005 press release from Senator Lieberman's office summarized the provisions of this legislation. The following information is based on this press release.

The bill would establish a 2010 US emissions level for greenhouse gases of 5,896 million metric tons (or the year 2000 levels) measured in units of CO_2 equivalents. All covered entities, those that have at least one facility which emits more than 10,000 metric tons of greenhouse gases measured in units of CO_2 equivalents per year, would be required to submit to EPA one tradeable allowance for each metric ton of greenhouse gases emitted during the reporting year. The Secretary of Commerce would be required to determine the amount of allowances to be given away free and the amount to be reserved for the public. The publicly reserved allowances would be sold by a newly established Climate Change Credit Corporation, with the proceeds going to specific programs identified in the *Climate Stewardship Act of 2005*. An entity may satisfy up to 15 percent of its emissions allowance requirements by submitting tradeable allowances from another nation's market in greenhouse gases, submitting a registered net increase in sequestration, or submitting emissions reductions that were registered by a person that is not a covered entity. The legislation would provide a means for establishing a registry system to track greenhouse gas emissions reporting, inventorying, and reduction registrations.

A.5.5 Allowance Price Forecasts

As discussed in Section A.4.0, Hill & Associates provided a forecast of SO_2, NO_x, and Hg allowance prices that correspond to its base case fuel forecast, as well as individual SO_2, NO_x, and Hg allowance price forecasts specific to the high and low fuel price forecast sensitivity cases. Although there are no regulatory programs in place for CO_2 emissions, Hill & Associates also developed a fuel price forecast that takes into account the potential impact of nationwide CO_2 regulations, and provided a separate set of SO_2, NO_x, Hg, and CO_2 allowance price forecasts specific to this regulated-CO_2 fuel price analysis. The remainder of this section discusses Hill & Associates' assumptions regarding CAIR and CAMR and presents the emissions allowance price forecasts that correspond to the base case, high, low, and regulated-CO_2 fuel price forecasts provided by Hill & Associates.

Hill & Associates expects that CAIR and CAMR will be implemented as promulgated in 2005, and that these two regulations will be the primary regulations that drive fossil fuel decisions through the forecast period. For SO_2, CAIR replaces the existing cap-and-trade system with a "CAIR cap-and-trade" system. The CAIR cap-and-trade system will utilize existing Title IV SO_2 allowances, and beginning in 2010, 23 states and Washington, DC will be required to retire additional allowances for each ton of SO_2 emitted. Specifically, 2010 to 2014 vintage allowances will offset 0.5 ton of SO_2 per allowance instead of the current 1.0 ton, and vintages of 2015 and beyond will offset 0.35 ton of SO_2 per allowance. Allowances of vintages prior to 2010 can be used at their full value.

By 2009, the NO_x state SIP Call program will be replaced with an annual cap-and-trade system similar to the one in place for SO_2, and CAIR will increase the number of NO_x limit affected states to 24 (including Washington, DC). CAIR will continue the NO_x ozone season limit for 26 states, which the EPA designated as contributing to ozone nonattainment in other states. Twenty-three of the 26 states are included in the annual NO_x limit, with the additional three states affected only by a NO_x ozone season limit. CAIR establishes an annual NO_x limit of 1.5 million tons annually in 2009, decreasing to approximately 1.3 million tons annually in 2015. The 2009 limit will be supplemented by a pool of approximately 200,000 allowances, which are distributed to states based on each state's share of the total emissions reduction requirements for the region, bringing the 2009 total NO_x limit to 1.7 million tons.

Overall, Hill & Associates projects an even greater build-out of FGD equipment than has already been announced, driven by the SO_2 limitations mandated by CAIR. This will result in a reduction in demand for SO_2 allowances prior to the first phase of CAIR SO_2 limits beginning in 2010. Pre-2010 allowances will be "banked," which will smooth the transition to the reduced emissions levels under CAIR. SO_2 allowance prices are projected to be relatively stable through the first phase of CAIR, but will begin to increase in 2015 as the second phase of CAIR begins.

CAIR is expected to initiate a tremendous build-out of post-combustion NO_x control technologies. However, Hill & Associates does not expect the build-out in post-combustion NO_x controls to oversupply the market with NO_x allowances, and forecasts that NO_x allowance prices will increase through both the first and second phases of CAIR.

The first phase of CAMR is expected to have a minimal effect on the utility industry, since the co-benefits of SO_2 and NO_x control technologies implemented to ensure compliance with CAIR will virtually ensure compliance with the Hg limitations mandated by the first phase of CAMR. Therefore, Hill & Associates does not anticipate any additional control equipment specifically for Hg cleanup and compliance with the first phase of CAMR. Hill & Associates predicts that early banking of Hg allowances will occur, resulting in Hg allowances beginning to have value in 2010. The value of Hg allowances is expected to increase through the second phase of CAMR.

Hill & Associates carried forward the emissions restrictions that apply under CAIR and CAMR for the base case fuel forecast in developing the high, low, and regulated-CO_2 fuel price forecasts. The resulting allowance price forecasts for each of these scenarios differ from the base case and each other because of the shift in background fundamentals engendered in each case. In the high fuel price sensitivity case, the higher cost of natural gas and oil and the higher electricity demand would lead to higher compliance costs, since the use of coal is expected to increase along with higher emissions allowance prices. In the low fuel price sensitivity case, lower natural gas and oil costs and lower electricity demand would lead to a decrease in the use of coal and to lower allowance prices. In the regulated-CO_2 analysis, the reduced demand for coal, going forward, would reduce the demand for allowances and would result in lower SO_2, NO_x, and Hg emissions allowance prices.

Section A.4.0 presents a detailed discussion of the assumptions utilized by Hill & Associates in developing its regulated-CO_2 fuel price analysis. Although there are no existing CO_2 regulatory programs in place, this analysis assumes that beginning in 2010, the United States will have regulations that mandate a CO_2 compliance strategy for emissions from power plants. The Hill & Associates regulated-CO_2 fuel price analysis incorporates various aspects of the previously discussed S.342.

Hill & Associates SO_2, NO_x, and Hg allowance price forecasts are presented in Table A.5-6 for the base case fuel forecasts. The SO_2, NO_x, and Hg allowance price forecasts corresponding to Hill & Associates' high and low fuel price forecast sensitivity cases are presented in Tables A.5-7 and A.5-8, respectively. Table A.5-9 presents the SO_2, NO_x, Hg, and CO_2 allowance price forecasts corresponding to Hill & Associates' regulated-CO_2 fuel price analysis.

A.5.6 Consideration of Allowance Pricing in Economic Analysis

The allowance price forecasts summarized in this section will influence each Participant's capacity expansion planning efforts in the future. Section 5.0 of Volumes B through E includes a description of the methodology used to identify each Participant's most cost-effective capacity expansion plan, based on the assumptions presented throughout this Application. Of these assumptions, one of the most influential is the fuel price forecast presented in Section A.4.0. However, in determining a utility's most economic capacity expansion plan to satisfy future capacity requirements, it is prudent to add forecast emissions allowance prices to the fuel price forecast for existing units, as well as potential capacity additions, or candidate units. Further explanation of how emissions allowance price forecasts were included in the economic analysis is presented in Section 5.0 of Volumes B through E.

Table A.5-6
Forecast SO_2, NO_x, and Hg Allowance Prices
Hill & Associates' Base Case Fuel Price Forecast

Calendar Year	SO_2 Allowances (2005 $/ton)	NO_x Allowances (2005 $/ton)	Hg Allowances (2005 $/lb)
2009	-	2,076	-
2010	339	2,824	14,922
2011	338	2,889	14,825
2012	381	2,933	11,706
2013	381	2,931	14,933
2014	483	3,096	8,679
2015	672	4,825	16,352
2016	760	5,089	10,643
2017	832	4,261	9,884
2018	850	4,302	19,228
2019	845	5,506	18,260
2020	900	6,477	18,260
2021	958	6,007	19,482
2022	1,006	5,599	20,039
2023	1,065	7,015	35,536
2024	1,190	10,298	35,673
2025	1,190	10,896	55,635
2026	1,181	11,494	59,655
2027	1,218	12,092	63,675
2028	1,255	12,690	67,694
2029	1,293	13,288	71,714
2030	1,330	13,886	75,734

Table A.5-7
Forecast SO_2, NO_x, and Hg Allowance Prices
Hill & Associates' High Fuel Price Forecast

Calendar Year	SO_2 Allowances (2005 $/ton)	NO_x Allowances (2005 $/ton)	Hg Allowances (2005 $/lb)
2009	-	2,149	-
2010	363	2,895	15,255
2011	376	2,940	12,780
2012	427	3,075	12,636
2013	434	3,206	11,834
2014	549	3,428	10,263
2015	704	5,866	16,536
2016	765	5,200	15,304
2017	845	5,300	10,220
2018	865	6,408	19,621
2019	907	6,566	19,707
2020	1,053	8,082	18,934
2021	1,158	9,147	20,000
2022	1,173	10,025	21,417
2023	1,102	8,995	38,323
2024	1,207	11,262	38,750
2025	1,245	12,102	57,500
2026	1,282	12,942	61,525
2027	1,320	13,781	65,832
2028	1,357	14,621	70,440
2029	1,395	15,461	75,371
2030	1,433	16,301	80,647

Table A.5-8
Forecast SO_2, NO_x, and Hg Allowance Prices
Hill & Associates' Low Fuel Price Forecast

Calendar Year	SO_2 Allowances (2005 $/ton)	NO_x Allowances (2005 $/ton)	Hg Allowances (2005 $/lb)
2009	-	2,012	-
2010	305	2,662	14,301
2011	303	2,696	13,918
2012	348	2,847	13,271
2013	340	2,862	14,876
2014	423	2,941	10,263
2015	605	4,404	16,454
2016	675	2,832	11,986
2017	757	3,155	10,064
2018	692	4,034	18,934
2019	737	4,384	18,260
2020	702	4,443	16,352
2021	748	4,627	19,217
2022	717	4,766	19,476
2023	775	5,141	30,319
2024	794	5,299	35,673
2025	844	5,758	50,635
2026	836	5,731	53,877
2027	857	5,948	56,571
2028	877	6,164	59,399
2029	898	6,381	62,369
2030	918	6,598	65,488

Table A.5-9
Forecast SO_2, NO_x, and Hg Allowance Prices
Hill & Associates' Regulated-CO_2 Fuel Price Forecast

Calendar Year	SO_2 Allowances (2005 $/ton)	NO_x Allowances (2005 $/ton)	Hg Allowances (2005 $/lb)	CO_2 Allowances (2005 $/ton)
2009	-	1,663	-	-
2010	267	2,075	13,212	-
2011	278	2,118	13,913	-
2012	219	1,798	9,971	4.22
2013	299	1,796	13,819	8.45
2014	280	1,551	8,294	10.85
2015	340	3,361	13,438	10.01
2016	394	3,454	8,744	10.28
2017	424	3,678	8,577	8.89
2018	434	3,103	17,364	2.43
2019	430	3,106	16,896	3.46
2020	477	3,432	16,425	2.56
2021	488	3,047	16,628	2.97
2022	544	2,967	16,441	6.26
2023	575	3,292	21,707	7.92
2024	643	6,108	19,685	6.14
2025	632	6,328	36,158	6.94
2026	627	6,675	38,771	7.24
2027	647	7,022	41,384	7.81
2028	667	7,370	43,996	8.38
2029	687	7,717	46,609	8.95
2030	707	8,064	49,221	9.52

A.6.0 Supply-Side Alternatives

This section presents the supply-side technologies that were considered by the Participants, either as alternatives to TEC or as capacity resource options in addition to TEC. These alternatives include renewable technologies, conventional technologies, emerging technologies, advanced technologies, energy storage technologies, and distributed generation technologies. This section also includes a screening analysis of the supply-side alternatives, which will identify the technologies considered in the detailed economic analysis for each Participant.

A.6.1 Renewable Technologies

Renewable energy technologies are diverse; they include wind, solar, biomass, biogas, geothermal, hydroelectric, and ocean energy. The technical feasibility and cost of energy from nearly every form of renewable energy has improved since the early 1980s. However, most renewable energy technologies struggle to compete economically with conventional fossil fuel technologies and, in most countries, the renewable fraction of total electricity generation remains small. Nevertheless, the field is rapidly expanding from occupying niche markets to making meaningful contributions to the world's electricity supply.

This section provides an overview and analysis of various renewable energy technologies, including the following:

- Solid biomass (direct-fired, gasification and IGCC, and co-firing).
- Biogas (anaerobic digestion and landfill gas [LFG]).
- Waste-to-energy (WTE) (mass burn and refuse derived fuel [RDF]).
- Wind (onshore and offshore).
- Solar (solar thermal and solar photovoltaic [PV]).
- Geothermal.
- Hydroelectric.
- Ocean energy (ocean thermal energy conversion, wave, marine current, and tidal).

Generally, each technology is described with respect to its operating principles, applications, resource availability, cost and performance characteristics, and environmental impacts. Estimates for costs and performance parameters were based on Black & Veatch project experience, vendor inquiries, and a literature review. Capital costs are in 2006 dollars and reflect the total project cost, including direct and indirect costs. Levelized costs are based on the municipal tax exempt bond rates presented in

Section A.4. Owner's costs were not included in the total project cost because such costs vary significantly for renewable technologies. The inclusion of these owner's costs would further increase the cost of the renewable technologies.

The use of municipal tax exempt bond financing presented in Section A.4 will result in lower levelized costs than for private sector financing. Levelized costs for municipal utilities are also lower, since municipal utilities are exempt from property taxes; whereas, independent power producers (IPPs) are not exempt from property taxes. As discussed below, municipal utilities have some financial incentives available to them for the development of renewable projects; however, it is in general less likely that municipals will be able to utilize the incentives compared to the private sector. Overall, there are generally more incentives available to IPPs for the development of renewable projects as discussed below. It is possible that the incentives available to IPPs can more than offset the higher financing costs of the IPPs. As such, estimates have been developed for the expected range of savings for IPP development of renewable projects net of the IPP higher financing costs and are presented as appropriate in tables throughout the remainder of this section. As discussed below, certain specific situations may result in the use of multiple incentives for renewable projects that could result in lower costs than shown by the ranges in the tables, but these would be specific cases and not the case in general. Furthermore, many of the incentives are subject to renewal or require appropriation and cast uncertainty over their application in general.

Financial Incentives for Renewable Technologies

A number of financial incentives are available for the installation and operation of renewable energy technologies. The following discussion summarizes incentives that are available to new renewable energy facilities. Although many of the incentives are designed as tax credits, non-taxable entities may be able to benefit from the incentives by contracting with a taxable entity or using other project structures. Estimates of possible all-in savings from tax credits and accelerated depreciation to a tax-paying entity (i.e. independent power producers, or IPPs) compared to a municipal utility as described in the following discussion are provided throughout this section when applicable.

Tax Related Incentives

The predominant incentive offered by the federal government for renewable energy has been through the US tax code in the form of tax deductions, tax credits, or accelerated depreciation. An advantage of this form of incentive is that it is defined in the tax code and is not subject to annual congressional appropriations or other limited budget pools (such as grants and loans). Tax related incentives include the Section 45

Production Tax Credit (PTC), Section 48 Investment Tax Credit (ITC), and accelerated depreciation. The ability to utilize tax credits is limited not only by specific legal considerations, but also by practical considerations. It can be difficult to line up the risks and benefits of a specific transaction with the appropriate participants and their tax status.

Municipal utilities and other tax-exempt entities are not able to directly take advantage of these tax incentives. Tax-exempt entities, however, do enjoy a number of other benefits when financing and operating capital investments. The most obvious benefit is freedom from federal and state income tax liability. Depending on project location and local laws, payment of property taxes may also be reduced or eliminated. These entities are also able to issue tax-exempt debt, which carries considerably lower interest rates than comparable corporate debt.

The Section 45 PTC is available to private entities subject to taxation for the production of electricity from various renewable energy technologies. The *Energy Policy Act of 2005* expanded and extended the PTC through 2007. For most technologies, the facility must be in service by January 1, 2008. The income tax credit amounts to 1.5 cents/kWh (subject to annual inflation adjustment and equal to 1.9 cents/kWh in 2006) of electricity generated by wind, solar, geothermal, and closed-loop biomass. The credit is equal to 0.75 cents/kWh (inflation adjusted, equal to 1.0 cents/kWh in 2006) for all other renewable energy technologies. A problem with the credit is the ever present threat of expiration, which promotes boom and bust building patterns.

The Section 48 ITC effectively offsets a portion of the initial capital investment in a project. The *Energy Policy Act of 2005* modified the ITC to include additional resources and to increase the credit amount. The ITC provisions are now:

- **Solar** – Eligible solar equipment includes solar electric and solar thermal systems. The credit amount for solar is 30 percent for projects that come online in 2006 and 2007; otherwise, it is 10 percent.
- **Fuel cells** – Fuel cells installed in 2006 and 2007 are eligible for the ITC. The credit amount is 30 percent with the maximum credit capped at $1,000/kW.
- **Microturbines** – Microturbines installed in 2006 and 2007 are eligible for the ITC. The credit amount is 10 percent with the maximum credit capped at $200/kW.
- **Geothermal** – Geothermal includes equipment used to produce, distribute, or use energy derived from a geothermal deposit. It does not include geothermal heat pumps. The credit amount is 10 percent, but it cannot be taken in conjunction with the PTC.

The language of the PTC extension does not allow claiming of both the PTC and the ITC. Project developers must choose one or the other. For capital intensive solar projects, the ITC is typically more attractive. For geothermal projects, the PTC is more attractive. The ITC also interacts with accelerated depreciation, as discussed further below.

Section 168 of the Internal Revenue Code contains a Modified Accelerated Cost Recovery System (MACRS) through which certain investments can be recovered through accelerated depreciation deductions. There is no expiration date for the program. Under this program, certain power plant equipment may qualify for 5-year, 200 percent (i.e., double) declining-balance depreciation, while other equipment may also receive less favorable depreciation treatment. Renewable energy property that will receive the 5-year MACRS includes:

- **Solar** – Solar property that meets the same standards for eligibility required by the federal 10 percent investment tax credit.
- **Wind** – Wind property subject to the same 25 percent limit on dual-fueled equipment required for solar property.
- **Geothermal** – Geothermal property up to the electrical transmission stage.
- **Biomass** – Qualifying Facilities 80 MW or less that directly burn at least 50 percent biomass to generate electricity. The power plant must burn the biomass directly to qualify.

The accelerated depreciation law also specifies that the depreciable basis is reduced by the value of any cash incentives received by the project, and by half of any federal investment tax credits (e.g., the ITC). This provision has the effect of lowering the depreciable basis to 95 percent for projects that receive the 10 percent ITC (and 85 percent for projects that take the 30 percent ITC) but no other cash incentives.

Non Tax-Related Incentives

The Renewable Energy Production Incentive (REPI) program was developed as a public sector counterpart to the PTC (Section 45) discussed previously. The REPI has been recently renewed through September 30, 2016 as part of the *Energy Policy Act of 2005*. Qualifying facilities must use solar, wind, ocean, geothermal, or biomass (except for municipal solid waste) generation technologies. Under the REPI program, qualifying facilities are eligible for an annual incentive payment of 1.5 cents/kWh (subject to annual inflation adjustment and equal to 1.9 cents/kWh in 2005). The payment is given for a period of ten years after the facility begins operation. The payment is subject to the availability of annual congressional appropriations.

There are two major shortcomings of the REPI program as it currently exists. First, the REPI program's reliance on annual Congressional appropriations limits its effectiveness as a financial incentive. Second, program appropriations for recent years (2003 and 2004) have not been sufficient to make full incentive payments for electricity. As a result, planners of renewable energy generation facilities have often not relied on REPI payments when evaluating the feasibility of projects. The DOE recognizes the problems of the REPI program and has sought and reviewed comments on options to make REPI a more effective incentive. These options would require either regulatory or statutory change and would need significantly higher levels of appropriations, which may be unrealistic.

Clean Renewable Energy Bonds (CREBs) were introduced as part of the *Energy Policy Act of 2005* as a response to the perceived problems with the REPI program. CREBs provide interest-free loans to public utilities (including rural electric co-ops), while providing tax credits to purchasers (the investors who buy the bonds). Qualifying projects are renewable energy projects which meet the same technical definitions as the Section 45 PTC (with the exception of the placed-in-service date). Congress authorized $800 million in bonds over two years with repayment terms of 12 to 15 years.

Of the $800 million allocated, a maximum of $500 million is for governmental entities, with the remainder reserved for co-ops. The deadline for applying for CREBs was April 26, 2006. The IRS indicated that projects would be funded starting with the smallest request and continuing with the next smallest until the funds are exhausted. This makes the CREB funds much more likely to be available for small projects.

Florida Incentives

Passage of SB 888, a comprehensive energy bill for Florida, includes a Florida Energy Commission, the Renewable Energy Technologies Grants program, tax exemptions for alternative energy technologies, and tax credits for development and expansion of facilities that produce renewable energy in Florida. SB 888 amends Section 186.801, F.S. As part of the analysis of electric utility ten-year site plans, the Florida Public Service Commission (FPSC) is to review the plan's effect on fuel diversity within the State. SB 888 creates Section 366.92, F.S. which states the intent of the Legislature to develop renewable energy and allows the FPSC to adopt goals for increasing the use of Florida renewable energy resources

SB 888 includes four private sector and three municipal sector incentive programs. Most are not applicable to electric generating facilities. The following is a summary of the portions of SB 888 related to electric generating facilities.

- Corporate Renewable Energy Production Tax Credit – While Florida has no individual income tax, it does have a corporate income tax. With the enactment of SB 888, a corporate renewable energy tax credit was created in the amount of $0.01/kWh of electricity produced and sold by the taxpayer to an unrelated party in the taxable year. A facility placed in service after May 1, 2006 receives a credit based on their full production. The State puts a limit of $5 million in credits in the State fiscal year.
- Florida Renewable Energy Technologies Grants Program – This newly established program (by SB 888) is open to in-state municipalities, utilities, not-for-profit organizations, commercial businesses and others to offset the capital cost of renewable installations. Up to $15 million may be available for fiscal year 2006-07. These are matching funds for demonstration, commercialization, research and development projects in renewable energy. Factors that are considered in awarding the grants are economic development, matching funds, technical feasibility, and public visibility among others.

A.6.1.1 Biomass

Biomass is any material of recent biological origin; the most common form is wood. Electricity generation from biomass is the second most prolific source of renewable electric generation after hydroelectric power. Solid biomass power generation options include direct-fired biomass, biomass gasification, and co-fired biomass, as described in the following subsections.

A.6.1.1.1 Direct-Fired Biomass. According to the US Department of Energy, there is about 35,000 MW of installed biomass combustion capacity worldwide.[1] Combined heat and power applications in the pulp and paper industry comprise the majority of this capacity.

Operating Principles

Direct biomass combustion power plants in operation today use the same steam Rankine cycle that was introduced commercially 100 years ago. In many respects, biomass power plants are similar to coal plants. When burning biomass, pressurized steam is produced in a boiler and then expanded through a turbine to produce electricity. Prior to its combustion in the boiler, the biomass fuel may require processing to improve the physical and chemical properties of the feedstock. Furnaces used in biomass

[1] US Department of Energy, Oak Ridge National Laboratory, "Biomass Frequently Asked Questions," available at http://bioenergy.ornl.gov/faqs.

combustion include spreader stoker fired, suspension fired, fluidized bed, cyclone, and pile burners. Advanced technologies, such as integrated biomass gasification combined cycle and biomass pyrolysis, are currently under development; however, there are no IGCC plants currently operating with biomass as a primary fuel.

Applications

Although wood is the most common biomass fuel, other biomass fuels include agricultural residues such as bagasse (sugar cane residues), dried manure and sewage sludge, black liquor from pulp mills, and dedicated fuel crops such as fast growing grasses and eucalyptus.

Biomass plants usually have a capacity of less than 50 MW because of the dispersed nature of the feedstock and the large quantities of fuel required. As a result of the smaller scale of the plants and lower heating values of the fuels, biomass plants are commonly less efficient than modern fossil fuel plants. In addition to being less efficient, biomass is generally more expensive than conventional fossil fuels on a $/MBtu basis because of added transportation costs. These factors usually limit the use of direct-fired biomass technology to inexpensive or waste biomass sources.

Resource Availability

To be economically feasible, dedicated biomass plants are located either at the source of a fuel supply (such as at a sawmill) or within 100 miles of numerous suppliers. Wood and wood waste are the primary biomass resources and are typically concentrated in areas of high forest product industry activity. In rural areas, agricultural production can often yield significant fuel resources that can be collected and burned in biomass plants. These agricultural resources include bagasse, corn stover, rice hulls, wheat straw, and other residues. Energy crops, such as switchgrass and short rotation woody crops, have also been identified as potential biomass sources. In urban areas, biomass is typically comprised of wood wastes such as construction debris, pallets, yard and tree trimmings, and railroad ties. Locally grown and collected biomass fuels are relatively labor intensive and can provide substantial employment benefits to rural economies. In general, the availability of sufficient quantities of biomass is less of a feasibility concern than the high costs associated with transportation and delivery of the fuel.

Based on recent biomass resource assessments with which Black & Veatch is familiar, the expected cost of clean wood residues in the region can vary by up to 40 percent, depending on the type of residue, quantity, and hauling distance. To reflect this variance, a delivered price range of $1.25 to $2.00 per MBtu was assumed in this analysis.

Cost and Performance Characteristics

Table A.6-1 presents typical characteristics of a 30 MW stoker boiler biomass plant with Rankine cycle using wood waste as fuel.

Table A.6-1
Direct Biomass Combustion Technology Characteristics

Performance	
Typical Duty Cycle	Baseload
Net Plant Capacity (MW)	30
Net Plant Heat Rate (HHV,[1] Btu/kWh)	14,500
Capacity Factor (percent)	70 to 90
Economics ($2006)	
Total Project Cost ($/kW)	2,306 to 3,331
Fixed O&M ($/kW-yr)	71.75
Variable O&M ($/MWh)	10.25
Levelized Cost[2] ($/MWh)	73 to 112
Possible Savings for IPPs ($/MWh)	0 to 10
Technology Status	
Commercial Status	Commercial
Installed US Capacity (MW)	7,000

[1]HHV--Higher Heating Value.
[2]The low ends of the levelized costs are based on a 90 percent capacity factor, a capital cost of $2,306/kW, and a fuel price of $1.25/MBtu. The high ends of the levelized costs are based on a 70 percent capacity factor, a capital cost of $3,331/kW, and a fuel price of $2.00/MBtu.

Environmental Impacts

Biomass power projects must maintain a careful balance to ensure long-term sustainability with minimal environmental impact. Most biomass projects target the use of biomass waste material for energy production, saving valuable landfill space. Biomass projects that burn forestry or agricultural products must ensure that both fuel harvesting and collection practices are sustainable and do not adversely affect the environment.

Unlike fossil fuels, biomass is viewed as a carbon-neutral power generation fuel. While CO_2 is emitted during biomass combustion, a nearly equal amount of CO_2 is absorbed from the atmosphere during the biomass growth phase. Furthermore, biomass fuels contain little sulfur compared to coal and, therefore, produce less SO_2. Finally, unlike coal, biomass fuels typically contain only trace amounts of toxic metals, such as Hg, cadmium, and lead. However, biomass combustion still must include technologies to control emissions of NO_x, PM, and CO to maintain BACT standards.

A.6.1.1.2 Biomass Gasification and IGCC. Biomass gasification is an emerging technology that converts solid biomass into a gaseous fuel which can then be combusted or otherwise utilized. There are numerous uses for the gas and many different gasifier technologies. IGCC is a developing application that combines a gasifier with a conventional combined cycle power plant (combustion turbine followed by a steam cycle). The majority of IGCC plants constructed worldwide to date are fossil fueled, and there are only two coal fired IGCC plants generating power in the United States. There are no IGCC plants currently operating with biomass as a primary fuel.

Operating Principles

Biomass gasification is a process to convert solid biomass into a gaseous fuel. This is accomplished by heating the biomass in an environment low in oxygen ("fuel rich"). Gasification is a promising process for biomass conversion. By converting solid fuel to a combustible gas, gasification allows the use of more advanced, efficient, and environmentally benign energy conversion processes such as gas turbines and fuel cells to produce power, and chemical synthesis to produce ethanol and other value added products. There is a huge variety of gasification technologies including updraft, downdraft, fixed grate, entrained flow, fluidized bed, and molten metal baths. The technology choice depends primarily on the fuel characteristics and the desired capacity of the plant.

The primary product of air-blown gasification is a low heating value fuel gas, typically 15 to 20 percent (150-200 Btu/ft^3) of the heating value of natural gas (1,000 Btu/ft^3). Using oxygen, steam, or indirect heating results in a higher quality gas, although at higher costs. Gasifier fuel gas is alternatively known as syngas and producer gas.

Applications

The primary advantage of gasification over direct combustion is the versatility of the gasification product. Gasification expands the use of solid fuel to include practically all the uses of natural gas and petroleum, including close-coupled boilers, gas engines and turbines, fuel cells, chemical synthesis, and Stirling engines. The various fuel gas conversion options are illustrated on Figure A.6-1.

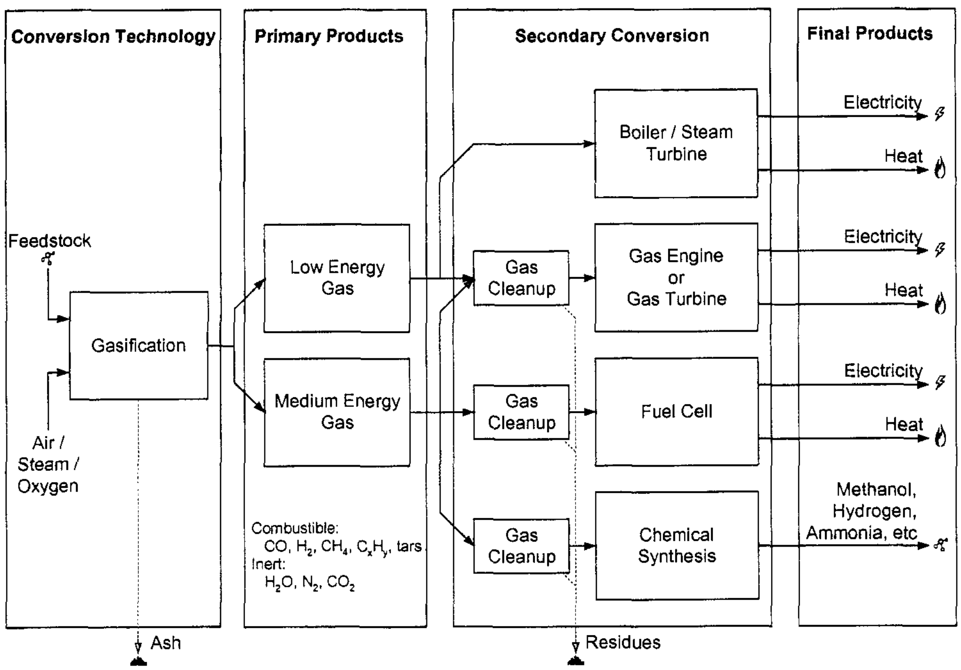


Figure A.6-1
General Gasification Flow

One of the principal focus areas for biomass gasification technology developers has been biomass IGCC. In an IGCC plant, the syngas exiting the gasifier is cleaned and combusted in a combustion turbine, generating power. Heat is then exhausted from the gas turbine at a high enough temperature to generate steam for use in a traditional steam cycle. Commercial-scale IGCC coal fired power plants are considered to be a highly efficient solid-fuel technology. Net conversion to electricity for biomass IGCC plants is projected to be approximately 35 percent, compared to 20 to 25 percent for direct-fired biomass plants. The potentially significant increase in efficiency makes biomass IGCC attractive; however, the recent problems experienced with the technology demonstration will need to be overcome.

Although there are many gasifiers installed that produce fuel gas for close-coupled combustion in a boiler (essentially staged combustion), recent attempts to demonstrate more advanced processes, such as IGCC, have not been successful. Issues have been related partially to the gasification process itself, but also to supporting ancillary equipment, such as fuel handling and gas cleanup. Regardless, there are several biomass gasification equipment suppliers, including Foster Wheeler, Energy Products of Idaho, and Primenergy, that continue to develop gasification technology for other applications.

Resource Availability

A biomass gasification or biomass IGCC plant would have the same resource availability issues as a direct-fired biomass plant. To be economically feasible, it should be located either at the source of a fuel supply or within 100 miles of numerous suppliers. Wood, wood byproducts, agricultural residues, energy crops, and urban wood wastes are all suitable fuels for a biomass IGCC plant.

Like other biomass conversion technologies, an IGCC biomass plant would be limited in capacity by the amount of resource that could feasibly be delivered. A reasonable estimate for this limit is 30 MW to 75 MW, depending on the location. Conversely, coal IGCC power plants are typically limited by the gas turbine capacity, not by fuel availability, and can be designed for much larger capacities similar to other fossil fuel power plants.

Cost and Performance Characteristics

Given the lack of commercial experience, cost and performance estimates for an IGCC biomass plant are uncertain. Since it would be limited to a size much smaller than an IGCC coal plant, an IGCC biomass plant would not benefit from the economies of scale of such plants. Furthermore, an IGCC biomass plant would be significantly more costly than a stand-alone biomass combustion plant, however more efficient. Table A.6-2 presents typical characteristics for a biomass IGCC combustion plant.

Environmental Impacts

An IGCC biomass project would have the same long-term sustainability concerns as other biomass conversion technologies. Biomass is viewed as a carbon-neutral power generation fuel. While CO_2 is emitted during biomass conversion, a nearly equal amount of CO_2 is absorbed from the atmosphere during the biomass growth phase. Furthermore, biomass fuels contain little sulfur compared to coal and therefore produce less SO_2. Finally, unlike coal, biomass fuels typically contain only trace amounts of toxic metals, such as Hg, cadmium, and lead. However, biomass gasification technologies still must include equipment to control emissions of NO_x, PM, and CO to maintain BACT standards. It is important to note that given that biomass IGCC has higher efficiency than biomass combustion-based power plants, the pounds of pollution per MWh generated are substantially less.

Table A.6-2
Biomass IGCC Technology Characteristics

Performance	
Typical Duty Cycle	Baseload
Net Plant Capacity (MW)	30 to 75
Net Plant Heat Rate (HHV, Btu/kWh)	10,000 to 11,500
Capacity Factor (percent)	60 to 80
Economics ($2006)	
Total Project Cost ($/kW)	2,500 to 4,000
Fixed O&M ($/kW-yr)	70
Variable O&M ($/MWh)	15
Levelized Cost(1) ($/MWh)	78 to 132
Possible Savings to IPPs ($/MWh)	0 to 10
Technology Status	
Commercial Status	Demonstration
Installed US Capacity (MW)	0

(1)The low ends of the levelized costs are based on an 80 percent capacity factor, a fuel cost of $1.25/MBtu, and a capital cost of $2,500/kW. The high ends of the levelized costs are based on a 60 percent capacity factor, a fuel cost of $2.00/MBtu, and a capital cost of $4,000/kW.

A.6.1.1.3 Biomass Co-Firing.

Operating Principles

One of the most economical methods to burn biomass is to co-fire it with coal. Co-fired projects are usually implemented by retrofitting a biomass fuel feed system to an existing coal plant, although greenfield facilities can also be designed to accept a variety of fuels.

As discussed in the previous section, a major challenge to biomass power is that the dispersed nature of the feedstock and high transportation costs generally preclude plants larger than 50 MW. By comparison, coal power plants rely on the same basic power conversion technology, but can have much higher unit capacities, exceeding 1,000 MW. As a result of this larger capacity, modern coal plants are able to obtain a higher efficiency at a lower cost. Through co-firing, biomass benefits from this higher efficiency through a more competitive cost than a stand-alone, direct-fired biomass plant.

Applications

There are several methods of biomass co-firing that can be used to produce energy on a commercial scale. Provided that they were initially designed with some fuel flexibility, stoker and fluidized bed boilers generally require minimal modifications to accept biomass. For these types of boilers, simply mixing the fuel into the coal pile may be sufficient to co-fire biomass.

Cyclone boilers and pulverized coal boilers (the most common in the utility industry) require a smaller fuel size than stokers and fluidized beds and may necessitate processing of the biomass prior to combustion. There are two basic approaches to co-firing in this case: co-feeding the biomass through the coal processing equipment or separately processing and then injecting the biomass. The first approach blends the fuels and feeds the mixture to the coal processing equipment (crushers, pulverizers, etc.). In a cyclone boiler, up to 10 percent of the coal heat input can be replaced with biomass using this method. Pulverizers in a pulverized coal boiler are not designed to process relatively low density biomass, and fuel replacement is generally limited to approximately 2 or 3 percent if the fuels are mixed. The second approach (separate biomass processing and injection) allows higher co-firing percentages (10 to 15 percent) in a pulverized coal unit, but costs more than processing a fuel blend.

Even at these limited co-firing rates, plant owners and operators have raised numerous concerns about the negative effects of co-firing on plant operations. These include the following:

- Negative impact on plant capacity.
- Negative impact on boiler performance.
- Ash contamination decreasing the quality of coal ash.
- Increased O&M costs.
- Minimal NO_x reduction potential (usually proportional to biomass heat input).
- Boiler fouling/slagging because of the high alkali in biomass ash (more of a concern with fast growing biomass, such as energy crops).
- Potentially negative impacts on SCR air pollution control equipment (catalyst poisoning).

These concerns have hampered the adoption of widespread biomass co-firing by electric utilities in the United States. However, most of these concerns can be addressed through proper system design, fuel selection, and limits on the amount of co-firing.

Coal and biomass co-firing can also be considered in the design of new power plants. Designing the plant to accept a diverse fuel mix allows the boiler to incorporate biomass fuel, ensuring high efficiency with low O&M impacts. Fluidized bed technology is often the preferred boiler technology since it has inherent fuel flexibility. There are many fluidized bed units around the world that burn a wide variety of fuels, including biomass. An example is a 240 MW circulating fluidized bed (CFB) in Finland, which burns a mixture of wood, peat, and lignite. This unit is capable of burning various fuels, ranging from 100 percent biomass to 100 percent coal.

Resource Availability

For viability, the candidate coal plant should be located within 100 miles of suitable biomass resources. The United States has a larger installed biomass power capacity than any other country in the world. US-based biomass power plants provide 7,000 MW of capacity to the national power grid. Coal power generation accounted for 2.02 trillion kWh in 2005, which comprised 52.2 percent of the total generation in the United States. Conversion of as little as 5 percent of this generation to biomass co-firing would increase electricity production from biomass by nearly 400 percent.

The local resources available for biomass co-firing are the same as those for dedicated biomass plants. Biomass is assumed to be available at a cost of between $1.25 and $2.00 per MBtu.

Cost and Performance Characteristics

Table A.6-3 presents typical characteristics for a biomass and coal co-fired plant. The characteristics are based on co-firing 20 MW of biomass (separate injection) in a new 765 MW (net) pulverized coal power project. Except for fuel, the characteristics are provided on an incremental basis (changes that would be expected compared to the coal plant). The primary capital cost for the project would be related to the biomass material handling system.

The incremental levelized costs presented for the co-fired biomass plant were calculated as the differential cost between co-firing and operating on only coal, with the cost and performance of the coal unit based on the estimated cost and performance for the proposed Taylor Energy Center (TEC) presented in Section A.3.0. That is, the levelized cost for TEC without co-firing was calculated and compared to the levelized cost for TEC assuming 20 MW of biomass co-firing.

Analysis of the range of incremental levelized costs presented in Table A.6-3 indicates that there would be a negligible impact on the levelized costs of TEC if biomass was to be co-fired with TEC's fuel blend. The range of incremental levelized costs of between approximately \$-0.20/MWh to approximately \$0.22/MWh is based on a biomass component of between approximately \$21/MWh to approximately \$37/MWh.

Table A.6-3
Co-Fired Biomass Technology Characteristics

Performance	
Typical Duty Cycle	Typically baseload, depends on host
Net Plant Capacity (MW)	20
Net Plant Heat Rate (Btu/kWh)	Increase 0.2 to 0.5 percent
Capacity Factor (percent)	Unchanged
Economics (Incremental Costs in \$2006)	
Total Project Cost(1) (\$/kW)	205 to 410
Total Project Cost(2) (\$/kW)	8.20 to 16.40
Fixed O&M(1) (\$/kW-yr)	5.13 to 10.25
Fixed O&M(2) (\$/kW-yr)	0.21 to 0.41
Variable O&M (\$/MWh)	Unchanged
Levelized Cost(3) (\$/MWh)	-0.20 to 0.22 (incremental cost)
Technology Status	
Commercial Status	Commercial
Installed US Capacity (MW)(4)	>1,000 MW

(1)Based on biomass capacity.
(2)Based on total plant capacity (750 MW).
(3)The low end of the levelized cost is based on a net biomass capacity of 20 MW, heat rate increase of 0.2 percent, capital cost of \$205/kW, and fixed O&M of \$5.12/kW-yr. The high end of the levelized cost is based on a net plant capacity of 30 MW, heat rate increase of 0.5 percent, capital cost of \$410/kW, and fixed O&M cost of \$10.25/kW-year.
(4)Estimate for the biomass portion of plants that co-fire coal and biomass. Actual capacity is unknown.

Environmental Impacts

As with direct-fired biomass plants, the biomass fuel supply must be collected in a sustainable manner. Assuming this is the case, co-firing biomass in a coal plant generally has overall positive environmental effects. The clean biomass fuel typically reduces emissions of SO_2, CO_2, NO_x, and heavy metals, such as Hg.

A.6.1.2 Biogas

Biogas technology refers to the process of generating electricity with gas captured from the anaerobic digestion of manure or naturally occurring landfill gas. The following subsections describe the formation of these fuels and their ability to produce renewable energy.

A.6.1.2.1 Anaerobic Digestion.

Operating Principles

Anaerobic digestion is a naturally occurring process that occurs when bacteria decompose organic materials in the absence of oxygen. The byproduct of this decomposition is comprised of 50 to 80 percent methane. The most common applications of anaerobic digestion include industrial wastewater, animal manure, or human sewage as feedstock. According to the *World Biomass Report 2004-2013*, the projected total installed capacity of anaerobic digestion will grow from 185 MW in 2004 to 575 MW in 2013. It is estimated that 203 MW of this growth will be installed in Western Europe, 68 MW in North America, and 46 MW in Australia.[2]

Applications

Anaerobic digestion is commonly used in municipal wastewater treatment as a first-stage treatment process for sewage sludge. Increasingly stringent agricultural manure and sewage treatment management regulations are the primary drivers for the heightened interest in anaerobic digestion technologies. Use of anaerobic digestion technologies in wastewater treatment applications results in less biosolids residue compared to aerobic (digestion in the presence of oxygen) technologies. Power production from digestion facilities is typically a secondary consideration.

The Los Angeles Department of Water and Power has announced a new agreement to purchase power from a proposed 40 MW anaerobic digestion facility that will process 3,000 tons per day (tpd) of municipal green waste, such as landscape trimmings and food waste, to produce biogas for power production. The proposed facility, which is scheduled to be on line by 2009, would be the largest of its kind. There are various other high solids digestion systems installed worldwide, primarily in Europe and Japan.

Biogas produced by anaerobic digestion can be used for power generation, direct heat applications, and absorption chilling. Reciprocating engines are the most common power conversion device, although demonstrations with microturbines and fuel cells have also been successful.

[2]The World Biomass Report, *Bioenergy News*, December 2004, http://www.bioenergy.org.nz.

Resource Availability

For on-farm manure digestion, the resource is readily accessible and only minor modifications to existing manure management techniques are required to produce biogas suitable for power generation. In some cases, economies of scale may be realized by transporting manure from multiple farms to a central digestion facility. For central plant digestion of manure from several sources, the availability and close proximity of a large number of livestock operations is necessary to provide a sufficient manure feed rate to the facility. However, the larger size of regional facilities does not necessarily guarantee better economics, because of higher manure transportation costs. For anaerobic digestion of municipal sewage wastes, the resource is readily available at the wastewater treatment plant.

Cost and Performance Characteristics

Table A.6-4 presents typical characteristics of farm-scale dairy manure anaerobic digestion systems using reciprocating engine technology.

