Ten Year Site Plan

JEA®

Building Community®

April 2009

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List of Abbreviations

Type of Generation Units

CA	Combined Cycle - Steam Turbine Portion, Waste Heat Boiler (only)
CC	Combined Cycle
CT	Combined Cycle – Combustion Turbine Portion
GT	Combustion Turbine
FC	Fluidized Bed Combustion
IC	Internal Combustion
ST	Steam Turbine, Boiler, Non-Nuclear

Status of Generation Units

FC	Existing generator planned for conversion to another fuel or energy source
M	Generating unit put in deactivated shutdown status
P	Planned, not under construction
RT	Existing generator scheduled to be retired
RP	Proposed for repowering or life extension
TS	Construction complete, not yet in commercial operation
U	Under construction, less than 50% complete
V	Under construction, more than 50% complete

Types of Fuel

BIT	Bituminous Coal
FO2	No. 2 Fuel Oil
FO6	No. 6 Fuel Oil
MTE	Methane
NG	Natural Gas
SUB	Sub-bituminous Coal
PC	Petroleum Coke
WH	Waste Heat

Fuel Transportation Methods

PL	Pipeline
RR	Railroad
TK	Truck
WA	Water

Introduction

The Florida Public Service Commission (FPSC) is responsible for ensuring that Florida's electric utilities plan, develop, and maintain a coordinated electric power grid throughout the state. The FPSC must also ensure that electric system reliability and integrity is maintained, that adequate electricity at a reasonable cost is provided, and that plant additions are cost-effective. In order to carry out these responsibilities the FPSC must have information sufficient to assure that an adequate, reliable, and cost-effective supply of electricity is planned and provided.

The Ten-Year Site Plan (TYSP) provides information and data that will facilitate the FPSC's review. This TYSP reports the environmentally sound, power supply strategy, which provides reliable electric service at the lowest practical cost to JEA's customers. The report covers a planning period from January 1, 2009 to December 31, 2018.

1.0 Description of Existing Facilities

1.1 Power Supply System Description

1.1.1 System Summary

JEA is the eighth largest municipally owned electric utility in the United States in terms of number of customers. 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 and serves more than 414,000 customers.

JEA consists of three financially separate entities: the JEA Electric System, the St. Johns River Power Park bulk power system, and the Robert W. Scherer bulk power system. The total net capability of JEA's generation system is 3,621 MW in the winter and 3,371MW in the summer. Details of the existing facilities are displayed in TYSP Schedule 1.

The Electric System

The Electric System consists of generating facilities located on three plant sites within the City; the J. Dillon Kennedy Generating Station (Kennedy), the Northside Generating Station (Northside), and the Brandy Branch Generating Station (Brandy Branch). Collectively, these plants consist of two dual-fired (petroleum coke/coal) Circulating Fluidized Bed steam turbine-generator units (Northside steam Units 1 and 2); one dual-fired (oil/gas) steam turbine-generator unit (Northside steam Unit 3); four dual-fired (gas/diesel) combustion turbine-generator units (Kennedy CT 7, Brandy Branch CTs 1, 2, and 3); five diesel-fired combustion turbine-generator units (Kennedy CTs 3 and Northside CTs 3, 4, 5, and 6); and one combined cycle heat recovery steam generator unit (Brandy Branch steam Unit 4).

The Bulk Power Systems

St. John's River Power Park

The St. Johns River Power Park (SJRPP) is jointly owned by JEA (80 percent) and FP&L (20 percent). SJRPP consists of two nominal 638 MW bituminous coal fired units located north of the Northside Generating Station in Jacksonville, FL. Unit 1 began commercial operation in March 1987 and Unit 2 followed in May 1988. The two units have operated efficiently since commercial operation.

Although JEA is the majority owner of SJRPP, both owners are entitled to 50 percent of the output of SJRPP. Since FP&L's ownership is only 20 percent, JEA has agreed to sell, and FPL has agreed to purchase, on a "take-or-pay" basis, 37.5 percent of JEA's 80 percent share of the generating capacity and related energy of SJRPP. This sale will continue until the earlier of the Joint Ownership Agreement expiration in 2022 or the realization of the sale limits. For the purposes of this Ten Year Site Plan, the 37.5% sale to FP&L is suspended as of April 2016.

Robert W. Scherer Generating Station

Robert W. Scherer Unit 4 is a coal-fired generating unit with a net output of 846 MW located in Monroe County, Georgia. JEA and FP&L have purchased an undivided interest of this unit from Georgia Power Company. JEA has a 23.6 percent ownership interest in Unit 4 (200 net MW) and proportionate ownership interests in associated common facilities and the associated coal stockpile. JEA purchased 150 megawatts of Scherer Unit 4 in July 1991, and purchased an additional 50 megawatts in June 1995. Georgia ITS delivers the power from the unit to the jointly owned 500 kV transmission lines.

1.1.2 Purchased Power

Southern Company Unit Power Sales

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. These capacity obligations are firm and subject only to the availability of Miller Units 1 through 4 and Scherer Unit 3. The capacity and energy are priced based on the specific cost of these units. In addition, JEA occasionally purchases economy interchange power from Southern Company over and above the UPS. JEA plans to continue to hold the transmission rights for this capacity after the expiration of the UPS Purchase.

Constellation Energy Commodities Group, Inc

Constellation Energy Commodities Group, Inc (Constellation) and JEA entered into a power purchase and sale agreement in October 2006. The purchase power agreement entitles JEA to 75 MW, 150 MW, and 150 MW of peaking capacity and energy for the three consecutive winter seasons 2007/08 through 2009/10. The contract states that Constellation will deliver the firm energy to the Georgia side of the Florida /Georgia ITS.

Clean Power

In 2004, JEA issued a Request for Proposal (RFP) for renewable resources. As a result of this RFP, JEA has under contract 9.6 MW of renewable resources. The contract is for landfill gas generation from Trailridge landfill located in west of Duval County. These resources are included in this TYSP.

Nuclear Generation

In March 2008, the JEA Board of Directors approved the pursuit of nuclear energy partnerships with the goal of providing 10 percent of JEA's power from nuclear sources. Adding power from nuclear sources to JEA's portfolio is part of a strategy for greater regulatory diversification and fuel diversification. Meeting this goal will result in a smaller carbon footprint for JEA's customers.

In June 2008, JEA entered into a purchase power agreement (PPA) with the Municipal Electric Authority of Georgia (MEAG) for a portion of MEAG's entitlement to Vogtle Units 3 and 4, which are proposed new nuclear units to be constructed at the existing Plant Vogtle located in Burke County, GA. Under this PPA, JEA will be entitled to a total of 206 MW of firm capacity from the proposed units. After accounting for transmission losses, JEA's is anticipating to receive a total of 200 MW of net firm capacity from the proposed units. For purposes of the analyses, it has been assumed that 100 MW (net) of capacity is available to JEA beginning January 1, 2016 from Vogtle Unit 3, and an additional 100 MW (net) is available to JEA beginning January 1, 2017 from Vogtle Unit 4.

Table 1-1: JEA Purchased Power Schedule

Contract	Contract Start Date	Contract End Date	MW [1]	Product Type
Southern Company	January 1980	June 1, 2010	207	Annual
Constellation	December 2007	March 15, 2010	150	Winter Only
Landfill Energy Systems	December 2008	January 2019	9.6	Annual
MEAG	January 2016 & 2017	December 2036 & 2037	200	Annual

[1] Capacity level may vary over contract term.

The Energy Authority

The Energy Authority (TEA), actively trades energy with a large number of counterparties throughout the United States, and is generally able to acquire capacity and energy from other market participants when any of TEA's members, including JEA, require additional resources. TEA generally acquires the necessary short-term purchase for the season of need based on market conditions among a number of potential suppliers within Florida and Georgia. TEA has reserved firm transmission rights across the Georgia ITS to the Florida/Georgia border, therefore capacity from generating units located in Georgia should provide levels of reliability similar to capacity

Schedule 1: Existing Generating Facilities
As of December 31, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Plant	Unit		Unit	Fuel Type		Fuel Transport		Commercial In-Service	Expected Retirement	Gen Max Nameplate	Net MW Capability			
Name	Number	Location	Type	Primary	Alt.	Primary	Alt.	Mo/Yr	Mo/Yr	kW	Summer	Winter	Ownership	Status
Kennedy										372,400	201	254		
	3	12-031	GT	FO2		WA	TK	7/1973	(a)	168,600	51	63	Utility	(b)
	7	12-031	GT	NG	FO2	PL	WA	6/2000		203,800	150	191	Utility	
Northside										1,263,700	1,322	1,356		
	1	12-031	ST	PC	BIT	WA	RR	2003	(a)	350,000	293	293	Utility	
	2	12-031	ST	PC	BIT	WA	RR	2002	(a)	350,000	293	293	Utility	
	3	12-031	ST	NG	FO6	PL	WA	7/1977	(a)	563,700	524	524	Utility	
	3-6	12-031	GT	FO2		WA	TK	1/1975	(a)	248,400	212	246	Utility	
Brandy Branch										676,000	651	796		
	1	12-031	GT	NG	FO2	PL	TK	5/2001	(a)	203,800	150	191	Utility	
	2	12-031	CT	NG	FO2	PL	TK	5/2001	(a)	203,800	150	191	Utility	
	3	12-031	CT	NG	FO2	PL	TK	5/2001	(a)	203,800	150	191	Utility	
	4	12-031	CA	WH				1/2005	(a)	268,400	201	223	Utility	
Girvin Landfill	1-2	12-031	IC	NG		PL		6/1997	(a)	1.2	1.2	1.2	Utility	
St. Johns River Power Park										1,359,200	1,002	1,020		
	1	12-031	ST	BIT/PC		RR	WA	3/1987	3/2027	679,600	501	510	Joint	(c)
	2	12-301	ST	BIT/PC		RR	WA	5/1988	5/2028	679,600	501	510	Joint	(c)
Scherer	4	13-207	ST	SUB	BIT	RR	RR	2/1989	2/2029	846,000	194	194	Joint	(d)
JEA System Total											**3,371**	**3,621**		

NOTES:
(a) Units expected to be maintained throughout the study period.
(b) Unit will be retired when Kennedy CT 8 achieves first fire in April 2009.
(c) Net capability reflects the JEA's 80% ownership of Power Park. Nameplate is original nameplate of the unit.
(d) Nameplate and net capability reflects the JEA's 23.64% ownership in Scherer 4.
(e) Numbers may not add due to rounding.

available within Florida. TEA, with input from JEA, selects the best offer. TEA then enters into back-to-back power purchase agreements with the supplier and with the purchaser, JEA.

TEA's ability to acquire capacity and/or energy and TEA's firm transmission rights across the Georgia ITS gives JEA a degree of assurance that a plan which includes short-term market purchases is viable. In the Ten Year Site Plan, JEA identifies areas of seasonal, capacity needs in which JEA will engage TEA for acquisition of capacity during those seasons.

Cogeneration

JEA encourages and continues to monitor opportunities for cogeneration. Cogeneration facilities reduce the demand from JEA's system and/or provide additional capacity to the system. JEA purchases power from four customer-owned qualifying facilities (QF's), as defined in the Public Utilities Regulatory Policy Act of 1978, having a total installed summer peak capacity of 13 MW and winter peak capacity of 14 MW. JEA purchases energy from these QF's on as-available, non-firm basis. Table 1-2 lists JEA customers have Qualifying Facilities located within JEA's service territory.

1.1.3 Power Sales Agreements

Florida Public Utilities Company

JEA furnishes wholesale power to Florida Public Utilities Company (FPU) for resale to the City of Fernandina Beach in Nassau County, north of Jacksonville. In September 2006, JEA and FPU signed a 10 year renewal agreement which began January 1, 2008 and extends through December 31, 2017. In this report, it is assumed that JEA will serve FPU throughout this TYSP reporting period. Sales to FPU in 2008 totaled 424 GWh or 3.13% of JEA's total system energy requirement.