Table A.6-4
Farm-Scale Anaerobic Digestion Technology Characteristics

Performance	
Typical Duty Cycle	Baseload
Net Plant Capacity (MW)	0.085
Capacity Factor (percent)	70 to 90
Economics ($2006)	
Total Project Cost ($/kW)	2,358 to 3,895
Variable O&M ($/MWh)	15.38
Levelized Cost(1) ($/MWh)	46 to 76
Possible Savings for IPPs ($/MWh)	0 to 10
Technology Status	
Commercial Status	Commercial
Installed Worldwide Capacity (MW)	6,300

(1)The low end of the levelized cost is based on a capacity factor of 90 percent and capital cost of $2,358/kW. The high end of the levelized cost is based on a capacity factor of 70 percent and capital cost of $3,895/kW.

Environmental Impacts

Anaerobic digesters provide the following positive environmental impacts:

- Reduce pathogens in the waste stream.
- Eliminate odor problems.
- Reduce methane emissions relative to atmospheric decomposition of manure, which are a significant contributor to greenhouse gas emissions.
- Help prevent nutrient overloading in the soil resulting from manure spreading.

A.6.1.2.2 Landfill Gas.

Operating Principles

LFG is produced by the decomposition of the organic portion of landfill waste. LFG typically has a methane content in the range of 45 to 55 percent and is considered an environmental risk. There is increased political and public pressure to reduce air and ground water pollution and to hedge the risk of explosion associated with LFG. From a generating perspective, LFG is a valuable resource that can be burned as fuel by reciprocating engines, small gas turbines, or other devices. LFG energy recovery is currently regarded as one of the more mature and successful WTE technologies. Currently, there are more than 600 LFG energy recovery systems installed in 20 countries.

Applications

LFG can be used to generate electricity and process heat or can be upgraded for pipeline sales. Power production from an LFG facility is typically less than 10 MW. There are several types of commercial power generation technologies that can be easily modified to burn LFG. Internal combustion engines are by far the most common generating technology choice. Approximately 75 percent of the landfills that generate electricity use internal combustion engines.[3] Depending on the scale of the gas collection facility, it may be feasible to generate power via a combustion turbine or a boiler and steam turbine. Testing with microturbines and fuel cells is also under way, although these technologies do not appear to be economically viable for power generation.

Resource Availability

Gas production at a landfill is dependent on the depth and age of waste in place and the amount of precipitation received by the landfill. In general, LFG recovery may be economically feasible at sites that have more than 1 million tons of waste in place,

[3] EPA Landfill Methane Outreach Program, http://www.epa.gov/lmop/proj/index.htm.

more than 30 acres available for gas recovery, a waste depth greater than 40 feet, and at least 25 inches of annual precipitation.

Cost and Performance Characteristics

The economics of installing an LFG energy facility depend heavily on the characteristics of the candidate landfill. The payback period of an LFG energy facility at a landfill that has an existing gas collection system can be as short as 2 to 5 years, especially if environmental credits are available. However, the cost of installing a new gas collection system at a landfill can prohibit installing an LFG facility. Table A.6-5 presents cost and performance estimates for typical LFG projects using reciprocating engines.

Table A.6-5
Landfill Gas Technology Characteristics

Performance	
Typical Duty Cycle	Baseload
Net Plant Capacity (MW)	0.2 to 15
Capacity Factor (percent)	70 to 90
Economics ($2006)	
Total Project Cost ($/kW)	1,333 to 2,768
Variable O&M ($/MWh)	15.38
Levelized Cost(1) ($/MWh)	34 to 59
Possible Savings for IPPs ($/MWh)	0 to 10
Technology Status	
Commercial Status	Commercial
Installed US Capacity (MW)	1,100

(1)The low end of the levelized cost is based on a net plant capacity of 15 MW, a 90 percent capacity factor, and a capital cost of $1,333/kW. The high end is based on a net plant capacity of 0.2 MW, a 70 percent capacity factor, and a $2,768/kW capital cost.

Environmental Impacts

LFG combustion releases pollutants similar to many other fuels, but is generally perceived as environmentally beneficial. Since LFG is principally composed of methane, if not combusted, LFG is released into the atmosphere as a greenhouse gas. As a greenhouse gas, methane is 23 times more harmful than CO_2. Collecting the gas and converting the methane to CO_2 through combustion greatly reduces the potency of LFG as a source of greenhouse gas emissions.

A.6.1.3 Waste-to-Energy

WTE technologies can use a variety of refuse types and technologies to produce electrical power. The economic feasibility of a WTE facility, though, is difficult to assess. Costs are highly dependent on transportation, processing, and tipping fees associated with a particular location. Values discussed in the following subsections should be considered representative of the technology at a generic site.

A.6.1.3.1 Municipal Solid Waste Mass Burn. There are currently 65 WTE plants in the United States using mass burn technology to generate electricity. These plants burn municipal solid waste (MSW) in an "as-discarded" form, with minimal or no preprocessing of the waste. Because of concerns about environmental pollutants (particularly dioxin), opposition to new MSW projects has increased significantly. In addition, costs for MSW facilities have often exceeded initial estimates. Since 1996, only one new MSW facility has come on line in the United States, and it was later shut down because of lack of waste resources.

Operating Principles

Converting refuse or MSW to energy can be accomplished by a variety of technologies. The degree of refuse processing determines the method used to convert MSW to energy. Refuse that has had limited processing to remove noncombustible and oversize items is typically combusted in a waterwall furnace similar to coal and biomass furnaces. The MSW is fed to a reciprocating grate in the boiler. The combustion generates steam in the walls of the furnace, which is converted to electrical energy via a steam turbine generator system. Other furnaces used in mass burning applications include refractory furnaces, rotary kiln furnaces, and controlled air furnaces for smaller modular units.

Applications

The avoided cost of waste disposal is a primary component in determining the economic viability of a WTE facility. High costs for land and waste transportation increase the feasibility of an MSW facility. The 65 operating mass burn plants have an annual capacity to process 22.1 million tons of waste. Large MSW facilities typically process 500 to 3,000 tons of MSW per day (the average amount produced by 200,000 to 1,200,000 residents), although there are a number of facilities operating in the 200 to 500 tpd size range. According to the Integrated Waste Services Association, the average design capacity of mass burn plants operating in the United States is approximately 1,000 tons of waste per day.

Resource Availability

MSW plants are high capital cost projects that require an inexpensive and abundant fuel source to operate profitably. For this reason, plants are typically sited near large population centers or in areas of high priced land. The EPA estimates that the average American generates about 4 to 5 pounds of garbage per day, most of which would otherwise be sent to a landfill.

Cost and Performance Characteristics

Table A.6-6 provides the typical ranges of performance and cost for a facility burning 500 tons of MSW per day.

Table A.6-6
MSW Mass Burning Technology Characteristics

Performance	
Typical Duty Cycle	Baseload
Net Plant Capacity (MW)	15
Net Plant Heat Rate (HHV Btu/kWh)	16,500
MSW Consumption (tpd)	500
Capacity Factor (percent)	75 to 85
Economics ($2006)	
Total Project Cost ($/kW)	5,125 to 7,175
Fixed O&M ($/kW-yr)	256 to 359
Variable O&M ($/MWh)	67 to 87
Levelized Cost(1) ($/MWh)	120 to 206
Possible Savings for IPPs ($/MWh)	0 to 10
Technology Status	
Commercial Status	Commercial
Installed US Capacity (MW)	1,856

(1)The low end of the levelized cost is based on a capacity factor of 85 percent, capital cost of $5,125/kW, fixed O&M of $256/kW-year, and variable O&M of $66.6/MWh. The high end of the levelized cost is based on a capacity factor of 75 percent, capital cost of $7,175/kW, fixed O&M of $359/kW-year, and variable O&M of $87.1/MWh. Includes a tipping fee of $50 per ton with an assumed 4,720 Btu/lb heating value.

Environmental Impacts

One of the most significant environmental benefits of burning MSW is that it reduces landfill deposits. The combustion byproducts produced when MSW is burned are similar to those of most organic combustion materials. PM must be abated, and NO_x can form if the combustion temperature is too high. Unlike coal, the sulfur emissions from MSW are low. One MSW emission that is atypical of fossil fuels is dioxin, which the EPA has ruled to be carcinogenic. This issue has been intensely debated in the scientific community, but MSW projects face opposition as a result of the ruling.

A.6.1.3.2 Refuse Derived Fuel.

Operating Principles

RDF is an evolution of MSW technology. Rather than burning trash in its bulky native form, trash is processed and converted to fluff or pellets for ease of handling and improved combustibility.

Applications

RDF is preferred over MSW in many WTE applications because it can be combusted with the same technology used to combust coal. Spreader stoker fired boilers, suspension fired boilers, fluidized bed boilers, and cyclone furnace units have all been used to generate steam from RDF. Fluidized bed combustors are often preferred for RDF energy applications because of their high combustion efficiency, capability to burn RDF with minimal processing, and inherent ability to effectively reduce NO_x and SO_2 emissions.

There are 15 operating RDF plants in the United States, with an annual capacity to process 7.7 million tons of waste. Typical RDF facilities process 500 to 2,000 tons of RDF per day (the average amount produced by 200,000 to 800,000 residents). According to the Integrated Waste Services Association, the average design capacity of RDF plants operating in the United States is approximately 1,300 tons of waste per day.

Cost and Performance Characteristics

Table A.6-7 provides the typical ranges for performance and cost of an RDF facility burning 500 tons of waste per day.

Table A.6-7
RDF Technology Characteristics

Performance	
Typical Duty Cycle	Baseload
Net Plant Capacity (MW)	15
Net Plant Heat Rate (HHV Btu/kWh)	16,500
RDF Consumption (tpd)	500
Capacity Factor (percent)	75-85
Economics ($2006)	
Total Project Cost ($/kW)	7,175 to 9,225
Fixed O&M ($/kW-yr)	461 to 564
Variable O&M ($/MWh)	72 to 92
Levelized Cost(1) ($/MWh)	194 to 288
Possible Savings for IPPs ($/MWh)	0 to 10
Technology Status	
Commercial Status	Commercial
Installed US Capacity (MW)	636

(1)The low end of the levelized cost is based on a capacity factor of 85 percent, capital cost of $7,175/kW, fixed O&M of $461/kW-year, and variable O&M of $72/MWh. The high end of the levelized cost is based on a capacity factor of 75 percent, capital cost of $9,225/kW, fixed O&M of $563/kW-year, and variable O&M of $92/MWh. Includes a tipping fee of $50 per ton with an assumed 5,500 Btu/lb heating value.

Environmental Impacts

RDF has many of the same environmental obstacles as MSW and provides the same environmental benefits. However, RDF plants using fluidized bed technology can potentially achieve lower emissions than mass burn plants.

A.6.1.4 Wind

Operating Principles

Wind power systems convert the movement of air to power by means of a rotating turbine and a generator. Wind power has been the fastest growing energy source of the last decade, in percentage terms, with around 30 percent annual growth in worldwide capacity over the last 5 years. Cumulative worldwide wind capacity is now estimated to be more than 50,000 MW. Total installed wind capacity in the United States was

9,149 MW at the beginning of 2006. The US wind market has been driven by a combination of growing state mandates and the production tax credit (PTC), which provides an economic incentive for wind power. The PTC has been renewed several times and is currently set to expire on December 31, 2007.

Applications

Typical utility-scale wind energy systems consist of multiple wind turbines that range in size from 1 to 2 MW. Wind energy system installations may total 5 to 300 MW, although the use of single, smaller turbines is also common in the United States for powering schools, factories, water treatment plants, and other distributed loads. Furthermore, offshore wind energy projects are now being built in Europe and are planned in the United States, encouraging the development of larger turbines (up to 5 MW) and larger wind farm sizes.

Wind is an intermittent resource, with average capacity factors ranging from 25 to 40 percent. The capacity factor of an installation depends on the wind regime in the area and the energy capture characteristics of the wind turbine. Capacity factor directly affects economic performance; thus, reasonably strong wind sites are required for cost-effective installations. Since wind is intermittent, it cannot be relied upon as firm capacity for peak power demands. To provide a dependable resource, wind energy systems may be coupled with some type of energy storage to provide power when required, but this is not common and adds considerable expense to a system.

Resource Availability

Turbine power output is proportional to the cube of wind speed, which makes small differences in wind speed very significant. Wind strength is rated on a scale from Class 1 to Class 7, as shown in Table A.6-8. The State of Florida's wind resources are generally categorized as Class 1 or 2 and, therefore, may not be viable for baseload power production.

Cost and Performance Characteristics

Table A.6-9 provides typical characteristics for a 50 to 100 MW wind farm. Substantially higher costs are necessary for wind projects that require grid upgrades or long transmission tie lines. Capital costs for new onshore wind projects had remained relatively stable for several years, but current demand has driven up the cost by as much as 40 percent. Additionally, because of increased demand and impending PTC expiration, the current earliest delivery date for new turbines is 2008. Significant gains have been made in recent years in identifying and developing sites with better wind resources and improving turbine reliability. As a result, the average capacity factor for newly installed wind projects in the United States has increased from about 24 percent before 1999 to more than 32 percent in 2005.

Table A.6-8
US Department of Energy Classes of Wind Power

Wind Power Class	Height Above Ground: 50 m (164 ft)(1)	
	Wind Power Density (W/m^2)	Speed(2) (m/s)
1	0 to 200	0 to 5.60
2	200 to 300	5.60 to 6.40
3	300 to 400	6.40 to 7.00
4	400 to 500	7.00 to 7.50
5	500 to 600	7.50 to 8.00
6	600 to 800	8.00 to 8.80
7	800 to 2,000	≥ 8.80

(1)Vertical extrapolation of wind speed based on the 1/7 power law, as defined in Appendix A of the *Wind Energy Resource Atlas of the US, 1991.*
(2)Mean wind speed is based on Rayleigh speed distribution of equivalent mean wind power density. Wind speed is for standard sea level conditions. To maintain the same power density, wind speed must increase 3 percent per 1,000 m (5 percent per 5,000 ft) elevation.

Environmental Impacts

Wind is a clean generation technology from an emissions perspective. However, there are still environmental considerations associated with wind turbines. Opponents of wind energy frequently cite visual impacts and noise as drawbacks. Turbines are approaching and exceeding heights of 400 feet and, for maximum wind capture, tend to be located on ridgelines and other elevated topography. Turbines can cause avian fatalities and other wildlife impacts if sited in sensitive areas. To some degree, these issues can be partially mitigated through proper siting, environmental review, and public involvement during the planning process.

A.6.1.5 Solar

Solar radiation can be captured in numerous ways with a variety of technologies. The two major groups of technologies are solar thermal and solar photovoltaic (PV).

Table A.6-9
Wind Technology Characteristics

	Wind Farm
Performance	
Typical Duty Cycle	As Available
Net Plant Capacity (MW)	50 to 100
Capacity Factor (percent)	10 to 15[1]
Economics ($2006)	
Total Project Cost ($/kW)	1,333 to 1,640
Fixed O&M ($/kW-yr)	31
Levelized Cost[2] ($/MWh)	120 to 211
Possible Savings for IPPs ($/MWh)	5 to 20
Technology Status	
Commercial Status	Commercial
Installed US Capacity (MW)	9,149

[1]Representative of low wind speed site in southeastern United States.
[2]The low end of the levelized cost is based on a net plant capacity of 100 MW, capacity factor of 15 percent, and capital cost of $1,333/kW. The high end of the levelized cost is based on a net plant capacity of 50 MW, capacity factor of 10 percent, and capital cost of $1,640/kW.

A.6.1.5.1 Solar Thermal.

Operating Principles

Solar thermal technologies convert the sun's energy to electricity by capturing heat. Technological advances have expanded solar thermal applications to high magnitude energy collection and power conversion on a utility scale. The leading solar thermal technologies include parabolic trough, parabolic dish, power tower (central receiver), and solar chimney.

With adequate resources, solar thermal technologies are appropriate for a wide range of intermediate- and peak-load applications, including central station power plants and modular power stations in both remote and grid-connected areas. Commercial solar thermal parabolic trough plants in California currently generate more than 350 MW.

Most solar thermal systems (parabolic trough, parabolic dish, and central receiver) transfer the heat in solar insolation to a heat transfer fluid, typically a molten salt or heat transfer oil. By using thermal storage or by combining the solar generation system with a fossil fired system (a hybrid solar/fossil system), a solar thermal plant can provide dispatchable electric power.

Unlike the three other solar thermal technologies, solar chimneys do not generate power using a thermal heat cycle. Instead, they generate and collect hot air in a large (several square miles) greenhouse. A tall chimney is located in the center of the greenhouse. As the air in the greenhouse is heated by the sun, it rises and enters the chimney. The natural draft produces a wind current that rotates a collection of air turbines.

Applications

The larger solar thermal technologies (parabolic trough, central receiver, and solar chimney) are currently not economically competitive with other central station generation options (such as natural gas fired combined cycle units). Parabolic dish engine systems are small and modular and can be placed at load sites, directly offsetting retail electricity purchases. However, these systems have not been used in commercial applications.

Of the four technologies, parabolic trough represents the vast majority of installed capacity, primarily in the southwest US desert. There are nine Solar Electric Generating Station (SEGS) parabolic trough plants in the Mojave Desert that have a combined capacity of 354 MW. Other parabolic trough plants are being developed, including a 64 MW plant in Nevada and several 50 MW plants in Spain.

Parabolic dish engine systems of approximately 25 kW have been developed and are now being actively marketed. Recently, installation was completed on a six-dish test deployment at Sandia National Laboratories (SNL) in Albuquerque, New Mexico. On August 2, 2005, Southern California Edison publicly announced the completion of negotiations on a 20 year power purchase agreement (PPA) with Stirling Energy Systems (SES) for between 500 to 850 MW capacity of dish/Stirling units. On September 7, 2005, SES announced a contract with San Diego Gas & Electric to provide between 300 and 900 MW of solar power using the dish technology. Pricing for these PPAs remains confidential. If large deployments of dish/Stirling systems materialize, they are expected to drastically reduce capital and O&M costs and increase system reliability.

The US government has funded two utility-scale central receiver power plants: Solar One and its retrofit, Solar Two. Solar Two was a 10 MW installation near Barstow, California, but it is no longer operating, because of reduced federal support and high operating costs.

The first commercial chimney project has been proposed in Australia. Originally, this project was planned to be 200 MW with a chimney 1 km (0.62 mile) tall and a greenhouse 5 km (3.1 miles) in diameter. The estimated cost of that system was

$700 million. More recently, the project has been scaled down to 50 MW. Cost and dimension data for the scaled down system are not available.

Resource Availability

Solar radiation reaching the earth's surface, often called insolation, has two components: direct normal insolation (DNI) and diffuse insolation (DI). DNI, which typically comprises about 80 percent of the total insolation, is that part of the radiation which comes directly from the sun. DI is the part that has been scattered by the atmosphere or is reflected off the ground or other surfaces. On a cloudy day, all of the radiation is diffuse. The vector sum of DNI and DI is termed global insolation. Systems that concentrate solar energy use only DNI, while nonconcentrating systems use global insolation. Concentrating solar thermal systems (troughs, dishes, and central receivers) use DNI. Lower latitudes with minimum cloud coverage offer the greatest solar concentrator potential. Florida DNI ranges from 4.5 to 5.5 $kW/m^2/day$. Some locations in the southwest United States can have a DNI as high as 8.5 $kW/m^2/day$.

A general feature of solar thermal systems and solar technologies is that peak output typically occurs on summer days when electrical demand is high. Solar thermal systems that include storage allow dispatch that can improve the ability to meet peaking requirements. Land requirements for solar thermal systems are about 5 to 8 acres/MW.

Cost and Performance Characteristics

Representative characteristics for the four solar thermal power plant technologies previously described are presented in Table A.6-10.

A.6.1.5.2 Solar Photovoltaic. PVs have achieved considerable consumer acceptance over the last few years. PV module production tripled between 1999 and 2002. PV installations reached a worldwide output of more than 927 MW in 2004. Worldwide grid-connected residential and commercial installations grew from 120 MW per year in 2000 to 770 MW per year in 2004.[4] The majority of these installations were in Japan and Germany, where strong subsidy programs have made the economics of PV attractive. Large-scale (>100 kW) PV installations have been added at a rate of about 5 MW per year in recent years.

[4] Installed PV power as of the end of 2004, http://www.oja-services.nl/iea-pvps/isr/01.htm.

Table A.6-10
Solar Thermal Technology Characteristics[1]

	Parabolic Trough	Parabolic Dish	Central Receiver	Solar Chimney
Performance				
Typical Duty Cycle	Peaking - Intermediate	As Available - Peaking	Peaking - Intermediate	Intermediate - Baseload
Net Plant Capacity (MW)	100	1.2	50	200
Integrated Storage	6 hours	None	6 hours	Yes
Capacity Factor (percent)	35 to 40	20 to 25	35 to 40	60 to 80
Economics ($2006)				
Total Project Cost ($/kW)	3,588 to 4,612	3,075 to 4,100	4,100 to 5,125	3,588 to 4,612
Variable O&M ($/MWh)	20.5 to 25.6	10.3 to 20.5	25.6 to 30.8	10.3 to 20.5
Levelized Cost[2] ($/MWh)	117 to 166	139 to 235	136 to 188	59 to 104
Possible Savings to IPPs ($/MWh)	20 to 40	20 to 40	20 to 40	20 to 40
Technology Status				
Commercial Status	Commercial	Demonstration	R&D	R&D
Installed US Capacity (MW)	~350	< 1	10[3]	< 1

R&D = Research and Development.

[1] Parabolic trough cost estimates have the highest degree of uncertainty for near-term applications. Other technologies assume significant deployment.
[2]The low ends of the levelized costs are based on the higher capacity factors and the lower capital and O&M costs. The high ends of the levelized costs are based on the lower capacity factors and higher capital and O&M costs.
[3]No longer operating.

Operating Principles

The amount of power produced by PV installations depends on the material used and the intensity of the solar radiation incident on the cell. Single or polycrystal silicon cells are most widely used today. Single crystal cells are manufactured by growing single crystal ingots, which are then sliced into thin cell-sized material. The cost of the crystalline material is significant. The production of polycrystalline cells can cut material costs, with some reduction in cell efficiency. Thin film cells significantly reduce cost per unit area, but result in lower efficiency cells. Gallium arsenide cells are among the most efficient solar cells and have other technical advantages, but they are also more costly and typically are used only where high efficiency is required even at a high cost, such as space applications or in concentrating PV applications.

Applications

The modularity, simple operation, and low maintenance requirements of solar PV makes it ideal for distributed, remote, or off-grid applications. Most PV applications are smaller than 1 kW, although larger, utility-scale installations are becoming more prevalent. There are more than 50 PV systems worldwide with capacities greater than 1 MW, including three systems in Germany between 5 and 6.3 MW. The largest system in the United States is Tucson Electric's Springerville PV plant, with nearly 4.6 MW of capacity.

Resource Availability

Most PV systems installed today are flat plate systems that use global insolation. Concentrating PV systems, which use DNI, are being developed, but are not considered commercial at this time. Global insolation on latitude tilt surfaces in Florida range from 5 to 6 $kW/m^2/day$, compared with up to 7 $kW/m^2/day$ in the southwest United States.

Cost and Performance Characteristics

Table A.6-11 presents cost and performance characteristics of a 4 kW residential and a 50 kW commercial fixed-tilt, single crystalline PV system.

Environmental Impacts

A key attribute of solar PV cells is that they have virtually no emissions after installation. Some thin film technologies have the potential for discharge of heavy metals during manufacturing; however, proper monitoring and control can adequately address this issue.

A.6.1.6 Geothermal

Operating Principles

Geothermal resources can provide energy for power production and other applications by using heat from the earth to generate steam and drive turbine generators. The global installed capacity for geothermal power plants is approximately 8,900 MW (electrical). Additionally, about 16,000 MW (thermal) is used in direct heat applications. It is estimated that geothermal resources using today's technology could support between 35,500 MW and 72,000 MW of electrical generating capacity worldwide. Using enhanced technology that is currently under development, global geothermal resources have the potential to support up to 138,000 MW.

It is estimated that US geothermal resources could support between 6,300 and 11,700 MW of electric power with current technology and 15,000 to 25,000 MW with advanced technology.

Table A.6-11
Solar PV Technology Characteristics

	Residential	Commercial
Performance		
Typical Duty Cycle	As Available, Peaking	As Available, Peaking
Net Plant Capacity (kW)	4	50
Capacity Factor (percent)	18	20
Economics ($2006)		
Total Project Cost ($/kW)	8,713 to 12,813	7,688 to 9,738
Fixed O&M ($/kW-yr)	46.1	20.5
Variable O&M(1) ($/MWh)	53.3	23.6
Levelized Cost(2) ($/MWh)	597 to 830	437 to 542
Possible Savings for IPPs ($/MWh)	20 to 40	20 to 40
Technology Status		
Commercial Status	Commercial	
Installed US Capacity (MW)	365	

(1)Includes inverter replacement after 10 years.
(2)The lower levelized costs are based on the low ends of the total project costs, and the high levelized costs are based on the high ends of the total project costs.

Applications

In addition to generation of electricity and direct space heating applications, hot water and saturated steam from a geothermal resource can be used for a wide variety of process heat applications.

Resource Availability

Geothermal power is limited to locations where geothermal pressure reserves are discovered. Well temperature profiles determine the potential for geothermal development and the type of geothermal power plant installation. High energy sites are suitable for electricity production, while low energy sites are suitable for direct heating. Most of the geothermal resources in the United States are concentrated in the west and southwest parts of the country. There are minimal geothermal resources available east of the Mississippi River, and no resources suitable for power generation or direct heat applications in Florida.

Cost and Performance Characteristics

For representative purposes, a binary cycle power plant is characterized in Table A.6-12. In a binary cycle plant, a working fluid is boiled by heat transferred from a geothermal source across a heat exchanger, and then expanded through a turbine. Capital costs of geothermal facilities can vary widely, since the drilling of individual wells can cost as much as $4 million, and the number of wells drilled depends on the success of finding the resource.

Table A.6-12
Geothermal Technology Characteristics

Performance	
Typical Duty Cycle	Baseload
Net Plant Capacity (MW)	30
Capacity Factor (percent)	70 to 90
Economics ($2006)	
Total Project Cost ($/kW)	2,563 to 4,100
Fixed O&M ($/kW-yr)	205 to 308
Levelized Cost[(1)] ($/MWh)	61 to 122
Possible Savings for IPPs ($/MWh)	0 to 15
Technology Status	
Commercial Status	Commercial
Installed US Capacity[(2)] (MW)	2,534

[(1)]The low end of the levelized cost is based on a capacity factor of 90 percent, capital cost of $2,563/kW, and fixed O&M cost of $205/kW-year. The high end of the levelized cost is based on a capacity factor of 70 percent, capital cost of $4,100/kW, and fixed O&M cost of $308/kW-year.
[(2)]With the currently available technology, there are no viable geothermal power plant sites east of the Mississippi River.

Environmental Impacts

Dissolved minerals and hazardous noncondensable gases in geothermal fluids can be an environmental concern if not addressed properly (fluid reinjection addresses many concerns). Geothermal power plants with modern emissions control technologies have minimal environmental impact; they emit less than 0.2 percent of the CO_2, less than 1 percent of the SO_2, and less than 0.1 percent of the particulates of a clean fossil fuel plant. There is the potential for geothermal production to cause ground subsidence. This is rare in dry steam resources, but possible in liquid-dominated fields. However, carefully applied reinjection techniques can effectively mitigate this risk.

A.6.1.7 Hydroelectric

Operating Principles

Hydroelectric power is generated by capturing the kinetic energy of water as it moves from a higher elevation to a lower elevation by passing it through a turbine. The amount of kinetic energy captured by a turbine is dependent on the head (distance the water is falling) and the flow rate of the water. Often, the water is raised to a higher potential energy by blocking its natural flow with a dam. If a dam is not feasible, it is possible to divert water out of the natural waterway, through a penstock, and back to the waterway. Such "run-of-river" applications allow for hydroelectric generation without the impact of damming the waterway. The existing worldwide installed capacity for hydroelectric power is by far the largest source of renewable energy at 740,000 MW.[5]

Applications

Hydroelectric projects are divided into a number of categories on the basis of their size. Micro-hydroelectric projects generate below 100 kW. Systems generating between 100 kW and 1.5 MW are classified as mini-hydroelectric projects. Small hydroelectric systems generate between 1.5 and 30 MW. Medium hydroelectric projects generate up to 100 MW, and large hydroelectric projects generate more than 100 MW. Medium and large hydroelectric projects are good resources for baseload power generation if they have the ability to store a large amount of potential energy behind a dam and release it consistently throughout the year. Small hydroelectric projects generally do not have large storage reservoirs and are not dependable as dispatchable resources.

Resource Availability

A hydroelectric resource can be defined as any flow of water that can be used to capture the kinetic energy. Projects that store large amounts of water behind a dam can regulate the release of water through turbines and generate electricity regardless of the season. These facilities can generally serve baseload needs. Run-of-river projects do not impound the water but, instead, divert a part or all of the current through a turbine to generate electricity. At "run-of-river" projects, power generation varies with seasonal flows and can sometimes help serve summer peak loads.

[5] International Energy Agency, 2002.

All hydroelectric projects are susceptible to drought. In fact, the variability in hydropower output is rather large, even when compared to other renewable resources. The aggregate annual capacity factor for all hydroelectric plants in the United States has ranged from about 31 to 53 percent over the last decade.[6]

Florida does not have the natural resources required to develop any additional hydroelectric facilities.

Cost and Performance Characteristics

Hydroelectric generation is regarded as a mature technology that is unlikely to advance. Turbine efficiency and costs have remained somewhat stable, but construction techniques and costs continue to change. Capital costs are highly dependent on site characteristics and vary widely. Table A.6-13 provides ranges for performance and cost estimates for hydroelectric projects for two categories: new projects at undeveloped sites and additions or upgrades to hydroelectric projects at existing sites. These values are for representative comparison purposes only. Capacity factors are highly resource dependent and can range from 10 to more than 90 percent. Capital costs also vary widely with site conditions.

Environmental Impacts

The damming of rivers for small- and large-scale hydroelectric applications may have significant environmental impacts. One major issue involves the migration of fish and the disruption of spawning habitats. For dam projects, one of the common solutions to this problem is the construction of "fish ladders" to aid the fish in bypassing the dam when they swim upstream to spawn.

A second issue involves flooding existing valleys that often contain wilderness areas, residential areas, or archeologically significant remains. There are also concerns about the consequences of disrupting the natural flow of water downstream and disrupting the natural course of nature.

A.6.1.8 Ocean Energy

Ocean energy resources can be captured in numerous ways with a variety of technologies. The current areas of research and development are wave energy, ocean thermal energy conversion (OTEC), and tidal energy.

[6] Based on analysis of reported data from Global Energy Solutions, 2006.

Table A.6-13
Hydroelectric Technology Characteristics

	New	Incremental
Performance		
Typical Duty Cycle	Varies with Resource	Varies with Resource
Net Plant Capacity (MW)	<50	1 to 160
Capacity Factor (percent)	40 to 60	40 to 60
Economics ($2006)		
Total Project Cost ($/kW)	2,563 to 3,998	615 to 2,973
Fixed O&M ($/kW-yr)	5.1 to 25.6	5.1 to 25.6
Variable O&M ($/MWh)	5.1 to 6.2	3.6 to 6.2
Levelized Cost(1) ($/MWh)	51 to 119	16 to 93
Possible Savings for IPPs ($/MWh)	0	0 to 5
Technology Status		
Commercial Status	Commercial	Commercial
Installed US Capacity (MW)	79,842	NA

(1)The low end of the levelized cost is based on the higher capacity factors and the lower capital and O&M costs. The high end of the levelized cost is based on the lower capacity factors and the higher capital and O&M costs. Levelized costs for new hydroelectric assume 40MW plant, and levelized costs for incremental hydroelectric assume 80 MW of incremental capacity.

A.6.1.8.1 Wave.

Operating Principles

The kinetic energy of ocean waves can be converted to electric power using a wave energy conversion system (WECS). Many hundreds of WECS technologies have been suggested, but only a very small proportion of these have been evaluated beyond the concept stage. Of these, only a small number have been developed beyond laboratory testing to deployment as prototypes in real sea conditions. WECSs are generally categorized as shore-based (onshore and near-shore) or offshore systems.

Onshore and Near-Shore Applications

There are two basic shore-based wave energy designs: oscillating water column (OWC) devices and overtopping-tapered channel (TAPCHAN) devices.

OWC devices generate electricity from the wave-induced rise and fall of a water column. The energy in this water column is extracted via a moving air column using an air turbine. The main disadvantages with onshore systems, such as OWC, is that their construction is dependent on local conditions and the available wave power is low at the shoreline. Onshore devices also require a small tidal range and a suitable shoreline with a reservoir location. The onshore systems have an advantage over the near-shore and offshore systems because of their accessibility for maintenance and transmission. The most developed example of this design is Wavegen's 500 kW LIMPET device, which has been operating since 2001.

TAPCHAN devices generate electricity using conventional low head hydropower turbines. A tapering channel concentrates and funnels waves up a channel and increases their height so that they then spill into a reservoir. Since these devices are driven by water flowing from a reservoir back to the sea, this device produces a more stable power output.

Near-shore systems that can be built around existing breakwater structures include the Energetech device, which uses a parabolic wall to focus wave energy onto the collector and a Dennis-Auld turbine. In general, near-shore devices have the advantage that they can access higher wave power without the need for extensive electricity transmission. However, like onshore devices, their shoreline location may affect their adoption because of their aesthetically displeasing appearance.

Offshore Applications

There is much greater diversity of offshore WECSs than near-shore systems. The most common offshore WECSs are pneumatic devices, overtopping devices, float-based devices, and moving body devices. In general, offshore devices can access the greatest amount of wave power, but require extensive power transmission and maintenance since they are located in a more extreme environment.

Pneumatic devices generate electricity using air movement, often using an OWC concept similar to that of shore-based devices. Overtopping devices generate electricity using the same basic methodology as the shore-based versions. Float-based devices generate electricity using the vertical motion of a float rising and falling with each wave. The float motion is reacted against an anchor or other structure so that power can be extracted. Moving body devices use a solid body moving in response to wave action to generate electricity.

Float-based devices are the most common of all proposed designs. Well developed European designs that are still under consideration include a 1 MW demonstration plant consisting of four 250 kW buoys planned for 2006 at Makah Bay, Washington. A commercial ocean wave project constructed off the northern coast of Portugal in 2005 consists of three 750 kW machines. The Portuguese consortium in charge of the project intends to order 30 additional machines before the end of 2006, subject to performance of the first three.[7] A PowerBuoy float-based device is under development, and the first 50 kW unit of a 1 MW demonstration system was installed in June 2004 at Kaneohe Bay, Oahu, in Hawaii. This project has $2.8 million in additional funding from the US Navy. Additionally, a 2 to 5 MW wave power station in France was recently begun, along with a 1.25 MW wave power station in northern Spain.[8]

Cost and Performance Characteristics

Since there has not been large-scale commercialization of any of these technologies, there is a wide range of projected costs. These costs, and performance estimates, are based on theoretical calculations and are highly uncertain.

Environmental Impacts

WECSs are generally not considered to be environmentally harmful. However, there are some concerns with WECSs, including degradation of marine habitat and adverse visual impacts. These concerns may be mitigated through careful siting of projects.

A.6.1.8.2 Ocean Thermal Energy Conversion.

Operating Principles

An OTEC plant uses the temperature difference between warm surface water and cold deep water to generate electricity via a heat engine system. There are multiple configurations under development, but all OTEC facilities operate on the same basic principle. Comparatively warm surface water is used to heat a working fluid to create vapor and drive a turbine generator. Cold ocean water at depths exceeding 3,000 feet is then used to condense the working fluid. When compared to other renewable technologies, one of the greatest advantages of OTEC is the capability to provide baseload continuous power output.

Applications

OTEC is currently in active research and development by several organizations and corporations around the world. Most of these facilities are operated by laboratories or research organizations and receive the majority of their funding through grants, research foundations, or federal programs. The OTEC plants constructed or proposed to date have ranged from 18 kW to 10 MW net.

[7] Ocean Power Delivery Press Release, May 19, 2005. Accessed at: http://www.oceanpd.com/docs/OPD%20Enersis%20Press%20Release.pdf.
[8] Ocean Power Technologies Press Release, June 20, 2005. Accessed at: http://www.oceanpowertechnologies.com/pdf/french_wave_project.pdf.

OTEC plants allow a wide range of other services to be derived from the supply of cold deep ocean water, including desalinated water, air conditioning and industrial cooling, aquaculture, and chilled soil agriculture. Many of the current approaches to commercializing OTEC exploit the added value that these services bring for a small incremental increase in cost. Since air conditioning and aquaculture can generally use only a small amount of the water required for the OTEC plant, the main value added service is normally desalinated water.

Resource Availability

OTEC requires warm ocean surface water and cold deep ocean water with a temperature difference exceeding 36° F. Water cold enough to provide the required temperature difference is normally only found at depths of greater than 3,000 feet. In addition, surface water temperature requirements limit development to tropical waters. Land-based applications require steep underwater slopes to minimize the length of cold water piping. If offshore OTEC facilities are considered, the number of suitable locations for OTEC expands. However, offshore applications would require substantial underwater electricity transmission.

Cost and Performance Characteristics

In general, OTEC plants must be large to be economically viable, but there are no large demonstration plants to provide real-world cost data. Table A.6-14 presents the estimated performance and costs for onshore and offshore closed cycle OTEC facilities.

Environmental Impacts

There remain some important questions about the environmental impacts of OTEC plants. The most frequently raised points are: changes to thermal, salinity, and nutrient gradients within the vicinity; leakage of working fluid from closed cycle OTEC plants or of the chlorine used for controlling bio-fouling; fatalities of small organisms such as plankton; and the effects on commercial fishing.

A.6.1.8.3 Ocean Tidal.

Operating Principles

The generation of electrical power from ocean tides is similar to traditional hydroelectric generation. A tidal power plant consists of a tidal pond created by a dam, a powerhouse in the dam containing a turbo-generator, and a sluice gate in the dam to allow the tidal flow to enter and leave. Opening the sluice gate in the dam allows the rising tidal waters to fill the tidal basin. At high tide, these gates are closed, and the tidal basin behind the dam is filled to capacity. After the ocean waters have receded, the tidal basin is released through a turbo-generator in the dam. Power may be generated during ebb tide, flood tide, or both.

Table A.6-14
Ocean Thermal Energy Technology Characteristics

	Onshore	Offshore
Performance		
Typical Duty Cycle	Baseload	Baseload
Net Plant Capacity (MW)	10	100
Capacity Factor (percent)	90	90
Economics ($2006)		
Total Project Cost ($/kW)	10,250 to 15,375	2,563 to 5,125
Variable O&M ($/MWh)	13.3 to 25.6	13.3 to 25.6
Levelized Cost(1) ($/MWh)	133 to 206	46 to 90
Technology Status		
Commercial Status	Initial Demonstration	Development
Installed US Capacity (MW)	0	0

(1)The lower levelized costs are based on the low ends of the total project costs, and the higher levelized costs are based on the high ends of the total project costs.

Resource Availability

Because of the intermittent, although predictable, nature of the tidal resource, tidal power is typically used as an intermediate generation source for utilities. The capacity factor of tidal energy facilities may be expected to be around 25 percent. A few utility-scale facilities have been developed around the world. The largest facilities are a 240 MW plant in France and an 18 MW plant in Canada.

Times and amplitudes of high and low tide are predictable, although these characteristics will vary considerably by region. Economic studies suggest that tidal power will be most economical at sites where the mean tidal range exceeds about 16 feet. In the United States, these conditions only exist in Maine and Alaska, which precludes the rest of the country from the economic generation of power from this resource.

Cost and Performance Characteristics

Costs to develop a tidal energy facility are extremely site-specific and can vary considerably. Therefore, no estimates have been included in this Application.

Environmental Impacts

Utilization of tidal energy for power generation has the environmental advantage of a zero emissions technology. However, the environmental and aesthetic impact that the facility has on the coastline must be carefully evaluated. The main barriers to the increased use of tidal energy are the high cost and long period for the construction of the tidal generating system and concerns about impacts on sensitive estuarine ecosystems.

A.6.1.8.4 Marine Current.

Operating Principles

Marine current generation is based on capturing the energy from the movement of the ocean. This movement can be in the form of tidal streams, which are caused by the rise and fall of tides. As water flows in and out of estuaries, it carries energy that can be extracted. In some locations, such as the Gulf Stream, water moves in only one direction, and the flow is largely independent of the tides. In practice, electricity generation from marine currents is similar in many ways to electricity generation from wind power.

Technology in this area is still immature, and designs for tidal stream generators range from horizontal- and vertical-axis turbines to reciprocating hydrofoils and venturi systems. The horizontal- and vertical-axis turbine designs are similar to their counterparts in wind energy. Power is generated by the rotation or movement of the devices as water flows past them. Currently, a few large-scale prototypes have been built and tested, but no commercial tidal stream projects have yet been completed.

Resource Availability

Because of the intermittent, although predictable, nature of the tidal resource, tidal stream power would typically be used as an intermediate generation source for utilities. For tidal stream farms, capacity factors may range from around 20 to 45 percent, similar to wind farms.

In Florida, capturing power from the Gulf Stream was announced as being investigated as a potential power resource in 2004. The United States Navy was supposed to test a turbine designed by Florida Hydro Power and Light for use in the Gulf Stream.[9] Details or results of these tests are not available.

Cost and Performance Characteristics

Since there has not been large-scale commercialization of any of these technologies, there is a wide range of projected costs. Associated costs and performance estimates are therefore highly uncertain and have not been presented in this Application. Current cost estimates are much higher than most equivalent costs for other forms of conventional and renewable generation.

[9] http://www.dt.navy.mil/pressreleases/archives/000042.html

Environmental Impacts

Utilization of tidal energy for power generation has the environmental advantage of a zero emissions technology. However, the environmental impacts that facilities have on the coastline must be carefully evaluated. The main barriers to the use of tidal stream generation are the immaturity of the technology, high costs, and concerns about impacts on sensitive estuarine ecosystems.

A.6.2 Conventional and Emerging Technologies

The conventional generating options that were evaluated as potential sources of future capacity for the TEC Participants (FMPA, JEA, RCID, and Tallahassee) are discussed in this section. Options considered include joint ownership of greenfield units, individual ownership of units at existing Participant sites, and individual ownership of greenfield units. In addition to a general description, a summary of projected performance, emissions, capital cost, O&M costs, startup costs, construction schedules, scheduled maintenance requirements, and forced outage rates have been developed for each option.

Cost and performance estimates have been developed for several conventional self-build generation technologies that are proven, commercially available, and widely used in the power industry. Additionally, cost and performance estimates were developed for several types of emerging technologies. Emerging technologies are technologies that cannot be considered conventional for various reasons, as discussed further in this analysis. The conventional technologies considered include simple cycle combustion turbines, combined cycle configurations, and CFB units. The emerging technologies include IGCC units, a new simple cycle combustion turbine (GE LMS100), and new nuclear generating unit designs.

Although the combustion turbines and the combined cycle alternatives discussed herein assume a specific manufacturer (General Electric, or GE) and specific models (e.g., aeroderivative and frame combustion turbines), doing so is not intended to limit the alternatives considered solely to GE models. Rather, such assumptions were made to provide indicative output and performance data. Several manufacturers offer similar generating technologies with similar attributes, and the performance data presented in this analysis should be considered indicative of comparable technologies across a wide array of manufacturers.

The capital cost estimates developed include both direct and indirect costs. An allowance for general owner's cost items, as summarized in Table A.6-15, has been included in the cost estimates. Table A.6-16 presents the matrix of generating unit alternatives considered for selected sites. The cost estimates were developed on an engineer, procure, and construct (EPC) basis. The EPC cost estimates were then adjusted, as appropriate, to develop site-specific cost estimates.

Table A.6-15
Possible Owner's Costs

Project Development	Owner's Contingency
• Site selection study • Land purchase/rezoning for greenfield sites • Transmission/gas pipeline right-of-way • Road modifications/upgrades • Demolition • Environmental permitting/offsets • Public relations/community development • Legal assistance • Provision of project management	• Owner's uncertainty and costs pending final negotiation • Unidentified project scope increases • Unidentified project requirements • Costs pending final agreements (i.e., interconnection contract costs) **Owner's Project Management** • Preparation of bid documents and the selection of contractors and suppliers • Performance of engineering due diligence • Provision of personnel for site construction management
Spare Parts and Plant Equipment • Combustion turbine materials, gas compressors, supplies, and parts • Steam turbine materials, supplies, and parts • Boiler materials, supplies, and parts • Balance-of-plant equipment/tools • Rolling stock • Plant furnishing and supplies	**Taxes/Advisory Fees/Legal** • Taxes • Market and environmental consultants • Owner's legal expenses • Interconnect agreements • Contracts (procurement and construction) • Property
Plant Startup/Construction Support • Owner's site mobilization • O&M staff training • Initial test fluids and lubricants • Initial inventory of chemicals and reagents • Consumables • Cost of fuel not recovered in power sales • Auxiliary power purchases • Acceptance testing • Construction all-risk insurance	**Utility Interconnections** • Natural gas service • Gas system upgrades • Electrical transmission • Water supply • Wastewater/sewer **Financing (included in fixed charge rate, but not in direct capital cost)** • Financial advisor, lender's legal, market analyst, and engineer • Loan administration and commitment fees • Debt service reserve fund

Table A.6-16
Generating Unit Alternatives for Selected Sites

Supply Alternatives	FMPA	JEA	RCID	TALLAHASSEE
Joint Development Alternatives[1, 2]				
Three 1x1 train IGCC[3]	Joint	Joint	Joint	Joint
3x1 GE 7FA combined cycle	Joint	Joint	Joint	Joint
Nuclear option[3]	Joint	Joint	Joint	Joint
Existing Site--Individual Participant Options				
GE LM6000 simple cycle	Lake Worth	No	No	Hopkins[5]/Purdom[6]
GE LMS100 simple cycle[3]	TCEC	Northside/Kennedy	No	Hopkins[5]/Purdom[6]
GE 7EA simple cycle	Lake Worth	No	No	Hopkins[5]/Purdom[6]
GE 7FA simple cycle	TCEC	Northside/Kennedy	No	Hopkins[5]
1x1 GE LM6000 combined cycle	No	No	CEP	Hopkins[5]
1x1 GE 7FA combined cycle	TCEC/Cane Island	Northside/Kennedy	No	Hopkins[5]
250 MW CFB	No	Northside/Kennedy	No	Hopkins[5,7]
Single 1x1 train IGCC	No	Kennedy	No	Hopkins[5,7]
Greenfield--Individual Participant Options				
GE LM6000 simple cycle	Yes	No	No	Yes
GE LMS100 simple cycle[3]	Yes	Yes	No	Yes
GE 7EA simple cycle	Yes	No	No	Yes
GE 7FA simple cycle	Yes	Yes	No	Yes
1x1 GE LM6000 combined cycle	No	No	No	Yes
1x1 GE 7FA combined cycle	Yes	Yes	No	Yes
250 MW CFB	Yes	Yes	No	Yes
Single 1x1 train IGCC	Yes	No[4]	No	Yes

(1)All costs for joint development alternatives were developed assuming installation at a greenfield site.

(2)A joint development CFB option was not evaluated due to similarity with the TEC and higher capital cost resulting from multiple boiler units required for a 750 MW output.

(3)IGCC, nuclear, and the GE LMS100 are considered emerging technologies that are not commercially proven. Power producing IGCC plants are currently being considered by utilities and developers in the United States, but have yet to be demonstrated commercially. Although existing nuclear plants are considered proven, future plants will employ new designs and technologies. The first GE LMS100 entered commercial operation in the United States in July 2006 and, therefore, is not yet considered a commercially proven technology.

(4)Although JEA would consider a greenfield individual IGCC option, for purposes of this Application, a unit at Northside/Kennedy will offer a lower cost due to existing infrastructure and O&M savings.

(5)Not all combinations of individual options can be located at Hopkins. Transmission infrastructure improvements will be required to accommodate any additional generation at Hopkins.

(6)Not all combinations of individual options can be located at Purdom. The impact on the environmental signature of any additional combustion turbine installed at Purdom will require a limit on the maximum annual run hours of that unit and require the retrofit of SCR and CO catalyst on the existing Purdom 8 combined cycle unit.

(7)To locate a CFB, IGCC, or any other solid fuel alternative at Hopkins would require the purchase of additional land adjacent to the existing plant site and a citizen referendum (compliant with City of Tallahassee Code of Ordinances and Land Development Code) approving the project.

A.6.2.1 Generating Alternatives Assumptions

A.6.2.1.1 General Capital Cost Assumptions. Unless otherwise discussed for each site, the following general assumptions were applied in developing the cost and performance estimates:

- The site has sufficient area available to accommodate construction activities including, but not limited to, office trailers, lay-down, and staging.
- Pilings are assumed under major equipment, and spread footings are assumed for all other equipment foundations.
- All buildings will be pre-engineered unless otherwise specified.
- Construction power is available at the boundary of the site(s).
- Combustion turbines will be dual fueled, with natural gas as the primary fuel and No. 2 ultra-low sulfur diesel (ULSD) fuel oil as the backup fuel. The cost of fuel unloading and delivery to the site(s) is included.
- Gasifiers for the Tallahassee and FMPA IGCC options will burn bituminous coal, while the gasifiers for JEA and the joint development options will burn petcoke due to the potential for waterborne delivery.
- The Tallahassee and FMPA CFB options will burn 100 percent bituminous coal, while the JEA CFB options for existing sites with existing barge delivery operations will burn a blend of 80 percent petcoke and 20 percent bituminous coal. The JEA greenfield CFB option will burn bituminous coal.
- The LMS100 is assumed to have standard SCR. The LM6000, 7EA, and 7FA will have hot SCR. Except for the LMS100, the simple cycle units will not include a CO catalyst, but will have a spool piece for future installation.
- GE 7FA combined cycle plants will include SCR and a CO catalyst to reduce emissions.
- Standard sound enclosures will be included for the combustion turbines.
- Natural gas pressure is assumed to be adequate for the 7EA simple cycle and the 7FA simple and combined cycle alternatives. Gas compressors will be included for the LM6000 and LMS100 aeroderivative combustion turbines. A regulating and metering station is assumed to be part of the owner's cost for each alternative.
- Demineralized water will be provided via portable demineralizers for simple cycle alternatives and will be supplied by a demineralized water treatment system for the combined cycle and solid fuel options.

- The LMS100 and the combined cycle alternatives will utilize cooling towers. Ground water or treated sewage effluent will be used as cooling water.
- The LMS100 has an intercooled compressor and will not utilize inlet cooling. The LM6000 will include the SPRINT option, and will also include inlet chillers. The frame machines (simple cycle turbines and combined cycles) will utilize evaporative cooling.
- Field erected storage tanks include the following:
  - Service/fire water storage tank.
  - Fuel oil storage tank (3 days' storage capacity).
  - Demineralized water storage tank (3 days' storage capacity).

A.6.2.1.2 Fuel Assumptions.

- Fuel gas is 100 percent methane with 0.2 grain of sulfur per 100 standard cubic feet (scf), with a heat content of 21,515 Btu/lb, lower heating value (LHV).
- Fuel oil is ULSD with 0.0015 percent (by weight) sulfur and maximum 0.015 percent fuel bound nitrogen, and a heat content of 18,400 Btu/lb LHV.
- Coal is western Kentucky bituminous coal with a heat content of 11,600 Btu/lb HHV.
- Petcoke is assumed to have a heat content of 14,000 Btu/lb HHV, 6.5 percent sulfur, and 0.4 percent ash.

A.6.2.1.3 Direct Cost Assumptions.

- Total direct capital costs are expressed in 2006 dollars.
- Direct costs include the costs associated with the purchase of equipment, erection, and contractors' services.
- Construction costs are based on an EPC contracting philosophy.
- Spare parts for startup are included. Initial inventory of spare parts for use during operation is included in the owner's costs.
- Permitting and licensing are included in the owner's costs.

A.6.2.1.4 Indirect Cost Assumptions. The following items are assumed in the capital cost estimate:

- General indirect costs, including all necessary services required for checkout, testing, and commissioning.
- Insurance, including builder's risk, general liability, and liability insurance for equipment and tools.

- Engineering and related services.
- Field construction management services including field management staff with supporting staff personnel, field contract administration, field inspection and quality assurance, and project control.
- Technical direction and management of startup and testing, cleanup expense for the portion not included in the direct cost construction contracts, safety and medical services, guards and other security services, insurance premiums, and performance bonds.
- Contractor's contingency and profit.
- Transportation costs for delivery to the jobsite.
- Startup and commissioning spare parts.
- Interest during construction and financing fees will be accounted for separately in the economic evaluation and, therefore, are not included in the capital cost or owner's cost estimates.

A.6.2.1.5 Meteorological Conditions. An average annual temperature and relative humidity of 70° F and 72 percent, respectively, were used for developing performance estimates for use in production cost modeling. Additionally, a winter temperature of 24° F (relative humidity of 91.9 percent) and a summer temperature of 98° F (relative humidity of 54.9 percent) were used to develop seasonal performance estimates.

A.6.2.1.6 Performance Degradation. Power plant output and heat rate performance will degrade with hours of operation due to factors such as blade wear, erosion, corrosion, and increased tube leakage. Periodic maintenance and overhauls can recover much, but not all, of the degraded performance when compared to the unit's new and clean performance. The degradation that cannot be recovered is referred to herein as *nonrecoverable degradation*, and estimates have been developed to capture its impacts. Nonrecoverable degradation will vary from unit to unit, so specific nonrecoverable output and heat rate factors have been developed and are presented in Table A.6-17. The degradation percentages are applied one time to the new and clean performance data, and reflect lifetime aggregate nonrecoverable degradation.

A.6.2.2 Existing Sites

Some Participants have existing generating sites that can accommodate future generating unit expansion. FMPA will be developing the Treasure Coast Energy Center (TCEC) and can use the existing Cane Island or Lake Worth sites to add generation. JEA has the existing Northside and Kennedy generating stations that can accommodate future expansion. RCID will consider 1x1 LM6000 combined cycle generating units at the Central Energy Plant (CEP). The City of Tallahassee has the existing Hopkins and

Table A.6-17
Nonrecoverable Degradation Factors

Unit Description	Degradation Factor	
	Output (%)	Heat Rate (%)
GE LM6000 Simple Cycle	3.2	1.75
GE LMS100 Simple Cycle	3.2	1.75
GE 7EA Simple Cycle	3.2	1.75
GE 7FA Simple Cycle	3.2	1.75
GE 1x1 LM6000 Combined Cycle	3.2	1.75
GE 1x1 7FA Combined Cycle	2.7	1.50
GE 3x1 7FA Combined Cycle	2.7	1.50
IGCC	2.7	1.50
CFB	0.0	1.50

Purdom sites; however, both sites would require substantial infrastructure improvement and have other factors that limit their capability to accommodate additional generation in their current states. Generic greenfield generating unit alternatives were also developed for FMPA and JEA, and only greenfield generating unit alternatives were developed for Tallahassee for the reasons described in this section.

The City of Tallahassee's existing generating sites (Purdom and Hopkins) can accommodate additional generation. However, additional transmission infrastructure and or/land, depending upon the unit added, would be required for new unit additions at the Hopkins site beyond already committed projects. It should be noted that Tallahassee is proceeding with the planned repowering of the existing Hopkins Unit 2 steam turbine to a 1x1 combined cycle (currently scheduled for completion in May 2008) and will continue to evaluate possible repowering to a 2x1 combined cycle in the future. Any new generation located at the Purdom site (limited to simple cycle combustion turbines only) would have runtime constraints and would require additional emissions controls (SCR and CO catalyst) on the existing Purdom 8 combined cycle. These additional costs would make the all-in costs of future generating unit additions at either Hopkins or Purdom comparable with the projected all-in costs for greenfield unit additions. Therefore, for the purposes of this Application, no site-specific assumptions were developed for Tallahassee's supply-side alternatives, and the costs of each alternative were only developed on a greenfield basis.

The Northside generating station (Northside) is a large acreage site, located in JEA's north district load center, just north of the portion of the St. Johns River running west to east. The first generating unit was placed in service at Northside in 1966. Northside currently consists of generating units that were repowered with two CFBs, one oil-and-gas-fired boiler and steam turbine, and four combustion turbines. The total summer net capability at Northside is 1,267 MW, and the total winter net capability is 1,301 MW.

The Kennedy generating station (Kennedy) is also a large acreage site, located in JEA's urban core load center, and consists of a simple cycle GE 7FA and three older combustion turbines. Two of the combustion turbines were recently placed in reserve shutdown. The total summer net capability at Kennedy is 312 MW, and the total winter net capability is 379 MW.

A final Determination of Need Order was issued for Unit 1 at the TCEC site by the Florida Public Service Commission (FPSC) on July 27, 2005. This site will have adequate acreage to accommodate up to four (including Unit 1) 1x1 GE 7FA combined cycle units or a combination of combined cycle and simple cycle units. Site certification for TCEC was issued in May 2006. TCEC is located within Phase III-North of the Midway Industrial Park in St. Lucie County, Florida. The TCEC site is 5 miles southwest of Ft. Pierce, 8 miles northwest of Port St. Lucie, and occupies 68.1 acres.

Kissimmee Utility Authority's Cane Island Power Park site is located approximately 5 miles west of the city limits of Kissimmee, Florida. The site currently has three natural gas and No. 2 oil fueled generating units, including Cane Island 1 (a simple cycle LM6000 combustion turbine), Cane Island 2 (a 1x1 7EA combined cycle), and Cane Island 3 (a 1x1 7FA combined cycle), with a total installed summer capacity of 388 MW. The units are jointly owned by Kissimmee Utility Authority (KUA) and FMPA.

The Cane Island site was designed for approximately 1,000 MW of combustion turbine and combined cycle capacity and is served by the Florida Gas Transmission and Gulfstream natural gas pipeline systems. The site is interconnected at 230 kV with Progress Energy Florida (PEF), Orlando Utilities Commission (OUC), Tampa Electric Company, and KUA. The site uses treated sewage effluent from Toho Water Authority for cooling water. FMPA has rights to construct additional generation on the site through the existing Cane Island Participation Agreement. The site also has rights for additional cooling water from Toho Water Authority.

For the purposes of the economic evaluation performed for FMPA, it has been assumed that the capital costs for units constructed at Cane Island would be similar to the capital costs for similar units constructed at TCEC. Therefore, site-specific assumptions for FMPA's 1x1 7FA combined cycle alternative have only been developed for unit additions at TCEC.

The Lake Worth Utilities (LWU) site is located on Florida's east coast in Palm Beach County. The Tom G. Smith plant has nine small generating units, five of which are reciprocating engines. The total capacity of the generating units at the LWU site is 88 MW and 97 MW in the summer and winter seasons, respectively.

The CEP is located in Orlando and has enough available site space to accommodate two additional units. Current generating resources at the CEP include a 1x1 LM6000 combined cycle and two diesel generators. The total summer capacity of the generating units located at the CEP is 60 MW.

A.6.2.2.1 Northside Site-Specific Assumptions. The following assumptions were developed specifically for the Northside site alternatives. These assumptions were developed to incorporate changes in both the EPC cost and the owner's cost for each Northside site option:

- The existing coal yard will require modification to accommodate construction of the CFB alternative.
- Additional demolition will be needed for the installation of the 1x1 7FA combined cycle option.
- The existing fuel oil system will be used for backup fuel supply for the simple cycle and combined cycle alternatives.
- Existing site security (fences, gates, etc.) will be used.
- There will be a reduced need for site civil works, surfacing and repaving, size and number of buildings, and site lighting as compared to the greenfield site alternatives.
- The existing site fire protection system, bulk material handling systems, raw water supply systems, sanitary waste systems, and transmission systems will be used.

A.6.2.2.2 Kennedy Site-Specific Assumptions. The following assumptions were developed specifically for the Kennedy site alternatives. These assumptions were developed to incorporate changes in both the EPC cost and the owner's cost for each Kennedy site option:

- Demolition of existing facilities, including the generation building, fuel oil tank, water treatment, and substation, will be required.
- New construction will require refurbishment of the existing dock.
- Upgrades and modifications of the natural gas supply system for increased flow volume and/or pressure will be required for the simple cycle and combined cycle alternatives.

- The existing fuel oil system will be used for backup fuel supply for the simple cycle and combined cycle alternatives.
- The existing site security (fences, gates, etc.) will be used.
- There will be a reduced need for site civil works, surfacing and paving, size and number of buildings, and site lighting as compared to the greenfield alternatives.
- The existing site fire protection system, bulk material handling systems, raw water supply systems, and sanitary systems will be used.
- The existing transmission systems will be used.

A.6.2.2.3 Lake Worth Site-Specific Assumptions. The following assumptions were developed specifically for the LWU site alternatives. These assumptions were developed to incorporate changes in both the EPC cost and the owner's cost for each LWU site option:

- There will be a reduced need for site civil works, surfacing and paving, size and number of buildings, and site lighting as compared to greenfield alternatives.
- The existing fuel oil system will be used for backup fuel supply for the simple cycle alternatives.
- The existing site security (fences, gates, etc.) will be used.
- The existing natural gas pipeline for the simple cycle alternatives will be used.
- The existing transmission systems will be used.

A.6.2.2.4 TCEC Site-Specific Assumptions. The following assumptions were developed specifically for the TCEC site alternatives. These assumptions were developed to incorporate changes in both the EPC cost and the owner's cost for each TCEC site option:

- The planned TCEC Unit 1 gas pipeline will be used, which will be designed to accommodate up to four (including Unit 1) 1x1 GE 7FA combined cycle units.
- The planned TCEC Unit 1 substation will be used.
- Water for cooling tower makeup can be supplied from the planned wastewater treatment plant that Fort Pierce Utilities Authority (FPUA) will construct, in conjunction with development of TCEC Unit 1.
- All wastewaters, except for sanitary waste, will be routed to the FPUA site for disposal in two deep injection wells.

- Service water, evaporative cooler makeup water, demineralizer water makeup, and fire water makeup will be supplied from existing onsite groundwater wells.
- The planned transmission lines will be used.
- The planned storage pond will be used.
- The planned control room, warehouse, and miscellaneous service buildings will be used.
- The planned service water tank and fuel oil tank will be used.
- The planned oil/water separator will be used.
- The planned site security (fences, gates, etc.) will be used.

A.6.2.2.5 CEP Site-Specific Assumptions. The following assumptions were developed specifically for the units considered for the CEP. These assumptions were developed to incorporate changes in both the EPC cost and the owner's cost:

- There will be a reduced need for site civil works, surfacing and paving, size and number of buildings, and site lighting as compared to the greenfield alternatives.
- The existing fuel oil system will be used for backup fuel supply for the simple cycle alternative.
- The existing site security (fences, gates, etc.) will be used.
- The existing natural gas pipeline for the simple cycle alternative will be used.
- The existing transmission systems will be used.

A.6.2.3 Generic Site Assumptions

The following assumptions were developed specifically for the generic greenfield site alternatives. Generic greenfield site alternatives will be developed for the joint development alternatives, and the individual ownership alternatives for FMPA, JEA, and Tallahassee. The alternatives evaluated for each Participant are presented in Table A.6-15:

- The plant will not be located on wetlands nor require any other mitigation.
- Service and fire water will be supplied via onsite groundwater wells.
- Potable water will be supplied from the local water utility.
- Wastewater disposal will utilize local sewer systems.
- Cooling water will be treated sewage effluent or groundwater. Allowances for pipeline costs will be included in the owner's cost.

- Costs for transmission lines are included as part of the owner's cost. An onsite switching station (230 kV) with a breaker position for each generator is included as part of the direct capital cost.

A.6.2.4 Simple Cycle Combustion Turbine Alternatives

Combustion turbine generators (CTGs) are sophisticated power generating machines that operate according to the Brayton thermodynamic power cycle. A simple cycle combustion turbine generates power by compressing ambient air and then heating the pressurized air to approximately 2,000° F or more, by burning oil or natural gas, with the hot gases then expanding through a turbine. The turbine drives both the compressor and an electric generator. A typical combustion turbine would convert 30 to 35 percent of the fuel to electric power. A substantial portion of the fuel energy is wasted in the form of hot (typically 900° F to 1,100° F) gases exiting the turbine exhaust. When the combustion turbine is used to generate power and no energy is captured and utilized from the hot exhaust gases, the power cycle is referred to as a "simple cycle" power plant.

Combustion turbines are mass flow devices, and their performance changes with changes in the ambient conditions at which the unit operates. Generally speaking, as temperatures increase, combustion turbine output and efficiency decrease due to the lower density of the air. To lessen the impact of this negative characteristic, most of the newer combustion turbine-based power plants often include inlet air cooling systems to boost plant performance at higher ambient temperatures.

Combustion turbine pollutant emission rates are typically higher on a part per million (ppm) basis at part load operation than at full load. This limitation has an effect on how much plant output can be decreased without exceeding pollutant emissions limits. In general, combustion turbines can operate at a minimum load of about 50 percent of the unit's full load capacity while maintaining emission levels within required limits.

Advantages of simple cycle combustion turbine projects include low capital costs, short design and construction schedules, and the availability of units across a wide range of capacity. Combustion turbine technology also provides rapid startup and modularity for ease of maintenance.

The primary drawback of combustion turbines is that, due to the cost of natural gas and fuel oil, the variable cost per MWh of operation is high compared to other conventional technologies. As a result, simple cycle combustion turbines are often the technology of choice for meeting peak loads in the power industry, but are not usually economical for baseload or intermediate service.

Three different commercially proven combustion turbine sizes were evaluated. The GE LM6000 has a nominal output in the range of 50 MW at ISO conditions with the SPRINT™ design feature included. The GE 7EA has a nominal output of about 85 MW, while the GE 7FA has a nominal output of about 170 MW at ISO conditions.

A.6.2.4.1 GE SPRINT LM6000 Combustion Turbine. The GE SPRINT LM6000 was selected as a potential simple cycle alternative due to its modular design, efficiency, and size. It is a two-shaft gas turbine engine derived from the core of the CF6-80C2, GE's high thrust, high efficiency aircraft engine.

The LM6000 consists of a five-stage low-pressure compressor (LPC), a 14-stage variable geometry high-pressure compressor (HPC), an annular combustor, a two-stage air-cooled high-pressure turbine (HPT), a five-stage low-pressure turbine (LPT), and an accessory drive gearbox. The LM6000 has two concentric rotor shafts, with the LPC and LPT assembled on one shaft, forming the LP rotor. The HPC and HPT are assembled on the other shaft, forming the HP rotor.

The LM6000 uses the LPT to power the output shaft. The LM6000 design permits direct-coupling to 3,600 revolutions per minute (rpm) generators for 60 hertz (Hz) power generation. The gas turbine drives its generator through a flexible, dry type coupling connected to the front, or "cold," end of the LPC shaft. The LM6000 gas turbine generator set has the following attributes:

- Full power in approximately 10 minutes.
- Cycling or peaking operation.
- Synchronous condenser capability.
- Compact, modular design.
- More than 5 million operating hours.
- More than 450 turbines sold.
- 97.8 percent documented availability.
- LM6000 SPRINT™ - spray intercooling for power boost.
- Dual fuel capability.

The capital cost estimate was based on utilizing GE's Next-Gen package for the LM6000. This package includes more factory assembly, resulting in less construction time. Table A.6-20 presents the operating characteristics of the LM6000 SPRINT combustion turbine at a winter temperature of 24° F (relative humidity of 91.9 percent) and a summer temperature of 98° F (relative humidity of 54.9 percent), and annual average temperature conditions (70° F with a relative humidity of 72 percent). High temperature SCR would be used to control NO_x to 2 ppmvd while operating on natural gas. Water injection and SCR would be used to control NO_x emissions when operating on ULSD. Table A.6-21 presents estimated emissions for the LM6000.

Table A.6-20
GE LM6000 PC SPRINT Combustion Turbine Characteristics

Ambient Condition	Net Capacity (MW)[1]	Net Plant Heat Rate (Btu/kWh, HHV)[1, 2]
Winter (24° F) (Full Load)	47.4	9,637
Summer (98° F) (Full Load)	46.2	10,171
Average (70° F and 72% R.H.) (Full Load)	47.3	9,933
Average (70° F and 72% R.H.) (75% Load)	26.5	11,304
Average (70° F and 72% R.H.) (50% Load)	17.5	13,444

[1]Net capacity and net plant heat rate include degradation factors, inlet chilling is considered on full load cases above 60° F, and performance is preliminary.
[2]Heat rate assumes operation on natural gas.

Table A.6-21
GE LM6000 PC SPRINT Estimated Emissions[1]

NO_x, ppmvd at 15% O_2	2
NO_x, lb/MBtu	0.0072
SO_2, lb/MBtu	0.0005
Hg, lb/MBtu	0.0
CO_2, lb/MBtu	114.8
CO, ppmvd at 15% O_2	29
CO, lb/MBtu	0.0648

[1]Emissions are at full load at 70° F, reflect operation on natural gas, and include the effects of SCR.

A.6.2.4.2 GE 7EA Combustion Turbine. The GE 7EA combustion turbine is a highly reliable, mid-size packaged combustion turbine developed specifically for 60 Hz applications. With design emphasis placed on energy efficiency, availability, performance, and maintainability, the GE 7EA is a proven technology with approximately 800 units installed worldwide, and more than a million hours of operation. The simple, medium-sized design of the GE 7EA lends to flexibility in plant layout and easy, low-cost addition of increments of power when phased capacity expansion is necessary. The unit has a 3,600 rpm shaft speed and is directly coupled to the generator.

The GE 7EA is fuel-flexible and can operate on natural gas, LNG, distillate fuel oil, and treated residual fuel oil. The 7EA is an ideal generating unit for sites that require efficient peaking generation or reliable capacity from multiple units. The 7EA is rated at 85.4 MW, which is greater than the LM6000, but less than the 7FA. For this analysis, it has been assumed that the GE 7EA will be dual-fueled, capable of firing either natural gas or ULSD.

Table A.6-22 presents the operating characteristics of the GE 7EA combustion turbine at a winter temperature of 24° F (relative humidity of 91.9 percent), a summer temperature of 98° F (relative humidity of 54.9 percent), and an annual average temperature of 70° F (relative humidity of 72 percent). The 7EA will utilize dry-low NO_x combustors and SCR to control NO_x to 2 ppmvd on natural gas. Dry-low NO_x combustors, water injection, and SCR will be used for NO_x control when firing fuel oil. Table A.6-23 presents estimated emissions for the 7EA.

A.6.2.4.3 GE 7FA Combustion Turbine. The GE 7FA combustion turbine, originally introduced in 1986, is the result of a multi-year development program using technology advanced by GE Aircraft Engines and GE's Corporate Research and Development Center. The development program facilitated the application of technologies such as advanced bucket cooling techniques, compressor aerodynamic design, and new alloys for F-class gas turbines, enabling these machines to attain higher firing temperatures (2,400° F) than previous generating units.

The GE 7FA combustion turbines have an 18-stage compressor and a 3-stage turbine, and feature cold-end drive and axial exhaust, which is beneficial for combined cycle arrangements. With reduced cycle time for installation and startup, the GE 7FA can be installed relatively quickly. The packaging concept of the GE 7FA features consolidated skid-mounted components, controls, and accessories, which reduce piping, wiring, and other onsite interconnection work.

Table A.6-22
GE 7EA Combustion Turbine Characteristics

Ambient Condition	Net Capacity (MW)[1]	Net Plant Heat Rate (Btu/kWh, HHV)[1, 2]
Winter (24° F) (Full Load)	89.7	11,793
Summer (98° F) (Full Load)	72.4	12,399
Average (70° F and 72% RH) (Full Load)	78.4	12,134
Average (70° F and 72% RH) (75% Load)	58.7	13,214
Average (70° and 72% RH) (50% Load)	39.0	16,100

RH = Relative humidity.

(1)Net capacity and net plant heat rate include degradation factors, evaporative cooling is considered at full load cases above 60° F, and performance is preliminary.
(2)Heat rate assumes operation on natural gas.

Table A.6-23
GE 7EA Estimated Emissions[1]

NO_x, ppmvd at 15% O_2	2
NO_x, lb/MBtu	0.0074
SO_2, lb/MBtu	0.0005
Hg, lb/MBtu	0.0
CO_2, lb/MBtu	114.8
CO, ppmvd at 15% O_2	25.1
CO, lb/MBtu	0.0549

(1)Emissions are at full load at 70° F, reflect operation on natural gas, and include the effects of SCR.

The GE 7FA combustion turbine has also exhibited outstanding environmental characteristics. Because of the higher specific output of these machines, smaller amounts of NO_x and CO are emitted per unit of power produced for the same exhaust concentrations as other generating technologies. GE 7FA turbines have accumulated more than 900,000 operating hours using dry-low NO_x burners, which will be part of the NO_x control strategy when operating on natural gas. Evaporative cooling will be used for inlet cooling.

Table A.6-24 presents the operating characteristics of the GE 7FA combustion turbine at a winter temperature of 24° F (relative humidity of 91.9 percent), a summer temperature of 98° F (relative humidity of 54.9 percent), and an annual average temperature of 70° F (relative humidity of 72 percent). The 7FA will utilize dry-low NO_x combustors and SCR to control NO_x to 2 ppmvd on natural gas. The GE 7FA combustion turbine will be dual-fueled, with water injection used for NO_x control when firing fuel oil. Table A.6-25 presents estimated emissions for the 7FA.

A.6.2.5 Combined Cycle Alternatives

Combined cycle power plants use one or more CTGs and one or more steam turbine generators to produce energy. Combined cycle power plants operate according to a combination of both the Brayton and Rankine thermodynamic power cycles. HP steam is produced when the hot exhaust gas from the CTG is passed through a heat recovery steam generator (HRSG). The HP steam is then expanded through a steam turbine, which spins an electric generator. It is assumed that duct firing will be used in the combined cycle option.

Combined cycle configurations have several advantages over simple cycle combustion turbines. Advantages include increased efficiency and potentially greater operating flexibility if duct burners are used. Disadvantages of combined cycles relative to simple cycles include a small reduction in plant reliability and an increase in the overall staffing and maintenance requirements due to added plant complexity.

Combined cycle alternatives were considered for both joint and individual ownership. A 3x1 GE 7FA combined cycle was considered for joint ownership, and a 1x1 GE 7FA combined cycle was considered for individual ownership for JEA, FMPA, and the City of Tallahassee. The former was selected for joint ownership because it has a similar capacity to TEC. The Participants are assumed to retain similar ownership shares, on a percentage basis, to the ownership shares of TEC for the 3x1 combined cycle alternative. In addition, a 1x1 GE LM6000 combined cycle was evaluated for RCID, which has a much smaller system than the other Participants.

Table A.6-24
GE 7FA Combustion Turbine Characteristics

Ambient Condition	Net Capacity (MW)(1)	Net Plant Heat Rate (Btu/kWh, HHV)(1, 2)
Winter (24° F) (Full Load)	177.0	10,585
Summer (98° F) (Full Load)	148.5	11,065
Average (70° F and 72% RH) (Full Load)	160.0	10,826
Average (70° F and 72% RH) (75% Load)	119.8	11,816
Average (70° and 72% RH) (50% Load)	79.6	14,223

(1)Net capacity and net plant heat rate include degradation factors, evaporative cooling is considered at full load cases above 60° F, and performance is preliminary.
(2)Heat rate assumes operation on natural gas.

Table A.6-25
GE 7FA Estimated Emissions(1)

NO_x, ppmvd at 15% O_2	2
NO_x, lb/MBtu	0.0073
SO_2, lb/MBtu	0.0005
Hg, lb/MBtu	0.0
CO_2, lb/MBtu	114.8
CO, ppmvd at 15% O_2	7.5
CO, lb/MBtu	0.0165

(1)Emissions are at full load at 70° F, reflect operation on natural gas, and include the effects of SCR and dry-low NO_x combustors.

A combined cycle based on the 501G CTG was not evaluated for this application, although this technology is a potentially viable alternative. A 2x1 501G combined cycle would offer a total capacity similar to the 3x1 GE 7FA combined cycle alternative discussed in the following subsection. When in combined cycle, the 501G offers similar performance levels to a 3x1, with about a 2 percent improvement in efficiency. Each gas turbine unit offers more output and, therefore, fewer units are required. The base power island consisting of the gas turbines, HRSGs, and steam turbine has an approximate 8 percent lower cost than a comparably sized 7FA combined cycle. However, current 501G gas turbines have much higher emissions rates than the 7FA because of their higher firing temperatures and, therefore, require more expensive pollution control equipment to meet acceptable stack emissions rates for permitting. Therefore, the installed capital cost savings will be less than the cost differential for the power island. As a result, with the small differential in capital cost and efficiency, the 3x1 7FA combined cycle is considered a comparable alternative to a 2x1 501G combined cycle. The slight reductions in efficiency and cost offered by the 501G would not change the results of the economic evaluations. In addition, the 501G combustion turbines have significantly less operating experience compared to the 7FA. Southern Power Company's response to the Participants' RFP, described in Section A.7.0, was based on 501G technology and was considered a conventional alternative and was evaluated for each Participant.

A.6.2.5.1 GE 7FA Combined Cycle Alternatives. The 3x1 combined cycle generating unit would include three GE 7FA CTGs, three HRSGs, one steam turbine generator, and a cooling tower. The 1x1 combined cycle generating unit includes one GE 7FA CTG, one HRSG, and one steam turbine generator. Both combined cycle units will be dual-fueled, with natural gas as the primary fuel and ULSD as the backup fuel. Each combustion turbine will include evaporative cooling.

Each HRSG will convert waste heat from the combustion turbine exhaust to steam for use in driving the steam turbine generator. Each HRSG is expected to be a natural circulation, three-pressure, reheat unit with supplemental duct firing (on natural gas only) to maintain full steam turbine generator load at all ambient conditions. SCR and dry low-NO_x burners will be included to control NO_x to 2 ppmvd while burning natural gas, and a CO catalyst will be included to reduce emissions. Water injection will be used for NO_x control when burning natural gas and ULSD.

The steam turbine is expected to be a tandem-compound, single reheat condensing turbine operating at 3,600 rpm. The steam turbine will have one HP section, one intermediate-pressure (IP) section, and a two-flow LP section. Turbine suppliers' standard auxiliary equipment, lubricating oil system, hydraulic oil system, and supervisory, monitoring, and control systems are included. A single synchronous generator is included, which will be direct coupled to the steam turbine. The steam turbine generator will be located outdoors, with a building provided for the major auxiliary electrical power equipment.

Table A.6-26 presents the operating characteristics of the GE 3x1 7FA and the GE 1x1 7FA combined cycle generating units at a winter temperature of 24° F (relative humidity of 91.9 percent), a summer temperature of 98° F (relative humidity of 54.9 percent), and annual average temperature conditions (70° F with a relative humidity of 72 percent). Table A.6-27 presents estimated emissions for the GE 3x1 7FA and the GE 1x1 7FA combined cycle generating units.

A.6.2.5.2 GE SPRINT LM6000 Combined Cycle. The GE SPRINT LM6000 was selected as a potential combined cycle alternative for RCID because of its modular design, efficiency, and, most importantly, size. The SPRINT option includes equipment to inject water into an interstage of the compressor to cool the air and increase overall mass flow through the machine. As the air droplets evaporate, temperature is reduced, and the mass flow rate is increased. The LM6000 features a cold end generator drive, which allows for axial exhaust of combustion gases into the HRSG.

The HRSG will be a dual-pressure, natural circulation unit using combustion turbine exhaust to produce HP and LP steam for use in the steam turbine generator. Duct burner capability will be included to increase steam generation capability. An SCR with ammonia injection skid will be provided. Additionally, the HRSG will include a spool section for a CO catalyst.

The capital cost estimate was based on utilizing GE's Next-Gen package for the LM6000. This package includes more factory assembly, resulting in less construction time. Table A.6-28 presents the operating characteristics of the LM6000 SPRINT combustion turbine in combined cycle configuration at annual average temperature conditions (70° F with a relative humidity of 72 percent). SCR will be used to control NO_x to 2 ppmvd while operating on natural gas. Water injection and SCR will be used to control NO_x emissions when operating on ULSD. Table A.6-29 presents estimated emissions for the LM6000 combined cycle.

A.6.2.6 CFB Alternatives

In a CFB boiler, a portion of the combustion air is introduced through the bottom of the bed. The bed material normally consists of fuel, limestone (for sulfur capture), and ash. The bottom of the bed is supported by water cooled membrane walls with specially designed air nozzles, which distribute the air uniformly. The fuel and limestone are fed into the lower bed where, in the presence of fluidizing air, the fuel and limestone quickly and uniformly mix under the turbulent environment and behave like a fluid. Carbon

Table A.6-26
GE 7FA Combined Cycle Characteristics

Ambient Condition	3x1 Combined Cycle Net Capacity (MW)(1)	3x1 Combined Cycle Net Plant Heat Rate (Btu/kWh, HHV)(1, 2)	1x1 Combined Cycle Net Capacity (MW)(1)	1x1 Combined Cycle Net Plant Heat Rate (Btu/kWh, HHV)(1, 2)
Winter (24° F) (Full Load)	789.4	7,079	261.2	7,132
Summer (98° F) (Full Load)	867.9	7,476	286.6	7,545
Average (70° F and 72% RH) (Full Load)	907.3	7,412	298.8	7,492
Average (70° F and 72% RH) (75% Load)(3)	580.2	7,282	191.6	7,350
Average (70° F and 72% RH) (50% Load)(3)	428.4	7,877	141.1	7,968

(1)Net capacity and net plant heat rate include degradation factors, and performance is preliminary. Summer and average full load net capacity and net plant heat rate include supplemental firing.
(2)Heat rate presented assumes operation on natural gas.
(3)Part load performance percent load is based on gas turbine load point.

Table A.6-27
GE 7FA Combined Cycle Estimated Emissions(1)

Emission Type	3x1 Combined Cycle	1x1 Combined Cycle
NO_x, ppmvd at 15% O_2	2	2
NO_x, lb/MBtu	0.0072	0.0072
SO_2, lb/MBtu	0.0005	0.0005
Hg, lb/MBtu	0.0	0.0
CO, lb/MBtu	0.0036	0.0036
CO_2, lb/MBtu	114.8	114.8

(1)Emissions are at full load at 70° F, reflect operation on natural gas, and include the effects of SCR and CO catalyst.

Table A.6-28
GE 1x1 LM6000 PC SPRINT Combined Cycle Characteristics

Ambient Condition	Net Capacity (MW)[1]	Net Plant Heat Rate (Btu/kWh, HHV)[1, 2]
Winter (24° F) (Full Load)	60.0	7,806
Summer (98° F) (Full Load)	51.0	8,941
Average (70° F and 72% RH) (Full Load)	59.2	8,562
Average (70° F and 72% RH) (75% Load)	37.9	8,356
Average (70° F and 72% RH) (50% Load)	26.4	9,486

(1)Net capacity and net plant heat rate include degradation factors, and performance is preliminary.
(2)Heat rate assumes operation on natural gas.

Table A.6-29
GE 1x1 LM6000 PC SPRINT Combined Cycle
Estimated Emissions[1]

NO_x, ppmvd at 15% O_2	2
NO_x, lb/MBtu	0.0072
SO_2, lb/MBtu	0.0005
Hg, lb/MBtu	0.0
CO_2, lb/MBtu	114.8
CO, ppmvd at 15% O_2	29
CO, lb/MBtu	0.0648

(1)Emissions are at full load at 70° F, reflect operation on natural gas, and include the effects of SCR.

particles in the fuel are exposed to the combustion air, and the balance of the combustion air is introduced at the top of the lower dense bed. Such staged combustion limits the formation of NO_x.

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

One of the key and most recognized advantages of CFB technology is its ability to burn a wide variety of low grade fuels such as peat, coal wastes, sludges, municipal wastes, biomass, oil shales, and petcoke, in addition to any high grade coals. CFBs can be designed to burn these fuels individually or in combination, providing the end user with flexibility in choosing the most economical mix to minimize generation costs. For evaluation purposes, an 80 percent petcoke and 20 percent western Kentucky bituminous coal blend was considered for the JEA existing site CFB alternatives. 100 percent western Kentucky bituminous coal was considered for the Tallahassee, FMPA, and JEA greenfield CFB options.

CFBs are also widely recognized as being inherently low in emissions, due in large part to the low combustion temperatures that reduce thermal NO_x formation, and the ability to introduce limestone directly into the furnace to control SO_2 emissions. CFB technology has matured to the point that operating plants have demonstrated availability comparable to the most modern solid fuel fired plants.

The 250 MW CFB unit will include one steam generator and one condensing steam turbine generator. The steam turbine generator will include a standard sound enclosure and will be housed in an engineered generation building that includes a control room, electrical equipment room, battery room, motor control center, switchgear room, and various offices. Selective noncatalytic reduction (SNCR) will be used to control NO_x emissions, and a fabric filter will be used to control particulate emissions. In addition to limestone injection into the boiler, a polishing circulating dry scrubber will be used for further SO_2 control. The cooling system will consist of a wet mechanical draft cooling tower.

Table A.6-30 presents the operating characteristics of the CFB alternative at a winter temperature of 24° F (relative humidity of 91.9 percent), a summer temperature of 98° F (relative humidity of 54.9 percent), and an annual average temperature of 70° F (relative humidity of 72 percent). Table A.6-31 presents the estimated emissions from the CFB unit.

Table A.6-30
250 MW CFB Characteristics

Ambient Condition	100 Percent Coal		80/20 Percent Petcoke/ Coal Blend	
	Net Capacity (MW)(1)	Net Plant Heat Rate (Btu/kWh, HHV)(1)	Net Capacity (MW)(1)	Net Plant Heat Rate (Btu/kWh, HHV)(1)
Winter (24° F) (Full Load)	248.9	9,571	248.4	9,125
Summer (98° F) (Full Load)	250.0	9,529	244.0	9,288
Average (70° F and 72% RH) (Full Load)	250.6	9,505	247.3	9,163
Average (70° F and 72% RH) (75% Load)	184.9	9,750	185.5	9,364
Average (70° F and 72% RH) (50% Load)	119.2	10,264	123.7	9,650
Average (70° F and 72% RH) (min Load)	92.9	10,682	74.2	10,151

(1)Net plant heat rate and net capacity include degradation factors, and performance is preliminary.

Table A.6-31
250 MW CFB Unit Estimated Emissions(1)

Emission Type	100 Percent Coal	80/20 Percent Petcoke/Coal Blend
NO_x, lb/MBtu	0.09	0.07
SO_2, lb/MBtu	0.11	0.124
Hg, lb/TBtu	1.55	1.55
CO, lb/MBtu	0.115	0.115
CO_2, lb/MBtu	207.7	207.7

(1)Emissions at full load at 70° F.

A.6.2.7 Emerging Technology Alternatives

This section presents an analysis of supply-side technologies that are not considered conventional because of poor reliability, lack of demonstrated performance, or political/regulatory impedance. The three types of emerging technologies considered are IGCC, the GE LMS100, and nuclear fission. There are fewer than 20 power producing IGCC plants operating throughout the world, with only two operating in the United States, and many of these plants have experienced reliability problems. Next generation IGCC technology plants are incorporating design improvements and are under development, but are not assumed to be available for reliable commercial generation until 2018. The GE LMS100 is a new combustion turbine, and only in July 2006 did the first LMS100 begin commercial operation. In total, only about half a dozen LMS100 units had been ordered from GE at the time of this report. Nuclear technology is well understood and commercially proven, but a nuclear plant has not been permitted in the United States for over two decades. Additionally, future nuclear plants will employ new technologies. These three emerging technologies are discussed in more detail in the following subsections.

A.6.2.7.1 IGCC Alternatives. In the IGCC power generation process, fuel (petcoke, coal, or other solid fuel) is converted to syngas, which is treated and then combusted in modified gas turbines in a combined cycle power generation unit. IGCC advantages include the capability of operating with relatively low emissions, low water usage, and efficiency comparable to CFB and pulverized coal technologies. The capital and operating costs and availability are currently significant disadvantages for IGCC, but the technology is expected to become more competitive as additional IGCC plants are built and the technology matures. The cost associated with reducing Hg and CO_2 emissions is generally lower for IGCC than for CFB and pulverized coal technologies.