Table 1-2: JEA Service Territory Qualifying Facilities

Cogenerator Name	Unit Type	In-Service Date	Net Capability(1) – MW	
			Summer	Winter
Anheuser Busch	COG(2)	Apr-88	8	9
Baptist Hospital	COG	Oct-82	3	3
Ring Power Landfill	SPP(3)	Apr-92	1	1
St Vincent's Hospital	COG	Dec-91	1	1
Total			13	14

Notes:
(1) Net generating capability, not net generation sold to JEA.
(2) Cogenerator.
(3) Small Power Producer.

1.2 Transmission and Distribution

1.2.1 Transmission and Interconnections

The JEA transmission system consists of 728 circuit-miles of bulk power transmission facilities operating at four voltage levels: 69 kV, 138 kV, 230 kV, and 500 kV (Figure 1-1).

The 500 kV transmission lines are jointly owned by JEA and FPL and complete the path from FPL's Duval substation (to the west of JEA's system) to the Florida interconnect at the Georgia Integrated Transmission System (ITS). Along with JEA and FPL, Progress Energy Florida and the City of Tallahassee each also own transmission interconnections with the Georgia ITS. JEA's first contingency import entitlement over these transmission lines is 1,228 MW out of 3,600 MW.

The 230 kV and 138 kV transmission system provides a backbone around JEA's service territory, with one river crossing in the north and no river crossings in the south, leaving an open loop. The 69 kV transmission system extends from JEA's core urban load center to the northwest, northeast, east, and southwest to fill in the area not covered by the 230 kV and 138 kV transmission backbone.

JEA owns and operates three 230 kV tie-lines terminating at FPL's Duval substation in Duval County, one 230 kV tie-line terminating at Beaches Energy's Sampson substation (FPL metered tie-line) in St. Johns County, one 230 kV tie-line terminating at Seminole Electric Cooperative's Black Creek substation in Clay County, and one 138 kV tie-line terminating at Beaches Energy's Penman Road substation.

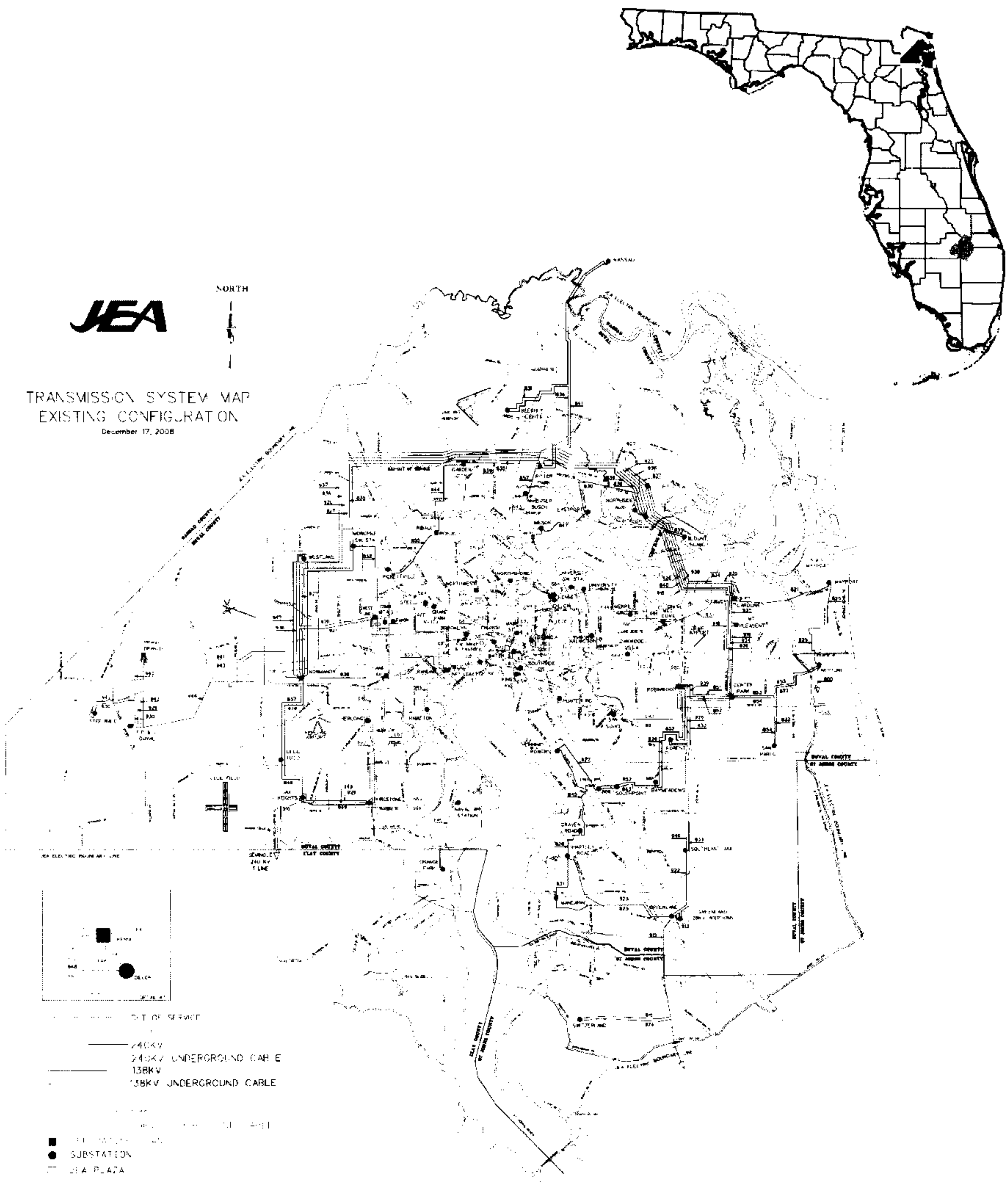
JEA also owns and operates a 138 kV transmission loop that extends from the 138 kV backbone north to the Nassau substation, where JEA delivers wholesale power to FPU for resale within the City of Fernandina Beach, Nassau County, Florida.

1.2.2 Transmission System Considerations

JEA continues to evaluate and upgrade the bulk power transmission system as necessary to provide reliable electric service to its customers. JEA continually assesses, in compliance with North American Electric Reliability Corporation (NERC) and Florida Reliability Coordinating Council's (FRCC) standards, the needs and options for increasing the capability of the transmission system.

JEA performs system assessments using JEA's published Transmission Planning Process in conjunction with and as an integral part of the FRCC'S published Regional Transmission Planning Process which facilitates coordinated planning by all transmission providers, owners, and stakeholders with the FRCC Region. FRCC's members include investor owned utilities, municipal utilities, a federal power agency,

Figure 1-1: JEA Transmission/Generation Facilities System Map



power marketers, and independent power producers. The FRCC Board of Directors has the responsibility to ensure that the FRCC Regional Transmission Planning Process is fully implemented. The FRCC Planning Committee, which includes representation by all FRCC members, directs the FRCC Transmission Working Group, in conjunction with the FRCC Staff, to conduct the necessary studies to fully implement the FRCC Regional Transmission Planning Process. The FRCC Regional Transmission Planning Process meets the principles of the Federal Energy Regulatory Commission (FERC) Final Rule in Docket No. RM05-35-000 (1) coordination, (2) openness, (3) transparency, (4) information exchange, (5) comparability, (6) dispute resolution, (7) regional coordination, (8) economic planning studies, and (9) cost allocation for new projects.

1.2.3 Transmission Service Requirements

In addition to JEA's obligation to serve JEA's native retail territorial load, JEA also has contractual obligations to provide transmission service for:

- the delivery of FPL's share of SJRPP energy output from the plant to FPL's interconnections
- the delivery of Cedar Bay's energy output from the plant to FPL's interconnections
- the delivery of backup, non-firm, as available tie capability for Beaches Energy System

JEA also engages in market transmission service obligations via the Open Access Same-time Information System (OASIS) where daily, weekly, monthly, and annual firm and non-firm transmission requests are submitted by potential transmission service subscribers.

1.2.4 Distribution

The JEA distribution system operations at three primary voltage levels; 4.16 kV, 13.2 kV, and 26.4 kV. The 26.4 kV system serves approximately 86% of JEA's load, including 75% of the 4.16 kV substations. The current standard is to serve all new distribution loads, except loads in the downtown network, with 26.4 kV systems. Conversion of the aging 4 kV infrastructure continues to be implemented. JEA has approximately 6200 miles of distribution circuits of which approximately half is underground.

1.3 Demand Side Management

1.3.1 Interruptible Load

Interruptible load is non-firm load that can be shed during times of peak demand, reducing the need for capacity resources to meet peak demands. JEA forecasts 121 MW and 167 MW of interruptible load in the winter and summer of 2009, respectively. The interruptible load represents approximately 4.0 percent of the total peak demand in the winter of 2009 and 5.7 percent of the forecasted total peak demand in the summer of 2009. JEA forecasts that its interruptible load will remain constant throughout the forecast period.

1.3.2 Demand Side Management

In 2004, JEA studied numerous Demand Side Management (DSM) measures, evaluated the measures using the Commission-approved Florida Integrated Resource Evaluator (FIRE) model, and developed goals and a plan based upon these results. The Rate-Impact Measure or RIM test was used to determine the cost-effectiveness of the DSM alternatives appropriate for a municipal utility. Some investor-owned utilities in the state also use the RIM test to determine cost-effective DSM alternatives. None of the alternatives tested were found to be cost-effective for JEA, at that time. The inability to find cost-effective DSM measures was primarily due to the low cost of new generation, high efficiency of new generation, low interest rates, and low fuel price projections. In August 2004, the PSC approved JEA's Plan for zero DSM goals for 2005-2014.

JEA agreed to continue several DSM programs, including residential energy audits, commercial energy audits, and community conservation initiatives. With the rising costs of generation technologies and all fuel types, JEA has continued to look for cost-effective DSM measures.

In fiscal year 2006/07, JEA contracted with Summit Blue Consulting to identify potential DSM programs for JEA over the five year period, 2008 – 2012. The RIM test was used to determine the cost-effectiveness of the portfolio of DSM programs recommended. Summit Blue recommended two program types in the portfolio: Energy Efficiency programs (EE) and Demand Response (DR) programs. JEA is establishing the following programs and will be monitoring their performance.

Energy Efficiency Programs

- Energy Efficient Product Rebates
- Low income weatherization

Demand Response Programs

- Direct Load Control (DLC)

JEA's DSM programs and Planning Reserve Guidelines are currently being further evaluated to determine a DSM plan that, with JEA's existing non-firm load, will be achievable and robust.

1.4 Clean Power and Renewable Energy

JEA recognizes the importance of integrating renewable energy into its power supply portfolio. To that end, JEA has pursued several clean power initiatives and is in the process of evaluating potential new renewable energy resources. The remainder of this section discusses JEA's Clean Power Program, JEA's existing renewable energy resources, and potential new renewable energy resources being evaluated by JEA.

1.4.1 Clean Power Programs

Since 1999, JEA has worked closely with the Sierra Club of Northeast Florida (Sierra Club), the American Lung Association (ALA), and local environmental groups to establish a process to maintain an action plan entitled "Clean Power Action Plan." The "Clean Power Action Plan" has an Advisory Panel which is comprised of participants from the Jacksonville community. These local members provide guidance and recommendations to JEA in the development and implementation of the Clean Power Program. Current members of the Advisory Panel include the Sierra Club, ALA, and the newest member, the City of Jacksonville Environmental Protection Board.

JEA has made considerable progress related to clean power initiatives. This progress includes installation of clean power systems, commitment to purchase power agreements, legislative and public education activities, and research into and development of clean power technologies.