There have been approximately 20 power producing IGCC projects operated throughout the world, and only four power producing IGCC plants that have the ability to use coal or petcoke are currently operating. These plants have capacities ranging from 250 to 300 MW. Each of these plants has operated for more than 7 years, and, as an aggregate, they have modestly demonstrated the IGCC technology on a commercial scale. Two of the four operating, power producing IGCC plants with the ability to operate on coal or petcoke are located in the United States. Both of these plants were subsidized by the US government. To date, a large-scale, US-based power producing IGCC plant has not been proven economically feasible without subsidization.

The operating US-based IGCC plants experienced numerous problems during their initial years of operation. These problems resulted in poor availability and either a net plant heat rate or a net output worse than the designed performance. Plant modifications and O&M procedure improvements have improved performance. Low emissions rates, approaching the emissions from natural gas combined cycle power generation, have been demonstrated.

The complexity and relative immaturity in technology of the IGCC allows opportunities for deficiencies in design, vendor supplied equipment, construction, operation, and maintenance. However, the experience gained from operating IGCC units will improve the initial availability of new IGCC units. Significant downtime of the gasifier(s) should still be expected during the first several years of plant operation, making IGCC a more risky technology than pulverized coal or CFB options for reliably meeting future capacity and energy requirements. However, long-term availabilities for a single-train IGCC unit are expected to range from 80 to 85 percent, and long-term forced outage rates are expected to range from 7 to 10 percent. If the gas turbine(s) can operate on backup fuel when syngas is not available, the combined cycle availability is expected to exceed 90 percent.

Two separate IGCC alternatives were considered for evaluation, including joint development of a three 1x1 train IGCC by the Participants (with similar ownership shares among the Participants, on a percentage basis, as for TEC) and individual ownership of a single 1x1 train IGCC by FMPA, JEA, and Tallahassee. Cost and performance estimates have been developed for both the three-train and single-train IGCC alternatives. The three 1x1 train IGCC alternative would consist of three 1x1 GE 7FB combined cycles, with eight 16 percent (of the total required for the entire three-train configuration) GE Quench, entrained flow gasifiers. Each combustion turbine would utilize two gasifiers, with two spare gasifiers (for the total plant) to increase reliability. The single 1x1 train IGCC alternative would consist of a single 1x1 GE 7FB combined cycle and three 50 percent GE Quench entrained flow gasifiers, with the spare 50 percent gasifier included to increase reliability. The GE Quench entrained flow gasifiers assumed are typical of the gasification technologies that have been previously demonstrated in the United States.

The three-train IGCC option and the brownfield single-train option are assumed to utilize 100 percent petcoke, while the greenfield single-train IGCC alternative is assumed to burn 100 percent western Kentucky bituminous coal. These assumptions were made to reflect the assumed location of each option. The joint development three-train IGCC is assumed to be located at a site that will have the capability to economically receive delivery of petcoke, similar to the TEC site. The single-train IGCC alternatives are assumed to be located at greenfield sites that would not have the capability to economically receive deliveries of petcoke.

Tables A.6-32A and A.6-32B present the anticipated output and performance of the two IGCC alternatives at a winter temperature of 24° F (relative humidity of 91.9 percent), a summer temperature of 98° F (relative humidity of 54.9 percent), and annual average temperature conditions of 70° F (relative humidity of 72 percent). Estimated emissions for the IGCC alternatives are presented in Table A.6-33.

A.6.2.7.2 GE LMS100 Combustion Turbine. The LMS100 is a new GE unit and has the disadvantage of not being commercially proven. After the reliability of the LMS100 has been successfully demonstrated, it will likely replace the use of two-unit blocks of LM6000s in the future.

The LMS100 is currently the most efficient simple cycle gas turbine in the world. In simple cycle mode, the LMS100 has an efficiency of 46 percent, which is 10 percent greater than the LM6000. It has a high part-load efficiency, cycling capability (without increased maintenance cost), better performance at high ambient temperatures, modular design (minimizing maintenance costs), the ability to achieve full power from a cold start in 10 minutes, and is expected to have high availability, though this availability must be commercially demonstrated before the LMS100 can be considered a conventional alternative.

The LMS100 is an aeroderivative turbine and has many of the same characteristics of the LM6000. The former uses off-engine intercooling within the turbine's compressor section to increase its efficiency. The process of cooling the air optimizes the performance of the turbine and increases output efficiency. At 50 percent turndown, the part-load efficiency of the LMS100 is 40 percent, which is a greater efficiency than most simple cycle combustion turbines at full load.

There are two main differences between the LM6000 and the LMS100. The LM6000 uses the SPRINT intercooling system to cool the compressor with a micro-mist of water, while the LMS100 cools the compressor air with an external heat exchanger after the first stage of compression. Unlike the LM6000, which has an HP turbine and a power turbine, the LMS100 has an additional IP turbine to increase output efficiency.

As a packaged unit, the LMS100 consists of a 6FA turbine compressor, which outputs compressed air to the intercooling system. The intercooling system cools the air, which is then compressed in a second compressor to a high pressure, heated with combusted fuel, and then used to drive the two-stage IP/HP turbine described above. The exhaust stream is then used to drive a five-stage power turbine. Exhaust gases are at a temperature of less than 800° F, which allows the use of a standard SCR system for NO_x control.

Table A.6-32A
Three 1x1 Train and Single 1x1 Train IGCC Alternatives
(Bituminous Coal)

Ambient Condition	Three 1x1 Train IGCC		Single 1x1 Train IGCC	
	Net Capacity (MW)(1)	Net Plant Heat Rate (Btu/kWh, HHV)(1,2)	Net Capacity (MW)(1)	Net Plant Heat Rate (Btu/kWh, HHV)(1,2)
Winter (24° F) (Full Load)	870	9,443	290	9,443
Summer (98° F) (Full Load)	823	9.605	274	9.605
Average (70° F and 72% RH) (Full Load)	864	9,414	288	9,414
Average (70° F and 72% RH) (75% Load)(3)	671	9,939	224	9,939
Average (70° F and 72% RH) (50% Load)(3)	470	10,902	157	10,902

(1)Performance assumes operation on bituminous coal.
(2)Net capacity and net plant heat rate include degradation.
(3)Part load performance percentage is based on combustion turbine load point.

Table A.6-32B
Three 1x1 Train and Single 1x1 Train IGCC Alternatives
(Petcoke)

Ambient Condition	Three 1x1 Train IGCC		Single 1x1 Train IGCC	
	Net Capacity (MW)(1)	Net Plant Heat Rate (Btu/kWh, HHV)(1,2)	Net Capacity (MW)(1)	Net Plant Heat Rate (Btu/kWh, HHV)(1,2)
Winter (24° F) (Full Load)	870	10,049	290	10,049
Summer (98° F) (Full Load)	823	10,221	274	10,221
Average (70° F and 72% RH) (Full Load)	864	10,018	288	10,018
Average (70° F and 72% RH) (75% Load)(3)	671	10,576	224	10,576
Average (70° F and 72% RH) (50% Load)(3)	470	11,601	157	11,601

(1)Heat rate assumes operation on petcoke.
(2)Net capacity and net plant heat rate include degradation.
(3)Part load performance percentage is based on combustion turbine load point.

Table A.6-33 IGCC Unit Estimated Emissions(1)		
Emission Type	Bituminous Coal IGCC	Petcoke IGCC
NO_x, lb/MBtu	0.06	0.06
SO_2, lb/MBtu(2)	0.015	0.015
Hg, lb/MBtu	0.2	0.2
CO_2, lb/MBtu	207	220
CO, lb/MBtu	0.05	0.05

(1)Emissions at full load at 70° F, and do not include the effects of SCR or CO catalyst. There is concern with HRSG fouling when operating the current design of IGCC plants with these systems.
(2)SO_2 emissions include SO_3.

Table A.6-34 presents the operating characteristics of the LMS100 combustion turbine at a winter temperature of 24° F (relative humidity of 91.9 percent), a summer temperature of 98° F (relative humidity of 54.9 percent), and an annual average temperature of 70° F (relative humidity of 72 percent). Standard SCR will be used to control NO_x to 2 ppmvd while operating on natural gas. Water injection and SCR will be used to control NO_x while operating on ULSD. Table A.6-35 presents estimated emissions for the LMS100.

Table A.6-34 GE LMS100 Combustion Turbine Characteristics		
Ambient Condition	Net Capacity (MW)(1)	Net Plant Heat Rate (Btu/kWh, HHV)(1, 2)
Winter (24° F) (Full Load)	95.6	8,961
Summer (98° F) (Full Load)	86.4	9,360
Average (70° F and 72% RH) (Full Load)	96.5	9,095
Average (70° F and 72% RH) (75% Load)	72.1	9,543
Average (70° F and 72% RH) (50% Load)	47.8	10,609

(1)Net capacity and full load net plant heat rate include degradation factors, evaporative cooling is not considered, and performance is preliminary.
(2)Heat rate assumes operation on natural gas.

Table A.6-35
GE LMS100 Estimated Emissions[1]

NO_x, ppmvd at 15% O_2	2
NO_x, lb/MBtu	0.0072
SO_2, lb/MBtu	0.0005
Hg, lb/MBtu	N/A
CO_2, lb/MBtu	114.8
CO, ppmvd at 15% O_2	11.4
CO, lb/MBtu	0.025

[1]Emissions are at full load at 70° F, and include the effects of SCR and CO catalyst.

A.6.2.7.3 Nuclear Fission. A uranium-fueled nuclear fission process has been used to create energy in the United States for several decades. Inside a nuclear reactor, uranium atoms are bombarded by neutrons. Each time a neutron is absorbed by a uranium atom, the atom becomes unstable and splits, a process known as fission. During this process, the atom produces additional neutrons, usually two and a half for each fission. These neutrons split more uranium atoms, creating more neutrons. This scenario perpetuates, resulting in a chain reaction. The fission process generates heat in the reactor core, and the generated heat is transferred to water, which is circulated to the steam generator.

Currently, nuclear power in the United States faces obstacles related to public perception, capital costs, and environmental issues concerning disposal of spent fuel. Combined, these factors explain why nuclear plants have fallen out of favor as a generating resource. However, rising fuel prices, greenhouse gas emissions concerns, and increasing energy demand may make new nuclear fission plants a viable option for producing power in the future.

Westinghouse and GE are currently developing and licensing nuclear units with the Nuclear Regulatory Commission (NRC). The two units are the Westinghouse AP-1000 and the GE ESBWR. The AP-1000 was approved by the NRC in 2004, and the NRC is expected to approve the ESBWR in 2007.

The units consist of a nuclear island (NI), turbine island (TI), radwaste building, cooling tower, and additional yard facilities. The units described in this subsection are assumed to be located at a greenfield site in northern Florida.

The TI consists of the steam turbine and the switchgear building. The switchgear building includes standard electrical equipment and switchgear for a large nuclear unit.

The radwaste building has both liquid and solid radwaste treatment systems. In addition to the treatment systems, costs for the radwaste building include communications, lighting, and security systems.

The cooling tower is one of the major yard facilities and is assumed to be a mechanical draft cooling tower with a pump house and retention pond. Other yard facilities include transformers, fuel and chemical storage systems, a makeup water treatment building, grounding system, radwaste tunnel, and a service building.

The large capacity of a nuclear unit would not be practical to meet each individual Participant's capacity needs; it is therefore assumed that the unit would be jointly owned, with each Participant retaining a percentage ownership share, which would provide similar capacity to the capacity that each would receive from TEC. It is further assumed that the Participants would cooperate with other entities to purchase the remaining capacity in excess of the total capacity of TEC. As such, this option would not be fully committed to by the TEC Participants.

Nuclear units have virtually no emissions, and there will be no emissions control equipment included with the plant. Currently, there is no way to dispose of spent fuel rods after the fission process, but the operating costs of the nuclear unit include such expenses in the future. The estimated operating characteristics of the AP-1000 and ESBWR nuclear units are presented in Table A.6-36.

The *Energy Policy Act of 2005* included several incentives for new nuclear construction. The incentives included extending the Price Anderson Act, reauthorizing the Nuclear Power 2010 Program, providing loan guarantees and risk insurance, and extending the production tax credits to nuclear energy. The US Department of Energy (DOE) has suggested that the incentives are not mutually exclusive and that companies will be able to apply for more than one of the incentives.

The Price-Anderson Act authorizes methods of insuring the public for damages from nuclear accidents and the *Energy Policy Act of 2005* extension includes insuring all power reactors issued construction permits through December 31, 2005.

The Nuclear Power 2010 program was unveiled in February 2002 and is a joint cost-sharing in cooperation with industry and government to identify sites for new nuclear power plants, develop and bring to market advanced plant designs and nuclear plant technologies (Generation III+), evaluate the business case for building new nuclear power plants, and demonstrate untested regulatory processes[10]. The *Energy Policy Act of 2005* reauthorized the program.

[10] http://www.ne.doe.gov/NucPwr2010/NucPwr2010.html

Table A.6-36
Nuclear Unit – Performance and Costs

	Westinghouse AP-1000	GE ESBWR
Commercial Status	Developmental	Developmental
Construction Period (months)	72	72
Performance		
Net Capacity (MW)	1,200	1,578
Net Plant Heat Rate (Btu/kWh)	9,715	9,715
Capacity Factor (percent)	80 to 90	80 to 90
Economics ($2006)		
Total Project Cost ($/kW)	2,149	1,813
Fixed O&M ($/kW-yr)	62.5	62.5
Levelized Cost(1) ($/MWh)	48 to 53	44 to 48

(1)The low end of the levelized cost is based on a 90 percent capacity factor, and the high end is based on an 80 percent capacity factor.

On August 4, 2006 the DOE finalized a rule enacting the *Energy Policy Act of 2005* Standby Support Program, which provides developers of new advanced nuclear plants with risk insurance. The program allows the DOE to enter into contracts with a maximum of six reactors whereby the first "initial two reactors" are each eligible for indemnification of covered costs up to $500 million per contract for losses due to certain litigation or regulatory-related delays, and the "subsequent four reactors" could receive 50 percent of covered costs, up to $250 million each, after a 180-day delay[11]. The *Energy Policy Act of 2005* also authorizes the DOE to enter into loan guarantees for projects that reduce, sequester, or are free of emissions and air pollutants and/or those that use new technologies including advanced nuclear power plants.

The *Energy Policy Act of 2005* extended the production tax credits to nuclear energy. The policy permits taxpayers producing electricity at qualified facilities to claim a credit equal to 1.8 cents per kilowatt-hour of electricity produced for eight years[12]. The

[11] Weil, Jenny, Hiruo, Elaine, and Michael Knapik. DOE lays ground rules for incentives for new reactors. Nucleonics Week, Vol. 47, No. 32, pg 1.

[12] Weil, Jenny, Hiruo, Elaine, and Michael Knapik. DOE lays ground rules for incentives for new reactors. Nucleonics Week, Vol. 47, No. 32, pg 1.

national capacity limit is 6,000 MW. Qualifying facilities are those facilities for which construction is proceeding on schedule with an in-service date before 2021[13].

A.6.2.8 Capital Costs, O&M Costs, Schedule, and Maintenance Summary

The capital costs, O&M costs, schedules, forced outage, and maintenance assumptions for the generating alternatives are summarized in Table A.6-34. All costs are provided in 2006 dollars. The EPC cost is inclusive of engineering, procurement, construction, and indirect costs for construction of each alternative utilizing a fixed price, turnkey type contracting structure. Owner's costs were developed using the previously described assumptions, with site-specific cost additions or reductions as discussed previously. The assumed owner's cost allowance is representative of typical owner's costs, exclusive of escalation, financing fees, and interest during construction, which will be accounted for separately in the economic analyses.

Fixed and variable O&M costs are also provided in 2006 dollars. Fixed costs include labor, maintenance, and other fixed expenses excluding backup power, property taxes, and insurance. Variable costs include outage maintenance, consumables, and replacements dependent upon unit operation. Construction schedules are indicative of typical construction durations for the alternative technology and plant size. Actual costs and schedules will vary from the preliminary estimates provided in Table A.6-37.

The scheduled and forced outage assumptions for the generating alternatives are also presented in Table A.6-37.

A.6.3 Advanced Technologies

Advanced technologies include developmental technologies near commercial status that offer the potential for cost and efficiency improvements over conventional technologies. The technologies evaluated include advanced combustion, fuel cell, and coal technologies.

A.6.3.1 Advanced Combustion Turbine Technologies

When used in a combined cycle configuration, combustion turbines have many advantages, including low capital cost, high efficiency, and short construction periods. This section describes several advanced combustion turbines that can improve output, performance, and efficiency in combined cycle configurations. Operation of a combustion turbine approaches an idealized thermodynamic cycle called the air-standard

[13] Weil, Jenny, Hiruo, Elaine, and Michael Knapik. DOE lays ground rules for incentives for new reactors. Nucleonics Week, Vol. 47, No. 32, pg 1.

Table A.6-37
Capital Costs, O&M Costs, and Schedules for the Generating Alternatives (All Costs in 2006 Dollars)

Supply Alternative	EPC Cost ($Millions)	Owner's Cost ($Millions)	Total Cost ($Millions)	Total Cost ($/kW) at 70° F	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	Construction Schedule (Months)	Scheduled Maintenance (days)	Forced Outage (percent)
Joint Ownership Options									
3x1 GE 7FA	376.1	112.9	488.9	647.8	4.89	4.29	36	17	3.0
Three-Train 1x1 GE IGCC	1506.8	452.0	1958.8	2,467.2	38.41	5.86	53	22	10.0
FMPA Brownfield Options									
GE LM6000 SC	31.0	7.8	38.8	818.0	16.84	3.18	12	10	2.0
GE LMS100 SC	52.4	13.1	65.5	678.6	8.80	3.91	17	10	2.0
GE 7EA SC	40.9	10.3	51.2	651.9	9.05	18.31	13	10	2.0
GE 7FA SC	57.9	14.5	72.4	452.0	4.82	24.71	14	10	2.0
1x1 GE 7FA CC	157.8	47.4	205.1	685.7	6.13	4.36	30	14	3.0
JEA Brownfield Options(1)									
GE LMS100 SC	52.1	13.0	65.1	674.5	8.80	3.91	17	10	2.0
GE 7FA SC	57.3	14.4	71.7	447.9	4.82	24.71	14	10	2.0
1x1 GE 7FA CC	156.9	47.1	204.0	682.7	6.13	4.36	30	14	3.0
250 MW CFB	419.0	125.7	544.7	2173	32.29	5.09	41	21	5.0
Single-Train 1x1 GE IGCC	548.4	164.5	712.9	2,475.4	40.71	5.86	38	22	10.0
RCID Brownfield Option									
1x1 GE LM6000 CC	56.4	16.9	73.3	1,237.2	25.79	2.74	18	10	3.0
FMPA Greenfield Options									
GE LM6000 SC	32.8	8.2	41.0	867.2	22.67	3.18	12	10	2.0
GE LMS100 SC	55.3	13.8	69.1	715.5	11.66	3.91	17	10	2.0
GE 7EA SC	44.9	11.3	56.2	715.5	14.51	18.31	13	10	2.0
GE 7FA SC	61.7	15.5	77.2	481.8	7.50	24.71	14	10	2.0
1x1 GE 7FA CC	170.3	51.1	221.3	741.1	9.07	4.36	33	14	3.0
250 MW CFB	446.4	133.9	580.3	2,315.5	38.15	3.64	44	21	5.0

Table A.6-37 (Continued)
Capital Costs, O&M Costs, and Schedules for the Generating Alternatives (All Costs in 2006 Dollars)

Supply Alternative	EPC Cost ($Millions)	Owner's Cost ($Millions)	Total Cost ($Millions)	Total Cost ($/kW) at 70° F	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	Construction Schedule (Months)	Scheduled Maintenance (days)	Forced Outage (percent)
FMPA Greenfield Options (continued)									
Single-Train 1x1 GE IGCC	558.6	167.6	726.2	2,893.6	40.71	5.86	41	22	10.0
JEA Greenfield Options									
GE LMS100 SC	54.7	13.7	68.5	709.3	11.66	3.91	17	10	2.0
GE 7FA SC	61.3	15.4	76.7	478.7	7.50	24.71	14	10	2.0
1x1 GE 7FA CC	168.9	50.6	219.6	734.9	9.07	4.36	33	14	3.0
250 MW CFB	441.6	132.4	574.0	2,290.9	38.15	3.64	44	21	5.0
Tallahassee Greenfield Options									
GE LM6000 SC	32.4	8.1	40.5	809.8	22.67	3.18	12	10	2.0
GE LMS100 SC	53.0	13.3	66.3	687.0	11.66	3.91	17	10	2.0
GE 7EA SC	44.3	11.1	55.4	706.2	14.51	18.31	13	10	2.0
GE 7FA SC	60.5	15.2	75.7	491.0	7.50	24.71	14	10	2.0
1x1 GE LM6000 CC	59.5	17.9	77.4	1,307.4	25.79	2.74	18	10	3.0
1x1 GE 7FA CC	167.1	50.1	217.2	726.7	9.07	4.36	33	14	3.0
250 MW CFB	435.4	130.6	566.0	2,258.1	38.15	3.64	44	21	5.0
Single-Train 1x1 GE IGCC	558.6	167.6	726.2	2,893.6	40.71	5.86	41	22	10.0

(1)JEA's brownfield options do not include anticipated costs for transmission and gas pipeline system upgrades.

Brayton cycle. The Brayton cycle is an all-gas cycle that uses air and combustion gases as the working fluids, as opposed to the Rankine cycle, which is a vapor-based cycle. Three Brayton cycles show promise as advanced technologies: the humid air turbine (HAT) cycle, Kalina cycle, and Cheng cycle.

A.6.3.1.1 Humid Air Turbine Cycle. The HAT cycle is an intercooled, regenerative cycle burning natural gas with a saturator. The saturator adds substantial amounts of moisture to the compressor discharge air so that the combustor inlet flow contains 20 to 40 percent water vapor. The warm humidified air from the saturator is then further heated by the turbine exhaust in a recuperator before being sent to the combustor. The water vapor adds to the turbine output, while intercooling reduces the compressor work requirement. The heat addition in the recuperator reduces the amount of fuel heat input required. Although the HAT cycle may offer future energy efficiencies and cost savings, it is a developmental technology that is not ready for commercial application. Table A.6-38 presents typical performance and cost characteristics for the HAT cycle.

Table A.6-38
HAT Cycle Performance and Costs

Commercial Status	Developmental
Construction Period (months)	20 to 28
Performance	
Plant Capacity (MW)	250 to 650
Net Plant Heat Rate (Btu/kWh)	6,500
Capacity Factor (percent)	60 to 80
Economics ($2006)	
Total Project Cost ($/kW)	513 to 820
Fixed O&M ($/kW-yr)	5.1 to 10.3
Variable O&M ($/MWh)	2.1 to 4.1
Levelized Cost(1) ($/MWh)	65 to 77

(1)The low end of the levelized cost is based on an 80 percent capacity factor, 650 MW plant capacity, capital cost of $513/kW, fixed O&M cost of $5.1/kW-year, and variable O&M cost of $2.1/MWh. The high end of the levelized cost is based on a 60 percent capacity factor, 250 MW plant capacity, capital cost of $820/kW, fixed O&M cost of $10.3/kW-year, and variable O&M cost of $4.1/MWh.

A.6.3.1.2 Kalina Cycle. The Kalina cycle is a combined cycle plant configuration that injects ammonia into the vapor side of the cycle. The ammonia/water working fluid provides thermodynamic advantages because of the nonisothermal boiling and condensing behavior of the working fluid's two-component mixture. Ammonia has a lower boiling point than water, which allows the cycle to start spinning the steam turbine at much lower temperatures than conventional systems. This capability allows more effective heat acquisition, regenerative heat transfer, and heat rejection.

The cycle is similar in nature to the combined cycle process, except that exhaust gas from the combustion turbine enters a heat recovery vapor generator (HRVG). Fluid (70 percent ammonia, 30 percent water) from the distillation condensation subsystem (DCSS) enters the HRVG to be heated. A portion of the mixture is removed at an intermediate point from the HRVG and is sent to a heat exchanger, where it is heated with vapor turbine exhaust from the IP vapor turbine. The moisture returns to the HRVG, where it is mixed with the balance of flow, superheated, and expanded in the vapor turbine generator (VTG). Additional vapor enters the HRVG from the HP vapor turbine, where it is reheated and supplied to the inlet of the IP vapor turbine. The vapor exhausts from the vapor turbine and condenses in the DCSS. The Kalina cycle is still a developmental technology for large-scale applications. There are currently four plants operating worldwide that use this technology. Capital costs are still high, and power outputs are limited to under 5 MW. The Kalina cycle could be retrofitted to an existing plant or gas compressor station to capture waste heat. Table A.6-39 presents typical performance and cost characteristics for the Kalina cycle.

A.6.3.1.3 Cheng Cycle. The Cheng cycle is a steam-injected gas turbine, which increases efficiency over the gas turbine cycle by injecting large volumes of steam into the combustor and/or turbine section. The basic Cheng cycle is composed of a compressor, combustor, turbine, generator, and HRSG. The HRSG provides injection steam to the combustor as well as process steam. The amount of steam injection is limited to the allowable loading of the turbine blades.

The typical application of the Cheng cycle is in a cogeneration facility, but it has also been proposed as a retrofit for simple cycle combustion turbines. Table A.6-40 presents typical performance and cost characteristics for the Cheng cycle.

A.6.3.2 Fuel Cell

Fuel cell technology has been developed by government agencies and private corporations. Fuel cells are an important part of space exploration and are receiving considerable attention as an alternative power source for automobiles. In addition to these two applications, fuel cells continue to be considered for power generation to meet permanent and intermittent power demands.

Table A.6-39
Kalina Cycle Performance and Costs

Commercial Status	Developmental
Construction Period (months)	26 to 29
Performance	
Plant Capacity (MW)	50 to 500
Net Plant Heat Rate (Btu/kWh)	6,700
Capacity Factor (percent)	60 to 80
Economics ($2006)	
Total Project Cost ($/kW)	820 to 1,025
Fixed O&M ($/kW-yr)	4.1 to 11.3
Variable O&M ($/MWh)	2.1 to 4.1
Levelized Cost(1) ($/MWh)	71 to 82

(1)The low end of the levelized cost is based on a 500 MW plant capacity, 80 percent capacity factor, capital cost of $820/kW, fixed O&M cost of $4.1/kW-year, and variable O&M cost of $2.1/MWh. The high end of the levelized cost is based on a 50 MW plant capacity, 60 percent capacity factor, capital cost of $1025/kW, fixed O&M cost of $11.3/kW-year, and variable O&M cost of $4.1/MWh.

Table A.6-40
Cheng Cycle Performance and Costs

Commercial Status	Developmental (larger units)
Construction Period (months)	20 to 28
Performance	
Plant Capacity (MW)	25 to 250
Net Plant Heat Rate (Btu/kWh)	8,000 to 9,000
Capacity Factor (percent)	60 to 80
Economics ($2006)	
Total Project Cost ($/kW)	1,230 to 2,563
Fixed O&M ($/kW-yr)	6.2 to 11.3
Variable O&M ($/MWh)	2.1 to 4.1
Levelized Cost[1] ($/MWh)	87 to 128

[1]The low end of the levelized cost is based on a 250 MW plant capacity, 8,000 Btu/kWh net plant heat rate, 80 percent capacity factor, capital cost of $1,230/kW, fixed O&M cost of $6.2/kW-year, and variable O&M cost of $2.1/MWh. The high end of the levelized cost is based on a 25 MW plant capacity, 9,000 Btu/kWh net plant heat rate, 60 percent capacity factor, capital cost of $2,563/kW, fixed O&M cost of $11.3/kW-year, and variable O&M cost of $4.1/MWh.

A.6.3.2.1 Operating Principles. Fuel cells convert hydrogen-rich fuel sources directly to electricity through an electrochemical reaction. Fuel cell power systems have the promise of high efficiencies because they are not limited by the Carnot efficiency that limits thermal power systems. Fuel cells can sustain high efficiency operation even at part load. The construction of fuel cells is inherently modular, making it easy to size plants according to power requirements.

There are four major fuel cell types under development: phosphoric acid, molten carbonate, solid oxide, and proton exchange membrane. The most developed fuel cell technology for stationary power is the phosphoric acid fuel cell (PAFC). PAFC plants range from around 200 kW to 11 MW in size and have efficiencies on the order of 40 percent. PAFC cogeneration facilities can attain efficiencies approaching 88 percent when the thermal energy from the fuel cell is utilized for low grade energy recovery. The development of solid-oxide fuel cell gas turbine combined cycles could potentially allow electrical conversion efficiencies of 60 to 70 percent. Molton carbonate fuel cells operate at temperatures of 600° C and above, and can attain efficiencies approaching 60 percent.

If waste heat is captured, overall thermal efficiency can reach 85 percent or higher. Proton exchange membrane fuel cells operate at lower temperatures and have efficiencies on the order of 40 percent.

A.6.3.2.2 Applications. Most fuel cell installations generate less than 1 MW. Commercial fuel cell plants are typically fueled by natural gas, which is converted to hydrogen gas in a reformer. However, if available, hydrogen gas can be used directly. Other fuel sources under investigation include methanol, biogas, ethanol, and other hydrocarbons.

In addition to the potential for high efficiency, the environmental benefits of fuel cells remain the primary reasons for their development. High capital cost, short fuel cell stack life, and uncertain reliability - the primary disadvantages of fuel cell systems - continue to be the focus of research and development. The cost for these systems is expected to drop significantly as development efforts continue, partially spurred by interest from the automotive transportation sector.

A.6.3.2.3 Performance and Cost Characteristics. The performance and cost characteristics of a typical fuel cell plant are shown in Table A.6-41. Significant cost is required to replace the fuel cell stack every 3 to 5 years because of degradation. The stack alone can represent up to 40 percent of the initial capital cost. Most fuel cell technologies are still developmental, and power produced by commercial models is not competitive.

A.6.3.3 Advanced Coal Technologies

A.6.3.3.1 Pressurized Fluidized Bed. Coal fired plants continue to supply a large portion of the energy requirements in the United States. Current research is focused on making the conversion of energy from coal more clean and efficient. Pressurized fluidized bed systems have been developed to improve coal conversion efficiency.

Pressurized fluidized bed combustion (PFBC) is a variation of fluid bed technology in which combustion occurs in a pressure vessel at 10 to 15 atmosphere. The PFBC process involves burning crushed coal in a limestone or dolomite bed. High combustion efficiency and excellent sulfur capture are advantages of this technology. In combined cycle configurations, PFBC exhaust is expanded to drive both the compressor and CTG. HRSGs transfer heat from this exhaust to generate steam, in addition to the steam generated from the PFBC boiler. Overall thermal efficiencies of PFBC combined cycle configurations are 45 to 47 percent. Second-generation PFBC systems are in the developmental stage. Since this technology is in the developmental stage, it is difficult to accurately quantify the capital costs. This technology is not yet mature enough to be considered for a new generation project. Table A.6-42 presents typical performance and cost characteristics for PFBC.

Table A.6-41 Fuel Cell Technology Characteristics	
Commercial Status	Developmental/Early Commercial
Performance	
Net Capacity per Unit (kW)	100 to 250
Net Plant Heat Rate (Btu/kWh)	7,000 to 9,500
Capacity Factor (percent)	30 to 70
Economics ($2006)	
Total Project Cost ($/kW)	5,125 to 7,175
Fixed O&M(1) ($/kW-yr)	513 to 718
Variable O&M ($/MWh)	5.1 to 10.3
Levelized Cost(2) ($/MWh)	243 to 673

(1)Includes costs for cell stack replacement every 4 years.
(2)The low end of the levelized costs are based on a 250 kW plant capacity, 7,000 Btu/kWh net plant heat rate, 70 percent capacity factor, capital cost of $5,125/kW, fixed O&M cost of $513/kW-year, and variable O&M cost of $5.1/MWh. The high end of the levelized costs are based on 100 kW plant capacity, 9,500 Btu/kWh net plant heat rate, 30 percent capacity factor, capital cost of $7,175/kW, fixed O&M cost of $718/kW-year, and variable O&M cost of $10.3/MWh.

A.6.3.3.2 Advanced Supercritical Cycle. Supercritical cycles operate above the critical point of water, where there is no distinction between water and steam. Supercritical cycles have been developed to improve Rankine cycle efficiency.

In the industry, supercritical has typically referred to a cycle with main steam conditions of 3,500 psig and 1,050° F, with single reheat at 1,075° F. Advanced supercritical cycles generally involve steam conditions with higher temperatures and pressures than the current industry standard, within limits set by current materials. Currently, this limit is thought to be steam conditions around 4,700 psig at 1,130° F, with double reheat at 1,165° F. Maximum thermal efficiency may approach 47 percent.

A.6.3.3.3 Ultrasupercritical Cycle. Ultrasupercritical represents a step change to temperatures and pressures above those in advanced supercritical. Main steam conditions of 5,500 psig and 1,300° F are being investigated. Operation at these conditions will require the development of more advanced materials. This technology is still in the research and development stage. Thermal efficiency is predicted to be between 52 and 55 percent.

Table A.6-42
PFBC Performance and Costs

Commercial Status	Developmental
Construction Period (months)	32 to 38
Performance	
Plant Capacity (MW)	150 to 350
Net Plant Heat Rate (Btu/kWh)	8,000 to 9,000
Capacity Factor (percent)	60 to 80
Economics ($2006)	
Total Project Cost ($/kW)	1,845 to 2,460
Fixed O&M ($/kW-yr)	20.5 to 35.9
Variable O&M ($/MWh)	4.1 to 5.1
Levelized Cost(1) ($/MWh)	53 to 77

(1)The low end of the levelized cost is based on a 350 MW plant capacity, 8,000 Btu/kWh net plant heat rate, 80 percent capacity factor, capital cost of $1,845/kW, fixed O&M cost of $20.5/kW-year, and variable O&M cost of $4.1/MWh. The high end of the levelized cost is based on a 150 MW plant capacity factor, 9,000 Btu/kWh, 60 percent capacity factor, capital cost of $2,460/kW, fixed O&M cost of $35.9/kW-year, and variable O&M cost of $5.1/MWh.

A.6.4 Energy Storage Technologies

Energy storage technologies convert and store electricity, increasing the value of power by allowing better utilization of off-peak baseload generation and the mitigation of instantaneous power fluctuations. Different types of technologies are available that provide a variety of storage durations. Storage durations range from microseconds (superconducting magnets, flywheels, and batteries), to minutes (flywheels and batteries), to hours and seasonal storage (pumped hydroelectric, batteries, and compressed air). An analysis of technologies that could be used on a commercial level is provided in the following subsections.

A.6.4.1 Pumped Hydroelectric Energy Storage

Pumped hydroelectric energy storage is the oldest and most prevalent of the commercial-scale energy storage options. More than 23,000 MW of pumped storage generation has been installed in the United States.[14] A pumped storage hydroelectric facility requires a reservoir/dam system similar to a conventional hydroelectric facility.

[14] Global Energy Decisions, July 2006.

During times of minimal load demand, excess low cost energy is used to pump water from a lower reservoir to an upper reservoir above a dam. When energy is required during the high cost, peak electrical demand periods, the water in the upper reservoir is released through a turbine to produce electricity.

Capital cost and project lead time are the primary considerations for implementation of this storage technology. Capital costs are typically very high on a dollar per kW basis, and a 4 or 5 year construction period is common for larger pumped storage facilities. Additionally, it is difficult to gain environmental approvals for damming up the nation's river systems or developing reservoirs on mountain tops. Geographic and geologic conditions largely preclude many areas from consideration of this technology. Table A.6-43 presents typical performance and cost estimates for pumped hydroelectric energy storage.

A.6.4.2 Battery Storage

A battery storage system consists of the battery, direct current (dc) switchgear, dc/alternating current (ac) converter and charger, transformer, ac switchgear, and a building to house the components. During peak power demand periods, the battery system can discharge power to the utility system for about 4 to 5 hours. The batteries are then recharged during non-peak hours. In addition to the high initial cost, a battery system would require replacement every 4 to 10 years, depending on the duty cycle.

Currently, most utility-scale battery systems are lead-acid batteries. The Electricity Storage Association (ESA) Web site lists five lead-acid battery systems larger than 1 MWh, with the largest being the 10 MW, 40 MWh system at Chino, California.[15] The site also provides information on other emerging battery technologies. The sodium-sulfur (Na-S) technology being developed in Japan is moving toward commercial status. The ESA site discusses the use of Na-S technology at more than 30 sites in Japan, totaling 20 MW. Recently, Appalachian Power Company announced the planned deployment of a 1.2 MW Na-S battery energy system near Charleston, West Virginia.[16] Table A.6-44 provides the cost and performance characteristics of a 5 MW (15 MWh) system.

[15] Electricity Storage Association, www.electricitystorage.org/.
[16] AEP Substation to Get Commercial-Scale Energy Storage System, *Power Engineering*, October 2005.

Table A.6-43
Pumped Hydroelectric Energy Storage Performance and Costs

Commercial Status	Commercial
Construction Period (months)	12 to 60
Performance	
Plant Capacity (MW)	30 to 1,500
Capacity Factor (percent)	10 to 15
Economics ($2006)	
Total Project Cost ($/kW)	1,538 to 2,665
Fixed O&M ($/kW-yr)	5.1 to 13.3
Variable O&M ($/MWh)	2.1 to 5.1
Levelized Cost[1] ($/MWh)	154 to 340

[1]The low end of the levelized cost is based on a 1,500 MW plant capacity, 15 percent capacity factor, capital cost of $1,538/kW, fixed O&M cost of $5.1/kW-year, and variable O&M cost of $2.1/MWh. The high end of the levelized cost is based on a 30 MW plant capacity, 10 percent capacity factor, capital cost of $2,665/kW, fixed O&M cost of $13.3/kW-year, and variable O&M cost of $5.1/MWh. The cost of off-peak energy is assumed to be $30/MWh.

Table A.6-44
Lead-Acid Battery Energy Storage - Performance and Costs

Commercial Status	Commercial
Construction Period (months)	12 to 18
Performance	
Plant Capacity (MW)	5
Energy Capacity (MWh)	15
Capacity Factor (percent)	10 to 15
Economics ($2006)	
Total Project Cost ($/kW)	2,870 to 3,280
Fixed O&M ($/kW-yr)	30.8
Variable O&M(1) ($/MWh)	440.8 to 481.8
Levelized Cost(2) ($/MWh)	766 to 970

(1)Includes battery replacement at 10 years.
(2)The low end of the levelized cost is based on a capacity factor of 15 percent, capital cost of $2,870/kW, and variable O&M cost of $440.8/MWh. The high end of the levelized cost is based on a capacity factor of 10 percent, capital cost of $3,280/kW, and variable O&M cost of $481.8/MWh.

A.6.4.3 Compressed Air Energy Storage

Compressed air energy storage (CAES) is a technique used to supply electrical power to meet peak loads within an electric utility system. This method uses the power surplus from baseload coal and nuclear plants during off-peak periods to compress and store air in an underground formation. The compressed air is later heated (with a fuel) and expanded through a gas turbine expander to produce electrical power during peak demand. A simple compressed air storage plant consists of an air compressor, turbine, generator unit, and a storage vessel. Exhaust gas heat recuperation can be added to increase efficiency.

The thermodynamic cycle for a compressed air storage facility is similar to that of a simple cycle gas turbine. Typically, gas turbines will consume 50 to 60 percent of their net power output to operate an air compressor. In a compressed air storage plant, the air compressor and the turbine are not connected, and the total power generated from the gas turbine is supplied to the electrical grid. By using off-peak energy to compress the air, the need for expensive natural gas or fuel oil is reduced by as much as two thirds, compared with conventional gas turbines.[17] This results in a very attractive heat rate for CAES plants, ranging from 4,000 to 5,000 Btu/kWh. Since fuel (typically natural gas) is supplied to the system during the energy generation mode, CAES plants actually provide more electrical power to the grid than was used to compress the air.

The location of a CAES plant must be suitable for cavern construction or for the reuse of an existing cavern. However, suitable geology is widespread throughout the United States, with more than 75 percent of the land area containing appropriate geological formations.[18] There are three types of formations that can be used to store compressed gases: solution mined reservoirs in salt, conventionally mined reservoirs in salt or hard rock, and naturally occurring porous media reservoirs (aquifers).

The basic components of a CAES plant are proven technologies, and CAES units have a reputation for achieving good availability. The first commercial-scale CAES plant in the world was a 290 MW plant in Huntorf, Germany. This plant has been operating since 1978, providing 2 hours of generation with 8 hours of charging. In 1991, a 110 MW CAES facility was installed in McIntosh, Alabama. This plant remains the only US CAES installation, although several new plants have been announced recently. Table A.6-45 lists the performance and cost characteristics of a CAES system.

[17] Nakhamkin, M., Anderson, L., Swenson, E., "AEC 110 MW CAES Plant: Status of Project," *Journal of Engineering for Gas Turbines and Power*, October 1992, Vol. 114.
[18] Mehta, B., "Compressed Air Energy Storage: CAES Geology," *EPRI Journal*, October/November 1992.

Table A.6-45
Compressed Air Energy Storage Performance and Costs

Commercial Status	Commercial
Construction Period, months	26 to 29
Performance	
Net Plant Capacity (MW)	100 to 500
Net Plant Heat Rate (Btu/kWh)	4,000 to 5,000
Capacity Factor (percent)	10 to 25
Economics ($2006)	
Total Project Cost ($/kW)	492 to 748
Fixed O&M ($/kW-yr)	5.1 to 16.4
Variable O&M ($/MWh)	3.1 to 6.2
Levelized Cost[1] ($/MWh)	102 to 191

[1]The low end of the levelized cost is based on a 500 MW plant capacity, 4,000 Btu/kWh net plant heat rate, 25 percent capacity factor, capital cost of $492/kW, fixed O&M cost of $5.1/kW-year, and variable O&M cost of $3.1/MWh. The high end of the levelized cost is based on a 100 MW plant capacity, 5,000 Btu/kWh net plant heat rate, 10 percent capacity factor, capital cost of $748/kW, fixed O&M cost of $16.4/kW-year, and variable O&M cost of $6.2/MWh. Assumes $30/MWh off-peak energy.

A.6.5 Distributed Generation Technologies

There are several advantages associated with using distributed generation technology as a portion of a utility's generation capacity. In general, distributed generation options are small, reliable units that can help a utility to adequately meet peak demands. Distributed generation alternatives can also be used to provide baseload for smaller utilities. Two types of distributed generation technologies were analyzed.

A.6.5.1 Reciprocating Engines

Reciprocating engines are proven prime movers for electric generation, industrial processes, and many other applications. Reciprocating engines operate according to either an Otto or Diesel thermodynamic cycle, very much like a personal automobile. These cycles use similar mechanics to produce work, but differ in the way that they combust fuel.

Reciprocating engines contain multiple pistons that are individually attached by connecting rods to a single crankshaft. Fuel is burned at the other end of the piston's sealed combustion chambers. A mixture of fuel and air is injected into the combustion chamber, where, after compression, an explosion is caused. The explosion provides energy to force the pistons down; this linear motion is translated into the angular rotation of the crankshaft by the connecting rods. The combustion chambers are vented and the piston pushes the exhaust gases out, completing two rotations of the crankshaft. The process is repeated and work is performed.

Reciprocating engine generator sets are commonly used in power generation, either for emergency backup or peak load shaving. However, there is also a well established market for installation of generator sets as the primary power source for small power systems and isolated facilities that are located away from the transmission grid.

When used for power generation, medium speed engines (less than 1,000 rpm) are typically used since they are more efficient and have lower O&M costs than smaller, higher speed machines. Reciprocating engines have relatively constant efficiency rates from 100 to 50 percent load, they have excellent load-following characteristics, and they can maintain guaranteed emissions rates down to approximately 25 percent load, thus providing superior part-load performance. Typical startup times for larger reciprocating engines are on the order of 15 minutes. However, some engines can be configured to start up and be completely operational within 10 seconds for use as emergency backup power.

Spark ignition engines are designed to operate on gaseous fuels such as natural gas, propane, and waste gases from industrial processes. Compression ignition engines are designed to operate on liquid fuels such as diesel fuel oil and biodiesel. Because they have such flexibility, engine generators are well suited for use as conventional or renewable power generation. Table A.6-46 provides performance and cost characteristics for typical reciprocating engine installations.