JEA currently has approximately 82 MW of capacity committed toward its Clean Power Program goal, including approximately 321 kW of solar photovoltaic (PV) capacity, 9 MW of solar thermal capacity, 6 MW in landfill biogas capacity, 800 kW in digester biogas capacity, 10 MW of wind capacity, 9.6 MW of a landfill project, and 43 MW of generating unit efficiency improvements.

1.4.2 Renewable Energy

In 2005, JEA received a Sierra Club Clean Power Award for its voluntary commitment to increasing the use of solar, wind and other renewable or green power sources. Since that time, JEA has implemented new renewable energy projects and continues to explore additional opportunities to increase its utilization of renewable energy. As further discussed below, JEA's existing renewable energy sources include installation of solar photovoltaic (PV), solar thermal, landfill and wastewater treatment biogas capacity, and wind capacity.

1.4.2.1 Solar and the Solar Incentive

JEA has installed 35 solar PV systems, totaling 220 kW, on all of the public high schools in Duval County, as well as many of JEA's facilities, and the Jacksonville International Airport (one of the largest solar PV systems in the Southeast). To further promote the acceptance and installation of solar energy systems, JEA implemented the Solar Incentive Program in early 2002. This program provides cash incentives for customers to install solar PV and solar thermal systems on their homes or businesses.

JEA provided customer incentives for more than 25 solar PV systems (for a total of 98 kW) until January 2005, when the PV incentive was discontinued. In addition to the PV incentive program, JEA established a residential net-metering program to encourage the use of customer-sited solar PV systems.

1.4.2.2 Landfill Gas and Biogas

JEA owns and operates three internal combustion engine generators located at the Girvin Road landfill. This facility was placed into service in July 1997, and is fueled by gas produced by the landfill. The facility originally had four generators, with an aggregate net capacity of 3 MW. Since that time, gas generation has declined, and one generator was removed and placed into service at the Buckman Wastewater Treatment facility. The JEA Buckman Wastewater Treatment Plant previously dewatered and incinerated the sludge from the treatment process and disposed of the ash in a landfill. The new facility manages the sludge using two anaerobic digesters and a sludge dryer to produce a fertilizer pellet product. The methane gas from the digesters is used by the sludge dryer and the 800 kW generator.

JEA has under contract 9.6 MW of renewable resources for landfill gas generation from Trailridge landfill located in west of Duval County. JEA also receives approximately 1,500 kW of landfill gas from the North Landfill, which is pumped to the Northside Generating Station and is used to generate power at Northside Unit 3.

1.4.2.3 Wind

As part of its ongoing effort to utilize more sources of renewable energy, JEA has entered into a 20 year agreement with Nebraska Public Power District (NPPD) to participate in a wind generation project located in Ainsworth, Nebraska. JEA's participation in NPPD's wind generation project allows JEA to receive environmental credits associated with this green power project. Under the wind generation agreement, JEA has agreed to purchase 10 MW of capacity from NPPD's wind generation facility for a 20 year period. In turn, NPPD will buy back the energy at specified on/off peak charges. JEA expects that it will retain the rights to the environmental credits (green tags) and will sell the green tags unless JEA needs them to meet state or federal environmental requirements.

1.4.2.4 Biomass

JEA has issued several RFPs for renewable energy resources. In a continuing effort to obtain cost effective biomass generation, JEA completed a detailed feasibility study of both self-build stand-alone biomass units and the co-firing of biomass in Northside 1 and 2. The JEA self-build projects would not be eligible for the tax advantages afforded to developers, but would take advantage of JEA's low cost tax exempt financing. The co-firing alternative for Northside 1 and 2 must consider potential reliability issues associated with both of those units because of their low cost petroleum coke fuel. The price of petroleum coke is extremely volatile, but is expected to be lower than the cost of biomass on an as-fired basis a significant portion of the time.

JEA receives unsolicited as well as solicited offers for biomass and other renewable generation. JEA evaluates the feasible offers, but has been unable to successfully execute a contract for cost-effective biomass or other renewable generation. One notable example is the 70 MW biomass project burning E-grass that JEA executed in 2002 with Biomass Investment Group (BIG). Even though JEA executed the purchase power agreement, BIG never implemented the project.

1.4.2.5 Research Efforts

Many of Florida's renewable resources such as offshore wind, tidal, and energy crops need additional research and development before they can become large-scale technologies. JEA's renewable energy research efforts have focused on the development of these technologies through a partnership with the University of North Florida's (UNF) Engineering Department. UNF and JEA are currently working on the following projects:

- JEA has worked with the UNF to quantify the winter peak reductions of solar hot water systems.
- UNF along with the University of Florida has evaluated the effect of biodiesel fuel in a utility-scale combustion turbine. Biodiesel has been extensively tested on diesel engines, but combustion turbine testing has been very limited.

- UNF is evaluating the tidal hydro-electric potential for North Florida particularly in the Intercoastal Waterway where small proto-type turbines have been tested.
- JEA, UNF, and other Florida municipal utilities partnered on a grant proposal to the Florida Department of Environmental Protection to evaluate the potential for offshore wind development in Florida.
- JEA is also providing solar PV equipment to UNF for installation of a solar system at the UNF Engineering Building to be used for student education.
- JEA developed a 15 acre biomass energy farm where the energy yields of various hardwoods and grasses were evaluated over a 3 year period.
- JEA participated in the research of a high temperature solar collector that has the potential for application to electric generation or air conditioning.

1.4.2.6 Generation Efficiency and New Natural Gas Generation

Since the late 1990's JEA began to modernize their natural gas/oil fleet of generating units by replacing inefficient steam units and inefficient combustion turbines with efficient combined cycle units and efficient combustion turbines. Natural gas emits approximately 70 percent of the CO_2 of No. 6 oil on a fuel basis. This program, coupled with the much greater efficiency of a combined cycle unit compared to No. 6 oil steam units and inefficient combustion turbines results, in significant reduction of CO_2 on a per MWh basis.

1.4.2.7 Prior and Ongoing Projects

As a result of its fleet efficiency improvement efforts, JEA has retired the following units:

- Kennedy Steam Unit 8--43 MW Summer Natural Gas/Heavy Oil.
- Kennedy Steam Unit 9--43 MW Summer Natural Gas/Heavy Oil.
- Kennedy Steam Unit 10--97 MW Summer Natural Gas/Heavy Oil.
- Kennedy Combustion Turbine Unit 4--51 MW Summer No. 2 Oil.
- Kennedy Combustion Turbine Unit 5--51 MW Summer No. 2 Oil.
- Southside Steam Unit 4--67 MW Summer Natural Gas/Heavy Oil.
- Southside Steam Unit 5--142 MW Summer Natural Gas/Heavy Oil.

The retirement of these units and their replacement with an efficient combined cycle and efficient simple cycle combustion turbines significantly reduces CO_2 emissions. JEA's replacement units include Brandy Branch Unit 1, a 7FA simple cycle combustion turbine, Brandy Branch Combined Cycle, a 2x1 7FA combined cycle, and Kennedy CT Unit 7, a 7FA simple cycle 7FA combustion turbine. These units all burn natural gas as their primary fuel with ultra low sulfur diesel as a back-up fuel.

JEA also is installing Kennedy CT Unit 8, which is an efficient 7FA simple cycle combustion turbine designed to burn natural gas as its primary fuel and ultra low sulfur diesel as a back-up. The installation of Kennedy CT Unit 8 will allow the retirement of Kennedy CT Unit 3, another inefficient combustion turbine. Commercial operation of Kennedy CT 8 is scheduled for April 2009. The installation of Kennedy Unit 8 and the retirement of Kennedy Combustion Turbine Unit 3 further increases the efficiency of JEA's natural gas-fueled generating fleet.

1.4.2.8 Greenland Energy Center

JEA is in the process of permitting the installation of Greenland Units 1 and 2 which will be efficient 7FA simple cycle combustion turbines designed to burn natural gas as their primary fuel with ultra low sulfur oil as back-up. The installation of Greenland Units 1 and 2 further increase the efficiency of JEA's natural gas fueled generating fleet.

The conversion of Greenland Units 1 and 2 to combined cycle is the corner stone of JEA's generating unit efficiency improvement program. The conversion allows the output of the combined cycle unit to increase over 60 percent without any increase in CO_2 emissions. The installation of the combined cycle conversion of the Greenland combustion turbines along with the Brandy Branch combined cycle unit allows JEA to generate a large amount of energy with natural gas with its attendant lower CO_2 emissions per unit of electrical output.

The Greenland combined cycle project replaces capacity and energy that JEA planned to receive as its share in the suspended Taylor Energy Center Supercritical Pulverized Coal Unit. Replacing JEA's share of Taylor Energy Center capacity with capacity and energy from the Greenland combined cycle reduces JEA's CO_2 emissions by over 1 million tons per year from what they otherwise would have been.

2.0 Forecast of Electric Power Demand, and Energy Consumption

Over the past six months, a greater uncertainty in forecasting short-term demand growth, and to a lesser degree long-term demand growth, has emerged due to the global financial crisis and the resulting downturn in consumer demands. JEA's service territory has a diverse mix of industrial customers including a significant military presence. This diverse mix of customers tends to moderate the long term impact of economic downturns. In addition, the Jacksonville Port Authority is expanding their cargo processing capability with two new port terminal additions and the Navy is adding a nuclear carrier to Mayport, both of these industrial and military additions will lead to job development and community growth. It is too soon to determine how the current global and local economic environments will translate into an impact on JEA's long-term growth outlook; however, in response to the forecasted impact on the short-term outlook, JEA has adopted a complementary forecast methodology that better reflects recent history and short-term growth expectations.

The proposed 2009 Demand and Energy forecast takes into account these fundamental changes by applying the most recent historical annual growth trends to the nearest forecast year. This is accomplished by utilizing a growing historical period of average annual growth rates (AAGR) and applying the AAGR to the next subsequent forecast year.

For example, the actual AAGR from 2007 to 2008 for the summer peak demand is 0.35%. This one year AAGR when applied to the 2008 weather normalized integrated hourly summer demand of 2,907 MW results in the 2009 forecasted weather normalized integrated hourly summer demand of 2,917 MW. For the same season, the AAGR from 2006 to 2008 is 1.26%. The forecasted 2009 weather normalized integrated hourly summer demand of 2,917 MW results in the 2010 forecasted weather normalized integrated hourly summer demand of 2,954 MW. This method continues for the 10 year historical period to produce a 10 year forecast period such that the most recent history is reflected in the nearest future, but the overall historical trend is eventually reflected in the overall 10 year forecast for both demand and energy.

This method puts additional weighting on recent historical demand growth rates and maintains a 10 year historical demand growth rate trend when compared to JEA's other forecast methodologies. JEA continues to monitor customer consumption patterns and will adjust the forecast methods periodically as new trends are observed.

JEA continues to use 97° F (summer) and 25° F (winter) as weather normalization temperatures. The winter seasonal extreme for a year is the lowest temperature during the months of December, January, and February, and the summer seasonal extreme is the highest temperature during the months of July, August, and September.

The results of the summer and winter peak demand forecasts are shown in Table 2-1 for total demand, non-firm demand, and firm demand levels. During the TYSP forecast period, the total demand for the summer peak is forecast to increase at an average annual growth rate of 2.04 percent overall. The summer and winter interruptible load is held constant throughout the study period. The average annual increase in summer firm peak demand is 2.15 percent. During the winter period, the growth rate of the TID for the winter peak is projected to increase at an average annual growth rate of 1.44 percent. The average annual increase in winter firm peak demand is 1.04 percent.

Table 2-1 indicates that the firm winter peak demand is projected to increase from 2,872 MW in 2009 to 3,359 MW in 2018, and the firm summer peak demand is projected to increase from 2,750 MW in 2009 to 3,331 MW in 2018. Figure 2-1 shows the historical and forecast summer and winter peaks for JEA.

The NEL forecast for JEA is shown in Table 2-2. The NEL is forecast to increase at an average annual growth rate of 1.36 percent during the TYSP period. NEL is forecast to increase from 13,838 GWh in 2009 to 15,625 GWh in 2018. Figure 2-2 shows the historical and forecast NEL for JEA.

Table 2-1: Peak Demand Forecast

Year	Total Peak Demand		Non-Firm Demand		Firm Peak Demand	
	Winter (MW)	Summer (MW)	Winter (MW)	Summer (MW)	Winter (MW)	Summer (MW)
1999	2,403	2,427	0	0	2,403	2,427
2000	2,478	2,380	0	0	2,478	2,380
2001	2,666	2,389	0	0	2,666	2,389
2002	2,590	2,562	0	0	2,590	2,562
2003	3,083	2,535	0	0	3,083	2,535
2004	2,668	2,539	0	0	2,668	2,539
2005	2,860	2,815	0	0	2,860	2,815
2006	2,919	2,835	0	0	2,919	2,835
2007	2,722	2,897	0	0	2,722	2,897
2008	2,914	2,866	0	0	2,914	2,866
2009	3039	2,917	121	167	2,918	2,750
2010	3,022	2,954	121	167	2,901	2,787
2011	3,058	2,973	121	167	2,937	2,806
2012	3,138	3,047	121	167	3,017	2,880
2013	3,122	3,109	121	167	3,001	2,942
2014	3,174	3,179	121	167	3,053	3,012
2015	3,218	3,244	121	167	3,097	3,077
2016	3,287	3,340	121	167	3,166	3,173
2017	3,367	3,417	121	167	3,246	3,250
2018	3,480	3,498	121	167	3,359	3,331
Average Annual Growth Rate	1.44%	2.04%	0.00%	0.00%	1.04%	2.15%

Figure 2-2: Historical and Forecast Summer and Winter Peaks

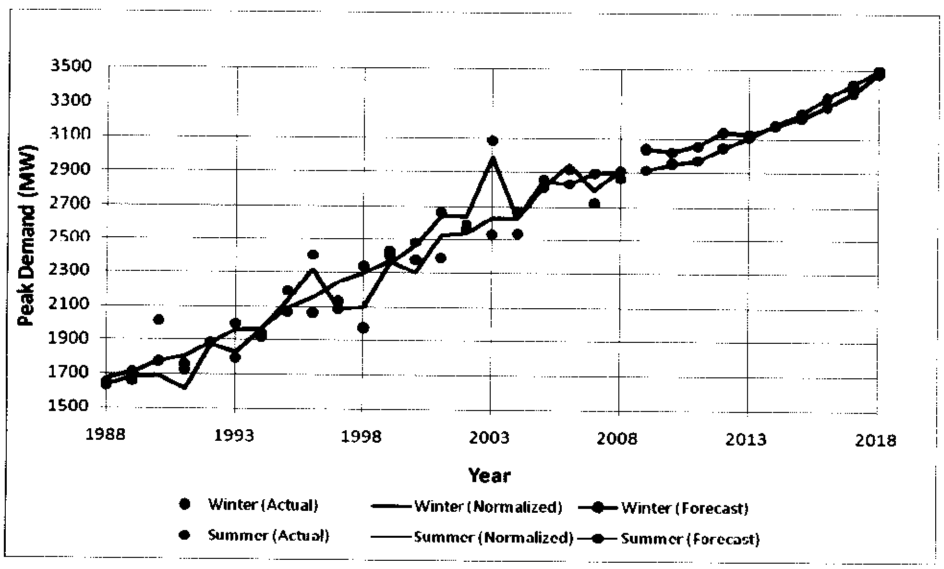
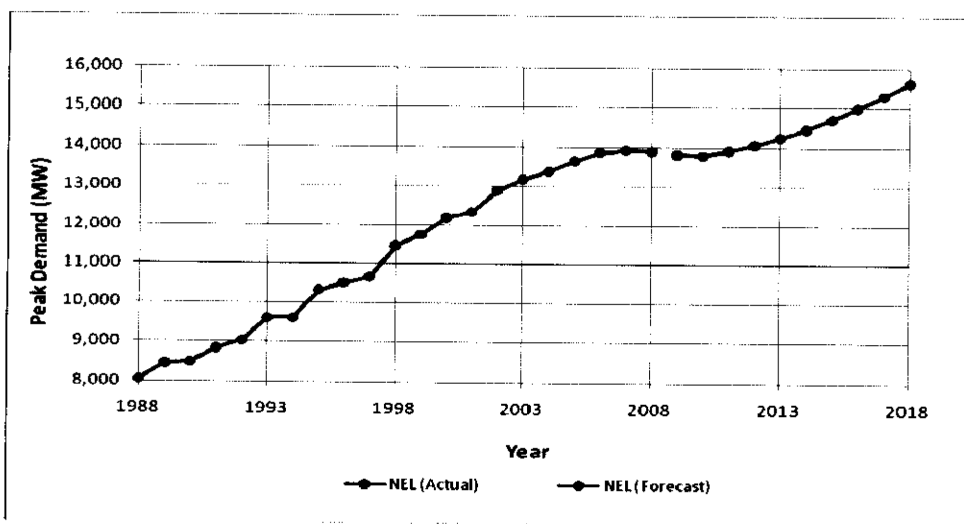


Table 2-2: JEA Forecasted Net Energy for Load

Calendar Year	Net NEL (GWh)	Heating and Cooling Degree-Days	
		HDD	CDD
1999	11,782	1,206	2,611
2000	12,190	1,478	2,456
2001	12,322	1,213	2,537
2002	12,983	1,333	2,872
2003	13,204	1,432	2,616
2004	13,243	1,427	2,834
2005	13,696	1,342	2,682
2006	13,811	1,170	2,742
2007	13,854	1,128	2,662
2008	13,530	1,369	2,499
2009	13,838	1,310	2,651
2010	13,809	1,310	2,651
2011	13,936	1,310	2,651
2012	14,077	1,310	2,651
2013	14,271	1,310	2,651
2014	14,466	1,310	2,651
2015	14,715	1,310	2,651
2016	15,000	1,310	2,651
2017	15,297	1,310	2,651
2018	15,625	1,310	2,651
Average Annual Growth Rate	1.36%	0.00%	0.00%

Figure 2-3: Historical and Forecast Net Energy for Load



Schedule 2.1: History and Forecast of Energy Consumption and Number of Customers By Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	Rural and Residential			Commercial			Industrial		
Calendar Year	GWH Sales	Average Number of Customers	Average kWh/ Customer	GWH Sales	Average Number of Customers	Average kWh/ Customer	GWH Sales	Average Number of Customers	Average kWh/ Customer
1998	4,643	301,883	15,380	1,035	31,297	33,070	4,835	3,094	1,562,702
1999	4,529	305,917	14,805	1,036	31,873	32,504	5,130	3,203	1,601,623
2000	4,701	312,103	15,062	1,079	32,351	33,353	5,205	3,309	1,572,983
2001	4,884	319,532	15,285	1,104	32,990	33,465	5,411	3,450	1,568,406
2002	5,108	326,362	15,651	1,157	33,841	34,189	5,479	3,475	1,576,691
2003	5,226	332,492	15,718	1,184	33,762	35,069	5,605	3,630	1,544,077
2004	5,400	348,320	15,503	1,185	32,123	36,889	5,396	3,638	1,483,233
2005	5,550	358,770	15,469	1,249	33,087	37,738	5,686	3,747	1,517,473
2006	5,637	357,232	15,780	1,289	37,136	34,704	5,658	4,206	1,345,307
2007	5,478	364,284	15,039	1,328	39,919	33,279	5,832	4,521	1,290,035
2008	5,364	365,632	14,670	1,357	40,608	33,417	5,777	4,599	1,256,240
2009	5,486	373,944	14,670	1,388	41,531	33,417	5,908	4,703	1,256,240
2010	5,474	373,174	14,670	1,385	41,446	33,417	5,896	4,694	1,256,240
2011	5,525	376,606	14,670	1,398	41,827	33,417	5,951	4,737	1,256,240
2012	5,581	380,421	14,670	1,412	42,251	33,417	6,011	4,785	1,256,240
2013	5,657	385,648	14,670	1,431	42,831	33,417	6,093	4,851	1,256,240
2014	5,735	390,924	14,670	1,451	43,417	33,417	6,177	4,917	1,256,240
2015	5,834	397,663	14,670	1,476	44,166	33,417	6,283	5,002	1,256,240
2016	5,946	405,349	14,670	1,504	45,019	33,417	6,405	5,098	1,256,240
2017	6,064	413,369	14,670	1,534	45,910	33,417	6,531	5,199	1,256,240
2018	6,194	422,244	14,670	1,567	46,896	33,417	6,672	5,311	1,256,240

Schedule 2.2: History and Forecast of Energy Consumption and Number of Customers By Class

Calendar Year	(11) Street & Highway Lighting GWH	(12) Other Sales to Ultimate Customers GWH	(13) Total Sales to Ultimate Customers GWH	(14) Sales For Resale GWH	(15) Utility Use & Losses GWH	(16) Net Energy For Load GWH	(17) Other Customers (Avg. Number)	(18) Total Number of Customers
1998	77	0	10,590	438	442	11,470	3	336,295
1999	86	0	10,781	454	547	11,782	3	341,012
2000	120	0	11,105	482	603	12,190	2	347,782
2001	109	0	11,508	453	361	12,322	2	355,994
2002	112	0	11,856	446	681	12,983	2	363,698
2003	115	0	12,130	453	595	13,178	2	369,904
2004	76	0	12,057	468	718	13,243	2	384,108
2005	111	0	12,596	486	615	13,696	2	395,606
2006	110	0	12,694	522	595	13,811	7	398,581
2007	113	0	12,751	624	479	13,854	5	408,729
2008	117	0	12,615	451	464	13,530	3	414,418
2009	120	0	12,902	462	474	13,838	3	420,181
2010	119	0	12,875	461	474	13,809	3	419,317
2011	120	0	12,993	465	477	13,936	3	423,172
2012	122	0	13,125	470	481	14,077	3	427,460
2013	123	0	13,305	476	491	14,271	3	433,332
2014	125	0	13,487	483	495	14,466	3	439,261
2015	127	0	13,720	491	504	14,715	3	446,833
2016	130	0	13,985	500	515	15,000	3	455,469
2017	132	0	14,262	510	526	15,297	3	464,481
2018	135	0	14,568	521	536	15,625	3	474,454

Schedule 3.1: History and Forecast of Summer Peak Demand

(MW)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)		(11)	(12)	(13)
Calendar Year	Total Demand	Interruptible Load	Load Management		QF Load Served By QF Gen.	Incremental Conservation		Net Firm Peak Demand	Time Of Peak			Cumulative Conservation Since 1980	
			Residential	Comm./Ind.		Residential	Comm./ind.		Month	Day	H.E.	Residential	Comm./Ind.
1999	2,427	0	0	0	0	0	0	2,427	8	2	1600	0	0
2000	2,380	0	0	0	0	0	0	2,380	7	20	1400	0	0
2001	2,389	0	0	0	0	0	0	2,389	8	8	1800	0	0
2002	2,562	0	0	0	0	0	0	2,562	7	19	1600	0	0
2003	2,535	0	0	0	0	0	0	2,535	7	10	1600	0	0
2004	2,539	0	0	0	0	0	0	2,539	8	2	1700	0	0
2005	2,815	0	0	0	0	0	0	2,815	8	17	1800	0	0
2006	2,835	0	0	0	0	0	0	2,835	8	4	1700	0	0
2007	2,897	0	0	0	0	0	0	2,897	8	7	1700	0	0
2008	2,866	0	0	0	0	0	0	2,866	8	7	1600	0	0
2009	2,917	167	0	0	0	0	0	2,750	---	---	---	0	0
2010	2,954	167	0	0	0	0	0	2,787	---	---	---	0	0
2011	2,973	167	0	0	0	0	0	2,806	---	---	---	0	0
2012	3,047	167	0	0	0	0	0	2,880	---	---	---	0	0
2013	3,109	167	0	0	0	0	0	2,942	---	---	---	0	0
2014	3,179	167	0	0	0	0	0	3,012	---	---	---	0	0
2015	3,244	167	0	0	0	0	0	3,077	---	---	---	0	0
2016	3,340	167	0	0	0	0	0	3,173	---	---	---	0	0
2017	3,417	167	0	0	0	0	0	3,250	---	---	---	0	0
2018	3,498	167	0	0	0	0	0	3,331	---	---	---	0	0