A.6.5.2 Microturbines

The microturbine is essentially a small version of the combustion turbine. It is typically offered in the size range of 30 to 60 kW. These turbines were initially developed in the 1960s by Allison Engine Co. for ground transportation. The first major field trial of this technology was in 1971, with the installation of turbines in six Greyhound buses. By 1978, the buses had traveled more than a million miles, and the turbine engine was viewed by Greyhound management as a technical breakthrough. Since this initial application, microturbines have been used in many applications, including small-scale electric and heat generation in industry, waste recovery, and continued use in vehicles.

Table A.6-46
Reciprocating Engine Technology Characteristics

Engine Type	Spark Ignition (Natural Gas)	Compression Ignition (Diesel)
Commercial Status	Commercial	Commercial
Performance		
Net Plant Capacity (kW)	1 to 5,000	1 to 10,000
Net Plant Heat Rate (Btu/kWh)	9,700	7,800
Capacity Factor (percent)	30 to 70	30 to 70
Economics ($2006)		
Total Project Cost ($/kW)	461 to 1,128	359 to 820
Variable O&M ($/MWh)	15.4 to 25.6	15.4 to 25.6
Levelized Cost(1) ($/MWh)	108 to 152	137 to 172

(1)The low ends of the levelized costs are based on the higher plant capacities and capacity factors, and the lower capital and O&M costs. The high ends of the levelized costs are based on the lower plant capacities and capacity factors, and the higher capital and O&M costs.

Microturbines operate on a principle similar to that of larger combustion turbines. Atmospheric air is compressed and heated with the combustion of fuel, then expanded across turbine blades, which in turn operate a generator to produce power. The turbine blades operate at very high speeds in these units, up to 100,000 rpm, versus the slower speeds observed in large combustion turbines. Another key difference between the large combustion turbines and the microturbines is that the compressor, turbine, generator, and electric conditioning equipment are all contained in a single unit about the size of a refrigerator, versus a unit about the size of a railcar. The thermal efficiency of these smaller units is currently in the range of 20 to 30 percent, depending on the manufacturer, ambient conditions, and the need for fuel compression; however, efforts are under way to increase the thermal efficiency of these units to around 40 percent.

Potential applications for microturbines are very broad, given the fuel flexibility, size, and reliability of the technology. The units have been used in electric vehicles, distributed generation, and resource recovery applications. These systems have been used in many remote power applications around the world to bring reliable generation outside of the central grid system. In addition, these units are currently being used in several landfill sites to generate electricity with LFG fuel to power the facilities on the site. For example, the Los Angeles Department of Water and Power recently installed an array of 50 microturbine generators at the Lopez Canyon landfill. The project has a net output of 1,300 kW.

Microturbines offer fuel flexibility; fuels suitable for combustion include natural gas, ethanol, propane, biogas, and other renewable fuels. The minimum requirement for fuel heat content is around 350 Btu/scf, depending upon microturbine manufacturer.

Microturbine costs are often discussed as being about $1,000 per kilowatt, but this is typically just the bare engine cost. Auxiliary equipment, engineering, and construction costs can be significant. Table A.6-47 provides performance and cost characteristics for typical microturbine installations.

Table A.6-47
Microturbine Technology Characteristics

Commercial Status	Early Commercial
Performance	
Net Capacity per Unit (kW)	15 to 60
Net Plant Heat Rate (Btu/kWh)	12,200
Capacity Factor (percent)	30 to 70
Economics ($2006)	
Total Project Cost ($/kW)	974 to 1,743
Variable O&M ($/MWh)	10.3 to 20.5
Levelized Cost(1) ($/MWh)	130 to 188

(1)The low end of the levelized cost is based on 60 kW plant capacity, 70 percent capacity factor, capital cost of $974/kW, and variable O&M cost of $10.3/MWh. The high end of the levelized cost is based on 15 kW plant capacity, 30 percent capacity factor, capital cost of $1,743/kW, and variable O&M cost of $20.5/MWh.

A.6.6 Supply-Side Screening

A supply-side screening was performed on each of the alternatives described previously in this section. The supply-side screening considers each alternative's feasibility, levelized cost, and overall reliability to meet each Participant's capacity and energy needs. The levelized cost for each alternative is determined on a dollar per MWh basis and includes capital costs, fuel costs, and O&M costs. The levelized cost is calculated to reflect an all-in cost for capacity at a given capacity factor and is used to make screening-level comparisons of different technologies. The costs for each alternative were levelized over an evaluation period equal to the alternative's unit life. Conventional alternative unit life assumptions are presented in Section A.4.0. All other alternatives were levelized over a 20 year period, with the exception of the advanced coal technologies, which were levelized over a 30 year period.

The alternatives that appear favorable in the supply-side screening will be evaluated further in the economic analyses presented in Section 5.0 of Volumes B through E. The following subsections present the results of the supply-side screening and a summary of the alternatives that will be considered by each Participant in the detailed economic analysis.

A.6.6.1 Renewable Technologies

Before a supply-side alternative can be appropriately considered for analysis on a levelized cost basis, the technology's reliability and feasibility to meet the Participants' capacity needs must be established. Several of the renewable technologies considered are still in the research and development stage. As a result of a lack of commercial demonstration, the biomass gasification with IGCC, parabolic dish, central receiver, solar chimney, ocean thermal, and marine current technologies were eliminated from further economic evaluation.

Unlike most of the conventional alternatives, the effectiveness of renewable technologies is highly dependent on the availability and sufficiency of the various renewable resources utilized for electric power production. Renewable technologies may be commercially viable in some areas of the United States, but unfeasible in other regions because of the high level of dependence on resource availability. Based on transmission considerations, renewable technology alternatives considered in this analysis were geographically limited to the State of Florida. Therefore, wind energy, solar parabolic trough, geothermal, and hydroelectric technologies were eliminated from further economic analysis. While LFG is available at various sites throughout the state, most of the available gas is already being utilized by other utilities, including JEA. Additionally, the amount of LFG available is not sufficient to mitigate the need for additional capacity for any of the Participants. Thus, additional LFG generation for JEA and new LFG generation for the other Participants will not be considered.

If an alternative is both commercially proven and feasible, based on resource availability, it can be appropriately considered on a levelized cost basis. The levelized costs of the remaining renewable alternatives were compared with the costs of conventional alternatives as shown on Figures A.6-2 and A.6-3, which are presented at the end of this section. For conservative comparison purposes, the conventional alternative levelized costs shown on Figures A.6-2 and A.6-3 reflect the highest cost greenfield units presented in Table A.6-37. Table A.6-48 presents the midpoint of the range of levelized costs for the renewable alternatives presented earlier in this section. It should be noted that the average levelized costs for renewable technologies shown in Table A.6-48 do not reflect any potential savings for IPPs, due to the uncertainty regarding extension of the incentives discussed in Section A.6.1. Although potentially feasible, MSW mass burn, RDF, and solar PV technologies were eliminated from further economic analysis on a levelized cost basis.

Table A.6-48
Renewable Alternative Screening Results

Technology	Average Levelized Cost ($/MWh)
Direct-Fired Biomass	92
Biomass IGCC	105
Co-Fired Biomass(1)	29
Anaerobic Digestion	61
Landfill Gas	47
MSW Mass Burn	163
Refuse-Derived Fuel	241
Wind	165
Solar Parabolic Trough	142
Solar Parabolic Dish	187
Central Receiver	162
Solar Chimney	81
Solar PV Residential	714
Solar PV Commercial	489
Geothermal	91
New Hydroelectric	85
Incremental Hydroelectric	54
Ocean Thermal Onshore	170
Ocean Thermal Offshore	68

(1) Represents average levelized cost for biomass component of the biomass co-firing alternative as discussed in Section A.6.1

Three renewable technology applications that may be feasible from both a cost and reliability standpoint are co-fired biomass, direct-fired biomass, and anaerobic digestion. Since supply-side alternatives are considered for the Participants' individual systems, these technologies must be considered separately for each Participant.

The range of levelized costs for co-fired biomass presented on Figure A.6-3 represents the costs for the biomass component of co-firing. As described in Section A.6.1, this calculation was based on co-firing 20 MW of biomass in a 765 MW supercritical pulverized coal unit, similar to the Taylor Energy Center.

Since FMPA's generation system is geographically diverse, it may be possible to economically deliver biomass to one of its existing sites; however, FMPA does not have complete ownership of any solid fuel fired generation unit that is suitable for biomass co-firing. As a result, biomass co-firing was not considered as a potential supply-side alternative for FMPA in the detailed economic analysis.

JEA could potentially co-fire biomass in its existing Northside Units 1 and 2; however, co-firing at the Northside units would not add any additional capacity to JEA's system and, therefore, would not mitigate JEA's need for capacity. Since it cannot meet capacity needs, biomass co-firing was not considered as a supply-side alternative for JEA's system.

Like FMPA, the City of Tallahassee and RCID do not have any existing solid fuel fired units in their generating systems. Since it is not currently possible for either the City of Tallahassee or RCID to co-fire biomass on any of their existing units, biomass co-firing was not considered in the detailed economic analyses for these Participants.

The range of levelized costs for direct-fired biomass tends to be higher than the range of levelized costs for the conventional baseload alternatives, in particular the conventional solid fueled units (TEC, the CFB, and the IGCC alternatives). Additionally, the availability of biomass resources for each Participant represents an area of uncertainty, especially as other utilities throughout the State of Florida begin considering biomass generation for their systems and competition for biomass resources intensifies. Given these considerations, direct-fired biomass was not considered in the detailed base case economic analysis for any of the Participants. However, a sensitivity analysis was performed for each Participant, which included a 30 MW direct-fired biomass alternative as a supply-side resource.

The levelized cost of the anaerobic digester is competitive with conventional technologies at a 90 percent capacity factor; however, the capacity of the digester considered is only 85 kW. Even if many of these facilities were available, they could not provide enough capacity to mitigate any Participant's initial need for capacity. Therefore, anaerobic digestion was not considered in the detailed economic analyses for FMPA, JEA, the City of Tallahassee, or RCID.

A.6.6.2 Conventional and Emerging Technologies

All of the conventional and emerging technologies presented in Table A.6-37 were compared on a levelized cost basis using the economic parameters described in Section A.4.0. The screening of conventional and emerging supply-side alternatives was performed for each individual Participant, based on the supply-side alternatives considered for each system as presented in Table A.6-16. Separate levelized cost curves were developed for peak load and baseload supply-side alternatives. Figures A.6-4, A.6-5, and A.6-6 present the levelized cost curves of peak load generating alternatives for FMPA, JEA, and the City of Tallahassee, respectively, while Figures A.6-7, A.6-8, A.6-9, and A.6-10 present the levelized cost curves of baseload generating alternatives for FMPA, JEA, the City of Tallahassee, and RCID, respectively. Figures A.6-4 through A.6-10 are presented at the end of this section.

Based on the results presented in the levelized cost curves, all of the conventional and emerging alternatives considered individually by each Participant were included in the detailed economic analyses in Section 5.0 of Volumes B through E, except for the nuclear alternatives. Although the nuclear alternatives appear attractive for baseload generation, they were not considered in the economic evaluations for a number of reasons. First, it is assumed that the nuclear alternatives would not be available for commercial operation for at least 15 years because of the time frame for project development, licensing, and construction. Thus, the first year that the nuclear alternative would be assumed to be available is 2021. Second, the size of a nuclear unit is such that it would need to be primarily developed and managed by an entity significantly larger than the Participants, even as an aggregate. Therefore, the Participants would have no control over the schedule of the project. Finally, while the capital costs for the nuclear alternatives appear very attractive, they are based primarily on vendor estimates. No new domestic nuclear units have been started in more than 25 years. While it may be possible to achieve the estimated costs, they represent a tremendous reduction from the costs of the most recently constructed US nuclear unit.

A.6.6.3 Advanced Technologies

Advanced technologies were screened by development status and feasibility. The advanced combustion, fuel cell, and coal technologies are still considered developmental stage technologies. Due to the early developmental stages of these technologies and the uncertainty relating to reliability and cost, these advanced technologies were not considered for further evaluation.

A.6.6.4 Energy Storage Systems

Energy storage systems offer the ability to shift demand during on-peak times to off-peak, thereby lowering demand during peak times. As such, these technologies can only serve peaking loads, not intermediate or baseload demands. Energy storage technologies include pumped hydroelectric, lead-acid battery, and compressed air. Each of these technologies stores energy collected during off-peak hours and then releases the energy during peak demand periods. Energy storage systems were screened by development status and average levelized cost. Each energy storage technology is considered commercially proven; however, most have a much higher average levelized cost than the conventional alternatives. In addition, because these technologies rely on storing energy during off-peak periods, they are limited to only peaking applications and, therefore, have lower availability than other conventional alternatives. As a result, no energy storage technologies were considered for further evaluation.

A.6.6.5 Distributed Generation Technologies

Distributed generation technologies include reciprocating engines and microturbines. These technologies are typically used for small demand applications. Reciprocating engines are considered commercially proven, while microturbines are in early commercial deployment. However, these technologies have a higher average cost than the conventional alternatives and were not considered for further evaluation.

Alternatives shaded in red were screened out due to a lack of commercial demonstration, alternatives shaded in green were screened out due to geographic or or resource constraints, alternatives shaded in black were elimnated as non-economic, and alternatives shaded in light blue were carried forward to the economic analyses.

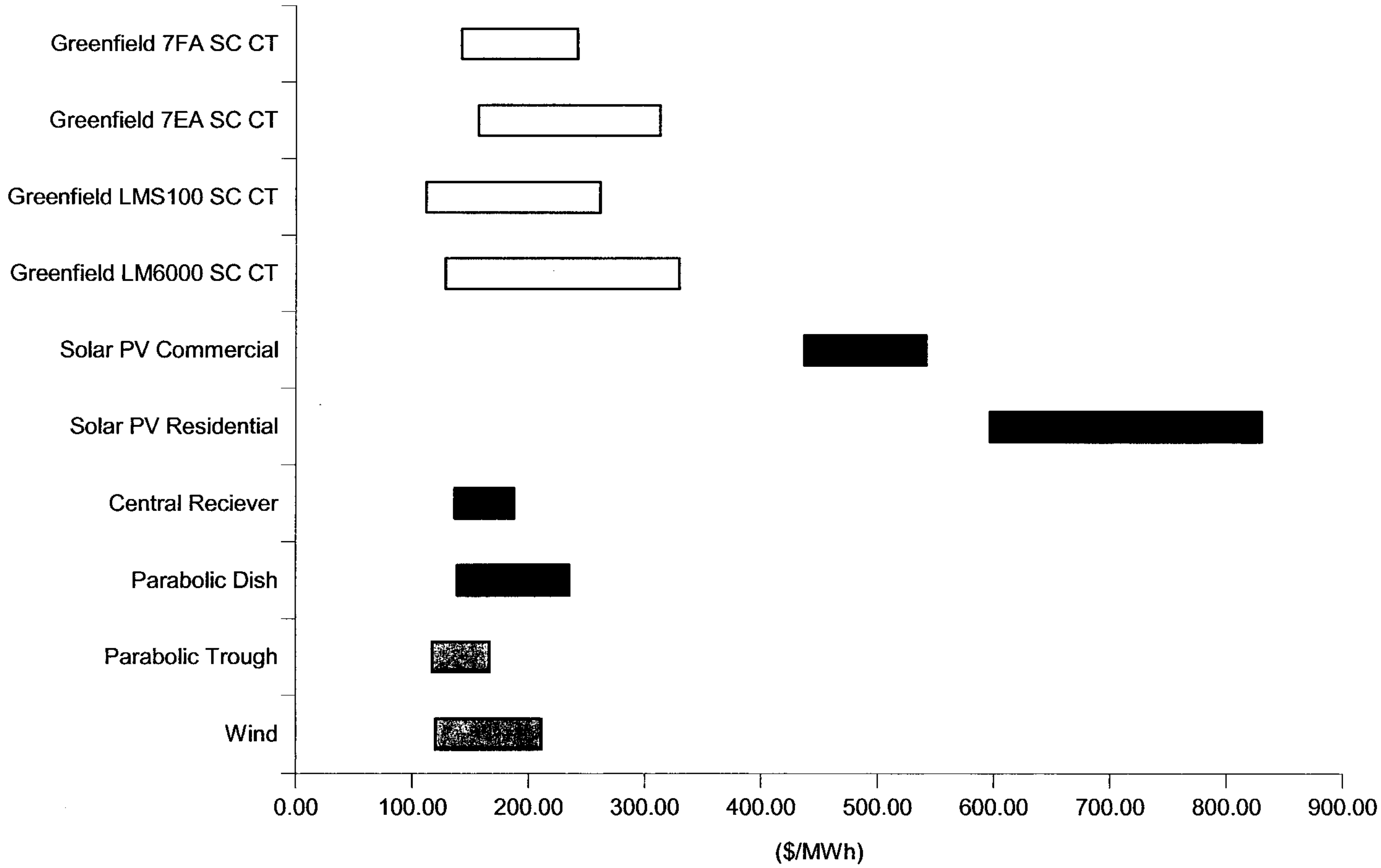


Figure A.6-2
Comparison of Levelized Costs for Conventional and Renewable Peak Load Supply-Side Alternatives

Alternatives shaded in red were screened out due to a lack of commercial demonstration, alternatives shaded in green were screened out due to geographic or or resource constraints, alternatives shaded in blue were only considered as sensitivities, alternatives shaded in black were elimnated as non-economic, alternatives shaded in orange were screened out for various reasons described in Section A.6.6, and alternatives shaded in light blue were carried forward to the economic analyses.

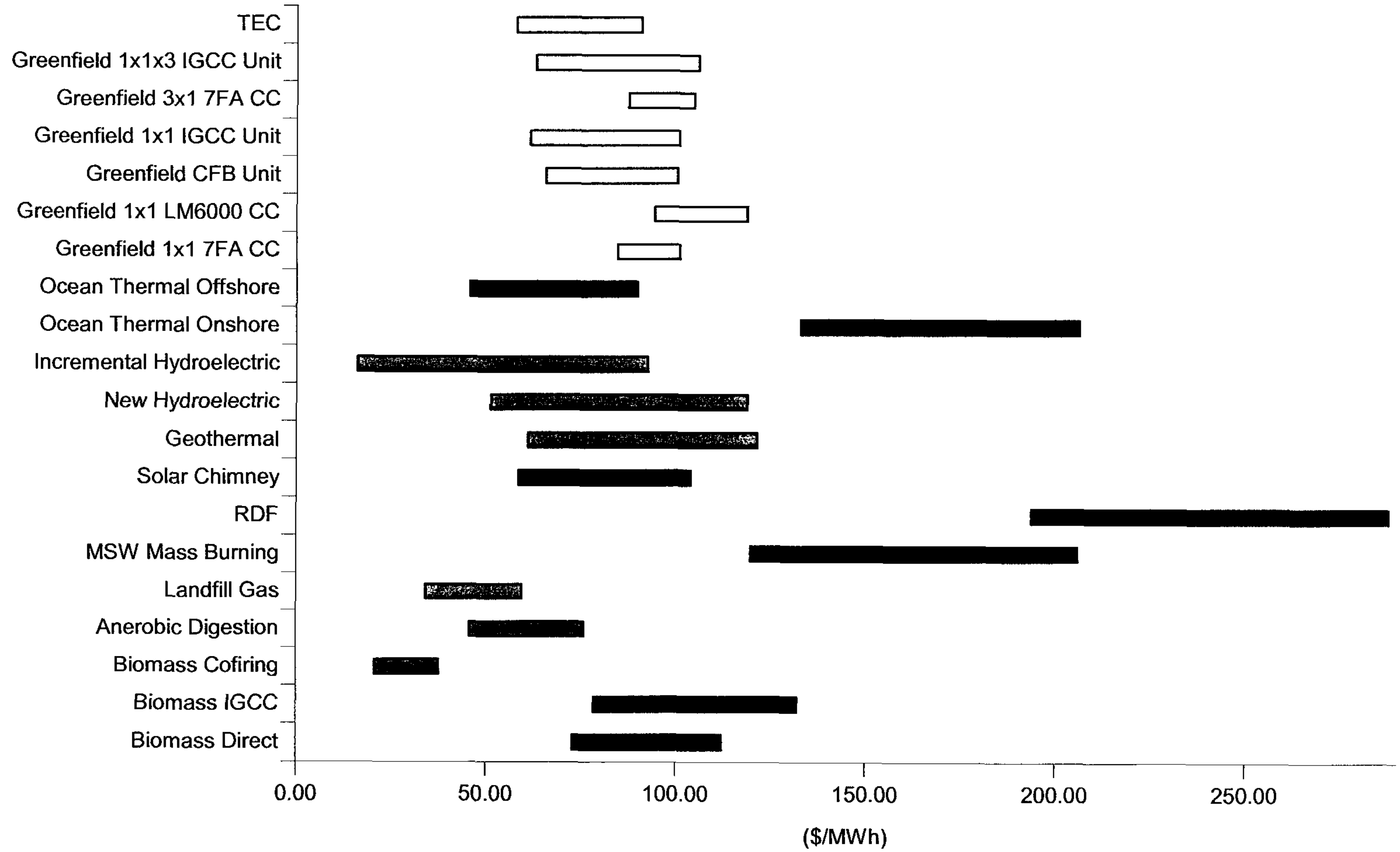


Figure A.6-3
Comparison of Levelized Costs for Conventional and Renewable Baseload Supply-Side Alternatives

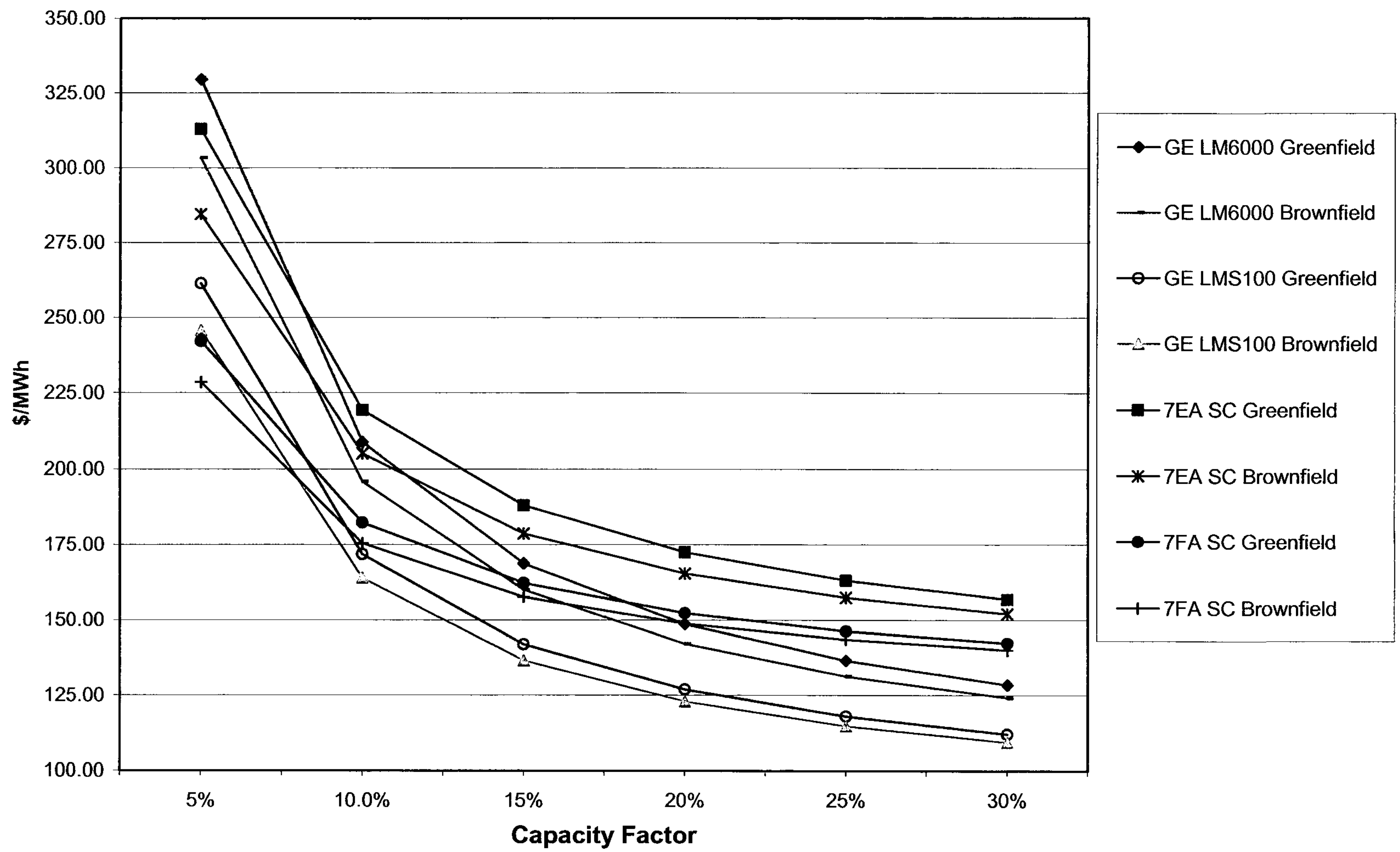


Figure A.6-4
FMPA Peak Load Conventional Alternative Levelized Cost Curves

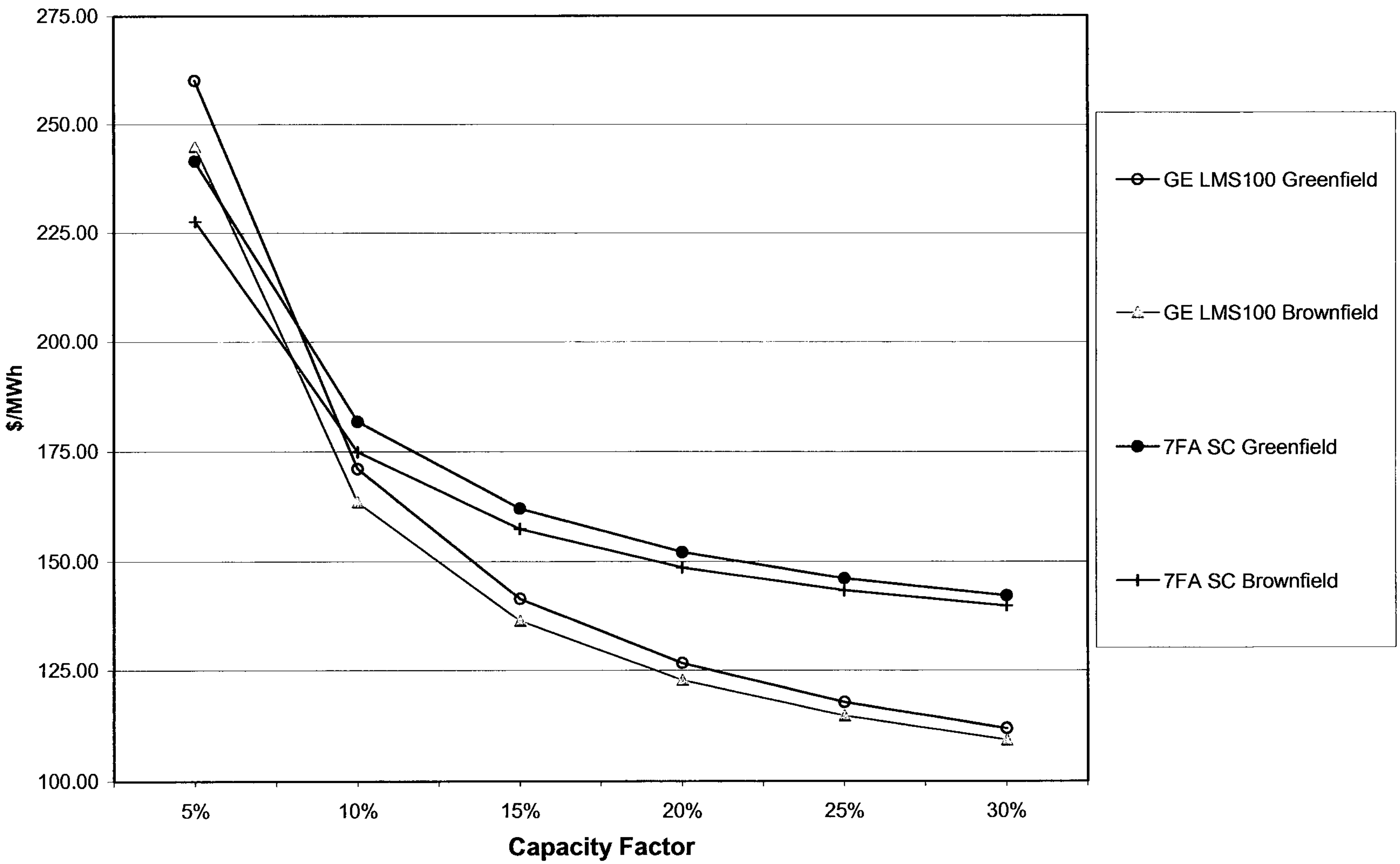


Figure A.6-5
JEA Peak Load Conventional Alternative Levelized Cost Curves

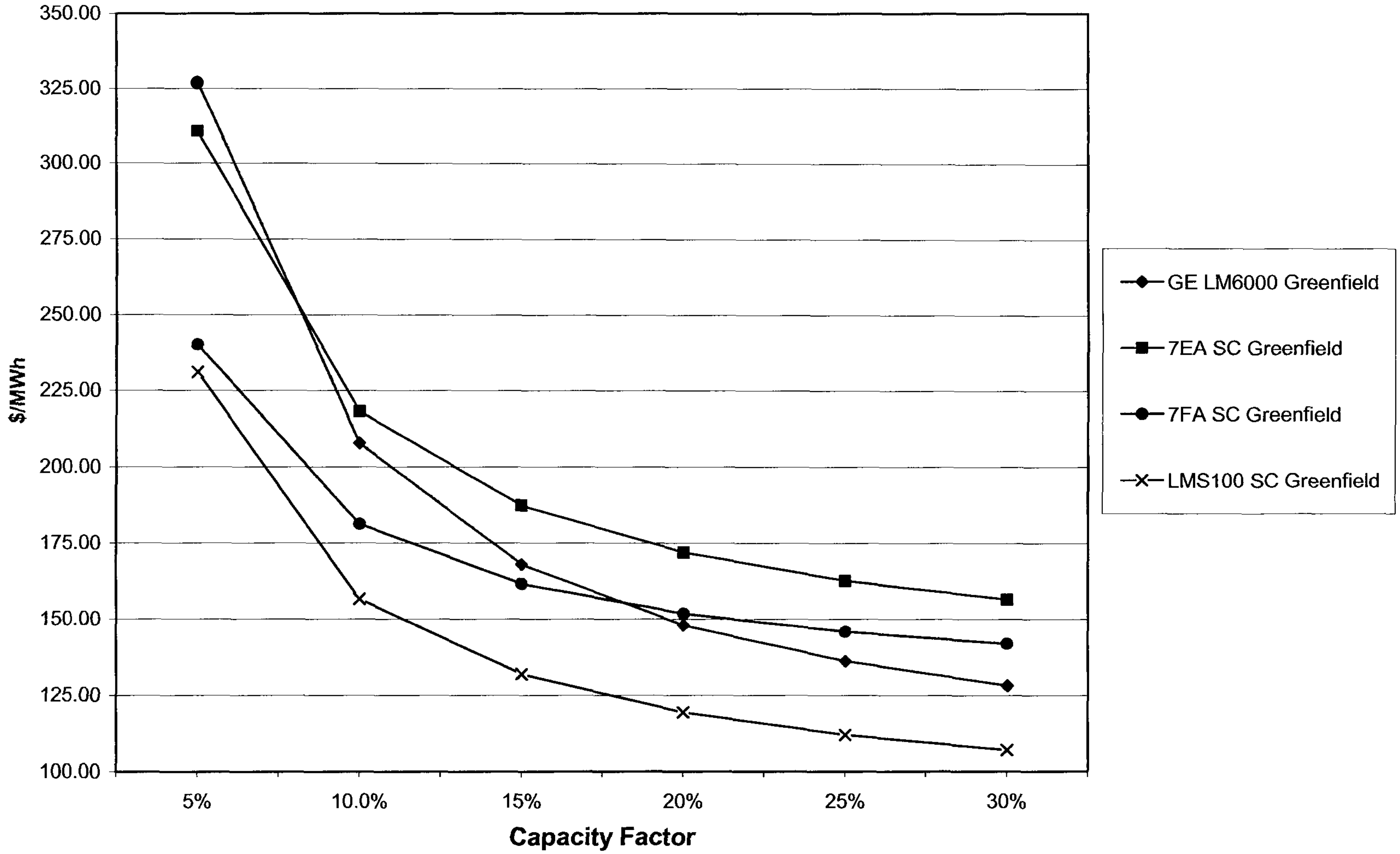


Figure A.6-6
The City of Tallahassee Peak Load Conventional Alternative Levelized Cost Curves

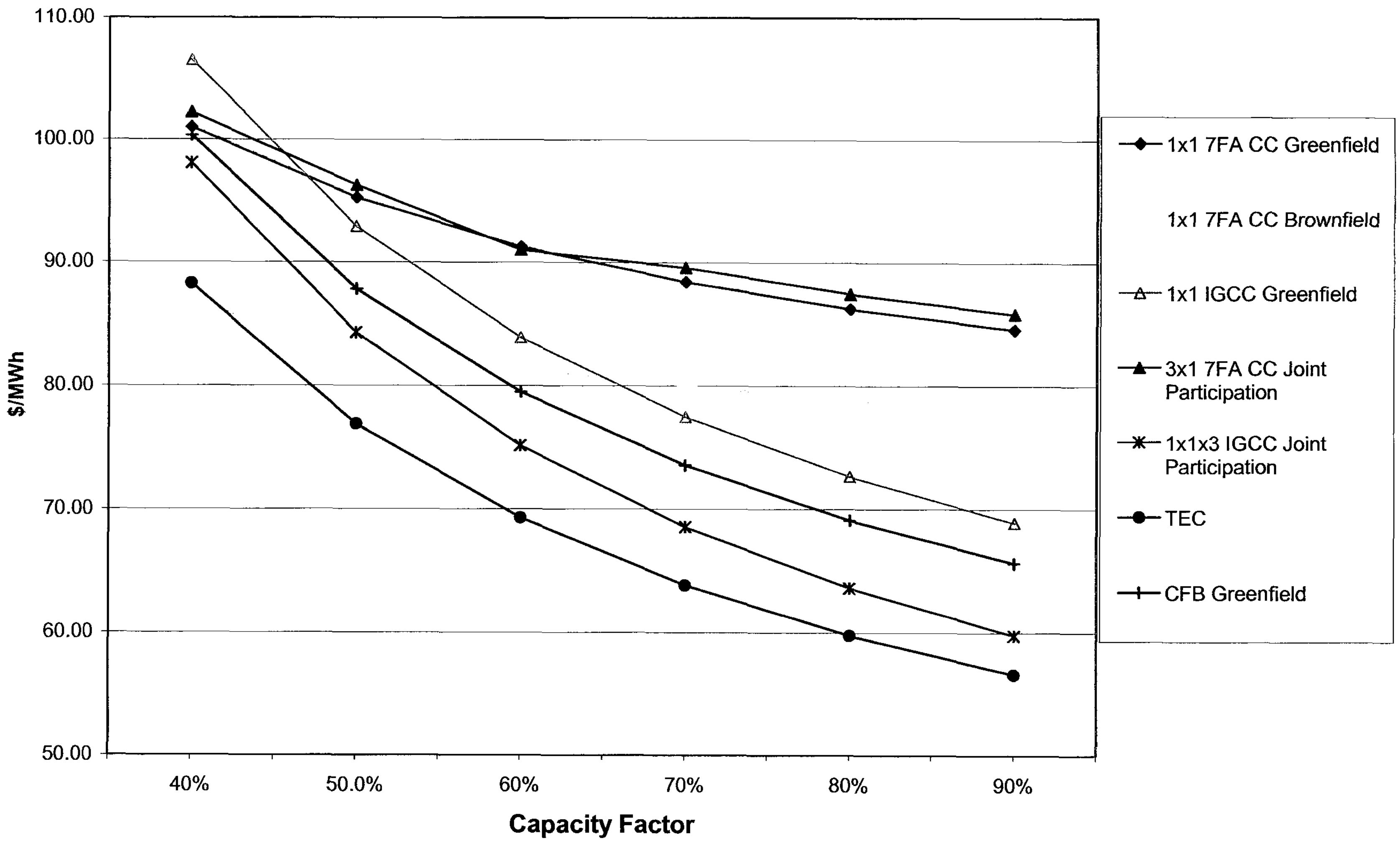


Figure A.6-7
FMPA Baseload Conventional Alternative Levelized Cost Curves

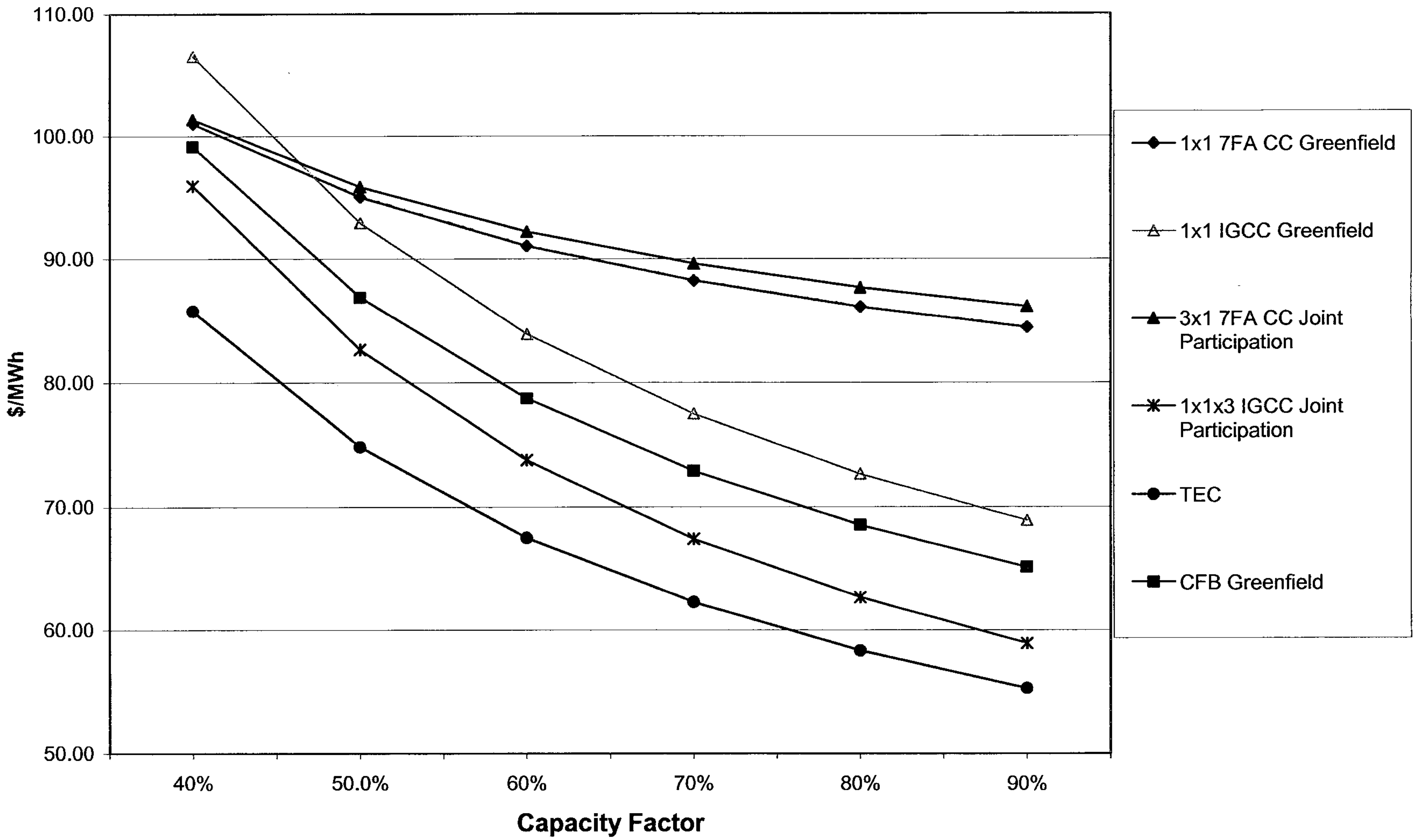


Figure A.6-8
JEA Baseload Conventional Alternative Levelized Cost Curves

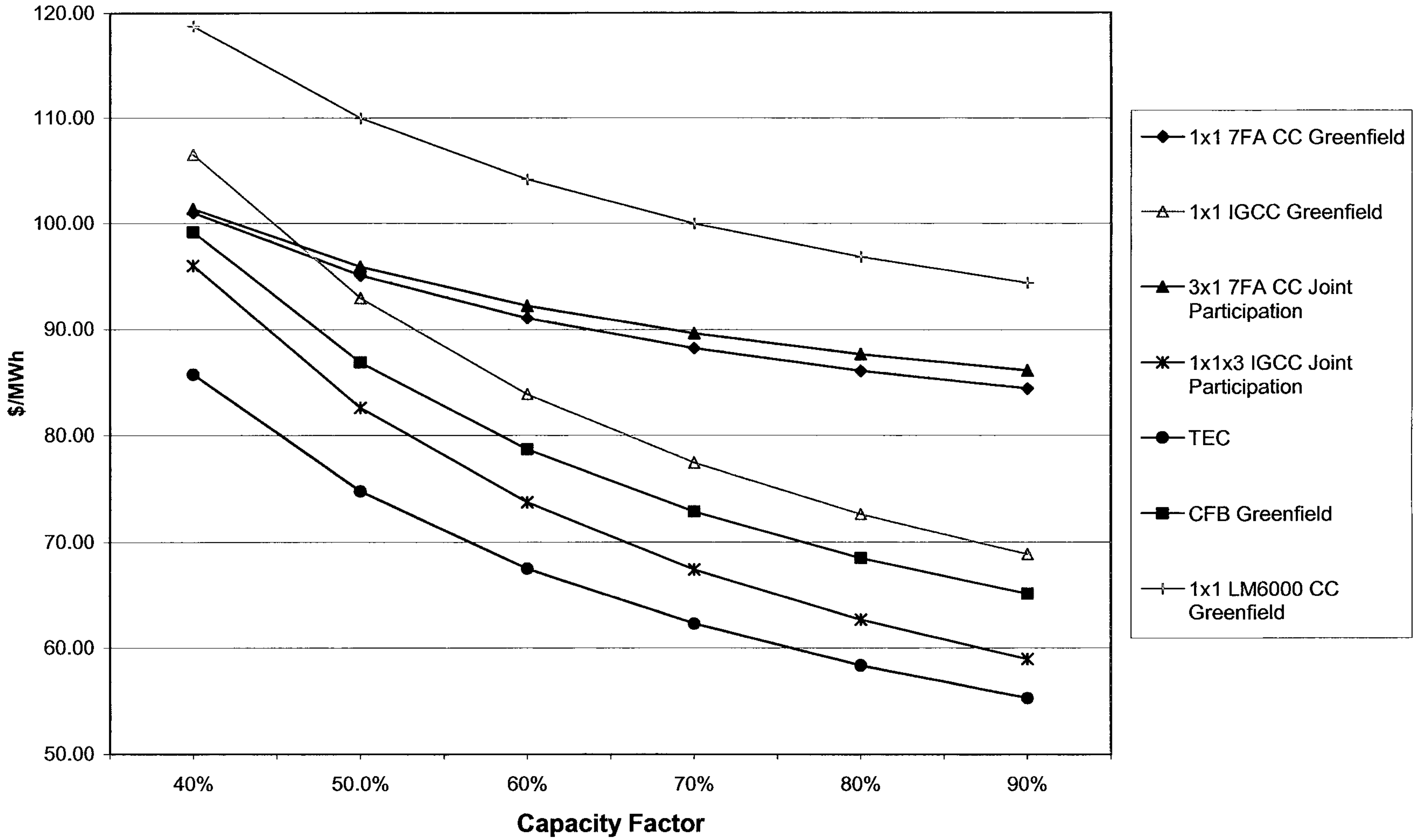


Figure A.6-9
The City of Tallahassee Baseload Conventional Alternative Levelized Cost Curves

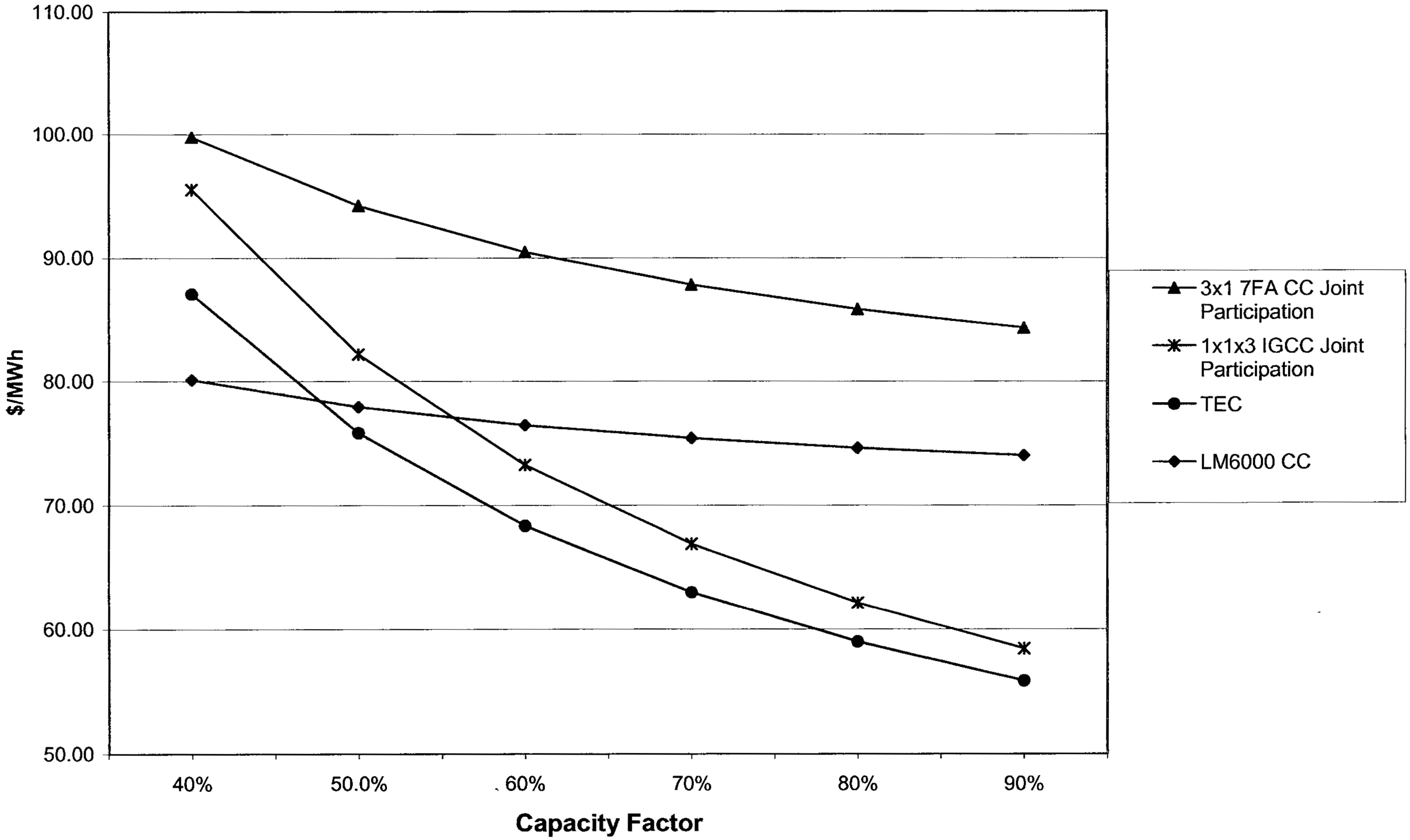


Figure A.6-10
RCID Baseload Conventional Alternative Levelized Cost Curves

A.7.0 Request for Proposal Process

A.7.1 Description of the RFP Process

On November 28, 2005, FMPA, JEA, RCID, and the City of Tallahassee (the Participants) issued a Request for Power Supply Proposals (RFP), which is presented in Appendix A.1 of this Application. The accompanying fuel prices are also presented in Appendix A.1. The RFP served as an invitation for qualified companies to submit proposals for the supply of capacity and energy to meet a portion of the projected power requirements of the Participants beginning on June 1, 2012, and continuing over a period of at least 10 years. The RFP requested a minimum of 100 MW (up to a maximum of 750 MW) to be allocated among the Participants, and required that the proposed capacity and energy be delivered into each Participant's system on a firm, first-call, non-recallable basis.

Stage 1 of the evaluation process for bids received in response to the RFP consisted of a compliance check with the following list of minimum requirements specified in the RFP:

(1) Proposers must attend the Pre-Bid Conference and submit a Notice of Intent to Bid by the appropriate deadline.

(2) The capacity and energy proposed are on a first-call, non-recallable basis. That is, as long as the unit(s) from which the capacity is purchased is available, the Participants have the right to the output of the unit(s) for the duration of the contract. The Participants' rights must be equal to or superior to any other party's rights to such unit(s) output.

(3) All proposals must remain in effect until August 1, 2006, or later if the purchase is to be finalized pending a transmission service request.

(4) The minimum capacity amount offered is 100 MW, allocated among the Participants.

(5) The minimum term for a proposal is 10 years.

(6) All generating units providing the proposed capacity must be in operation at least 2 months prior to the required delivery commencement date of the proposed power supply.

(7) Proposals must identify and include the location of each capacity resource and name the originating Balancing Authority. Proposed power supply from a resource(s) located outside of any of the Participants' Balancing Authority's areas must identify the firm transmission contract path from the power supply(ies) up to the Participants' Balancing Authority's area.

(8) The proposer must ensure that all emissions allowance requirements will be satisfied and that such costs are included in the proposal.

(9) The proposer must declare ownership or contractual status of a unit, plant, or system capacity as described in Section 14 of the RFP.

(10) The proposer must complete the appropriate RFP Forms 1 through 6 and provide all appropriate information requested in Attachment A. All forms requiring a signature must be signed by a duly authorized official.

(11) The proposer must be willing to provide an adequate Proposal Security and Performance Security prior to entering short-list negotiations.

(12) The proposer must clearly describe any contractual limits on energy utilization or physical limitations for the operation of the resource.

(13) The proposal must include scheduling provisions for the sale.

(14) Each proposal must contain the appropriate Proposal Fee in accordance with Section 9 of the RFP.

(15) Proposals for new construction projects must not be contingent upon participation by other third parties to support the project.

(16) If rated by any one or more of the three rating agencies, proposer must have, as a minimum, an investment grade credit rating on senior uninsured debt of Baa3 for Fitch, Baa3 for Moody's, or BBB- for Standard and Poor's. If not rated, the proposer must provide sufficient financial information for the Participants to evaluate the proposer's financial credit status.

(17) Proposers that propose to develop a power generating project to provide power to the Participants must have developed, and have had in operation for a minimum of 1 year, at least one currently operating power supply project that is similar to, or larger in size than, the project being proposed. Those proposing to provide the Participants with power from an existing generating resource, or a portfolio of resources, must have successfully provided similar levels of services to at least one electric utility for a minimum of 1 year.

The Participants reserved the rights to do as follows:

- Reject any proposal for failure to extend validity date if requested;
- Waive any requirement in the RFP;
- Not disclose the reason for rejecting a proposal;
- Negotiate an arrangement for power supply with more than one proposer at a time;
- Not select the proposal with the lowest price;

- Request clarifications from proposers at any time;
- Perform analyses based on further criteria applicable to certain individual Participants; and
- Reject any and all proposals for any reason or no reason received in response to the RFP.

Qualified bidders included electric utilities, independent power producers (IPPs), qualifying facilities (QFs), exempt wholesale generators, nonutility generators, and electric power marketers who have received certification by the Federal Energy Regulatory Commission (FERC). Proposers unfamiliar to the Participants were required to provide proof of experience.

A.7.2 Summary of RFP Responses

The RFP was distributed to more than 40 potential bidders and published in seven major newspapers around the country. The mandatory pre-bid conference was held on December 20, 2005, in Jacksonville, Florida, and was attended by potential bidders from seven companies. Of the attendees, two companies submitted a Notice of Intent to Bid Form on December 27, 2005.

The proposal due date was modified to March 7, 2006, and two bids were received, both from Southern Power Company (Southern). The first proposal was for a 797 MW (net) supercritical pulverized coal unit to be constructed at the same site proposed for the TEC. The second proposal was for a natural gas fueled, 784 MW (net) 2x1 501G combined cycle unit. This unit was proposed to be constructed in St. Lucie County, Florida.

A.7.3 RFP Response Evaluation Process

The Southern proposals were initially received, logged, opened, and distributed by JEA on behalf of the Participants. The next two phases of the evaluation process were performed by R.W. Beck, Inc. (Beck). The first phase involved a screening of the minimum requirements as described in Section 19 of the RFP and listed in Section A.7.1. Southern had signed RFP Form 3, indicating that it concurred with and their proposals met all the minimum requirements set forth in the RFP. However, in the evaluation process, Beck identified four minimum requirements that were questionable in their completeness. These incomplete requirements would require that the Participants confirm in writing Southern's position on these minimum requirements to determine if any further assurances would be required. Minimum requirement No. 8 stated that the proposer must satisfy all emissions allowance requirements, and that such costs be included in the proposal. Southern's proposals stated that, "Emission costs are not included in the variable O&M charges, and these costs, if incurred by the Proposer, would be included in a separate emissions charge." To account for this omission, Beck added consistent emissions allowance prices to the evaluation of all proposals.

Beck prepared a busbar screening analysis for three alternatives: the two proposals that were submitted by Southern and the Participants' Self-Build Resource (TEC). The busbar analysis was undertaken in order to project annual power costs (in $/MWh) under a base set of assumptions as well as several sensitivity scenarios that reflected higher and lower than expected fuel prices and environmental, capital, and nonfuel O&M expenses.

A.7.4 Summary of the R.W. Beck Evaluation

The Beck evaluation of Southern's two proposals and the Self-Build Resource concluded that the Self-Build Resource is projected to have a lower delivered cost to the Participants than Southern's proposed coal resource or the combined cycle resource. Southern's proposed coal resource and combined cycle resource were projected to have higher costs than the Self-Build Resource over a range of evaluation scenarios.

Black & Veatch performed an independent evaluation of both Southern's coal and combined cycle proposals for each Participant, the results of which are presented in Section 6 of Volumes B through E of this Application.

A.8.0 Economic Analysis

A detailed economic analysis has been performed to evaluate the cost-effectiveness of participation in TEC for each Participant on an individual basis, and to determine the least-cost capacity expansion plan to meet each Participant's forecast capacity requirements. This section presents an overview of the assumptions and methodology used in the economic analyses, which remain constant for all Participants. Section 5.0 of Volumes B through E presents a more detailed discussion of the economic analysis methodology specific to each Participant.

The economic analyses were performed on an individual Participant basis and compared the economics of the least-cost capacity expansion plan, including each Participant's share of capacity and energy from TEC, with the economics of the least-cost expansion plan for each Participant's system that does not include participation in TEC. The capacity associated with participation in TEC, as well as construction of the supply-side alternatives presented in Section A.6.0, is only sufficient to satisfy forecast capacity requirements for a portion of the expansion planning horizon. To meet forecast capacity requirements, multiple unit additions were selected from supply-side alternatives considered for individual participation for each Participant that passed the supply-side screening described in Section A.6.0.

A.8.1 Expansion Planning and Production Costing Methodology

The supply-side evaluations of generating unit alternatives was performed using POWROPT, an optimal generation expansion model that Black & Veatch developed as an alternative to other optimization programs. POWROPT has been benchmarked against other optimization programs and has proven to be an effective modeling program. POWROPT and its detailed chronological production costing module, POWRPRO, have both been used in numerous Need for Power Applications filed with the FPSC, including FMPA's TCEC Unit 1 Need for Power Application filed in April 2005 (which was approved by the FPSC in July 2005) and the OUC Stanton B Need for Power Application filed in February 2006 (which was approved by the FPSC in May 2006).

POWROPT operates on an hourly chronological basis and is used to determine a set of optimal capacity expansion plans to satisfy forecast capacity requirements, simulate the operation of each of these plans, and select the most desirable plan based on cumulative present worth revenue requirements. POWROPT evaluates all combinations of generating unit alternatives and purchase power options, in conjunction with existing capacity resources, while maintaining user-defined reliability criteria. All capacity expansion plans were analyzed over a 30 year period from 2006 through 2035.

After the optimal generation expansion plan was selected using POWROPT, Black & Veatch's POWRPRO was used to obtain the annual production cost for the expansion plan. POWRPRO is a computer-based chronological production costing model developed for use in power supply systems planning. POWRPRO simulates the hour-by-hour operation of a power supply system over a specified planning period. Required inputs are carried forward from those used in POWROPT and include the performance characteristics of generating units, fuel costs, and the system hourly load profile for each year.

POWRPRO summarizes each unit's operating characteristics for every year of the planning horizon. These characteristics include, among others, each unit's annual generation, fuel consumption, fuel cost, average net operating heat rate, the number of hours that the unit is on line, the capacity factor, variable O&M costs, and the number of starts and associated costs. Fixed O&M costs are included only for new unit additions, since the fixed O&M costs for existing units are generally considered sunk costs that will not vary from one expansion plan to another. Annual capacity charges for existing power purchases likewise are not included, since they also represent sunk costs. Similarly, fixed costs for firm natural gas transportation capacity for existing units are considered sunk costs and are not included. The operating costs of each unit are aggregated to determine annual operating costs for each year of the expansion plan. Capital costs, fixed O&M costs, and fixed costs for natural gas transportation (for combined cycle capacity addition alternatives) are then added for each capacity addition selected, at which point the cumulative present worth cost (CPWC) of each expansion plan can be calculated.

The CPWC calculation accounts for annual system costs (fuel and energy, fixed O&M for capacity additions, nonfuel variable O&M, startup costs, and levelized capital costs) for each year of the expansion planning period and discounts each back to 2006 at the present worth annual discount rate of 5.0 percent. These annual present worth costs are then summed over the 2006 through 2035 period to calculate the total CPWC of the expansion plan being considered. Such analysis allows for a comparison of CPWC between various capacity expansion plans, and the plan with the lowest CPWC is considered the least-cost capacity expansion plan.

A 30 year evaluation period from 2006 through 2035 was used to evaluate the expansion plans. The 30 year evaluation period selected represents a reasonably long period to capture capital and operating costs. When evaluating high capital cost alternatives with long lifetimes such as coal units, it is important to use an evaluation period that is sufficiently long to capture the associated capital and operating costs. For instance, the addition of TEC in 2012 only allows 23 years for consideration of its capital and operating costs. It is also important to consider end effects associated with units with long lifetimes that have significant life left after the end of the evaluation period.

One challenge with the use of a longer evaluation period is having projections of load and fuel costs through the end of the evaluation. One commonly used approach, which was used in this evaluation, is to develop a detailed capacity expansion plan for the period that load and energy forecasts are available, and then fix the load and generating resources for the remainder of the evaluation period. This approach minimizes issues with long-range unit retirements and ensures that those retirements do not drive the evaluation results. For this evaluation, load and energy forecasts were developed through 2025, and loads were held constant after that period.

Detailed fuel cost projections were developed for a 25 year period (through 2030). The fuel cost projections were extrapolated to the end of the evaluation period based on the last year's escalation rate of each fuel being considered. These fuel costs, along with the other capital, operating, and maintenance costs over the evaluation period, were discounted back to 2006 using the present worth discount factor to develop the CPWC.

The issue of end effects associated with generating units is important when considering generating unit alternatives that have a long operating lifetime and relatively high capital costs, such as coal units. It is not uncommon for coal units to have actual operating lives of 50 to 60 years. As such, coal units have substantial remaining value at the end of the evaluation period utilized in this Application. This evaluation applies annual fixed charges associated with the capital costs of generating units based on the period over which they are financed and does not explicitly assign a numeric salvage value to generating units at the end of evaluation period. As such, plans with TEC have a significantly greater value than represented by the CPWC.

The most important consideration in selecting an evaluation methodology is that all assumptions made are internally consistent. The evaluation methodology described previously is internally consistent and is conservative with respect to the evaluation of the TEC as compared to other alternatives.

A.8.1.1 Peak Demand and Energy Growth

As presented in Section 3.0 of Volumes B through E, a forecast of peak demand and net energy for load was provided for each Participant's system. For evaluation purposes, each Participant's load was held constant from 2025 through the end of the study period for the reasons described previously in this section.

A.8.1.2 Fuel and Emission Allowance Price Forecasts

Section A.4.0 presents the fuel price forecasts used throughout this Application, while Section A.5.0 presents the forecast emission allowance prices used throughout this Application. Both fuel and emission allowance price forecasts were developed through 2030. Beyond 2030, these forecasts were extrapolated using the applicable escalation rates between 2029 and 2030 for each fuel and emission allowance price forecast.

A.8.1.3 Natural Gas Transportation

For all capacity expansion plan evaluations, it was necessary to account for firm natural gas transportation capacity associated with new combined cycle unit alternatives. For the combined cycle options included in Section A.6.0 (the 1x1 LM6000, the 1x1 7FA, and the 3x1 7FA), it was assumed that a Participant would purchase firm transportation so that 6.0 percent of the daily natural gas transportation allocation, in accordance with Florida Gas Transmission Company (FGT) tariff requirements, would be adequate to operate the unit at full load for an hour, based on the performance at average ambient conditions. The corresponding costs for firm natural gas transportation capacity were developed assuming the Firm Transportation Service reservation charge of $0.769 per MBtu (pursuant to FGT's April 2006 effective rates for incremental Firm Market Area Transportation). It has been assumed that the Participants would not purchase firm natural gas transportation capacity from FGT for simple cycle combustion turbines but, instead, would utilize an interruptible service rate assumed to be $0.37 per MBtu, which was added to the annual commodity price forecasts for natural gas provided in Section A.4.0. Any natural gas required for a Participant's system in excess of the firm natural gas transportation for the existing and new units is priced at the interruptible service rate.

A.8.1.4 Dispatch Assumptions

Variable O&M and estimated allowance costs were included in the unit dispatch modeling in POWROPT and POWRPRO along with fuel costs. These costs were included in the dispatch modeling to ensure the most cost-effective dispatch of both existing and new generating units. The costs for emission allowances were developed based on the emission allowance price forecasts presented in Section A.5.0. Because each generating unit, whether existing or being considered as a supply-side alternative, has a unique emissions profile, the annual adder for emissions allowance costs varies for each unit. A detailed discussion of how the emission allowance cost adders were developed for each Participant is presented in Section 5.0 of Volumes B through E.

A.8.1.5 Initial Coal Inventory for TEC

As discussed in Section A.3.0, the TEC site will include onsite fuel storage for up to approximately 90 days of operation. To account for the cost of coal initially required for the TEC, Black & Veatch developed a projection of the cost, assuming that coal inventory purchases would be made in the latter part of 2011 and the early part of 2012. The cost of the initial coal inventory was therefore based on the average fuel prices forecasted for 2011 and 2012. The resulting initial fuel inventory cost, which totals approximately $39.01 million, was treated similarly to the TEC capital cost and levelized over a 30 year period. No residual value was given to the initial fuel inventory at the end of the evaluation period.

A.9.0 Demand-Side Management Methodology

As required by Section 403.519 of the Florida Statutes, in its determination of need, the FPSC must take into consideration conservation measures taken by, or reasonably available to, the Participants that could mitigate the need for the proposed plant. To address this requirement, each Participant individually considered potential DSM measures that it had taken or was reasonably available to it in concluding to participate in the TEC. The results of these evaluations are presented in Section 7 of Volumes B, C, D, and E.

Both FMPA and JEA utilized the FPSC-approved Florida Integrated Resource Evaluator (FIRE) model for their DSM evaluations, consistent with the approach taken in numerous recent Need for Power filings, including FMPA's TCEC Unit 1 Need for Power Application (Docket No. 050256-EM) approved by the FPSC in July 2005, and the OUC Stanton Energy Center Unit B Combined Cycle Need for Power Application (Docket 060155-EM) approved by the FPSC in May 2006. The FIRE model was also utilized by JEA in its 2000 and 2004 Numeric Conservation Goals filings with the FPSC.

RCID and its customers continually evaluate opportunities for energy conservation. In light of the significant and successful conservation measures already in place within RCID's service territory (as described in Section D.7.0) and RCID's ongoing commitment to evaluate new conservation opportunities, a separate conservation review was not performed prior to RCID's determination to participate in TEC. The load forecast that supports RCID's participation in TEC, however, reflects the significant conservation measures already implemented by RCID and its customers. At a minimum, RCID and its customers will continue with their existing DSM programs. Also, as new facilities are built by RCID or its customers, consideration will be given to the application of existing energy conservation programs to those new facilities, and any appropriate new DSM options will be evaluated for the new facilities.

The City of Tallahassee's DSM evaluation was developed to be consistent with the evaluation methodology used in its recent internal evaluations of conservation and DSM measures.

The remainder of this section provides an overview of the FIRE model and discusses the DSM cost-effectiveness evaluation performed on behalf of the City of Tallahassee. A discussion of FMPA's and JEA's existing DSM and conservation programs, as well as details of the FMPA and JEA FIRE model evaluations and the results of those utilities' analyses, are presented in Sections B.7.0 and C.7.0, respectively. Section D.7.0 presents a discussion of RCID's conservation programs. Section E.7.0 presents a summary of the City of Tallahassee's existing DSM and conservation programs as well as the details and results of the City of Tallahassee's DSM evaluation.

A.9.1 FIRE Model Overview

The FIRE model was designed by Florida Power Corporation (now Progress Energy Florida [PEF]) and is used by several utilities in Florida. The output format of the model was originally developed to be consistent with the specifications of the FPSC and amended Rule 25-17.008 of the Florida Administrative Code issued on July 2, 1991.

The FIRE model presents cost-effective evaluations of DSM measures using three different tests: the Total Resources Test, the Participant Test, and the Rate Impact Test.

The cost-effectiveness of each measure is developed with respect to the "avoided unit," or TEC, for this evaluation. The utility theoretically would avoid construction of TEC through the implementation of a DSM program to slow the growth of demand and energy. The cost of each DSM measure is compared with the equivalent costs associated with the construction and operation of TEC.

The FIRE model incorporates two types of input files. The first contains data specific to the utility's avoided unit (TEC). The second input file contains data specific to the DSM measure being tested for cost-effectiveness. Input data for the avoided unit is on a per kW basis, allowing the potential DSM measures to be tested individually for cost-effectiveness.

A.9.1.1 FIRE Model Assumptions

The cost-effectiveness evaluation performed by the FIRE model is based on the following assumptions about the electric system:

- System demand is growing. Demand reductions caused by DSM will result in a reduced system demand growth rate, but not an overall reduction in system demand.
- Individual demand reductions can be related to a reduced rate of system growth.
- The generation growth reduction will be evaluated with respect to specified generation.
- Decreases or increases in revenue as a result of DSM programs will affect rate levels and will be passed on to participating and non-participating customers.
- Additional conservation that occurs after the next avoided unit will affect subsequent units and is not included in the current cost-effectiveness evaluation.

A.9.1.2 FIRE Model Test Explanation

This subsection details the different tests performed by the FIRE model, as well as various inputs to those tests and the overall FIRE model calculation methodology.

Total Resources Test

The purpose of the Total Resources Test is to measure the overall benefit-to-cost ratio of the demand-side measure. This test incorporates the cost to both the utility and the participating customer to most accurately estimate the net effect of the DSM measure on society.

Only external costs and benefits are included in this analysis. Costs to the utility and to the participating customer are included, while any transfer payments between the utility and its customers are not. These internal transfers are a cost to one party and a direct benefit to another and, therefore, cancel out in the overall analysis.

The Total Resources Test offers a useful measure of the societal improvement (or detriment) due to the implementation of the measure. The benefit-to-cost ratio for the Total Resources Test is calculated by taking the cumulative net present value of the DSM measure benefits and dividing by the cumulative net present value of associated costs. Measures with a value less than 1.0 denote measures that do not offer an overall benefit. A benefit-to-cost ratio greater than 1.0 indicates that the DSM measure should provide an overall benefit to society.

Participant Test

The Participant Test measures the effect of the DSM measure on participating customers. Only costs and benefits directly related to these customers are included in the analysis. Rebates or incentives available for participation in the demand-side measure are included, while their associated costs to the utility are ignored.

The results of this test provide a general indication of how willing customers will be to participate. The benefit-to-cost ratio for the Participant Test is calculated by taking the cumulative net present value of the DSM measure benefits to the participants and dividing by the cumulative net present value of associated costs. A benefit-to-cost ratio greater than 1.0 indicates that the DSM measure should provide savings to participating customers. If the measure results in a value less than 1.0, the customers will have a total cost more than the expected benefits of involvement. Under this scenario, it is unlikely that many customers will choose to participate in the measure.

Rate Impact Test

Traditionally, the Rate Impact Test has been considered the test of merit by the FPSC, because it measures the rate impact resulting from the implementation of a DSM measure for nonparticipating customers. Costs and benefits related to the cash flow of a utility are incorporated into this test. Rate-paying customers are generally unsupportive of measures that increase the cost of energy. This is due to the fact that many customers will pay higher energy rates without the benefit of being involved in the program.

The benefit-to-cost ratio for the Rate Impact Test is calculated by taking the cumulative net present value of the DSM measure benefits to the utility and dividing by the cumulative net present value of associated costs. A benefit-to-cost ratio greater than 1.0 indicates that the DSM measure should not result in increased energy rates for utility customers. A value of less than 1.0 indicates that utility rates will rise as a result of implementing the DSM measure under consideration.

A.9.2 City of Tallahassee DSM Evaluation Overview

The City's analysis of potentially cost-effective DSM was based on projections of total achievable capacity and energy reductions and their associated annual costs developed specifically for the City. Candidate DSM measures were initially screened using a cost-effectiveness test that was based on the busbar cost of each measure compared to comparable (appropriate) supply-side resources, where the costs of the supply-side resources and DSM measures were computed on a levelized basis over the DSM measure life.

The measures were then combined into bundles of measures affecting similar end uses and/or having similar costs per kWh saved. Projected capacity and energy savings, and implementation costs, were developed for each bundle. Chronological hourly load shapes were then developed for each bundle and combined into an overall DSM composite bundle (portfolio) load shape, which was applied as a load shape adjustment to the base demand and energy forecast. Instead of screening individual measures, the combined DSM measures were analyzed in a portfolio as a reduction to the City's hourly loads (including seasonal peak demands and energy requirements). The resulting system load shape was evaluated using production cost modeling. The CPWC results of the production cost models for the City's base case analysis and the scenario in which load projections were reduced to account for DSM savings were compared to one another. Such an analysis can be used to determine whether implementation of bundled DSM measures beyond what the City currently offers may be more beneficial than participating in TEC, or whether a combination of the implementation of the DSM measures along with participation in TEC will offer the City an economic advantage.

A.10.0 Consistency with Peninsular Florida Needs

This section describes the consistency of TEC with the power requirements of peninsular Florida. The information in this section is based in part on the *2006 Regional Load and Resource Plan* (2006 L&RP) for the State of Florida, compiled by the Florida Reliability Coordinating Council (FRCC) and published in July 2006. The FRCC is responsible for coordinating power supply reliability in peninsular Florida for the North American Electric Reliability Council (NERC). The 2006 L&RP summarizes forecast utility loads and resources, by type of capacity, through the year 2015. The report also includes proposed generation expansion plans, retirements of existing generating capacity, and capacity re-rates.

This section also presents a discussion of the existing and projected generation by fuel type throughout the State of Florida. The FPSC's *Review of Electric Utility 2005 Ten-Year Site Plans* was used as the basis for the information discussed herein.

A.10.1 Peninsular Florida Capacity and Reliability Needs

The need for TEC can be evaluated by comparing the existing and planned capacity in peninsular Florida with the capacity resources required to meet forecast peak loads plus reserve requirements. As shown in Table A.10-1, the weighted average summer and winter target reserve margins for the peninsular Florida utilities are 19.0 and 18.9 percent, respectively, as of January 1, 2006. The projections of reserve margins in peninsular Florida in Table A.10-2 should be compared to those weighted average target reserve margins.

The FRCC 2006 L&RP was developed based on the information submitted by FRCC members in the 2006 *Load and Resource Database* (LRDB). In developing Table A.10-2, all units that were listed with either "Regulatory Approval Pending" or "Planned but not Authorized" status were not included as committed additions. Committed capacity additions and reductions are defined as changes to existing units, such as re-rates, planned retirements, units that are currently under construction, and units that have received approval under the Florida Electrical Power Plant Siting Act, but are not yet under construction. Capacity additions that have received FPSC approval subsequent to the FRCC LRDB process, such as FPL's West County units, OUC's Stanton Energy Center Unit B, and Seminole Electric Cooperative's (SEC's) Seminole Generating Station Unit 3, have been included in the projection of installed capacity. It should be noted that while these three units have received approval from the FPSC, they have yet to receive approval from the Governor and Cabinet.

Table A.10-1
Peninsular Florida Weighted Average Reserve Requirement
(as of January 1, 2006)

Utility	Net Capacity (MW) [1]		Reserve Requirement [2]	
	Summer	Winter	Summer	Winter
Florida Keys Electric Cooperative Association [3]	21	21	15%	15%
Florida Municipal Power Agency [4]	1,409	1,475	18%	15%
Florida Power and Light Company	20,777	22,099	20%	20%
Gainesville Regional Utilities	612	632	15%	15%
JEA	3,387	3,552	15%	15%
Lakeland, City of	913	995	15%	15%
New Smyrna Beach, Commission of [3]	66	70	15%	15%
Orlando Utilities Commission	1,199	1,257	15%	15%
Progress Energy Florida	8,842	9,760	20%	20%
Reedy Creek Improvement District	43	44	15%	15%
Seminole Electric Cooperative	1,819	1,886	15%	15%
St. Cloud, City of	21	21	15%	15%
Tallahassee, City of	744	795	17%	17%
Tampa Electric Company	4,071	4,383	20%	20%
US Corps of Engineers – Mobile [3]	44	44	15%	15%
Total Net Capacity (MW)	**43,966**	**47,033**		
Weighted Average Reserve Requirement			**19.0%**	**18.9%**

[1]Source: 2006 FRCC Load and Resource Plan.
[2]Source: 2006 Ten-Year Site Plans.
[3]Reserve requirement has not been confirmed and is estimated at 15 percent.
[4]Includes members of the All-Requirements Project.

Table A.10-2
Peninsular Florida Installed Capacity and Reserve Margins of Existing Facilities and Committed Capacity Addition and Reductions(1)

(1) Calendar Year	(2) Projection of Installed Capacity (MW)	(3) Net Contracted Firm Interchange (MW)	(4) Projected Firm Net to Grid from Non-Utility Generator (NUG) (MW)	(5) Total Available Capacity (MW)	(6) Total Peak Demand (MW)	(7) Reserve Margin w/o Load Management and Int. Load		(8) Load Management and Interruptible Load (MW)	(9) Firm Peak Demand (MW)	(10) Reserve Margin w/Load Management and Int. Load	
						MW	Percent of Peak			MW	Percent of Peak
Summer Peak Demand											
2006	44,212	1,552	5,498	51,262	45,520	5,742	12.6	2,759	42,761	8,501	19.9
2007	46,005	1,552	5,272	52,829	46,725	6,104	13.1	2,947	43,778	9,051	20.7
2008	46,842	1,552	5,378	53,772	48,030	5,742	12.0	3,001	45,029	8,743	19.4
2009	47,237	1,552	5,528	54,317	49,233	5,084	10.3	3,023	46,210	8,107	17.5
2010	48,687	1,342	4,818	54,847	50,221	4,626	9.2	3,006	47,215	7,632	16.2
2011	48,596	1,342	4,611	54,549	51,343	3,206	6.2	3,025	48,318	6,231	12.9
2012	49,346	1,342	4,530	55,218	52,490	2,728	5.2	3,048	49,442	5,776	11.7
2013	49,346	1,342	3,876	54,564	53,686	878	1.6	3,075	50,611	3,953	7.8
2014	49,346	1,342	3,841	54,529	54,830	(301)	(0.5)	3,104	51,726	2,803	5.4
2015	49,188	1,342	4,169	54,699	56,130	(1,431)	(2.5)	3,112	53,018	1,681	3.2
Winter Peak Demand											
2006/07	47,632	1,552	5,494	54,678	48,296	6,382	13.2	3,504	44,792	9,886	22.1
2007/08	49,760	1,552	5,899	57,211	49,464	7,747	15.7	3,559	45,905	11,306	24.6
2008/09	50,130	1,552	5,707	57,389	50,732	6,657	13.1	3,605	47,127	10,262	21.8
2009/10	50,584	1,552	5,177	57,313	51,678	5,635	10.9	3,590	48,088	9,225	19.2
2010/11	52,132	1,342	5,159	58,633	52,869	5,764	10.9	3,612	49,257	9,376	19.0
2011/12	52,109	1,412	5,080	58,601	53,923	4,678	8.7	3,635	50,288	8,313	16.5
2012/13	52,859	1,342	4,273	58,474	55,086	3,388	6.1	3,666	51,420	7,054	13.7
2013/14	52,859	1,342	4,669	58,870	56,271	2,599	4.6	3,700	52,571	6,299	12.0
2014/15	52,670	1,342	4,378	58,390	57,674	716	1.2	3,734	53,940	4,450	8.2
2015/16	52,669	930	4,273	57,872	59,162	(1,290)	(2.2)	3,730	55,432	2,440	4.4

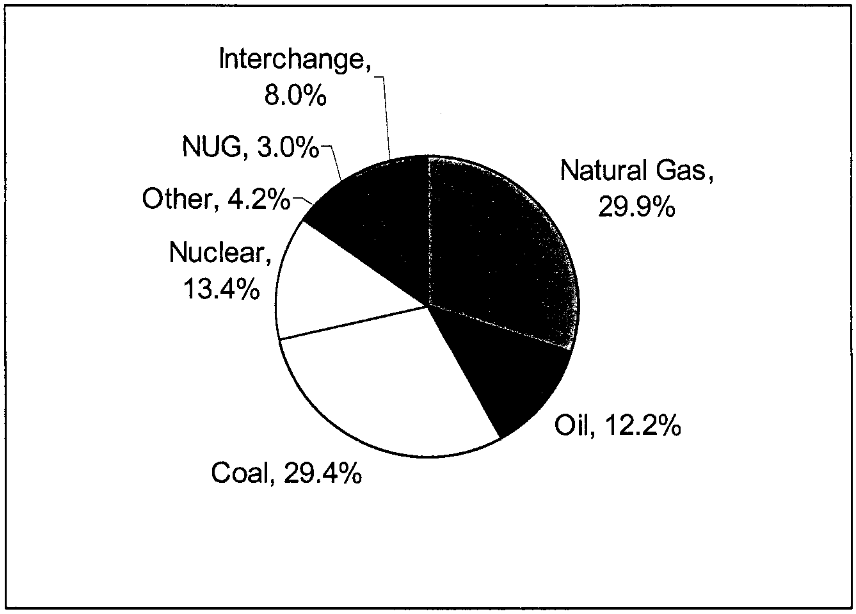
(1)Represents existing generating resources, planned retirements, planned capacity re-rates and de-rates, and planned generating facilities which have received approval to proceed with construction. Subsequent to the data collection period of the 2006 L&RP, FPL's West County units, OUC's Stanton B, and SEC's Seminole Generating Station Unit 3 received FPSC approval and are therefore included in the projected installed capacity.

Table A.10-2 illustrates that if only the committed additions presented in the 2006 L&RP are considered in the projections of installed capacity, forecasted capacity reserve margins will not satisfy target seasonal reserve margins beginning in the summer of 2009 and winter of 2011/12. Column (10) of Table A.10-2 shows that summer capacity reserve margins decrease below the target reserve margin of 19 percent beginning in 2009, with reserves projected at 17.5 percent, and decrease further to 3.2 percent in 2015. Similarly, winter reserve margins are projected to be only 16.5 percent by 2011/12, and decrease to 4.4 percent in 2015/16. Note that these reserve margins include the expected demand reductions associated with load management and interruptible load. If the expected demand reductions associated with load management and interruptible loads do not materialize as projected, Column (7) of Table A.10-2 indicates that the summer reserve margins would be below the target reserve margin in all years, with a low of negative 2.5 percent in 2015. Likewise, without load management and interruptible loads, winter reserve margins would be below the target reserve margin in all years as well, reaching a low of negative 2.2 percent in 2015/16. Thus, approval and construction of the TEC will help fill the capacity shortfall projected in the state that emerges after accounting for projects that are not yet committed.

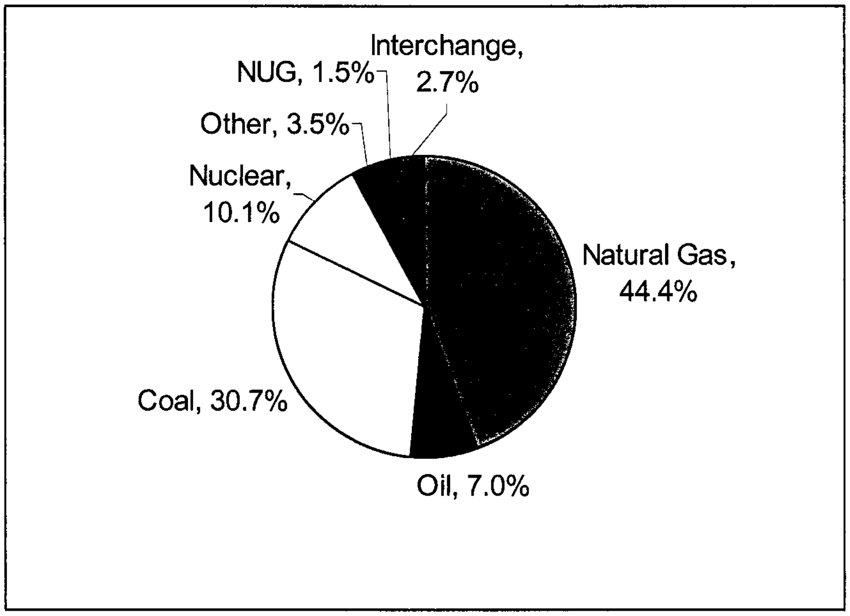
A.10.2 Existing Fuel Mix

The need for TEC is seen not only through comparison of existing generating capacity and capacity resource additions with forecast peak demand, but also through an evaluation of the existing and projected fuel mix throughout the State of Florida. Florida is already heavily dependent upon natural gas and is projected to grow more dependent. The FPSC's Department of Economic Regulation published its *Review of Florida Electric Utility 2005 Ten-Year Site Plans* in December 2005. Figure A.10-1, extracted from the FPSC's *Review*, indicates that in 2004, natural gas accounted for 29.9 percent of Florida's energy generation. Projections for 2014 indicate an increased reliance on natural gas, because natural gas is projected to account for 44.4 percent of total generation. Coal usage in Florida is projected to increase only slightly from 29.4 percent in 2004 to 30.7 percent in 2014, in spite of the addition of six planned coal units in that period of time, only two of which (Stanton B and Seminole Generating Station Unit 3) have been approved by the FPSC subsequent to the *Review of Florida Electric Utility 2005 Ten-Year Site Plans*.

This growing dependence upon natural gas exposes the state to the high price volatility associated with natural gas. This conclusion is bolstered by the rapid price escalation for natural gas supply encountered beginning in late August of 2005, as a result of Hurricane Katrina. Following this event, Henry Hub spot prices for natural gas rose to a September average of \$11.96/MBtu and further rose to an average of \$13.35/MBtu in December 2005 (oilnergy.com).



2004



2014

Figure A.10-1
Energy Generation by Fuel Type
(Source: *Review of Florida Electric Utility 2005 Ten-Year Site Plans*)

Request for Power Supply Proposals

IFB #JXF-031-06

For the

FLORIDA MUNICIPAL POWER AGENCY, JEA, REEDY CREEK IMPROVEMENT DISTRICT AND CITY OF TALLAHASSEE, FLORIDA

November 28, 2005

Pre-Bid Conference: Mandatory Attendance
Tuesday, December 20, 2005 – 9:00 AM
JEA, Tower 8 – Board Room, 21 W. Church Street, Jacksonville, FL 32202

Proposals are Due
Tuesday, February 28, 2006 - By 12:00 Noon
21 W. Church Street - Tower 1 – Suite 103 – Jacksonville, Fl 32202

JEA Will Open Bids at 2:00 PM on Tuesday, February 28, 2006
JEA Customer Center, 21 W. Church Street, CC6 North Conference Room
Jacksonville, FL 32202

FLORIDA MUNICIPAL POWER AGENCY, JEA, REEDY CREEK IMPROVEMENT DISTRICT AND CITY OF TALLAHASSEE, FLORIDA

IFB #JXF-031-06
Request for Power Supply Proposal
November 28, 2005

FLORIDA MUNICIPAL POWER AGENCY, JEA, REEDY CREEK IMPROVEMENT DISTRICT AND CITY OF TALLAHASSEE, FLORIDA

IFB #JXF-031-06
Request for Power Supply Proposal

1. Introduction

The Florida Municipal Power Agency ("FMPA" or "Agency"), JEA, Reedy Creek Improvement District ("RCID") and City of Tallahassee, Florida ("Tallahassee"), collectively the "Utilities" are issuing this Request for Proposals ("RFP") as an invitation to qualified companies to submit proposals for the supply of capacity and energy to meet a portion of the projected power requirements of the respective Utilities. The Utilities are interested in receiving bids as alternatives to their Self-Build Resource to evaluate whether the Self-Build Resource represents the best supply-side alternative available to meet a portion of their respective future requirements, taking into consideration price, reliability and other factors as described in this RFP.

To obtain firm transmission service to deliver the output of the Self-Build Resource to the respective Utilities, the Utilities are planning to interconnect the Self-Build Resource to the transmission systems of both Florida Power & Light Company ("FPL") and Progress Energy Florida, Inc. ("PEF") and are planning to have the required system transmission upgrades, if any, in service at the time the Self-Build Resource is placed in commercial operation.

The Utilities are seeking low cost alternatives that will provide fuel diversity and or reduce fuel price volatility. As an alternative to the Self-Build Resource, the Utilities will consider a unit contingent coal (solid fuel) purchase. Alternatively, the Utilities will consider a unit contingent purchase using another fuel type or pricing structure, or a firm wholesale power purchase. The resource will be delivered to the Utilities' system on a firm, first call, non-recallable basis. The Utilities' rights to the generating resources associated with the proposed purchase shall be equal to or greater than the rights of any other entity served by these generating resources. It is contemplated that the purchase will be either (a) a firm wholesale power purchase from an identifiable combination of generation, transmission and load comprised of an electric utility or group of utilities, or other entity (a "System"), i.e., a System Purchase or (b) a unit contingent purchase from one or more discreet units for which a back-up arrangement is preferred but not required. For a System Purchase, appropriate adjustments will be made to account for the impact on reserve requirements.

The Utilities are requesting proposals for up to 750 MW of net capacity to commence service on June 1, 2012 for contract periods of at least 10 years. The minimum amount of capacity purchase that the Utilities will consider is a purchase of 100 MW allocated among the Utilities.

The deadline for receipt of proposals by the Utilities is Tuesday, by 12:00 Noon February 28, 2006. A mandatory Pre-Bid Conference is currently scheduled for 9:30 A.M. on Tuesday, December 20, 2005 in Jacksonville, Florida.

For planning purposes the Utilities contemplate participation levels in the Self-Build Resource as shown below.

Utility	Proposed Share of Self-Build Resources	
	(%)	(MW)
FMPA	38.9	292
JEA	31.5	236
RCID	9.3	70
Tallahassee	20.3	152
Total	**100.0**	**750**

Each Utility's most recent 10 Year Site Plan required to be filed with the Florida Public Service Commission is available at the web site:

www.jea.com/business/services/publicnot/eprocure/bid_info.asp.

2. Definitions

Balancing Authority. Having to do with matching the power output of the generators within the electric power system(s) and energy transactions with entities outside the electric power system(s) with the load within the electric power system(s) and shall be as defined by the National Electric Reliability Council.

Dynamic Stability. Having to do with the response of synchronous machines to changes in operating conditions on a transmission system.