Schedule 3.2: History and Forecast of Winter Peak Demand

(MW)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)		(11)	(12)	(13)
Calendar Year	Total Demand	Interruptible Load	Load Management		QF Load Served By QF Gen.	Incremental Conservation		Net Firm Peak Demand	Time Of Peak			Cumulative Conservation Since 1980	
			Residential	Comm./Ind.		Residential	Comm./ind.		Month	Day	H.E.	Residential	Comm./Ind.
1999	2,403	0	0	0	0	0	0	2,403	1	6	0800	0	0
2000	2,478	0	0	0	0	0	0	2,478	1	27	0800	0	0
2001	2,666	0	0	0	0	0	0	2,666	1	3	0800	0	0
2002	2,590	0	0	0	0	0	0	2,590	1	4	0800	0	0
2003	3,083	0	0	0	0	0	0	3,083	1	24	0800	0	0
2004	2,668	0	0	0	0	0	0	2,668	1	29	0700	0	0
2005	2,860	0	0	0	0	0	0	2,860	1	24	0800	0	0
2006	2,919	0	0	0	0	0	0	2,919	2	14	0800	0	0
2007	2,722	0	0	0	0	0	0	2,722	1	30	0800	0	0
2008	2,914	0	0	0	0	0	0	2,914	1	3	0800	0	0
2009	3,039	121	0	0	0	0	0	2,872	---	---	---	0	0
2010	3,022	121	0	0	0	0	0	2,901	---	---	---	0	0
2011	3,058	121	0	0	0	0	0	2,937	---	---	---	0	0
2012	3,138	121	0	0	0	0	0	3,017	---	---	---	0	0
2013	3,122	121	0	0	0	0	0	3,001	---	---	---	0	0
2014	3,174	121	0	0	0	0	0	3,053	---	---	---	0	0
2015	3,218	121	0	0	0	0	0	3,097	---	---	---	0	0
2016	3,287	121	0	0	0	0	0	3,166	---	---	---	0	0
2017	3,367	121	0	0	0	0	0	3,246	---	---	---	0	0
2018	3,480	121	0	0	0	0	0	3,359	---	---	---	0	0

Schedule 3.3: History and Forecast of Annual Net Energy For Load

(GWH)										
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Calendar Year	Total Energy For Load	Interruptible Load	Load Management		QF Load Served By QF Generation	Incremental Conservation		Net Energy For Load	Cumulative Conservation Since 1980	
			Residential	Comm./Ind.		Residential	Comm./Ind.		Residential	Comm./Ind.
1999	11,782	0	0	0	0	0	0	11,782	0	0
2000	12,190	0	0	0	0	0	0	12,190	0	0
2001	12,322	0	0	0	0	0	0	12,322	0	0
2002	12,983	0	0	0	0	0	0	12,983	0	0
2003	13,204	0	0	0	0	0	0	13,204	0	0
2004	13,243	0	0	0	0	0	0	13,243	0	0
2005	13,696	0	0	0	0	0	0	13,696	0	0
2006	13,811	0	0	0	0	0	0	13,811	0	0
2007	13,854	0	0	0	0	0	0	13,854	0	0
2008	13,530	0	0	0	0	0	0	13,530	0	0
2009	13,838	0	0	0	0	0	0	13,838	0	0
2010	13,809	0	0	0	0	0	0	13,809	0	0
2011	13,936	0	0	0	0	0	0	13,936	0	0
2012	14,077	0	0	0	0	0	0	14,077	0	0
2013	14,271	0	0	0	0	0	0	14,271	0	0
2014	14,466	0	0	0	0	0	0	14,466	0	0
2015	14,715	0	0	0	0	0	0	14,715	0	0
2016	15,000	0	0	0	0	0	0	15,000	0	0
2017	15,297	0	0	0	0	0	0	15,297	0	0
2018	15,625	0	0	0	0	0	0	15,625	0	0

Schedule 4: Previous Year Actual and Two Year Forecast of Peak Demand and Net Energy for Load By Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Actual 2008		Forecast 2009		Forecast 2010	
Month	Peak Demand (MW)	Net Energy For load (GWH)	Peak Demand (MW)	Net Energy For load (GWH)	Peak Demand (MW)	Net Energy For load (GWH)
January	2,914	1,153	3,039	1,225	3,022	1,270
February	2,484	978	2,521	965	2,507	950
March	2,059	981	2,146	990	2,135	990
April	2,017	999	2,178	1,055	2,206	1,054
May	2,363	1,187	2,613	1,253	2,646	1,244
June	2,694	1,294	2,752	1,314	2,787	1,320
July	2,732	1,347	2,917	1,470	2,954	1,476
August	2,866	1,329	2,872	1,233	2,908	1,191
September	2,647	1,229	2,693	1,062	2,727	1,029
October	2,263	1,061	2,413	1,322	2,441	1,354
November	2,310	976	2,315	955	2,343	968
December	2,473	996	2,742	994	2,774	962
Total		13,530		13,838		13,809

Schedule 5: Fuel Requirements

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	Fuel	Type	Units	Actual 2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
(1)	NUCLEAR		TRILLION BTU	0	0	0	0	0	0	0	0	0	0	0
(2)	COAL [1]		1000 TON	2,975	3,442	3,047	2,960	2,718	2,893	2,814	2,916	3,369	3,497	3,472
(3)	RESIDUAL	STEAM	1000 BBL	132	317	293	511	475	318	233	216	161	150	168
(4)		CC		0	0	0	0	0	0	0	0	0	0	0
(5)		CT/GT		0	0	0	0	0	0	0	0	0	0	0
(6)		TOTAL:		132	317	293	511	475	318	233	216	161	150	168
(7)	DISTILLATE	STEAM	1000 BBL	17	6	6	7	5	5	7	5	8	6	8
(8)		CC		0	0	0	0	0	0	0	0	0	0	0
(9)		CT/GT		33	11	15	37	13	7	6	27	2	2	6
(10)		TOTAL:		50	17	22	44	18	12	13	32	11	8	13
(11)	NATURAL GAS	STEAM	1000 MCF	7,371	7,613	7,060	12,199	11,361	7,636	5,651	5,237	3,930	3,682	4,116
(12)		CC		9,505	9,126	14,490	11,981	17,645	20,759	25,142	25,044	17,605	12,789	14,988
(13)		CT/GT		765	1,318	2,181	4,090	4,282	1,716	1,058	2,392	534	393	582
(14)		TOTAL:		17,641	18,057	23,730	28,271	33,288	30,110	31,851	32,672	22,069	16,864	19,685
(15)	OTHER (SPECIFY) [2]		1000 TON	1,186	1,299	1,183	1,136	1,097	1,196	1,193	1,195	1,082	1,082	1,074

NOTES:

1. Coal includes JEA's share of SJRPP, JEA's share of Scherer 4 and Northside Coal. SJRPP sales suspension is assumed to be 4/2016.
2. Other includes Petroleum Coke at Northside.

Schedule 6.1: Energy Sources (GWh)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	Fuel	Type	Units	Actual 2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
(1)	Annual Firm Inter-Region Interchange [1]		GWH	2,076	1,456	685	0	0	0	0	0	859	1,714	1,654
(2)	NUCLEAR		GWH	0	0	0	0	0	0	0	0	0	0	0
(3)	COAL [2]		GWH	6,020	6,114	6,428	6,844	6,410	6,656	6,536	6,714	7,989	8,203	8,257
(4)	RESIDUAL	STEAM	GWH	179	167	303	279	175	123	116	92	78	80	80
(5)		CC	GWH	0	0	0	0	0	0	0	0	0	0	0
(6)		CT	GWH	0	0	0	0	0	0	0	0	0	0	0
(7)		TOTAL	GWH	179	167	303	279	175	123	116	92	78	80	80
(8)	DISTILLATE	STEAM	GWH	0	0	0	0	0	0	0	0	0	0	0
(9)		CC	GWH	0	0	0	0	0	0	0	0	0	0	0
(10)		CT	GWH	4	6	15	5	3	2	11	2	1	2	2
(11)		TOTAL	GWH	4	6	15	5	3	2	11	2	1	2	2
(12)	NATURAL GAS	STEAM	GWH	717	669	1,214	1,115	699	494	463	368	312	321	321
(13)		CC	GWH	1,253	2,016	1,702	2,515	2,908	3,546	3,519	2,583	2,374	1,973	1,973
(14)		CT	GWH	109	184	345	359	139	84	202	46	42	45	45
(15)		TOTAL	GWH	2,079	2,869	3,261	3,990	3,746	4,124	4,184	2,997	2,728	2,339	2,339
(16)	NUG [3]		GWH	9	78	78	78	79	78	78	78	79	78	52
(17)	HYDRO		GWH	0	0	0	0	0	0	0	0	0	0	0
(18)	Petroleum Coke		GWH	3,362	3,928	3,576	3,435	3,315	3,613	3,603	3,612	3,266	3,261	3,241
(19)	OTHER (SPECIFY)		GWH	0	0	0	0	0	0	0	0	0	0	0
(20)	NET ENERGY FOR LOAD		GWH	13,530	13,837	13,809	13,936	14,077	14,271	14,466	14,715	15,000	15,297	15,625

NOTES:

1. Includes UPS from Southern Company through May 2010 and purchased power form MEAG's future shares of Vogtle Units 3 & 4 starting 2016.
2. Coal includes JEA's share of SJRPP, JEA's share of Scherer 4 and Northside Coal. SJRPP sales suspension is assumed to be 4/2016.
3. NUG includes landfill gas.

Schedule 6.2: Energy Sources (Percent)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	Fuel	Type	Units	Actual 2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
(1)	Annual Firm Inter-Region Interchange [1]		%	15.3%	10.5%	5.0%	0.0%	0.0%	0.0%	0.0%	0.0%	5.7%	11.2%	10.6%
(2)	NUCLEAR		%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(3)	COAL [2]		%	44.5%	44.2%	46.6%	49.1%	45.5%	46.6%	45.2%	45.6%	53.3%	53.6%	52.8%
(4)	RESIDUAL	STEAM	%	1.3%	1.2%	2.2%	2.0%	1.2%	0.9%	0.8%	0.6%	0.5%	0.5%	0.5%
(5)		CC	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(6)		CT	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(7)		TOTAL	%	1.3%	1.2%	2.2%	2.0%	1.2%	0.9%	0.8%	0.6%	0.5%	0.5%	0.5%
(8)	DISTILLATE	STEAM	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(9)		CC	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(10)		CT	%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%
(11)		TOTAL	%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%
(12)	NATURAL GAS	STEAM	%	5.2%	4.8%	8.7%	7.9%	4.9%	3.4%	3.1%	2.5%	2.1%	2.1%	2.1%
(13)		CC	%	9.1%	14.6%	12.2%	17.9%	20.4%	24.5%	23.9%	17.2%	15.8%	12.6%	12.7%
(14)		CT	%	0.8%	1.3%	2.5%	2.6%	1.0%	0.6%	1.4%	0.3%	0.3%	0.3%	0.3%
(15)		TOTAL	%	15.0%	20.8%	23.4%	28.3%	26.2%	28.5%	28.4%	20.0%	18.2%	15.0%	15.1%
(16)	NUG [3]		%	0.1%	0.6%	0.6%	0.6%	0.6%	0.5%	0.5%	0.5%	0.5%	0.5%	0.3%
(17)	HYDRO		%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(18)	Petroleum Coke		%	24.9%	28.4%	25.9%	24.6%	23.5%	25.3%	24.9%	24.5%	21.8%	21.3%	20.7%
(19)	OTHER (SPECIFY)		%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(20)	NET ENERGY FOR LOAD		%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

NOTES:

1. Includes UPS from Southern Company through May 2010 and purchased power form MEAG's future shares of Vogtle Units 3 & 4 starting 2016.
2. Coal includes JEA's share of SJRPP, JEA's share of Scherer 4 and Northside Coal. SJRPP sales suspension is assumed to be 4/2016.
3. NUG includes landfill gas.

3.0 Forecast of Facilities Requirements

3.1 Future Resource Needs

Based on the peak demand and energy forecasts, existing supply resources and contracts, and transmission considerations, JEA has evaluated future supply capacity needs for the electric system. Table 3-1 displays the likely need for capacity when assuming the base case load forecast, installation of committed units, and existing unit changes in capacity for JEA's system for the term of this TYSP.

Table 3-1: Resource Needs After Committed Units

Winter [1]									
		Firm Capacity							Capacity Required For 15% Reserves
	Installed Capacity	Import	Export	QF	Available Capacity	Firm Peak Demand	Reserve Margin Before Maintenance		
Year	MW	MW	MW	MW	MW	MW	MW	Percent	MW
2009	3,621	367	383	0	3,605	2,918	687	24%	0
2010	3,750	367	383	0	3,734	2,901	832	29%	0
2011	3,750	10	383	0	3,377	2,937	439	15%	1
2012	4,119	10	383	0	3,746	3,017	729	24%	0
2013	4,119	10	383	0	3,746	3,001	745	25%	0
2014	4,119	10	383	0	3,746	3,053	693	23%	0
2015	4,119	10	383	0	3,746	3,097	649	21%	0
2016	4,119	110	383	0	3,846	3,166	679	21%	0
2017	4,114	210	0	0	4,324	3,246	1,078	33%	0
2018	4,113	210	0	0	4,323	3,359	964	29%	0
Summer									
		Firm Capacity							Capacity Required For 15% Reserves
	Installed Capacity	Import	Export	QF	Available Capacity	Firm Peak Demand	Reserve Margin Before Maintenance		
Year	MW	MW	MW	MW	MW	MW	MW	Percent	MW
2009	3,371	217	376	0	3,212	2,750	462	17%	0
2010	3,470	10	376	0	3,104	2,787	317	11%	101
2011	3,754	10	376	0	3,388	2,806	582	21%	0
2012	3,747	10	376	0	3,381	2,880	500	17%	0
2013	3,747	10	376	0	3,381	2,942	439	15%	3
2014	3,747	10	376	0	3,381	3,012	368	12%	84
2015	3,747	10	376	0	3,381	3,077	303	10%	158
2016	3,743	110	0	0	3,852	3,173	679	21%	0
2017	3,743	210	0	0	3,952	3,250	702	22%	0
2018	3,741	210	0	0	3,951	3,331	620	19%	0

Notes

1. Winter 2009 Peak is actual normalized peak.
2. Committed Capacity Additions
   a. Clean Power Purchase 9.6 MW winter 2009.
   b. Constellation Winter Purchases of 75 MW, 150 MW and 150 MW in 2007/08, 2008/09 and 2009/10, respectively.
   c. Kennedy CT 8 - 4/2009.
   d. GEC CTs - 6/2011.
3. Kennedy CTs 3 retirement - 4/2009.
4. UPS Purchase expires May 31, 2010.

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3.0 Forecast of Facilities Requirements

3.1 Future Resource Needs

Based on the peak demand and energy forecasts, existing supply resources and contracts, and transmission considerations, JEA has evaluated future supply capacity needs for the electric system. Table 3-1 displays the likely need for capacity when assuming the base case load forecast, installation of committed units, and existing unit changes in capacity for JEA's system for the term of this TYSP.

Table 3-1: Resource Needs After Committed Units

Winter (1)									
		Firm Capacity					Reserve Margin Before Maintenance		Capacity Required For 15% Reserves
	Installed Capacity	Import	Export	QF	Available Capacity	Firm Peak Demand			
Year	MW	MW	MW	MW	MW	MW	MW	Percent	MW
2009	3,621	367	383	0	3,605	2,918	687	24%	0
2010	3,750	367	383	0	3,734	2,901	832	29%	0
2011	3,750	10	383	0	3,377	2,937	439	15%	0
2012	4,119	10	383	0	3,746	3,017	729	24%	276
2013	4,119	10	383	0	3,746	3,001	745	25%	364
2014	4,119	10	383	0	3,746	3,053	693	23%	453
2015	4,119	10	383	0	3,746	3,097	649	21%	541
2016	4,119	10	383	0	3,746	3,166	579	18%	629
2017	4,114	113	0	0	4,227	3,246	981	30%	718
2018	4,113	216	0	0	4,329	3,359	970	29%	806
Summer									
		Firm Capacity					Reserve Margin Before Maintenance		Capacity Required For 15% Reserves
	Installed Capacity	Import	Export	QF	Available Capacity	Firm Peak Demand			
Year	MW	MW	MW	MW	MW	MW	MW	Percent	MW
2009	3,470	217	376	0	3,311	2,750	561	20%	46
2010	3,470	10	376	0	3,104	2,787	317	11%	13
2011	3,754	10	376	0	3,388	2,806	582	21%	296
2012	3,747	10	376	0	3,381	2,880	500	17%	371
2013	3,747	10	376	0	3,381	2,942	439	15%	447
2014	3,747	10	376	0	3,381	3,012	368	12%	522
2015	3,747	10	376	0	3,381	3,077	303	10%	597
2016	3,743	113	0	0	3,855	3,173	682	21%	673
2017	3,743	216	0	0	3,958	3,250	708	22%	748
2018	3,741	216	0	0	3,957	3,331	626	19%	824

Notes

1. Winter 2009 Peak is actual normalized peak.
2. Committed Capacity Additions
   a. Clean Power Purchase 9.6 MW winter 2009.
   b. Constellation Winter Purchases of 75 MW, 150 MW and 150 MW in 2007/08, 2008/09 and 2009/10, respectively.
   c. Kennedy CT 8 - 4/2009.
3. Kennedy CTs 3 retirement - 4/2009.
4. UPS Purchase expires May 31, 2010.

3.2 Projects In Progress

3.2.1 Kennedy CT 8

JEA is nearing the completion of an additional combustion turbine at the Kennedy Generating Station. This additional unit is a natural gas-fired simple-cycle GE frame 7FA combustion turbine, with ultra-low-sulfur diesel as backup fuel. The scheduled commercial operation date for the unit is April, 2009.

3.2.2 Greenland Energy Center

The Greenland Energy Center (GEC) is located in Duval County; south of J. Turner Butler Boulevard, east of Interstate 95, and north of St. Johns County. Currently, JEA has no generation stations east of the St. Johns River where JEA's territory has experienced the most growth. This site's ultimate build out capability is projected to be approximately 1,300 MW to meet future generation needs. This location provides increased system reliability, increased power quality, increased grid efficiency, and economic integration into the existing transmission system.

JEA is proceeding with the installation of two combustion turbine units at this new greenfield site. These units are natural gas-fired simple-cycle GE frame 7FA combustion turbine units, with diesel backup fuel. The scheduled commercial operation date for these units is June 2011.

JEA's 2007 TYSP reference plan included the addition of more than 200 MW of coal fired generation at the Taylor Energy Center. JEA's back up plan was to convert the 2 7FA CTs installed at GEC to a single 2x1 combined cycle unit. With the cancellation of the Taylor Energy Center in 2007, JEA initiated the actions necessary to execute this back-up plan. In JEA's 2008 TYSP, this CC conversion was forecasted to have an in service date of June 2012. In this TYSP filing, the combined cycle conversion is scheduled for June 2013.

3.3 Resource Plan

The analysis of JEA's electric system to determine the current plan included a review of existing electric supply resources including renewable energy, forecasts of customer energy requirements and peak demands, forecasts of fuel prices and availability, and an analysis of alternatives for resources to meet future capacity and energy needs.

Forecasts of system peak demand growth and energy consumption were utilized for the resource plan. A range of demand growth and NEL were assessed, with the base case peak demand indicating a need for additional capacity to meet system reserve requirements beginning summer 2010. This need encompasses the inclusion of existing supply resources including Kennedy CT Unit 8.

In addition to cost considerations, environmental, land use, and transmission deliverability considerations were factored into the resource plans. This ensured that the plans selected were holistically beneficial.

Based on modeling of the JEA system, forecast of demand and energy, forecast of fuel prices and availability, and environmental considerations, Table 3-2 presents the least-cost expansion plan which meets JEA's strategic goals. The expansion plan demonstrates robustness with small variance in supply alternatives over the numerous sensitivities.

Table 3-2
Reference Plan

Year	Season	Expansion Plan
2009	Winter	Clean Power Purchase (9.6 MW) Constellation Purchase (150 MW - Seasonal)
	Summer	Retire Kennedy CT 3 (53 MW) Build Kennedy CT 8 (177 MW)
2010	Winter	Constellation Purchase (150 MW - Seasonal)
	Summer	UPS Contract Expires (207 MW) TEA Purchase (100 MW - Seasonal)
2011	Summer	Build 2 - 7FA CTs at GEC (177 MW each)
2012		
2013	Summer	2x1 Combined Cycle Conversion at GEC (185 MW)
2016	Winter Summer	MEAG Plant Vogtle Purchase (100 MW) [1] SJRPP Sale Return From FPL (383 MW) [2]
2017	Winter	MEAG Plant Vogtle Purchase (100 MW) [1]
2018		

[1] After accounting for transmission losses, JEA is anticipating to receive a total of 200 MW of net firm capacity from the proposed units.

[2] SJRPP Sales return in April 2016.

Schedule 7: Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Peak

Winter

Year	Installed Capacity MW	Firm Capacity Purchases MW	Firm Capacity Sales MW	QF MW	Available Capacity MW	Firm Peak Demand MW	Reserve Margin Before Maintenance MW	Reserve Margin Before Maintenance Percent	Scheduled Maintenance MW	Reserve Margin After Maintenance MW	Reserve Margin After Maintenance Percent
2009	3,621	367	383	0	3,605	2,918	687	24%	0	687	24%
2010	3,750	367	383	0	3,734	2,901	832	29%	0	832	29%
2011	3,750	10	383	0	3,377	2,937	439	15%	0	439	15%
2012	4,119	10	383	0	3,746	3,017	729	24%	0	729	24%
2013	4,119	10	383	0	3,746	3,001	745	25%	0	745	25%
2014	4,305	10	383	0	3,932	3,053	879	29%	0	879	29%
2015	4,305	10	383	0	3,932	3,097	835	27%	0	835	27%
2016	4,305	110	383	0	4,032	3,166	865	27%	0	865	27%
2017	4,300	210	0	0	4,510	3,246	1,264	39%	0	1,264	39%
2018	4,299	210	0	0	4,509	3,359	1,150	34%	0	1,150	34%

Summer

Year	Installed Capacity MW	Firm Capacity Purchases MW	Firm Capacity Sales MW	QF MW	Available Capacity MW	Firm Peak Demand MW	Reserve Margin Before Maintenance MW	Reserve Margin Before Maintenance Percent	Scheduled Maintenance MW	Reserve Margin After Maintenance MW	Reserve Margin After Maintenance Percent
2009	3,470	217	376	0	3,311	2,750	561	20%	0	561	20%
2010	3,470	110	376	0	3,204	2,787	417	15%	0	417	15%
2011	3,754	10	376	0	3,388	2,806	582	21%	0	582	21%
2012	3,747	10	376	0	3,381	2,880	500	17%	0	500	17%
2013	3,954	10	376	0	3,588	2,942	646	22%	0	646	22%
2014	3,954	10	376	0	3,588	3,012	575	19%	0	575	19%
2015	3,954	10	376	0	3,588	3,077	510	17%	0	510	17%
2016	3,950	110	0	0	4,059	3,173	886	28%	0	886	28%
2017	3,950	210	0	0	4,159	3,250	909	28%	0	909	28%
2018	3,948	210	0	0	4,158	3,331	827	25%	0	827	25%

Note:

Represents plan shown on Schedule 8 and Table 3-2.