Equivalent Availability Factor ("EAF"). The sum of the hours the unit is fully or partially available to dispatch, weighted by the net derated capacity of the unit, divided by the total hours in the period.

Financially Firm. A power supply arrangement that is backed up by an agreement to pay financial damages, but is not backed by physical resources.

Georgia Integrated Transmission System ("Georgia ITS"). A statewide network shared by a member association currently consisting of Georgia Power Company, Georgia Transmission Company, Municipal Electric Authority of Georgia, and Dalton Utilities. Individual transmission lines and substations are owned and maintained by the individual participants, but operated as one system.

Independent Power Producer ("IPP"). An Independent Power Producer as defined under the Public Utility Regulatory Policy Act ("PURPA") and FERC regulations.

Load Flow. Having to do with the thermal limitations of a transmission system based on a given load level and dispatch at a given moment.

Performance Security. Refer to Section 16.

Proposal Due Date. Refer to Section 9.

Proposal Fee. Refer to Section 9.

Proposal Security. Refer to Section 16.

Qualifying Facility ("QF"). A cogeneration facility or small power production facility which is a qualifying facility, under PURPA and FERC regulations; is permitted to sell electric energy and capacity to the host Utility at the host Utility's avoided cost rate.

Respective Electric System. Those transmission facilities that will deliver the capacity and energy proposed in response to this solicitation from the Proposers point of delivery to the Utilities' individual loads. The Respective Electric Systems are defined differently for each of the Utilities that are party to this solicitation. These definitions appear in Section 8, subsection B of this solicitation.

Self-Build Resource. A proposed solid fuel resource, with a net rating of 750 MW, which the Utilities are planning to construct at a new site in Florida as described in Section 7.

3. Utility Descriptions

A. FMPA

1. General

The Florida Municipal Power Agency was created on February 24, 1978, by the signing of the Interlocal Agreement among its 29 members, which specified the purposes and authority of FMPA. FMPA was formed under the provisions of Article VII, Section 10 of the Florida Constitution; the Joint Power Act, which constitutes Chapter 361, Part II, as amended; and the Florida Interlocal Cooperation Act of 1969, which begins at Section 163.01 of the Florida Statutes, as amended. The Florida Constitution and the Joint Power Act provide the authority for municipal electric utilities to join together for the joint financing, construction, acquiring, managing, operating, utilizing, and owning of electric power plants. The Interlocal Cooperation Act authorizes municipal electric utilities to cooperate with each other on a basis of mutual advantage to provide services and facilities in a manner and in a form of governmental organization that will accord best with geographic, economic, population, and other factors influencing the needs and development of local communities.

Each city commission, utility commission, or authority that is a signatory to the Interlocal Agreement has the right to appoint one member to FMPA's Board of Directors, the governing body of FMPA. The Board has the responsibility of developing and approving FMPA's budget, approving and financing projects, hiring a General Manager, and establishing bylaws that govern how FMPA operates and policies that implement such bylaws. At its annual meeting, the Board elects a Chairman, Vice Chairman, Secretary, Treasurer and an Executive Committee. The Executive Committee consists of nine directors elected by the Board plus the current Chairman of the Board, the Vice Chairman, the Secretary, and the Treasurer. The Executive Committee meets regularly to manage and govern FMPA's day-to-day operations and approve expenditures and contracts. The Executive Committee is also responsible for monitoring budgeted expenditure levels and assuring that authorized work is completed in a timely manner.

2. All-Requirements Project

Under the All-Requirements Project ("ARP"), FMPA currently provides all the power requirements (above certain excluded resources) for fifteen of its members. Initially, the first five members of the ARP were non-generating utilities which had previously received all of their power requirements from full requirements contracts with either FPL or PEF. The latest members, Kissimmee Utility Authority and the City of Lake Worth, Florida, joined the ARP in 2002.

Current supply side resources for the ARP are classified into four main areas, the first of which is nuclear capacity. A number of the ARP members own small amounts of capacity in PEF's Crystal River Unit 3. A number of ARP members also participate in the St. Lucie Project providing them capacity and energy from St. Lucie Unit No. 2. Capacity from these two nuclear units is classified as "excluded resources" in the ARP. As such, the ARP members pay their own costs associated with the nuclear units and receive the benefits of the capacity and energy from these units. The ARP provides the balance of capacity and energy requirements for the members with participation in these nuclear units. The nuclear units are, however, considered in the capacity planning for the ARP.

The second category of resources is owned generation. This category includes generation that is solely or jointly owned by the ARP as well as ARP member participation in the Stanton, Tri-City, and Stanton II Projects.

The third category of resources is member generation. Capacity included in this category is generation owned by the ARP members either solely or jointly. The ARP purchases this capacity from the ARP members and then commits and dispatches the generation to meet the total requirements of the ARP.

The fourth category of resources is purchased power. This includes power purchased directly by the ARP as well as existing purchase power contracts of individual ARP members, which were entered into prior to the member joining the ARP.

B. JEA

1. General

JEA's electric service area covers all of Duval County and portions of Clay and St. Johns Counties. JEA's service area covers approximately 900 square miles.

The generating capability of JEA's system currently consists of the Kennedy, Northside, and Brandy Branch generating stations, and joint ownership in St. Johns River Power Park and Scherer generating stations. The total net capability of JEA's generation system is 3,476 MW in the winter and 3,257 MW in the summer.

JEA's transmission system consists of bulk power transmission facilities operating at 69 kV or higher. JEA's transmission system includes a 230 kV loop surrounding JEA's service territory. JEA is currently interconnected with FPL, Seminole Electric Cooperative (SECI), Florida Public Utilities (FPU) and the City of Jacksonville Beach.

JEA and FPL jointly own two 500 kV transmission lines that are interconnected with the Georgia ITS. JEA, FPL, PEF and Tallahassee each own transmission interconnections with the Georgia ITS.

2. Jointly Owned Generating Units

The St. Johns River Power Park (SJRPP) is jointly owned by JEA (80 percent) and FPL (20 percent). SJRPP consists of two nominal 638 MW bituminous coal fired units located north of the Northside Generating Station. Unit 1 began commercial operation in March of 1987 and Unit 2 followed in May of 1988. Both owners are entitled to 50 percent of the output of SJRPP. Since

FPL's ownership is only 20 percent, the remaining 30 percent of capacity and energy output is reflected as a firm sale from JEA.

JEA and FPL have purchased an undivided interest in Georgia Power Company's Robert W. Scherer Unit 4. Unit 4 is a coal-fired generating unit with a net output of 846 MW located in Monroe County, Georgia. JEA purchased 150 megawatts of Scherer Unit 4 in July 1991 and purchased an additional 50 megawatts on June 1, 1995. Georgia Power Company delivers the power from the unit to the jointly owned 500 kV transmission lines.

3. Purchased Power

Southern Company and JEA entered a Unit Power Sales (UPS) contract in which JEA currently purchases 200 MW of firm capacity and energy from specific Southern Company coal units through May 31, 2010. JEA has the unilateral option, upon three years notice, to cancel 150 MW of the UPS. In this plan, JEA will retain 200 MW of UPS during the contract term and reduce available capacity by 200 MW at the end of the contract term beginning the summer of 2010.

C. RCID

RCID is a political subdivision of the State of Florida and is located in Orange and Osceola Counties about 15 miles southwest of the City of Orlando. RCID encompasses approximately 25,000 acres or 40 square miles. Approximately 18,900 acres (76%) of RCID's property are located in Orange County and approximately 6,100 acres (24%) are located in Osceola County.

The Walt Disney World Resort Complex is located within the territorial boundaries of and comprises approximately 85% of the electrical requirements of RCID.

RCID is governed by a Board of Supervisors of five members. The Board has exclusive jurisdiction and control over all of the projects of RCID and over the budget and finances of RCID and, in general, is not required to obtain authority from any agency, instrumentality, commission or political subdivision of the State of Florida.

RCID owns facilities associated with, and is operating and maintaining an electrical generation, and distribution system that provides service within RCID. In addition to its own electric generation currently aggregating 43 MW, RCID purchases the remaining portion of its requirements from other suppliers.

The electric system has four ties to the Florida electric transmission grid operated at a nominal voltage of 69 kV. The transmission voltage is routed to eight power substations across 26 circuit miles of 69 kV line of which 14.5 miles are underground and 11.5 miles are overhead.

During the fiscal year ended September 30, 2004, the peak demand of the electric system was 189 MW occurring in July, and the net energy for load was 1,206,000 MWh. As of September 30, 2004, RCID served an average of 1,241 customers (meters) in RCID's service area. RCID is operating under a territorial agreement with PEF which was approved by the PSC on September 30, 1987. That agreement assigns the majority of the territory in RCID as RCID's service territory.

D. Tallahassee

Tallahassee owns, operates, and maintains an electric generation, transmission, and distribution system that supplies electric power in and around the corporate limits of the City. Tallahassee was incorporated in 1825 and has operated since 1919 under the same charter. Tallahassee began generating its power requirements in 1902 and Tallahassee's Electric Department presently serves approximately 103,000 customers located within a 221 square mile service territory. The Electric Department operates three generating stations with a total net generating capacity of 652 MW in the summer, and 699 MW in the winter.

Tallahassee has two fossil-fueled generating stations which contain combined cycle (CC), steam and combustion turbine (CT) electric generating facilities. The Sam O. Purdom Generating Station, located in the town of St. Marks, Florida has been in operation since 1952; and the Arvah B. Hopkins Generating Station, located on Geddie Road west of the City, has been in commercial operation since 1970. Tallahassee has also been generating electricity at the C.H. Corn Hydroelectric Station, located on Lake Talquin west of Tallahassee, since August of 1985.

Tallahassee maintains four points of interconnection with PEF; one at 69 kV, two at 115 kV, and one at 230 kV; and a 230 kV interconnection with the Georgia ITS. Tallahassee also operates two 69 kV psuedo-ties with PEF

Tallahassee's existing generation fleet is comprised by 233 MW (net summer rating) of CC generation, 48 MW (net summer rating) of steam generation and 20 MW (net summer rating) of combustion turbine ("CT") generation facilities located at Tallahassee's Sam O. Purdom Generating Station; 304 MW (net summer rating) of steam generation and 36 MW (net summer rating) of CT generation facilities located at the Arvah B. Hopkins Generating Station; and 11 MW from three units at the C.H. Corn Hydroelectric Station. All of Tallahassee's available steam generating units at these sites can be fired with natural gas, residual oil or both. The CC and CT units can be fired on either natural gas or diesel oil but cannot burn these fuels concurrently.

Tallahassee has a long-term firm capacity and energy purchase agreement with PEF for 11.4 MW. Tallahassee also has a short-term capacity and energy purchase agreement with Southern for 25 MW for June through August 2005.

4. RFP Schedule

The Utilities' timetable for this Request For Proposal ("RFP") process is shown below. Note that all times shown are based on the prevailing eastern time on the dates indicated; however, the dates shown are only estimates and assume one or more proposals will be acceptable to be included on a short list for further negotiations. This schedule may be modified at any time by the Utilities. Changes to the schedule will be available on the web site:

www.jea.com/business/services/publicnot/eprocure/bid_info.asp.

RFP Available for Distribution	November 28, 2005	
Notification of Conference Attendance Due	December 16, 2005 (Friday) [Noon]	
Pre-Bid Conference - MANDATORY	December 20, 2005 (Tuesday)	[9:30 A.M.]
Notice of Intent to Bid Form Due	December 27, 2005 (Tuesday)	[5:00 P.M.]
Deadline for Proposers'' Questions	February 14, 2006 (Tuesday) [5:00 P.M.]	
Sealed Proposal(s) Due Date	February 28, 2006 (Tuesday) [Noon.]	
Short-List/Commence Negotiations	May 2, 2006 (Tuesday)	
Utility Recommendations	May 30, 2006 (Tuesday)	
Contract(s) Approved	June 13, 2006 (Tuesday)	
Project In-Service Date	June 1, 2012	

5. Potential Power Supply Requirements

The Utilities require a joint bid, and may contract separately or jointly with the winning Proposer(s), if any. The Utilities are willing to accept a unit purchase that is contingent on all or part of the Utilities purchasing the total amount offered. The Utilities will not accept an offer to a subset of the group that is not offered to the whole group. Offers to each Utility should be based on the proposed share for each Utility presented in the table in Section 1 of this RFP. Potential Proposers may join with other providers to submit a proposal that meets all or a portion of the required megawatts as long as the minimum MW block is met. The Utilities will accept a variety of proposal types for capacity and energy in whole megawatt quantities for part or all of the basic capacity requirements. All Proposers must identify the specific resources and specific sites. Proposals based on supply resources located outside each Utility's Balancing Authority must also identify the transmission contracts for the transmission path that will be utilized from the resource(s) to the each Utility's Balancing Authority as more fully described in Section 8.

The Utilities may consider alternatives that could defer the timing for the unit. The Utilities prefer a purchase that will be subject to unavailability only due to planned maintenance or forced outages. Financially firm resources will not be acceptable to the Utilities.

The Utilities prefer solid fuel and prefer mature technologies but the Utilities will consider other fuel types and technologies if the evaluation shows these to be superior to solid fuel alternatives on the basis of the price and non-price criteria. The Utilities will consider the following generation technologies: gas fueled combined cycle; circulating fluidized bed; pulverized coal utilizing a super- or sub-critical coal fueled boiler or integrated gasification combined cycle ("IGCC"). The Utilities prefer a 100% dispatchable resource. Alternatives that provide replacement power would be a benefit to the Utilities.

In order to compare alternative technologies on an equal basis to the Self-Build Resource, Proposers will provide the following information on pollution control equipment and emission allowances.

A. Proposer should identify pollution control equipment (e.g., low NO_X burner, electrostatic precipitator, wet flue gas desulfurization, wet ESP, etc.)

B. Proposer should identify projected emission levels and cost of allowances. Proposers must procure all necessary emission offsets and will be responsible for all costs related to emissions, emission credits, and compliance with environmental regulations.

C. Proposers should address the following emission costs as a minimum: SO_2, NO_X, mercury emissions and a potential carbon tax.

The Utilities are willing to consider alternatives that involve a pass through of fuel and variable operations and maintenance costs or a contractually fixed energy charge. For alternatives involving a pass through of fuel costs, a contractually fixed heat rate is preferred. Fuel forecasts for coal, gas and oil fuels are provided in Attachment B and will be used as the basis for comparison to the Self-Build Resource. The current plan is to have Attachment B available at the Pre-Bid Conference.

For Proposers that are not fixing the energy charge, if the capacity/energy sale proposal is based on a pass-through fuel cost arrangement, the proposal energy price should be based upon the fuel forecast provided on Attachment B. The Henry Hub gas fuel price forecast and coal fuel price forecast for various types and sulfur contents to be used for purposes of our evaluation have been included. The proposal should include all factors to determine a total price based on the Henry Hub gas price and/or coal price and an explanation of the relationship of the energy rate to fuel prices. If any of this information is Proprietary Confidential Business Information, it should be so noted and the Utilities will maintain confidentiality per Section 13. If the proposal is based on a contractually fixed total energy cost, the proposal must include all information pertinent to the pricing and its escalation. Proposers are required to use the fuel forecast that most clearly fits the type of fuel being used by the resource. To the extent the Proposer wants to make an exception to the fuel forecast or transportation costs, such exception must be fully described and supported with appropriate calculations. The Utilities may or may not reflect these exceptions in the evaluation.

With respect to fixed and variable operation and maintenance expenses ("O&M") and environmental related charges, all charges must be itemized to show different components of costs. All assumptions used in calculating such costs must be clearly stated. Proposers must list components of costs and other performance parameters so the Utilities can verify that such costs are comparable to the Self-Build Resource. Typical components that may be included are the following:

A. Fixed O&M (labor, general equipment maintenance, insurance, property taxes, major maintenance, capital expenditures, administrative costs).

B. Variable O&M (maintenance charge costs related to use, lime, limestone, ash and scrubber sludge disposal, ammonia, catalyst replacement, SO_2, NO_X, mercury allowances, water related costs, and other consumables).

C. Heat Rate (minimum load level, full load, and intermediate levels at winter, summer and average ambient temperatures).

D. Availability and forced outage rate.

E. Other operating data/restrictions such as ramp rates, start-up costs (cold, hot), minimum load take requirements, etc. that may affect operating flexibility and expenses.

The Utilities prefer purchases that provide guarantees with respect to various major performance parameters such as output, heat rate, availability, forced outages, fixed and variable operating expenses and fuel prices. Compensation to the Seller will be adjusted if guaranteed performance parameters are not achieved.

6. Proposals for Unit Contingent Purchases or a System Purchases

Proposals involving a unit contingent purchase or a System Purchase should include all available data including Equivalent Availability Factor ("EAF"), maintenance schedules, net capacity, heat rate, fuel type, and other pertinent data for the specific unit(s). Proposals involving a system or portfolio capacity and energy sale to the Utilities must include information for all generating units and purchase contracts required to make the sale to the Utilities. All proposals for a System Purchase shall be on a non-recallable basis equivalent to native load delivered to the Balancing Authority of each of the Utilities. Details of the information required for each type of proposal are specified in Attachment A.

All proposals shall include scheduling provisions of the sale. The schedule should be established no more than 1 day in advance with the ability to change the schedule within 2-3 hours before the schedule commences except under emergency conditions when changes may be required as soon as physically possible if the resource is available. Utilities are seeking proposals that allow operating flexibility for the resources. Proposals must clearly describe any contractual limitations on energy usage (MWh) by day, month or year. As part of the scheduling provisions, the supplier will be required to fax daily to Utilities' dispatchers a schedule of estimated prices for the energy to be delivered for that day and the next day.

7. Self-Build Option

The Utilities' Self-Build Resource option will consist of a solid fuel generating unit with a super critical boiler located at a greenfield site in Florida. The unit is planned to have a maximum net capacity of 750 MW.

8. Transmission Arrangements

A. General Requirements

The Utilities require that capacity and energy proposed in response to this solicitation is deliverable into the Respective Electric Systems on a firm, non-recallable basis. The individual Respective Electric Systems and delivery points are defined further in Section 8, subsection B of this solicitation. Proposers are required to be responsible for (i) all costs associated with interconnecting generating resources; (ii) all transmission upgrades necessary for delivery of capacity and energy to the Respective Electric Systems, as applicable; and (iii) all required point-to-point transmission charges, losses, and other related charges necessary for firm transmission services to the Respective Electric Systems. The Utilities are indifferent to whether the Proposer intends to make up energy and capacity losses, or purchase replacements from the transmission providers; however, any capacity and energy proposed shall be net of losses, delivered to the respective transmission systems of the Utilities.

The Utilities will accept arrangements for transmission services that are either firm point-to-point, or firm network service, as applicable; however, each such service shall also be provided as the most secure and reliable form of transmission service offered under each transmission provider's tariff.

For the Self-Build Resource, the Utilities expect to deliver their respective shares of the capacity and energy of the resource in the following ways. JEA plans to either self-build transmission facilities from the Self-Build Resource to its transmission system, or to purchase firm point-to-point transmission service from potentially both PEF and FPL to deliver the output from the Self-Build Resource to the JEA system, depending on the location of the Self-Build Resource. Tallahassee plans to either self-build transmission facilities from the Self-Build Resource to its transmission system, or purchase firm point-to-point transmission service from PEF to deliver the output from the Self-Build Resource to the Tallahassee system. FMPA and the RCID plan to use their existing firm network type transmission service across the FPL and PEF systems to have the output from the Self-Build Resource delivered to FMPA's loads and to the RCID electric system.

The Utilities will accept transmission service arrangements that meet all of the general requirements of this section, including arrangements across multiple transmission systems. However, the Utilities preference is for: (i) a transmission service arrangement that does not consist of more than two intermediate Transmission System paths (between the generating switchyard and the Respective Electric System); (ii) a transmission service arrangement that does not include more than one series path between the Respective Electric System and the generator's resource; and (iii) a transmission service arrangement that includes the assignment of any tariff-provided transmission reassignment/redirection/ resale rights solely to the Utilities for the life of the agreement.

B. Individual Transmission System and Transmission Service Arrangement Descriptions

1. FMPA

FMPA purchases transmission services from several different investor-owned utilities and from one municipal electric utility. These transmission arrangements provide FMPA access to all systems interconnected with these utilities thus enabling the delivery of electric power to each of FMPA's participating members. FMPA is seeking proposals that are delivered to the FPL and PEF transmission systems.

FMPA's ARP has eight of the existing fifteen "Project Participants" geographically located within FPL's service area and the other seven Project Participants located within PEF's service area. All fifteen Project Participants are supplied their full-requirements power supply from FMPA and such power is delivered to the Project Participants over the transmission systems of FPL or PEF. Network type transmission arrangements are currently in place to provide for delivery of FMPA's existing network resources over the FPL and the PEF systems to its loads.

FMPA's ARP capacity needs are provided on a system basis; however, the utilization of FMPA's existing transmission arrangements with FPL and PEF must be separately planned. FMPA has determined for this bid evaluation that all of the proposed capacity must be deliverable to both FPL and PEF systems.

All bids to FMPA for potential power supplies where the supply resources originate from outside FPL's or PEF's Balancing Authority should be priced based on the Proposer supplying and/or arranging for transmission service from the sources of supply to the FPL and PEF Balancing Authority interfaces. The Proposer should be responsible for any required upgrades associated with transmission over the FPL or PEF systems. To the extent transmission credits are provided for upgrades provided by Proposers on the PEF or FPL systems, these will be credited back to the Proposers.

2. JEA

JEA is a Transmission Owner and a North America Electric Reliability Council ("NERC") Balancing Authority (formerly "Control Area") with established commercial transmission paths (contract paths) to FPL and SECI, via JEA's wholly-owned 230 kV transmission facilities. JEA also has a generator interconnection to the Cedar Bay Cogenerator in Jacksonville, FL (for delivery to FPL) as well as load service connections to the City of Jacksonville Beach and to FPU (for delivery to Fernandina Beach), each through JEA's wholly owned 138 kV transmission facilities.

Additionally, JEA jointly owns with FPL certain 500 kV transmission facilities that, combined with certain facilities of PEF and Tallahassee, form the Florida to Southern interface, a FERC-filed transmission interface that provides for the importing and exporting of power across the Florida and Georgia state line. This interface is operated by Southern Company Services to the north, and FPL to the south. JEA presently holds over 800 MW of capacity on this interface which interconnects directly with the Georgia ITS.

JEA will accept transmission service arrangements that meet all of the general requirements of this section, including arrangements across multiple transmission systems.

JEA operates a geographically-compact system with all of its obligations served through its wholly-owned transmission facilities. As such, JEA recognizes that their may be substantial economic benefits realized from the Proposer's construction of transmission facilities, to reduce the life-cycle costs of transmission services. JEA will accept such proposals that meet the intent of all of the previous requirements of this section, where applicable, as well as the following additional requirements:

- The Proposers proposal must provide that the resulting physical transmission facilities are first contingency safe in terms of both load flow and dynamic stability of affected facilities.
- The Proposer's proposal may assume that JEA will terminate the Proposer's lines at a JEA substation at no cost to the Proposer, provided the Proposer shall design the facilities to meet basic JEA standards (i.e., a matching voltage level). JEA acceptable points of interconnection include any combination of the JEA Brandy Branch, Greenland, Center Park or the future (2007) Jacksonville Heights Substations (all at 230 kV). A copy of the JEA transmission system map, in electronic (Bentley Microstation) format, shall be made available to a Proposer (who has notified JEA of his intent to bid) upon receipt of an electronic mail request.
- While the Proposer shall construct, own, and maintain the transmission facilities, the Proposer shall assign all rights to schedule and operate the facilities to JEA, for the life of the agreement. The assignment shall permit JEA to schedule and operate the facilities

within JEA's Balancing Authority as though the facilities were JEA's own transmitting facilities.

- The Proposer shall be responsible for all permitting, licensing, property acquisition, environmental and archaeological surveys, studies, and actions, and any and all other requirements that may arise and/or impede Proposer's ability to construct the proposed facilities. Particularly, JEA will not be required by the Proposer to initiate actions for permitting or eminent domain proceedings in order to establish the route of Proposer's transmission facilities.

3. RCID

RCID is interconnected at 69 kV to PEF at the Windemere, Clermont East, Osceola and Lake Bryan Substations and is also interconnected with the system of Tampa Electric Company. RCID purchases network type transmission service from PEF to deliver existing resources to its loads.

All capacity and energy for delivery to RCID that is proposed in response to this RFP shall be deliverable to the RCID ties. The Proposer should be responsible for any transmission upgrades associated with transmission over the PEF system. To the extent transmission credits are provided for upgrades provided by Proposers on the PEF system, these will be credited back to the Proposers.

4. Tallahassee

Tallahassee is a transmission owner and NERC Balancing Authority (formerly "Control Area") with established commercial transmission paths (contract paths) to the Georgia ITS and PEF. There are five points of interconnection with the Tallahassee system: one 230 kV tie with Georgia Power Company; and one 230 kV, two 115 kV ties and one 69 kV ties with PEF.

Tallahassee's 230 kV interconnection to the Georgia ITS, together with certain transmission facilities of PEF, FPL, and JEA, form the Florida to Southern interface, a FERC-filed transmission interface that provides for the importing and exporting of power across the Florida and Georgia state line. This interface is operated by Southern Company Services to the north, and FPL to the south. Transfers across Tallahassee's interconnection with Georgia Power Company are governed, in part, by an agreement among and between the Tallahassee, JEA, FPL and PEF. Tallahassee's current assigned import capability from the Southern Subregion of Southern Electric Reliability Council ("SERC") is limited to 200 MW.

Tallahassee operates a geographically compact system with all of its obligations served through its wholly owned transmission facilities. As such, Tallahassee recognizes that there may be substantial economic benefits realized from the Proposer's construction of transmission facilities, to reduce the life-cycle costs of transmission services. Tallahassee will accept such proposals that meet the intent of all of the previous requirements of transmission service, where applicable, as well as the following additional requirements:

- The Proposers proposal must provide that the resulting physical transmission facilities are first contingency safe in terms of both Load Flow and Dynamic Stability of affected facilities.

- The Proposers proposal may assume that Tallahassee will terminate the Proposer's lines at a Tallahassee substation at no cost to the Proposer, provided the Proposer shall design the facilities to meet basic Tallahassee standards (i.e., a matching voltage level). Tallahassee acceptable points of interconnection include any combination of Substation 18, Substation 5, Substation 7, Substation 20 or the plant switchyard at either the Hopkins Generating Station or the Purdom Generating Station. A copy of the Tallahassee transmission system map, in electronic format, shall be made available to a Proposer (who has notified Tallahassee of his intent to bid) upon receipt of an electronic mail request.
- While the Proposer shall construct, own, and maintain the transmission facilities, the Proposer shall assign all rights to schedule and operate the facilities to Tallahassee, for the life of the agreement. The assignment shall permit Tallahassee to schedule and operate the facilities within Tallahassee's Balancing Authority as though the facilities were Tallahassee's own transmitting facilities.
- The Proposer shall be responsible for all permitting, licensing, property acquisition, environmental and archaeological surveys, studies, and actions, and any and all other requirements that may arise and/or impede Proposer's ability to construct the proposed facilities. Particularly, Tallahassee will not be required by the Proposer to initiate actions for permitting or eminent domain proceedings in order to establish the route of Proposer's transmission facilities.

C. Additional Requirements and Considerations

1. Where resources originate outside the State of Florida, proposals must indicate Proposer's consideration for the limits and allocation of interface capacity among the owners of the transmission lines that make up the Florida to Southern interface.
2. The Utilities require the generation resources proposed in response to this RFP to be fully dispatchable. This quality may imply that specific transmission services may be required from the Transmission Providers to achieve useful dispatchability. The Proposer shall be responsible for providing all such services. Notwithstanding the Utilities' involvement in the process to determine the availability of the required transmission services, Proposers are informed that the process may be time consuming and costly. As such, Proposers should only submit proposals where information from reliable sources indicates that there is a fairly high likelihood that the transmission services required by their proposals will be available.
3. Proposers should provide backup information that would verify the reasonableness of assumptions and cost data associated with transmission service required for delivery of the proposed capacity and energy from the source(s) of supply to the Utilities delivery points. Such analyses should show all assumptions, including, among other things, contract paths, contracting parties, interface capability, intervening parties, and transfer capabilities. The Utilities may verify the transmission studies provided by the Proposers by performing its own load flow studies. Therefore, Proposers are encouraged to submit a hard copy of the transmission analysis results, plus the load flow cases in "raw data" ASCII IBM compatible format (i.e., PTI's PSS/E, GE's PSLF, IEEE common), along with all assumptions used in creating each case and any special instructions for reading the data. To the extent uncertainty exists regarding whether the Proposer has appropriately accounted for transmission limitations

and associated costs in the proposal, the Utilities may reflect this in the evaluation or reject the proposal.

9. Notice to Proposers

The Utilities have scheduled a mandatory Pre-Bid Conference for December 20, 2005 at 9:30 A.M EPT at the JEA offices, 8th Floor, 21 West Church Street, Jacksonville, FL 32202. Only qualified Proposers (see Section 14) will be permitted to attend the Pre-Bid Conference. The purpose of the conference is to answer all questions that Proposers may have about the Utilities' solicitation. Only written questions and written responses will be considered official. Companies that intend to submit proposals are requested to use this forum to obtain answers about the RFP and the form of the response to the RFP. Companies must register for the Pre-Bid Conference by submitting a written list of attendees via mail to the address below, via the Internet to E-Mail address, bids@jea.com or via facsimile to the attention of JEA Procurement Department (904) 665-7294, to arrive on or before December 16, 2005 at 12:00 Noon EPT.

All Proposers must provide written notification of their intent to submit a proposal no later than December 27, 2005 at 5:00 P.M. EPT. A Notice of Intent to Bid Form is included in Section 21 as RFP Form 1. On the Notice of Intent to Bid form, Proposers must indicate the agreement term(s) on which the proposal(s) will be based. All sections of the Notice of Intent to Bid form must be completed in full, signed by the Proposer, and submitted to the Utilities by facsimile or mail (not via the Internet) to the attention of Mr. Mike Lawson.

Sealed proposal packages will be received until February 28, 2006, at 12:00 P.M. EPT ("Proposal Due Date") at the offices of JEA as a representative for the Utilities. Any proposal submitted via the Internet will not be accepted. Each Proposer is required to submit a Proposal Summary (RFP Form 2), a Minimum Requirements Form (Form 3), a Pricing Proposal Form (Form 4), a Conflict of Interest Certificate (Form 5) and a Checklist (Form 6) as part of the proposal package. The forms are included in Section 21 of this RFP. The bidding company's name must be clearly identified on the outside of each proposal package. The Utilities reserve the right to reject all proposals received after the Proposal Due Date.

One original and six (6) copies of each proposal must be sealed and delivered to the following address:

JEA Procurement Department
Suite 103 JEA Tower Lobby
21 West Church Street
Jacksonville, FL 32202-3139

An electronic copy of the completed Proposal Pricing Form and all other spreadsheets included in the proposal must be submitted in Microsoft Office Suite 2000 or compatible format on CD or DVD.

The proposals must remain in effect until August 1, 2006 or later if the purchase is to be finalized pending a transmission service request. Each proposal package must be accompanied by a non-refundable Proposal Fee (in the form of a cashiers check made payable to JEA) in the amount of $5,000 per proposal. If a Proposer submits alternative arrangements, each alternative will be considered a separate proposal. A Proposer submitting multiple proposals is required to supply $5,000 Proposal Fee for each proposal.

10. Right of Rejection

This RFP is not an offer establishing any contractual rights. This solicitation is solely an invitation to submit proposals.

The Utilities reserve the right to:

- Reject any proposal for failure to extend validity date if requested;
- Waive any requirement in this RFP;
- Not disclose the reason for rejecting a proposal;
- Negotiate an arrangement for power supply with more than one Proposer at a time;
- Not select the proposal with the lowest price;
- Request clarifications from Proposers at any time;
- Perform analyses based on further criteria applicable to certain individual Utilities; and
- Reject any and all proposals for any reason or no reason received in response to this RFP.

11. Interpretations and Addenda

All questions regarding interpretation of this RFP, technical or otherwise, must be submitted in writing or by the Internet to the following:

By Fax:	Mr. Mike Lawson, Project Director (904) 665-7294
By E-Mail:	lawsmn@jea.com
By Mail or Courier:	JEA Procurement Department Suite 103 JEA Tower Lobby 21 West Church Street Jacksonville, FL 32202-3139

Only written or Internet transmitted responses provided by the Project Director to Proposers' questions will be considered official. A verbal response by a representative of the Utilities will not be considered an official response. Written responses to questions and requests for interpretations may, at the discretion of the Utilities, be provided to all Proposers either by posting on the Internet Website or by e-mail. All written questions must be received by the Utilities on or before February 14, 2006 at 5:00 P.M. EPT. Inquiries after this date may not receive responses. All addenda issued in connection with this RFP will be placed on the "Important Updates" page on the Internet Website

(www.jea.com/business/services/publicnot/eprocure/bid_info.asp),

at the time of issue and it shall be the responsibility of those Proposers that download the RFP from the Internet to regularly check the "Important Updates" page for addenda.

12. Errors, Modifications or Withdrawal of Proposal

Each Proposer should carefully review the information provided in the RFP prior to submitting a response. The RFP contains instructions that must be followed by all Proposers. Modifications (other than minor additions and/or corrections) to proposals already received by the Utilities will only be accepted prior to the Proposal Due Date. Proposals may be withdrawn by giving written notice (no Internet notices) to the Utilities prior to the Proposal Due Date. In such cases, a full refund of the Proposal Fee will be provided by the Utilities. Proposals withdrawn after the Proposal Due Date may result in forfeiture of the Proposal Fees.

13. Proprietary Confidential Business Information

All proposals shall become the property of the Utilities. Except as noted below, the Utilities will not disclose to third parties any information that is clearly labeled "Proprietary Confidential Business Information" in a proposal unless such disclosures are required by law or by order of a court or government agency having appropriate jurisdiction. Each page of Proprietary Confidential Business Information must be clearly labeled "PROPRIETARY CONFIDENTIAL BUSINESS INFORMATION" at the top of the page. The Utilities reserve the right to disclose information contained in proposals to the Florida Public Service Commission. The Utilities also reserve the right to disclose information contained in proposals to its consultant(s) for the sole purpose of assisting in the proposal evaluation process. The Utilities will require the consultant(s) to maintain the confidentiality of the document.

The Utilities are governmental entities subject to the Florida Public Records Law (Chapter 119, Florida Statutes). Some, or all, of the materials or information provided by Proposer to the Utilities will be considered a "public record" which the Utilities, by law, are obligated to disclose upon request of any person for inspection and copying, unless the public record or the information is otherwise specifically exempt by statute. Should Proposer provide any materials which it believes, in good faith, contain information which would be exempt from disclosure or copying under Florida law, Proposer shall indicate that belief by typing or printing, in bold letters, the phrase "Proprietary Confidential Business Information" both on the initial page and on the face of each affected page of such material and shall submit both a complete and a redacted version of such material. Should any person request to examine or copy any material so designated, only the redacted version of the affected material or page(s) thereof will be produced. If the person requests to examine or copy the complete version of the affected material or page(s), the Utilities shall notify the affected Proposer of that request, and Proposer, within thirty-six (36) hours of receiving such notification, shall either permit or refuse to permit such disclosure or copying. If Proposer refuses to permit disclosure or copying, Proposer agrees to, and shall, hold harmless and indemnify the Utilities for all expenses, costs, damages, and penalties of any kind whatsoever which may be incurred by the Utilities, or assessed or awarded against the Utilities, in regard to the Utility's refusal to permit disclosure or copying of such material. If litigation is filed in relation to such request and Proposer is not initially named as a party, Proposer shall promptly seek to intervene as a defendant in such litigation to defend its claim regarding the confidentiality of such material. This provision shall take precedence over any provisions or conditions of the Proposer's proposal and any provision of any other document relating to the disclosure of materials or information considered by the provider to be confidential or proprietary and shall constitute the Utility's sole obligation with regard to maintaining confidentiality of material or documents, of any kind, or any other information provided by Proposer or its Affiliates or Sub Contractors.

14. Proposer Qualifications

The Utilities will accept bids from any electric utility, independent power producer ("IPP"), qualifying facility ("QF"), exempt wholesale generator, or non-utility generator, or electric power marketer who has received certification as such by the FERC. Proposers to the Utilities may be required to provide proof of experience. Proposers that propose to develop a power generating project to provide power to the Utilities must have developed, and have had in operation for a minimum of one year, at least one currently operating power supply project that is similar to, or larger in size than, the project being proposed. Proposers proposing to provide the Utilities with power from an existing generating resource or a portfolio of resources must have successfully provided similar levels of services to at least one electric utility for a minimum of one year.

If rated by any one or more of the three rating agencies, Proposer must have as a minimum an investment grade credit rating on senior uninsured debt of Baa3 for Fitch, Baa3 for Moody's, or BBB- for Standard & Poor's. If not rated, the Proposer must provide sufficient financial information for the Utilities to evaluate Proposer's financial credit status.

Proposers offering capacity/energy sales from an existing unit(s) must own and operate the unit, plant or system capacity or must have the unit(s), plant or system capacity under contract. The Utilities may require proof of such contracts as well as proof of contracts for sales from a portfolio of resources. Any contracts submitted with the proposal may have the price and other sensitive information deleted before submittal to the Utilities. For proposals involving a new project, Proposer should supply information of status of the project including site development, permitting, purchase of land option, etc.

Electric power plant operators of a unit, plant, system or portfolio capacity proposal must provide proof of operating experience as requested in Attachment A.

Proposers must provide audited financial statements, if available, or other financial statements for the last three years. Such information must be provided for all entities, including affiliates involved in the transaction. For investor-owned utilities, this would include as a minimum FERC Form 1s and SEC 10K Forms. Proposers should also provide, where appropriate, the most recent Dunn and Bradstreet report, a description of pending litigation, and the most recent annual report, and the Proposer's most recent credit rating for senior unsecured debt as reported by Fitch, Moody's and/or S&P. Information supplied in response to this section may be provided solely on CDs in electronic format.

15. Capacity

Resources providing the proposed capacity whether unit, plant, system or portfolio sale or construction of an ownership proposal, must be in operation at least two months prior to the start date of the proposed power supply.

16. Proposal Security and Performance Security

The Utilities require that the Proposer provide a letter of commitment from a financial institution with a credit rating of at least A- from Fitch, A3 by Moody's or A- by S&P to be a guarantor for a Proposal Security to be established by the Proposer equal to five dollars per kW of the capacity offered in the proposal within ten (10) days of being notified that the proposal is on the short-list of proposals. The Proposal Security will be forfeited if the Proposer changes its proposal in a materially adverse manner after being short-listed or fails to establish a Performance Security within 3 days of contract execution with the Proposer. The Proposal Security is to remain in effect until the date at which proposals are to remain valid or at such time that the Utilities execute a contract and obtain a Performance Security with the Proposer providing the Proposal Security or the Utilities execute(s) agreement with a different Proposer or combination of Proposers to meet its requirements, or decides to reject all bids. The letter of commitment will state further that the financial institution will commit to be a guarantor for a Performance Security established by the Proposer when the contract is executed that will minimize the Utilities' exposure to direct and consequential damage due to failure of the Proposer to fulfill the terms and conditions of the contract awarded. The amount of the Performance Security will be a percentage of the revenues over the remaining life of the contract.

17. Default and Damages Provisions

The Utilities will negotiate the conditions of default and damages with the successful Proposer(s). Proposers should include suggested default and damage provisions in their proposals.

18. Ethics and Ex Parte Communication

A Proposers' proposal(s) may be disqualified at any point if bribery, conflict of interest, or interference in the evaluation process are determined, at the Utilities sole discretion.

Ethics

By signing the Bid Document, the Proposer certifies this Bid is made without any previous understanding, agreement or connection with any other person, firm, or corporation submitting a Bid for the same Work other than as a Subcontractor or supplier, and that this Bid is made without outside control, collusion, fraud, or other illegal or unethical actions.

The Proposer shall submit only one Bid in response to this Solicitation. If JEA has reasonable cause to believe the Proposer has submitted more than one Bid for the same Work, other than as a Subcontractor or sub-supplier, JEA may disqualify the Bid and may pursue debarment actions.

The Proposer shall disclose the name(s) of any public officials or employees of JEA who have any financial position, directly or indirectly, with this Bid by completing and submitting the Conflict of Interest Certificate. Failure to fully complete and submit the Conflict of Interest Certificate will disqualify the Bid. If JEA has reason to believe that collusion exists among the Proposers, JEA will reject any and all Bids from the suspected Proposers and will proceed to debar Proposer from future JEA Awards in accordance with the JEA Purchasing Code.

In accordance with Florida Statutes sec. 287.133, JEA will reject Bids from any persons or affiliates convicted of a public entity crime as listed on the Convicted Vendor list maintained by the Florida Department of Management Services. JEA shall not make an Award to any officer, director, executive, partner, shareholder, employee, member, or agent active in management of the Proposer listed on the Convicted Vendor list for any transaction exceeding $10,000 for a period of 36 months from the date of being placed on the Convicted Vendor list.

Ex Parte Communication

Ex Parte Communication is strictly prohibited. Failure to adhere to this policy will disqualify the Bid. JEA's policy on Ex Parte Communication will not prohibit the following:

1. Meetings called or requested by JEA and attended by Proposers for the purpose of discussing this Solicitation, evaluation, or selection process including, but not limited to, substantive

aspects of the Solicitation. Such meetings may include, but are not limited to, pre-Bid meetings, site visits to JEA's or Proposers' facilities, interviews/negotiation sessions as part of the selection process, and other presentations by Proposers, all of which are requested by JEA and will be limited to topics specified by JEA.

2. The addressing of the Awards Committee, the Procurement Appeals Board and the JEA Board at public meetings advertised and conducted pursuant to Florida Statutes sec. 286.011.
3. The filing of a written protest to any proposed Award to be made pursuant to this Solicitation, evaluation and selection process, which filing and prosecution shall give notice to all Proposers. Protest proceedings shall be limited to open public meetings advertised and conducted pursuant to Florida Statutes sec. 286.011 with no Ex Parte Communication outside those meetings.
4. Communications between the chief purchasing officer, buyer, organizational element managers or other JEA representatives and the Proposer for routine matters arising from procurements other than this Solicitation.

If the Proposer violates any requirement of this clause, the Bid may be rejected and JEA may debar offending companies and persons.

19. Evaluation Process

In the initial stages of the evaluation process, detailed cost estimates for the Self-Build Resource will be used as a benchmark for screening alternatives. After the Proposal Due Date, changing the proposed Self-Build Resource or repricing of bids is not anticipated; therefore, Proposers should provide their lowest cost offer on the Proposal Due Date. If there are changes in the Self-Build Resource after the Proposal Due Date, the remaining Proposers in the RFP process, may be given the opportunity to update their proposals.

The proposal evaluation process will be performed on a bid and negotiate basis. Information provided from each qualified Proposer by the Proposal Due Date will be used to develop a short-list of proposals from which selection(s) could be made for direct negotiations. No additional data will be considered after the Proposal Due Date, except for clarifications requested by the Utilities, changes in market fuel prices for applicable proposals, and possible transmission system study results obtained from FPL, PEF, and/or any other affected transmission provider. The Utilities will evaluate the proposals in terms of price and non-price factors. The first stage of the evaluation process for qualified Proposers will consist of a check of each proposal against the minimum requirements, as listed in this section of the RFP. After the minimum requirements screening, proposals for long-term arrangements may be screened by comparison with the Self-Build Resource proposal. The screenings will be performed on a present value busbar cost basis. Price and non-price evaluations may be conducted next. During the evaluation process, the Utilities may develop scenarios which include combining proposals from one or more Proposers.

Price and non-price evaluations may include a preliminary analysis of transmission limitations to verify that Proposers have properly addressed the limitations and included appropriate costs. Once a short-list of Proposers is developed, the Utilities may inform FPL and/or PEF and/or others, as appropriate, of the potential short-listed Proposers as possible power suppliers to the Utilities. Utilities may add further non-price criteria in their individual detailed analyses.

Additional system impact studies, that incorporate proposed power supply resources, may be used to verify the sufficiency of the transmission systems and their interfaces and determine if additional transmission system facilities may be required. Should the Utilities or others determine, based on their studies, that additional transmission facilities or costs are required to accommodate particular proposed power supplies, each affected Proposer will then be contacted by the Utilities with this information to explore possible alternatives, if any, to address the problem. To the extent that these problems cannot be resolved, the proposal may be rejected or the evaluation will reflect this cost uncertainty. Any costs associated with such transmission system studies performed by the Utilities, FPL or PEF will be the responsibility of the Utilities.

Proposals that remain on the short-list may be analyzed on an overall system cost basis. From this analysis, the Proposer(s) will be selected for participation in negotiations. The Proposer(s) selected will be notified for commencement of negotiations. Selection and rejection of proposals and notification of Proposers at all stages will remain entirely within the Utilities' discretion. The Utilities intend to notify Proposers not selected under this solicitation within a reasonable amount of time.

The Utilities may wish to evaluate the impact of transmission congestion and losses that may occur between the Proposer's supply resources and the Utilities' loads and may adjust the proposal to take such impacts into consideration. The Utilities encourage Proposers to supply to the Utilities any information that the Proposer may have related to the potential impact of transmission congestion and losses.

Minimum Requirements for All Proposals

Each proposal must satisfy certain minimum requirements before it will receive any further evaluation. The Proposer must demonstrate in its submittal that the following minimum requirements have been met:

1. Proposers must attend the Pre-Bid Conference and submit a Notice of Intent to Bid by the appropriate dead-line.

2. The capacity and energy proposed are on a first call, non-recallable basis, i.e., as long as the unit(s) from which the capacity is purchased is available, the Utilities have the right to the output of the unit(s) for the duration of the contract. The Utilities' rights must be equal to or superior to any other party's rights to such unit(s) output.

3. All proposals must remain in effect until August 1, 2006, or later if the purchase is to be finalized pending a transmission service request.

4. The minimum capacity amount offered is 100 MW allocated among the Utilities.

5. The minimum term for a proposal is ten (10) years.

6. All generating units providing the proposed capacity must be in operation at least two months prior to the required delivery commencement date of the term of the proposed power supply.

7. Proposals must identify and include the location of each capacity resource and name the originating Balancing Authority. Proposers proposing power supply from a resource(s) located outside of any of the Utilities' Balancing Authority's areas must identify the firm transmission contract path from the power supply(s) up to the Utilities' Balancing Authority's area.

8. The Proposer must ensure that all emissions allowance requirements will be satisfied and that such costs are included in the proposal.

9. The Proposer must declare ownership or contractual status of a unit, plant or system capacity as described in Section 14.

10. The Proposer must complete the appropriate RFP Forms 1 through 6 and provide all appropriate information requested in Attachment A. All forms requiring a signature must be signed by a duly authorized official.

11. The Proposer must be willing to provide an adequate Proposal Security and Performance Security prior to entering short-list negotiations.

12. The Proposer must clearly describe any contractual limits on energy utilization or physical limitations on the operation of the resource as described in Attachment A.

13. The proposal must include scheduling provisions for the sale.

14. Each proposal must contain the appropriate Proposal Fee in accordance with Section 9.

15. Proposals for new construction projects are not contingent upon participation by third parties to support the project.

16. If rated by any one or more of the three rating agencies, Proposer must have as a minimum an investment grade credit rating on senior uninsured debt of Baa3 for Fitch, Baa3 for Moody's, or BBB- for Standard & Poor's. If not rated, the Proposer must provide sufficient financial information for the Utilities to evaluate Proposer's financial credit status.

17. Proposers that propose to develop a power generating project to provide power to the Utilities must have developed, and have had in operation for a minimum of one year, at least one currently operating power supply project that is similar to, or larger in size than, the project being proposed. Proposers proposing to provide the Utilities with power from an existing generating resource or a portfolio of resources must have successfully provided similar levels of services to at least one electric utility for a minimum of one year.

Price Criteria

The Utilities will evaluate the proposal(s) as an alternative to develop the Self-Build Resource. The net present value of the revenue requirements to the Utilities over the contract period for each proposal may be compared with the net present value of revenue requirements over the contract period for the Self-Build Resource. Scores may be applied to each proposal and the Self-Build Resource project to reflect the projected cost.

Non-Price Criteria

Each proposal may be evaluated on a list of non-price criteria which the Utilities have developed. A score may be assigned to each criteria based on the extent to which the proposal satisfies the Utilities' preferences. The non-price score and price related score for each proposal may be used to determine the ranking of proposals.

The proposals will be evaluated on an overall basis in accordance with the following non-price criteria but each of the Utilities may consider additional non-price criteria in their individual detailed analysis:

Components of Power Cost -	To evaluate risk, the Utilities prefers Proposers that identify the true fixed and variable costs for the resources providing the power (e.g., the Proposer should identify the amount of fixed cost in the capacity charge and the amount of variable costs [fuel, variable operation and maintenance expenses, etc.] in the energy charge).
Contract Flexibility -	The Utilities prefer proposals with reasonable notice provisions that give the Utilities the sole right to increase or decrease the contract term and the amount of purchases.
Dispatchability -	The Utilities prefer provisions that would permit the Utilities to dispatch the resources off-line during periods when the Utilities deem it economical to do so. Dispatchability may also encompass the concept of scheduling power deliveries for economy transactions in a manner that contributes favorably to Utilities' needs.
Fuel Risk -	The Utilities prefer proposals that have firm fuel supply contracts (vs. spot purchases). Other preferred features are increased fuel diversity and decreased fuel price volatility. Multiple suppliers are preferred.
Firm Supply -	Proposals will be evaluated on the availability of generating resources, arrangements for firming or reserved capacity, and penalties for nonperformance.
Experience -	The Utilities prefer Proposers with experience providing services similar to that requested by the Utilities.
Transmission -	The Utilities prefer generating resources that minimize the number of intermediate transmission systems and are deliverable into both the FPL and PEF networks.
Technology -	Proposals utilizing mature technologies are preferable.

20. Final Contract

Any final contract(s) that result from the proposal evaluation and negotiation processes will be submitted to the Utilities respective decision making bodies for approval. The tentative date for approval of contract(s) is shown in Section 4, RFP Schedule.

21. RFP Forms and Attachments

Form 1	-	Notice of Intent to Bid Form
Form 2	-	Proposal Summary Form
Form 3	-	Minimum Requirements Form
Form 4	-	Pricing Proposal Form
Form 5	-	Conflict of Interest Certificate
Form 6	-	Checklist
Attachment A	-	Required Data to be Submitted with Proposals
Attachment B	-	Fuel Forecast (To be provided at the Pre-Bid Conference)

RFP Form 1

FMPA, JEA, RCID & Tallahassee

REQUEST FOR POWER SUPPLY PROPOSALS

Notice of Intent to Bid Form

Due: December 27, 2005 (5:00 PM EPT)

Date: ______________

Project Proposer Name: ______________________________
Title: ______________________________
Company Name: ______________________________
Address: ______________________________
____
Telephone: ______________________________
Fax: ______________________________
E-Mail: ______________________________
Project Name: ______________________________
Project Location: ______________________________
Agreement Term: ______________________________
Generation Technology: ______________________________
Primary Fuel: ______________________________
Specific Entity to Contract with the Utilities: ______________________________

Proposer Classification: (Utility, Qualified Facility, Exempt Wholesale Generator, Power Marketer, etc.)

____

Proposer Qualifications: Describe similar projects developed by Proposer, noting project capacity, location, contract commencement date, contract term, etc.
(Attach additional sheets as needed)

____
____
____
____
____
____

Proposer's Signature: ______________________________
(Duly Authorized)

RFP Form 2

FMPA, JEA, RCID & Tallahassee
REQUEST FOR POWER SUPPLY PROPOSALS

Proposal Summary Form

1. Company/Proposer ______________________

2. Name of Contact ______________________

3. Mailing Address ______________________

4. Telephone ______________________
   Fax ______________________
   E-Mail ______________________
5. Proposed Contract Start Date ______________________

6. Proposed Contract End Date ______________________

7. Proposed Contract Capacity Listing by Resource

Unit Name and Number	Net Rating (MW)	Fuel Type	Location	Proposed Capacity Delivered [1] (MW)	Utility Delivered to (FMPA, JEA, RCID, Tallahassee)	System Delivered to (e.g., PEF or FPL)
				Total Capacity (MW)		

[1] *Capacity delivered to Utilities at interface (receipt) point(s) on PEF or FPL systems.*

8. Proposer certifies that they have reviewed all Addenda including: Addendum ________ through _________.

9. Certification: Proposer hereby certifies that all of the statements and representations made in this proposal package, including attached documents, are true to the best of the Proposer's knowledge and belief. Proposer agrees to be bound by its representations and the terms and conditions of the Request for Proposals:

Signed: ______________________

(Typed): ______________________

Title: ______________________
(Duly Authorized)

Date: ______________________

RFP Form 3
Page 1 of 2

FMPA, JEA, RCID & Tallahassee
REQUEST FOR POWER SUPPLY PROPOSALS

Minimum Requirements Form

In submitting this form, we agree to the items below and/or have provided documents to attest to the information provided as requested below.

Duly Authorized Signature: ______________________ ______________________
(Date)

If the Proposer is an entity proposing a capacity sale from existing resources, the Proposer must provide sufficient documentation to demonstrate that over time the source utility or entity will have sufficient capacity to sell to FMPA as well as to serve its own load, if applicable, and other commitments.

All Proposers must demonstrate the following by attaching appropriate information to this form:

1. Proposers must attend the Pre-Bid Conference and submit a Notice of Intent to Bid by the appropriate dead-line.
2. The capacity and energy proposed are on a first call, non-recallable basis, i.e., as long as the unit(s) from which the capacity is purchased is available, the Utilities have the right to the output of the unit(s) for the duration of the contract. The Utilities' rights must be equal to or superior to any other party's rights to such unit(s) output.
3. All proposals must remain in effect until August 1, 2006, or later if the purchase is to be finalized pending a transmission service request.
4. The minimum capacity amount offered is 100 MW allocated among the Utilities.
5. The minimum term for a proposal is ten (10) years.
6. All generating units providing the proposed capacity must be in operation at least two months prior to the required delivery commencement date of the term of the proposed power supply.
7. Proposals must identify and include the location of each capacity resource and name the originating Balancing Authority. Proposers proposing power supply from a resource(s) located outside of any of the Utilities' Balancing Authority's areas must identify the firm transmission contract path from the power supply(s) up to the Utilities' Balancing Authority.
8. The Proposer must ensure that all emissions allowance requirements will be satisfied and that such costs are included in the proposal.
9. The Proposer must declare ownership or contractual status of a unit, plant or system capacity as described in Section 14.

RFP Form 3
Page 2 of 2

FMPA, JEA, RCID & Tallahassee
REQUEST FOR POWER SUPPLY PROPOSALS

Minimum Requirements Form

(Continued)

10. The Proposer must complete the appropriate RFP Forms 1 through 6 and provide all appropriate information requested in Attachment A. All forms requiring a signature must be signed by a duly authorized official.

11. The Proposer must be willing to provide an adequate Proposal Security and Performance Security prior to entering short-list negotiations.

12. The Proposer must clearly describe any contractual limits on energy utilization or physical limitations on the operation of the resource as described in Attachment A.

13. The proposal must include scheduling provisions for the sale.

14. Each proposal must contain the appropriate Proposal Fee in accordance with Section 9.

15. Proposals for new construction projects are not contingent upon participants by third parties to support the project.

16. If rated by any one or more of the three rating agencies, Proposer must have as a minimum an investment grade credit rating on senior uninsured debt of Baa3 for Fitch, Baa3 for Moody's, or BBB- for Standard & Poor's. If not rated, the Proposer must provide sufficient financial information for the Utilities to evaluate Proposer's financial credit status.

17. Proposers that propose to develop a power generating project to provide power to the Utilities must have developed, and have had in operation for a minimum of one year, at least one currently operating power supply project that is similar to, or larger in size than, the project being proposed. Proposers proposing to provide the Utilities with power from an existing generating resource or a portfolio of resources must have successfully provided similar levels of services to at least one electric utility for a minimum of one year.

FMPA, JEA, RCID & Tallahassee
REQUEST FOR POWER SUPPLY PROPOSALS

Pricing Proposal Form

Capacity Pricing

The Proposer should itemize the capacity pricing as required into various price components (i.e., capital, fixed O&M, etc.). The columns A through E are provided to allow the Proposer to list separate price components. These components should be described on the next page. The Proposer is not required to use all columns provided.

Delivered Capacity Rate								
Period 12 Mo. Ended Dec.	A $/kW-mo.	B $/kW-mo.	C $/kW-mo.	D $/kW-mo.	E $/kW-mo.	Total A-E $/kW-mo.	Capacity kW	Total $000
6/1/2012 to 12/31/2012								
2013								
2014								
2015								
2016								
2017								
2018								
2019								
2020								
2021								
2022								
2023								
2024								
2025								
2026								
2027								
2028								
2029								
2030								
2031								
2032								
2033								
2034								
2035								
2036								
2037								
2038								
2039								
2040								
2041								

2042								

FMPA, JEA, RCID & Tallahassee
REQUEST FOR POWER SUPPLY PROPOSALS

Pricing Proposal Form

Describe the components of and the methodology for determining the capacity rates.

FMPA, JEA, RCID & Tallahassee
REQUEST FOR POWER SUPPLY PROPOSALS

Pricing Proposal Form

Energy Pricing

The Proposer should itemize the energy pricing as required into various price components (fuel, variable O&M, etc.). The columns F through I are provided to allow the Proposer to list separate price components. These components should be described on the next page. The Proposer is not required to use all columns provided.

Delivered Energy Rate									
Period 12 Mo. Ended Dec.	Fuel Cost $/MMBtu	Heat Rate MMBtu/ MWh	F $/MWh	G $/MWh	H $/MWh	I $/MWh	Total F-I $/MWh	Projected Energy MWh	Total $000
6/1/2012 to 12/31/2012									
2013									
2014									
2015									
2016									
2017									
2018									
2019									
2020									
2021									
2022									
2023									
2024									
2025									
2026									
2027									
2028									
2029									
2030									
2031									
2032									
2033									
2034									
2035									
2036									
2037									
2038									
2039									
2040									
2041									

2042									

FMPA, JEA, RCID & Tallahassee
REQUEST FOR POWER SUPPLY PROPOSALS

Pricing Proposal Form

Describe the components of and the methodology for determining the energy rates.

CONFLICT OF INTEREST CERTIFICATE

JEA IFB No. ___________

Proposer must execute this form, if applicable, relative to Florida Statute 112.313. Failure to submit this form, if applicable, shall result in rejection of this bid.

I hereby certify that the following named JEA official(s) and employee(s) having material financial interest(s) (in excess of 5%) in this company have filed Conflict of Interest statements with the Supervisor of Elections, 105 East Monroe Street, Jacksonville, Duval County, Florida, prior to bid opening.

Name	Title or Position	Date of Filing

____
Signature

____
Company Name

____
Name of Certifying Official
(type or print)

____
Business Address

____
City, State, Zip Code

FMPA, JEA, RCID & Tallahassee
REQUEST FOR POWER SUPPLY PROPOSALS

Checklist

All RFP Forms checked below have been included as part of the response package *.

RFP Form 2 - Proposal Summary Form ____________

RFP Form 3 - Minimum Requirements Form ____________

RFP Form 4 - Pricing Proposal Form ____________

RFP Form 5 - Conflict of Interest Certificate ____________

Signature of Proposer: ____

Name of Project: ____

(*) *RFP Form 1 is the Notice of Intent to Bid Form which is sent to the Utilities prior to, and separately from, the proposal package.*

ATTACHMENT A

Required Supply Proposal Data

The following is required for all supply proposals as is applicable. The required data should be provided in sections numbered in accordance with the specific items detailed below. Each section should begin on a new page. Information provided, but not in the requested format, may be disregarded and the proposal rejected for incompleteness. General information (e.g., promotional material, 'boiler plate', etc.) may be provided with the proposal, but only the formatted information will be considered in the event of conflicting data. Any proposal that lacks requested information may be deemed incomplete and may be rejected in the Utilities sole discretion. The Utilities may request additional data or clarifying information from Proposers.

Information requirements are specified for two types of proposals: (i) those involving sales from specific generating unit(s) (a "Generating Unit Sale"); or (ii) a firm sale from a utility system (a "System Sale").

A-1 Generating Unit Power Sale

A-1.1 Identity of Proposer Contact

Provide the full name, business address, telephone, E-Mail address if available, and facsimile number of contact person from whom additional information can be requested.

A-1.2 General Description of Supply Proposals

(a) Provide a general overall executive summary of the Supply Proposals. The description must include identification of each major component of any involved electric generating unit(s), including unit type, unit manufacturer, date of manufacture, manufacturer's nameplate capacity rating, any reratings that have occurred since date of manufacture, location of resources, primary and secondary fuel type, term of contract, sites where similar units have been installed for commercial operation, and other relevant information.

(b) Fully describe the scheduling requirements and dependable capacity of the proposed resource.

A-1.3 Location of Generating Unit(s)

Identify the geographic location of the project and indicate whether or not such area is an attainment or a non-attainment air quality area. If no specific location has been identified, so state. Provide a segment of a USGS map showing geographical location of each generating unit relative to the Utilities service territories and surrounding area with interconnections and transmission lines indicated.

A-1.4 Capacity and Expected Energy Production

(a) Specify the amount of firm capacity offered for the contract period throughout the year under all ambient conditions. Output should be net of parasitic and auxiliary loads.

(b) Indicate the expected total net kilowatt-hours to be delivered to the interface with FPL's and PEF's transmission system or to the Tallahassee or JEA system as applicable under the contract, by hour, for a typical day's operation. Take into account step-up transformer losses, transmission losses to the interface, capacity degradation, and auxiliary loads. Identify limiting conditions (if any).

(c) Show separately, the amount of capacity provided for reserves, or firming service. The Utilities may wish to purchase unreserved capacity and reserves, or firming service, separately.

(d) Provide projected net heat rate curves (net of parasitic and auxiliary loads) for the full range of operations.

(e) Describe performance guarantees for output, heat rate and availability.

A-1.5 Schedule

Specify the time frame when capacity is available. If capacity is provided by a new generating facility, include a schedule for environmental permitting, design, procurement, construction and commissioning of the project, as applicable.

A-1.6 Proposed Agreement Term

(a) Specify proposed contract term.

(b) Specify any and all proposed provisions for renewal or extension, and cancellation notice, identifying any and all proposed conditions for the above to occur, including whether such events are proposed to be mutually or unilaterally determined.

A-1.7 Scheduling Requirements

(a) Specify: (1) annual availability in hours; (2) annual planned maintenance in hours; (3) expected annual full forced outages in hours; (4) expected annual partial forced outages in hours; (5) frequency, in months, and duration, in days, of periodic (less frequently than annually) major overhauls and/or recommended hours of operation between major overhauls.

(b) Specify the expected calendar months for annual planned maintenance to occur.

(c) Please specify any other scheduling requirements.

(d) Describe performance guarantees for forced outage rates and availability.

(e) Contractual limitations on energy utilization (if any).

A-1.8 History of Existing Facilities

(a) If the proposed facility is an existing generator, provide a narrative describing the project's operating history. Include construction start date, test operation start date, commercial operation date, monthly capacity factors, non-fuel operations and maintenance expenses, and net heat rates by month, for at least three (3) years or since commercial operation date. Also include major equipment additions and enhancements and associated costs.

(b) If the proposed facility is comprised of an existing generator(s), provide a narrative describing the project's maintenance history, including: (i) monthly and annual scheduled outages, (ii) number and duration of forced outages, (iii) forced and planned outage rates, (iv) dates and causes of all major equipment breakdowns by year, etc., and (v) all known equipment deficiencies.

A-1.9 The Utilities Rights

Verify that no party has superior rights to the Utilities.

A-1.10 Fuel Information

If the Proposer intends to submit a proposal that will be based on fuel costs other than those set forth in Attachment B as described in Section 5 of the RFP, the proposal must fully describe the fuel source for any proposed generating facility, and any fuel supply contracts, including price and escalation provisions, interruptibility, obligation to deliver, penalties for non-delivery, and dispatchability. Specify project fuel type(s) including for coal, sulfur content, ash content, and heat content, and associated fuel supply information to the extent known, including number and delivery capability of suppliers.

A-1.11 Operations and Maintenance Expenses

Fully describe and itemize all components of operations and maintenance expenses that are included in the proposal and state all assumptions used in the calculation of such expenses. At a minimum, pricing must include the following components to the extent applicable:

(a) Fixed operation and maintenance costs including labor, general equipment maintenance, insurance, property taxes, major maintenance, capital expenditures, and administrative costs.

(b) Variable operation and maintenance costs including limestone, ash and scrubber sludge disposal, ammonia, catalyst replacement, SO_2, NO_X, and mercury allowances, CO_2 taxes (if applicable), water related costs, and other consumables.

(c) If the fuel source requires any emission allowances, the Proposer shall specify if entitlements are now held for the required allowances. If entitlements to required allowances are not held, the Proposer shall identify the source from which allowances will be obtained, and any separate charge proposed to be assessed.

A-2 System Sale

A-2.1 Identity of Proposer Contract

Provide the full name, business address, telephone, and facsimile number of contract person from whom additional information can be requested.

A-2.2 General Description of Supply Proposals

(a) Provide a general overall summary of the Supply Proposals. The description must include identification of each resource in the electric system from which sale is being made (the "System").

(b) Describe the amount of capacity to be provided, the amount of total resources, and projected loads (including the proposal sale) on the System for each year of the proposed contract. Describe the scheduling requirement of the resource.

A-2.3 Location of Generating Facilities

Identify the geographic location of the generating resources on the System and the transmission system which interconnects these resources. Identify the transmission path and intervening transmission systems required to deliver the power in accordance with Section 8 of the RFP.

A-2.4 Capacity and Expected Energy Production

(a) Specify the amount of delivered capacity and maximum energy offered on typical days, months and years, taking into account seasonality of supply (if any) and transmission losses.

(b) Please indicate the firmness of the sale (i.e. verify that no other parties will have superior rights).

A-2.5 Proposed Agreement Term

(a) Specify proposed contract term.

(b) Specify any and all proposed provisions for renewal or extension, and cancellation notice, identifying any and all proposed conditions for the above to occur, including whether such events are proposed to be mutually or unilaterally determined.

A-2.6 Scheduling Requirement

Indicate all scheduling requirements applicable to the proposed system sale.

A-3 General Information

A-3.1 Financial Information

(a) Identify any and all Proposer affiliates.

(b) Provide audited financial statements, if available, or other financial statements for the last three years. Such information must be provided for all entities, including affiliates involved in the transaction. For investor owned utilities, this would include as a minimum, FERC Form 1's and SEC 10K forms. Proposers should also provide where appropriate, the most recent Dunn and Bradstreet report, a description of pending litigation and the most recent annual report.

(c) Most recent credit rating for senior unsecured debt as reported by Fitch, Moody's and/or S&P.

A-3.2 Pricing Information

(a) Specify on the RFP Form 4 - Proposal Pricing form, all proposed payment components and proposed incentive amounts, if any, and the conditions which engage such provisions. The Utilities requires that proposals clearly distinguish energy and capacity pricing components. For example fixed components may include fixed O&M capital, etc. Energy components may include fuel, variable O&M etc.

(b) Specify annual payment stream components, whether explicitly specified or driven by escalation factors. If price escalation factors are proposed, please identify what attribute the proposed factor is to represent (e.g., general inflation, general economic growth, etc.), proposed index or other source data to define the escalator (e.g., CPI, change in GDP, etc.), and Proposers current projection of designated escalator for each applicable time period.

A-3.3 Proposed Financial Security Arrangements

(a) Please describe the Proposal Security and the Performance Security.

(b) Please provide name and credit rating of financial institution providing letters of credit.

A-3.4 Transmission

Proposers are required to provide the following supporting data relating to transmission availability:

(a) A detailed description of the proposed wheeling and interconnection arrangements to deliver power to the Utilities as described in Section 8 of the RFP.

(b) Interconnection points at which the resources used for the sale are interconnected with the transmission provider in whose Balancing Authority the resource is located.

(c) A description of any required new interconnection facilities and estimated costs and cost responsibility for such facilities.

(d) A description of upgrades on the FPL, PEF or in third party transmission systems which may be required to accommodate the project and an estimate of costs and cost responsibility for such facilities.

(e) Backup information that would verify the reasonableness of assumptions and cost data associated with transmission service required for delivery of the proposed capacity and energy from the source(s) of supply to the point of delivery. Also, detailed analyses which will demonstrate that the Proposers' proposal can be qualified as a "network resource" under the FPL and PEF network transmission tariffs. Such analyses should show all assumptions, including, among other things, contract paths, contracting parties, interface capability, intervening parties, and transfer capabilities. The Utilities may verify the transmission studies provided by the Proposer by performing its own load flow studies. Therefore, Proposers are encouraged to submit a hard copy of the transmission analysis results plus the load flow cases in raw data ASCII IBM compatible format (i.e., PTI's PSS/E, GE's PSLF, IEEE common), along with all assumptions used in creating each case and any special instructions for reading the data.

A-3.5 Summary of Proposer's Qualification

(a) Provide a description of the Proposers' qualifications and experience applicable to the developing, designing, financing, constructing, operating and maintaining of the proposed project.

(b) Identify and describe existing generation facilities currently in commercial service on which Proposer has contracted, including (i) the name, address, telephone number, and specific contact of the owner of such facilities; (ii) a description of the facility and its location; (iii) the Proposers' scope of work relating to the project; and (iv) total contract value and duration.

ATTACHMENT B

Fuel Forecast

The current plan is to provide this Attachment at the Pre-Bid Conference.

STEAM COAL PRICE FORECAST FOR SELECTED COALS 2005-2030
CURRENT YEAR $ DOLLARS PER MMBTU (DELIVERED)

SUB-REGION	FLAVOR	MODELED QUALITY Btu/lb.	% SULFUR	Lbs. SO2/ mmBtu	Contract Delivery Year	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
NORTHERN APPALACHIA REGION SELECTED COALS																	
WEST, PA	MID-SULFUR	13,000	1.95	3.00		3.10	2.85	2.63	2.71	2.73	2.77	2.86	2.92	2.97	3.01	3.10	3.17
WEST, PA	HIGH-SULFUR	12,200	3.34	5.48		3.23	3.03	2.60	2.71	2.73	2.75	2.84	2.90	2.96	3.01	3.09	3.16
OHIO	MID-SULFUR	12,150	2.20	3.62		3.03	2.77	2.58	2.74	2.79	2.82	2.91	2.99	3.03	3.09	3.21	3.29
OHIO	HIGH-SULFUR	11,750	3.60	6.13		2.92	2.68	2.69	2.74	2.76	2.80	2.89	2.97	3.00	3.06	3.16	3.23
N. WV	MID-SULFUR	12,900	2.10	3.26		3.20	2.97	2.71	2.68	2.71	2.75	2.83	2.92	2.98	3.01	3.13	3.21
N. WV	HIGH-SULFUR	12,350	3.60	5.83		3.20	2.94	2.73	2.77	2.79	2.84	2.92	2.98	3.03	3.07	3.14	3.21
CENTRAL APPALACHIA REGION SELECTED COALS																	
S. WV-HI BTU-CSX	SUPER-COMPLIANCE	13,150	0.62	0.94		3.56	3.19	2.69	2.49	2.52	2.57	2.65	2.72	2.79	2.86	2.97	3.04
S. WV-HI BTU-NS	SUPER-COMPLIANCE	13,100	0.65	0.99		3.54	3.27	2.82	2.49	2.56	2.60	2.69	2.77	2.81	2.86	3.00	3.07
S. WV-MID BTU-CSX	COMPLIANCE	12,200	0.67	1.10		3.60	3.36	2.90	2.49	2.51	2.54	2.63	2.70	2.76	2.84	2.91	2.98
S. WV-MID BTU-NS	COMPLIANCE	12,350	0.67	1.09		3.64	3.26	2.85	2.50	2.57	2.59	2.67	2.76	2.79	2.85	2.96	3.01
S. WV-MID BTU-CSX	NEAR-COMPLIANCE	12,200	0.82	1.34		3.33	2.93	2.71	2.40	2.42	2.46	2.54	2.61	2.66	2.73	2.84	2.90
S. WV-MID BTU-NS	NEAR-COMPLIANCE	12,250	0.98	1.00		3.44	3.00	2.79	2.42	2.47	2.53	2.60	2.70	2.73	2.78	2.89	2.95
S. WV-MID BTU-CSX	MID-SULFUR	12,500	1.67	2.67		3.10	2.83	2.63	2.39	2.43	2.48	2.53	2.61	2.67	2.74	2.83	2.89
S. WV-MID BTU-NS	MID-SULFUR	12,800	1.67	2.61		2.46	2.39	2.38	2.42	2.46	2.54	2.59	2.69	2.72	2.77	2.88	2.95
E. KY-HI BTU-NS	SUPER-COMPLIANCE	13,100	0.57	0.87		3.58	3.26	2.76	2.48	2.51	2.56	2.64	2.71	2.78	2.85	2.94	3.01
E. KY-HI BTU-CSX	SUPER-COMPLIANCE	13,150	0.65	0.99		2.91	2.77	2.88	2.47	2.54	2.58	2.66	2.75	2.78	2.85	2.98	3.05
E. KY-MID BTU-NS	COMPLIANCE	12,700	0.67	1.06		3.43	3.12	2.70	2.40	2.42	2.45	2.52	2.59	2.65	2.73	2.80	2.86
E. KY-MID BTU-CSX	COMPLIANCE	12,500	0.69	1.10		3.61	3.11	2.74	2.47	2.53	2.55	2.64	2.72	2.76	2.81	2.92	2.97
E. KY-MID BTU-NS	NEAR-COMPLIANCE	12,300	1.00	1.63		3.26	2.84	2.57	2.36	2.40	2.46	2.53	2.61	2.67	2.74	2.84	2.89
E. KY-MID BTU-CSX	NEAR-COMPLIANCE	12,600	1.12	1.78		3.32	2.88	2.69	2.33	2.37	2.44	2.51	2.60	2.64	2.68	2.79	2.84
E. KY-MID BTU-NS	MID-SULFUR	12,100	1.74	2.88		2.59	2.49	2.41	2.43	2.47	2.52	2.60	2.68	2.74	2.81	2.91	2.96
E. KY-MID BTU-CSX	MID-SULFUR	12,300	1.75	2.85		2.54	2.46	2.41	2.37	2.41	2.47	2.54	2.64	2.67	2.72	2.84	2.90
ILLINOIS BASIN SELECTED COALS																	
INDIANA	COMPLIANCE	11,100	0.58	1.05		4.15	3.78	3.41	2.85	2.90	2.93	2.97	3.06	3.12	3.17	3.23	3.27
INDIANA	NEAR-COMPLIANCE	10,950	1.10	2.01		3.37	3.02	2.86	2.72	2.74	2.79	2.84	2.91	2.96	3.02	3.13	3.17
INDIANA	MID-SULFUR	11,000	1.70	3.09		3.29	3.01	2.78	2.70	2.73	2.82	2.90	2.96	2.97	3.02	3.12	3.20
INDIANA	HIGH-SULFUR	11,100	3.05	5.50		2.93	2.73	2.60	2.65	2.66	2.73	2.78	2.83	2.88	2.91	3.00	3.05
ILLINOIS	NEAR-COMPLIANCE	11,800	1.30	2.20		3.10	2.83	2.68	2.55	2.58	2.62	2.67	2.74	2.79	2.86	2.96	3.01
ILLINOIS	MID-SULFUR	11,550	1.70	2.94		3.12	2.84	2.66	2.63	2.65	2.70	2.74	2.81	2.86	2.92	3.01	3.05
ILLINOIS	HIGH-SULFUR	11,150	3.00	5.38		3.03	2.73	2.62	2.62	2.64	2.70	2.74	2.79	2.82	2.88	2.95	2.98
W. KY	NEAR-COMPLIANCE	11,900	0.98	1.65		3.11	2.97	2.96	2.81	2.76	2.82	2.89	2.93	2.95	3.01	3.08	3.13
W. KY	HIGH-SULFUR	11,600	3.19	5.50		2.80	2.46	2.46	2.53	2.56	2.61	2.66	2.70	2.75	2.80	2.86	2.90
WYOMING POWDER RIVER BASIN																	
PRB-N.GILLETTE	COMPLIANCE	8,350	0.44	1.05		2.87	2.81	2.44	2.45	2.50	2.51	2.54	2.60	2.62	2.66	2.75	2.80
PRB-S.GILLETTE	SUPER-COMPLIANCE	8,400	0.36	0.85		2.94	2.87	2.51	2.47	2.51	2.53	2.56	2.60	2.62	2.66	2.76	2.80
PRB-N.WRIGHT	SUPER-COMPLIANCE	8,800	0.35	0.80		2.91	2.84	2.48	2.43	2.47	2.48	2.51	2.56	2.58	2.62	2.71	2.76
PRB-S.WRIGHT	ULTRA-COMPLIANCE	8,800	0.24	0.55		3.04	2.98	2.61	2.48	2.53	2.53	2.56	2.62	2.64	2.69	2.82	2.87
LATIN AMERICA																	
LATIN AMER	HI BTU PANAMAX/JAX	13,000	0.6	0.92		2.73	2.86	2.99	3.06	3.10	3.06	2.99	2.94	3.06	3.09	3.11	3.02
LATIN AMER	MID BTU PANANMAX/JAX	12,000	1.17	1.95		2.66	2.88	3.01	3.08	3.14	3.12	3.05	2.99	3.12	3.17	3.19	3.10
PETROLEUM COKE																	
Pet Coke (Gulf Region)	Low Sulfur, High Grind	14,000				1.56	1.51	1.65	1.74	1.74	1.75	1.68	1.70	1.77	1.91	1.97	2.00
	Low Sulfur, Low Grind	14,000				1.51	1.46	1.60	1.69	1.69	1.69	1.63	1.65	1.71	1.85	1.91	1.94
Pet Coke (Gulf Region)	High Sulfur, High Grind	14,000				1.38	1.33	1.46	1.55	1.55	1.54	1.48	1.49	1.55	1.69	1.74	1.77
	High Sulfur, Low Grind	14,000				1.33	1.28	1.41	1.49	1.49	1.49	1.42	1.43	1.49	1.63	1.68	1.70
NATURAL GAS																	
Commodity	$/MMBtu					9.25	8.77	7.75	6.76	6.06	5.91	6.18	6.47	6.76	7.07	7.39	7.72
Commodity+Variable Charges	$/MMBtu					9.58	9.10	8.05	7.02	6.31	6.16	6.43	6.73	7.03	7.35	7.68	8.03
RESIDUAL FUEL OIL AND DIESEL																	
GC #6 1%	$/Bbl					7.42	7.02	6.93	6.84	6.69	6.62	6.74	6.91	7.08	7.27	7.52	7.80
GC #6 3%	$/Bbl					6.11	5.84	5.79	5.74	5.64	5.59	5.69	5.84	5.98	6.14	6.35	6.58
GC #2 0.5%	$/Bbl					13.96	12.59	12.31	12.06	11.70	11.52	11.71	12.00	12.30	12.63	13.09	13.60
GC #2 0.05%	$/Bbl					14.19	12.78	12.49	12.23	11.86	11.66	11.86	12.15	12.45	12.78	13.26	13.77
GC #2 0.0015%	$/Bbl					14.64	13.54	13.24	12.99	12.66	12.69	12.79	13.01	13.24	13.50	13.99	14.53

SUB-REGION	FLAVOR	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
NORTHERN APPALACHIA REGION SELECTED COALS														
WEST, PA	MID-SULFUR	3.33	3.43	3.46	3.59	3.67	3.82	3.92	4.02	4.10	4.24	4.36	4.48	4.61
WEST, PA	HIGH-SULFUR	3.33	3.45	3.47	3.58	3.66	3.81	3.92	4.01	4.13	4.26	4.39	4.52	4.66
OHIO	MID-SULFUR	3.55	3.64	3.69	3.81	3.89	4.06	4.21	4.35	4.43	4.62	4.77	4.93	5.10
OHIO	HIGH-SULFUR	3.50	3.58	3.79	3.86	3.95	4.13	4.28	4.38	4.47	4.64	4.79	4.94	5.09
N. WV	MID-SULFUR	3.36	3.45	3.49	3.61	3.68	3.85	3.94	4.05	4.12	4.27	4.39	4.51	4.64
N. WV	HIGH-SULFUR	3.35	3.46	3.49	3.61	3.70	3.82	3.90	3.98	4.08	4.18	4.28	4.38	4.49
CENTRAL APPALACHIA REGION SELECTED COALS														
S. WV-HI BTU-CSX	SUPER-COMPLIANCE	3.15	3.20	3.29	3.43	3.49	3.64	3.70	3.86	3.95	4.08	4.21	4.33	4.47
S. WV-HI BTU-NS	SUPER-COMPLIANCE	3.16	3.20	3.30	3.43	3.50	3.63	3.74	3.84	3.94	4.07	4.19	4.31	4.44
S. WV-MID BTU-CSX	COMPLIANCE	3.08	3.15	3.21	3.33	3.40	3.53	3.62	3.71	3.80	3.92	4.03	4.14	4.25
S. WV-MID BTU-NS	COMPLIANCE	3.10	3.17	3.23	3.36	3.45	3.60	3.73	3.83	3.91	4.07	4.20	4.33	4.47
S. WV-MID BTU-CSX	NEAR-COMPLIANCE	3.00	3.07	3.13	3.23	3.30	3.43	3.52	3.61	3.68	3.80	3.90	4.01	4.11
S. WV-MID BTU-NS	NEAR-COMPLIANCE	3.04	3.10	3.15	3.29	3.37	3.52	3.64	3.74	3.81	3.96	4.08	4.21	4.34
S. WV-MID BTU-CSX	MID-SULFUR	2.99	3.06	3.11	3.22	3.28	3.43	3.55	3.64	3.71	3.86	3.98	4.10	4.23
S. WV-MID BTU-NS	MID-SULFUR	3.05	3.11	3.16	3.30	3.38	3.53	3.66	3.75	3.82	3.97	4.09	4.22	4.35
E. KY-HI BTU-NS	SUPER-COMPLIANCE	3.13	3.18	3.25	3.38	3.44	3.59	3.68	3.80	3.89	4.02	4.15	4.27	4.40
E. KY-HI BTU-CSX	SUPER-COMPLIANCE	3.14	3.18	3.28	3.40	3.48	3.60	3.71	3.81	3.91	4.04	4.16	4.28	4.41
E. KY-MID BTU-NS	COMPLIANCE	2.95	3.03	3.08	3.19	3.26	3.39	3.48	3.60	3.66	3.79	3.90	4.02	4.14
E. KY-MID BTU-CSX	COMPLIANCE	3.06	3.13	3.18	3.32	3.41	3.56	3.69	3.78	3.87	4.02	4.15	4.29	4.42
E. KY-MID BTU-NS	NEAR-COMPLIANCE	2.99	3.07	3.12	3.20	3.28	3.41	3.51	3.61	3.68	3.81	3.92	4.04	4.16
E. KY-MID BTU-CSX	NEAR-COMPLIANCE	2.93	2.99	3.05	3.18	3.26	3.40	3.52	3.62	3.70	3.84	3.97	4.09	4.22
E. KY-MID BTU-NS	MID-SULFUR	3.07	3.14	3.19	3.27	3.35	3.48	3.59	3.69	3.76	3.89	4.00	4.12	4.24
E. KY-MID BTU-CSX	MID-SULFUR	3.00	3.07	3.12	3.25	3.33	3.48	3.59	3.68	3.76	3.90	4.01	4.14	4.26
ILLINOIS BASIN SELECTED COALS														
INDIANA	COMPLIANCE	3.34	3.41	3.47	3.55	3.60	3.72	3.81	3.87	3.92	4.03	4.11	4.20	4.29
INDIANA	NEAR-COMPLIANCE	3.27	3.44	3.53	3.60	3.63	3.75	3.86	3.91	3.95	4.07	4.15	4.24	4.33
INDIANA	MID-SULFUR	3.28	3.40	3.46	3.51	3.54	3.67	3.76	3.84	3.91	4.02	4.12	4.22	4.32
INDIANA	HIGH-SULFUR	3.17	3.27	3.29	3.37	3.42	3.54	3.62	3.69	3.75	3.86	3.95	4.04	4.13
ILLINOIS	NEAR-COMPLIANCE	3.14	3.20	3.24	3.34	3.40	3.54	3.62	3.72	3.78	3.90	4.00	4.11	4.22
ILLINOIS	MID-SULFUR	3.14	3.21	3.25	3.33	3.39	3.52	3.62	3.70	3.77	3.89	3.99	4.10	4.20
ILLINOIS	HIGH-SULFUR	3.06	3.14	3.16	3.23	3.30	3.42	3.51	3.65	3.67	3.81	3.92	4.03	4.15
W. KY	NEAR-COMPLIANCE	3.21	3.28	3.33	3.44	3.47	3.61	3.70	3.78	3.83	3.95	4.05	4.15	4.25
W. KY	HIGH-SULFUR	2.97	3.05	3.07	3.15	3.19	3.31	3.37	3.43	3.49	3.59	3.67	3.75	3.83
WYOMING POWDER RIVER BASIN														
PRB-N.GILLETTE	COMPLIANCE	2.84	2.89	2.93	3.11	3.16	3.41	3.47	3.54	3.58	3.74	3.85	3.96	4.08
PRB-S.GILLETTE	SUPER-COMPLIANCE	2.85	2.89	2.94	3.12	3.17	3.41	3.47	3.55	3.59	3.74	3.85	3.97	4.08
PRB-N.WRIGHT	SUPER-COMPLIANCE	2.80	2.84	2.89	3.07	3.12	3.37	3.43	3.50	3.54	3.70	3.81	3.92	4.04
PRB-S.WRIGHT	ULTRA-COMPLIANCE	2.91	2.92	3.00	3.11	3.16	3.39	3.44	3.52	3.56	3.71	3.81	3.92	4.03
LATIN AMERICA														
LATIN AMER	HI BTU PANAMAX/JAX	2.92	2.97	3.09	3.14	3.11	3.10	3.24	3.26	3.33	3.24	3.36	3.40	3.44
LATIN AMER	MID BTU PANANMAX/JAX	3.00	3.05	3.18	3.23	3.20	3.19	3.34	3.36	3.43	3.34	3.47	3.52	3.55
PETROLEUM COKE														
Pet Coke (Gulf Region)	Low Sulfur, High Grind	2.00	2.10	2.17	2.24	2.26	2.25	2.40	2.51	2.53	2.52	2.61	2.74	2.83
	Low Sulfur, Low Grind	1.93	2.03	2.10	2.17	2.18	2.17	2.32	2.43	2.45	2.44	2.52	2.65	2.74
Pet Coke (Gulf Region)	High Sulfur, High Grind	1.75	1.85	1.91	1.98	1.99	1.98	2.12	2.22	2.23	2.22	2.30	2.42	2.51
	High Sulfur, Low Grind	1.69	1.78	1.84	1.91	1.92	1.90	2.04	2.14	2.15	2.13	2.21	2.33	2.42
NATURAL GAS														
Commodity	$/MMBtu	8.08	8.45	8.82	9.23	9.65	10.09	10.55	11.03	11.52	12.05	12.60	13.17	13.77
Commodity+Variable Charges	$/MMBtu	8.40	8.78	9.17	9.59	10.02	10.48	10.96	11.45	11.96	12.51	13.08	13.67	14.29
RESIDUAL FUEL OIL AND DIESEL														
GC #6 1%	$/Bbl	8.09	8.39	8.70	9.03	9.36	9.70	10.05	10.54	10.80	11.19	11.60	12.02	12.45
GC #6 3%	$/Bbl	6.82	7.06	7.32	7.58	7.85	8.13	8.42	8.81	9.03	9.35	9.67	10.01	10.36
GC #2 0.5%	$/Bbl	14.13	14.68	15.25	15.85	16.47	17.11	17.78	18.47	19.19	19.95	20.73	21.53	22.38
GC #2 0.05%	$/Bbl	14.31	14.87	15.46	16.06	16.70	17.35	18.03	18.74	19.47	20.24	21.04	21.86	22.72
GC #2 0.0015%	$/Bbl	15.09	15.67	16.27	16.90	17.55	18.22	18.93	19.65	20.41	21.21	22.03	22.88	23.76