Schedule 8: Planned and Prospective Generating Facility Additions and Changes

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel Type		Fuel Transport						Net Capability		
Plant Name	Unit No.	Location	Unit Type	Primary	Alternate	Primary	Alternate	Construction Start Date	Commercial/ Change In-Service Date	Expected Retirement/ Shutdown	Gen Max Nameplate kW	Summer MW	Winter MW	Status
Planned and Prospective Generating Facility Changes														
Kennedy	3	Kennedy	GT	NG	FO2	PL	TK			04/01/09		(51)	(63)	RT
SJRPP	1	SJRPP	ST	Bit/PC		RR	WA		01/01/12			(6)	(6)	D
SJRPP	2	SJRPP	ST	Bit/PC		RR	WA		01/01/12			(6)	(6)	D
SJRPP	1	SJRPP	ST	Bit/PC		RR	WA		04/01/16			188	192	Sale To FPL Ends
SJRPP	2	SJRPP	ST	Bit/PC		RR	WA		04/01/16			188	192	
Planned and Prospective Generating Facility Additions														
Kennedy	8	Kennedy	GT	NG	FO2	PL	TK		04/01/09			150	191	V
Greenland Energy Center	1	GEC	CT	NG	FO2	PL	TK		06/01/11			142	188	U
	2	GEC	CT	NG	FO2	PL	TK		06/01/11			142	188	U
	3	GEC	CA	WH					06/01/13			207	186	P
Planned and Prospective Purchased Power Changes and Additions														
Constellation									12/15/08	03/15/09		0	150	Under Contract
TEA									06/01/10	09/15/10		100	0	Planned
Constellation									12/15/09	03/15/10		0	150	Under Contract
Southern Company										06/01/10		(207)	(207)	Contract Ends
MEAG									01/01/16	01/01/36		100	100	Under Contract
MEAG									01/01/17	01/01/37		100	100	Under Contract

Schedule 9.1: Status Report and Specifications of Proposed Generating Facilities 2008 Dollars

1. Plant Name and Unit Number:	Greenland Energy Center CT Units 1 & 2		
2. Capacity:		Gas	Oil
3. Summer MW		149 MW	158 MW
4. Winter MW		186 MW	191 MW
5. Technology Type:	Simple Cycle Combustion Turbine		
6. Anticipated Construction Timing:		Unit 1	Unit 2
7. Field Construction Start-date:		06/01/09	06/01/09
8. Commercial In-Service date:		06/01/11	06/01/11
9. Fuel			
10. Primary	Natural Gas		
11. Alternate	Diesel Fuel Oil		
12. Air Pollution Control Strategy:	Low NO_x Burners		
13. Cooling Method:	N/A		
14. Total Site Area:			
15. Construction Status:	Site prep. underway, equipment on order		
16. Certification Status:	Not Required		
17. Status with Federal Agencies:	Not Filed		
18. Projected Unit Performance Data:			
19. Planned Outage Factor (POF):	3.00%		
20. Forced Outage Factor (FOF):	2.00%		
21. Equivalent Availability Factor (EAF):	95.00%		
22. Resulting Capacity Factor (%):	5.0 %		
23. Average Net Operating Heat Rate (ANOHR):	10,800 Btu/kWh		
24. Projected Unit Financial Data:			
25. Book Life:	20 years		
26. Total Installed Cost (In-Service year $/kW):	$ 873.24		
27. Direct Construction Cost ($/kW):	Included in total installed cost		
28. AFUDC Amount ($/kW):	Included in total installed cost		
29. Escalation ($/kW):	Included in total installed cost		
30. Fixed O&M ($/kW-yr):	$ 9.33		
31. Variable O&M ($/MWh):	$ 15.57		

Schedule 9.2: Status Report and Specifications of Proposed Generating Facilities 2008 Dollars

1. **Plant Name and Unit Number:**	Greenland Energy Center Unit 3 – HRSG
2. **Capacity:**	
3. Summer MW	207 MW
4. Winter MW	186 MW
5. **Technology Type:**	Heat Recovery Steam Generator
6. **Anticipated Construction Timing:**	
7. Field Construction Start-date:	06/01/2011
8. Commercial In-Service date:	06/01/2013
9. **Fuel**	
10. Primary	Waste Heat
11. Alternate	
12. **Air Pollution Control Strategy:**	Selective Catalytic Reduction (SCR)
13. **Cooling Method:**	Mechanical Draft Cooling Tower
14. **Total Site Area:**	
15. **Construction Status:**	Planned, not under construction
16. **Certification Status:**	Underway
17. **Status with Federal Agencies:**	Underway
18. **Projected Unit Performance Data:**	
19. Planned Outage Factor (POF):	3.00%
20. Forced Outage Factor (FOF):	3.00%
21. Equivalent Availability Factor (EAF):	94.0 %
22. Resulting Capacity Factor (%):	60%
23. Average Net Operating Heat Rate (ANOHR):	7,191 Btu/kWh
24. **Projected Unit Financial Data:**	
25. Book Life:	30 years
26. Total Installed Cost (In-Service year $/kW):	$2,201.00
27. Direct Construction Cost ($/kW):	Included in direct construction cost
28. AFUDC Amount ($/kW):	Included in direct construction cost
29. Escalation ($/kW):	Included in direct construction cost
30. Fixed O&M ($/kW-yr):	$ 19.90
31. Variable O&M ($/MWh):	$ 11.52

Schedule 10: Status Report and Specification of Proposed Directly Associated Transmission Lines

1. Point of Origin and Termination	GEC and GEC Switching Station
2. Number of Lines	Two
3. Right of Way	Existing
4. Line Length	0.2 circuit miles
5. Voltage	230 kV
6. Anticipated Construction Time	Approximately 1 Month
7. Anticipated Capital Investment	Approximately $1.5 Million
8. Substations	GEC Switching Station
9. Participation with Other Utilities	No

4.0 Other Planning Assumptions and Information

4.1 Fuel Price Forecast

Fuel price forecasting is a major input in the development of JEA's future resource plan. JEA uses a diverse mix of fuels in its generating units. The forecast includes coal, natural gas, residual fuel oil, diesel fuel, and petroleum coke.

The fuel and emissions allowance price projections represent fully integrated forecasts. Fuel price supply and demand are considered in tandem with potential costs associated with regulation of various emissions, along with numerous other market influences to develop fully integrated projections of fuel and emissions allowance prices. This is important for all scenarios considered, but especially so when considering the potential impacts associated with acquiring any allowances for existent regulated emissions and considering the potential impacts of the regulation of CO_2.

Regulations of emissions of sulfur dioxide (SO_2), oxides of nitrogen (NO_x), and mercury (Hg) are reflected in each fuel price projection considered throughout this Application. While there is currently no State or Federal regulation of CO_2 emissions, several bills to regulate emissions of CO_2 (and other GHGs) have been proposed to the 110th US Congress.

The fuel price projections for natural gas, fuel oil, and coal used in this TYSP were developed based on those included in the US EIA Annual Energy AEO2008. At the time of JEA's assessment, the AEO 2009 forecast was not published. AEO2008 presents projections of energy supply, demand, and prices through 2030. The projections presented within AEO2008 are based on results from the EIA's NEMS. NEMS is a computer based, energy-economy modeling system of US energy markets and projects the production, imports, conversion, consumption, and prices of energy, subject to a variety of assumptions related to macroeconomic and financial factors, world energy markets, resource availability and costs, behavioral and technological choice criteria, technology characteristics, and demographics. The discussion of the fuel price projections presented within this section is intended to be an overview of the AEO2008 and, therefore, focuses on the more salient aspects of AEO2008 and elaborates on relevant conclusions and projections.

Analyses developed by the EIA are required to be policy-neutral. Therefore, the projections in AEO2008 generally are based on Federal and State laws and regulations in effect on or before December 31, 2007 (with few exceptions). As stated in AEO2008, the potential impacts of pending or proposed legislation, regulations, and standards – or of sections of legislation that have been enacted but that require implementing regulations or appropriation of funds that are not provided or specified in the legislation itself – are not reflected in the projections.

AEO2008 does consider potential impacts of both the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR) despite both rules recently being dismissed by the District of Columbia Circuit Court of Appeals. The dismissal of CAIR happened during publication of the AEO2008 (July 11, 2008) while CAMR was dismissed too late for EIA to remove the CAMR provisions from its analysis. CAIR and CAMR were promulgated by the US Environmental Protection Agency (EPA) in March 2005 and published in the *Federal Register* as final rules in May 2005. CAIR was created to limit emissions of SO_2 and NO_x from power plants in the United States, while the purpose of CAMR was to limit emissions of Hg from power plants in the United States. Both CAIR and CAMR are represented as regional cap-and-trade programs in AEO2008, because the document was developed prior to final decisions being made regarding the structure of State programs and participation in regional trading programs related to CAIR and CAMR.

The AEO2008 Reference Case forecast prices for natural gas and fuel oil delivered to the FRCC region are presented in Table 4-2[1]. Forecasts of prices for High Sulfur Eastern Interior and Powder River Basin (PRB) coal delivered to the Georgia/Florida region are presented in Table 4-1[2]. The fuel price projections shown in Tables 4-2 and 4-1 are presented in constant 2006 dollars per MBtu. For the economic analysis, the fuel price projections were converted to nominal dollars per MBtu by applying a 2.5 percent general inflation rate.

The natural gas price projections presented represent the AEO2008 projections for delivered natural gas to the FRCC region and do not include any usage charges or any other costs for firm or interruptible intrastate natural gas transportation.

Table 4-1 only presents forecast prices for coal delivered to the Georgia/Florida region from the Eastern Interior and PRB coal production region. The analyses assumes that

[1] Regional fuel price projections, such as those shown in Table 4-2 for FRCC, are not included in the AEO2008 report itself, but are available on the EIA Web site as *Supplemental Tables* (http://www.eia.doe.gov/oiaf/aeo/supplement/supref.html). The FRCC fuel price projections corresponding to the AEO2008, from which the data in Table 4-1 were extracted, are presented in Supplemental Table 69.

[2] Supplemental Table 69 to the AEO2008, referenced previously, only presents forecasts of prices for coal delivered to the FRCC region on a composite basis (i.e., a single coal price forecast, with no differentiation between coal type/production regions). EIA was able to provide forecast prices for coal delivered to the Georgia/Florida region from various coal production regions upon request. These projections are factored into the overall modeling and analysis used to generate the coal price projections shown in Supplemental Table 69 to the AEO2008.

PRB coal will continue to be burned in the existing Scherer plant, while Eastern Interior coal is assumed to be burned in the existing SJRPP and Northside units.

Although SJRPP and Northside have historically utilized coal from international sources (including Latin America), the characteristics of Eastern Interior coal are relatively comparable to the characteristics of the Latin American coal that has been used in the SJRPP and Northside units. AEO2008 does not include projections of the price of international coal for delivery to the United States. Given the similarities in coal characteristics and the capability of the SJRPP and Northside units to burn Eastern Interior coal, consideration of Eastern Interior coal is appropriate for the comparative economic analyses presented throughout this Application.

A blend of 1.8 percent sulfur residual fuel oil and natural gas is burned in Northside Unit 3. The 1970's-vintage combustion turbine units at Northside Generating Station are permitted to burn high sulfur diesel. The new combustion turbine units at Brandy Branch and Kennedy are permitted to burn low sulfur diesel as a backup to natural gas.

Table 4-1: Annual Energy Outlook 2008 Reference Case Price Projections
Forecast of High Sulfur Eastern Interior and
Low Sulfur Powder River Basin Coal Delivered to the Georgia/Florida Region(1)

Year	High Sulfur Eastern Interior (2.64 lb S/MBtu) (2006 $/MBtu)	Low Sulfur Powder River Basin (0.35 lb S/MBtu) (2006 $/MBtu)
2008	2.27	1.88
2009	2.38	1.97
2010	2.49	2.07
2011	2.52	2.08
2012	2.53	2.05
2013	2.52	2.06
2014	2.53	2.06
2015	2.51	2.05
2016	2.52	2.04
2017	2.52	2.04
2018	2.50	2.05

(1) Based on data received directly from the EIA.

Table 4-2: Annual Energy Outlook 2008 Reference Case Price Projections
Forecast of Natural Gas and Fuel Oil Delivered to the
Florida Reliability Coordinating Council Boundary[1]

Year	Natural Gas (2006 \$/MBtu)[2]	Distillate Fuel Oil (2006 \$/MBtu)[3]	Residual Fuel Oil (2006 \$/MBtu)
2008	7.53	17.05	10.08
2009	7.83	14.50	11.13
2010	7.44	13.83	10.33
2011	7.17	13.13	9.78
2012	7.23	12.43	9.14
2013	6.88	11.73	8.61
2014	6.64	11.45	8.36
2015	6.47	10.88	7.80
2016	6.40	10.45	7.36
2017	6.41	10.46	7.35
2018	6.46	10.60	7.46

(1) Based on data presented in Supplemental Table 69 to the AEO2008 Reference Case.

(2) Natural gas price projections do not include usage charges or firm or interruptible transportation charges within the State. These costs are accounted for in the economic analysis.

(3) Distillate fuel oil price projections reflect the "nonroad, locomotive, and marine" (NRLM) diesel regulation finalized in May 2004, which requires sulfur content for all NRLM diesel fuel produced by refiners to be reduced to 500 parts per million (ppm) starting mid-2007. NRLM also establishes a new ultra-low sulfur diesel (ULSD) limit of 15 ppm for nonroad diesel by mid-2010.

4.2 Economic Parameters

This section presents the economic parameters and methodology used to evaluate the economics of GEC as part of JEA's least-cost expansion plan to satisfy forecast capacity requirements throughout the TYSP period.

4.2.1 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.

4.2.2 Municipal Bond Interest Rate

JEA performs sensitivity assessments of project cost to test the robustness of JEA's reference plan. Project cost includes forecast of direct cost of construction, indirect cost, and financing cost. Financing cost includes the forecast of long term tax exempt municipal bond rates, issuance cost, and insurance cost. For JEA's plan development, the long term tax exempt municipal bond rate is assumed to be 6.0 percent. This rate is based on JEA's judgment and expectation that the long term financial markets will return to historical stable behavior under more stable economic conditions. Sensitivities to a higher long term tax exempt municipal bond rate of 7.0 percent was used in JEA's Need for Power application to conservatively test the potential of long term instability or tightness in the credit markets and the resulting effect on the GEC combined cycle conversion decision. The 7.0 percent interest rate assumed all debt would be fixed rates and that there would be no variable debt available to effectively lower the rate. Even though the markets are challenged, JEA continues to obtain fixed rate bond financing at favorable rates as reflected by the effective fixed rate of 5.48% obtained for the Scherer Bulk Power issuance in November 2008 and 5.28% for the Electric System issuance in January 2009.

The overall effective rate for JEA's entire debt portfolio including fixed rate and variable rate debts is 4.31%. Even though variable rate debt is tight, the effective variable interest rate remains low.

4.2.3 Present Worth Discount Rate

The present worth discount rate is assumed to be equal to the tax exempt municipal bond interest rate of 6.0 percent.

4.2.4 Interest During Construction Interest Rate

The interest during construction rate, or IDC, is assumed to be 6.0 percent.

4.2.5 Levelized Fixed Charge Rate

The fixed charge rate (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. Given the various economic lives and corresponding financing terms, different levelized fixed charge rates were developed. All levelized fixed charge rate calculations assume the 6.0 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 6.0 percent. The resulting 20 year fixed charge rate is 9.679 percent, and the 25 year fixed charge rate is 8.654 percent.

The levelized fixed charge rate is essentially the capital recovery factor, adjusted to include the bond issuance fee and the debt service reserve fund, plus 0.50 percent for property insurance, and was calculated as follows:

For the 20 year fixed charge rate where i = 6.0 percent, n = 20 years, DSRF = 1.0 year, bond issuance fees (fees) = 2.0 percent, and property insurance = 0.5 percent:

<u>Capital Recovery Factor (CRF)</u> =

$$\frac{\mathrm{i} \times \left[(1+\mathrm{i})^{n}\right]}{\left[(1+\mathrm{i})^{n}-1\right]} = \frac{0.06 \times \left[(1+0.06)^{20}\right]}{\left[(1+0.06)^{20}-1\right]} = 0.08719 = 8.719 \text{ Percent}$$

<u>Adjusted CRF (ACRF)</u> =

$$\frac{(1-(\mathrm{i} \times \mathrm{DSRF})) \times \mathrm{CRF}}{[1 - \mathrm{fees} - (\mathrm{DSRF} \times \mathrm{CRF})]} = \frac{(1-(0.06 \times 1.0)) \times 0.08719}{[1-0.02-(1.0 \times 0.08719)]} = 0.09179 = 9.179 \text{ Percent}$$

Levelized Fixed Charge Rate =

ACRF + property insurance = 0.09179 + 0.005 = 0.09679 = 9.679 Percent

For the 25 year fixed charge rate where i = 6.0 percent, n = 25 years, DSRF = 1.0 year, bond issuance fees (fees) = 2.0 percent, and property insurance = 0.5 percent:

Capital Recovery Factor (CRF) =

$$\frac{i \times \left[(1+i)^n\right]}{\left[(1+i)^n - 1\right]} = \frac{0.06 \times \left[(1+0.06)^{25}\right]}{\left[(1+0.06)^{25} - 1\right]} = 0.07823 = 7.823 \text{ Percent}$$

Adjusted CRF (ACRF) =

$$\frac{(1-(i \times \text{DSRF})) \times \text{CRF}}{[1 - \text{fees} - (\text{DSRF} \times \text{CRF})]} = \frac{(1-(0.06 \times 1.0)) \times 0.07823}{[1-0.02-(1.0 \times 0.07823)]} = 0.08154 = 8.154 \text{ Percent}$$

Levelized Fixed Charge Rate =

ACRF + property insurance = 0.08154 + 0.005 = 0.08654 = 8.654 Percent

JEA has not incurred additional expenses specifically due to the financial situations of its underwriters. However, in general, JEA's costs to the underwriters are increasing.

The credit crisis has had the following adverse effects on JEA:

- Higher variable rates at certain times on both auction rate securities as well as variable rate demand bonds
- Much higher costs for back up lines of credit used to support variable rate demand bonds
- Lack of adequate liquidity provided by banks in the variable rate market which could force the debt to be refunded with higher fixed rates

JEA's main day to day banking relationship is with Wachovia Bank. Wachovia has been purchased by Wells Fargo. The future impact on terms and conditions is not yet known. Regarding bank liquidity facilities, JEA has had many unfavorable changes to the Standby Bond Purchase Agreements that provide backup liquidity for JEA's variable rate debt. In general, credit is harder to obtain, it is more expensive, terms are more difficult, and the length of the agreement is generally 1 year.

5.0 Greenland Energy Center Project Overview

5.1 Description

The GEC combined cycle conversion will consist of converting the two simple cycle GE 7FA combustion turbines planned for operation at the GEC site in Jacksonville, Florida, to a 2x1 combined cycle configuration. The 2x1 GEC combined cycle will have a nominal net output rating of 522 MW at average ambient temperature conditions. Consideration will be made for installing future units at the site through space allocation. In general, consideration will be given to installing facilities required to support future units at the site when appropriate.

The GEC combined cycle will be dual fueled with natural gas as the primary fuel and ULSD fuel oil as a backup fuel. The combined cycle power plant will include heat HRSGs provided with natural gas-fired supplemental duct burners to increase power generation and a steam turbine bypass to the condenser to allow for simple cycle operation.

Subject to final approval by the Siting Board and the Florida Department of Environmental Protection (FDEP), GEC will be permitted for unlimited operation on natural gas and up to 500 hours per year on ULSD in combined cycle mode. GEC will have full steam bypass capability, allowing the combustion turbine units to operate in simple cycle mode.

The CTGs will be GE Model PG 7241 (FA) enhanced combustion turbines with dry low NOx (DLN) combustors and modulating inlet guide vanes. The CTGs will be installed outdoors and will include the following major features:

- Dual fuel firing system using natural gas or ULSD.
- DLN combustion system for pipeline gas firing.
- Direct connected generator with static excitation.
- Acoustic enclosure for turbine.
- Inlet air filter system with silencers.
- Lube oil systems.
- Static starting system.
- Water injection system for NOx reduction when firing fuel oil.
- Fire detection/CO2 fire protection systems.
- Mark VI control system with remote work stations.
- Off-line water wash system.
- Package electrical and electronics control compartments.

- Natural gas heating for maintaining the fuel gas temperature at the CTG manufacturer's recommended margin above hydrocarbon dew point temperature.

The HRSGs will be installed outdoors and will utilize exhaust heat from the combustion turbines to generate steam for use in driving the STG. The HRSGs are expected to be natural circulation, three-pressure, reheat units with supplemental duct firing by pipeline gas to increase unit output. Nominal cycle operating pressure will be 1,800 pounds per square inch gauge (psig). SCR for NOx emission control is expected to be included within each HRSG. Each HRSG will discharge to an exhaust stack. A stack damper will be included to minimize heat loss during shutdowns. Two 100 percent capacity condensate pumps and boiler feedwater pumps will be included for each HRSG.

The steam turbine is expected to be a tandem-compound single reheat condensing turbine operating at 3,600 revolutions per minute (rpm). The steam turbine will have one HP section with a nominal 1,800 psig throttle pressure, one IP section, and one low-pressure (LP) section. Turbine suppliers' standard auxiliary equipment; lubricating oil system; hydraulic oil system; and supervisory, monitoring and control systems will be utilized. A surface condenser will be provided for condensing steam from the turbine exhaust and will utilize a recirculating cooling tower system for cooling. The condenser will be designed for full steam flow bypass around the steam turbine. A synchronous generator will be direct coupled to the steam turbine. Generator suppliers' standard auxiliary equipment; supervisory, monitoring, and control systems; and static excitation system will be utilized. The steam turbine will be installed indoors with a fully enclosed turbine building.

A standby power diesel engine generator will be provided to maintain the plant in a ready condition if the transmission interconnection and, therefore, plant auxiliary power is lost. The standby power engine generator will use ULSD as fuel.

A multiple cell, mechanical draft, counterflow water cooling tower will be used for plant cooling. The cooling tower will be installed on a reinforced concrete basin that will include a pump intake structure housing two 50 percent capacity circulating water pumps and one 100 percent capacity auxiliary cooling water pump. A circulating water chemical feed system also will be included. The cooling tower will be equipped with drift eliminators.

5.2 Control Systems

5.2.1 Air Quality Control System

GEC will be subject to FDEP's Prevention of Significant Deterioration (PSD) permitting program, which requires Best Available Control Technology for emissions of various pollutants. GEC will minimize air pollutant emissions by using the most efficient and pollutant-preventing generating technology. This concept has been incorporated with the selection of a combined cycle process utilizing advanced combustion turbines. Compared to simple cycle generating plants, combined cycle units have higher efficiency and, therefore, generate more electrical output (megawatts) per unit of fuel consumed. As a result, air pollutant emissions per megawatt output are minimized. Pollution prevention is also incorporated through the use of clean fuels that minimize emissions of SO2 and particulate matter. In addition, advanced DLN combustion technology will be used to minimize NOx emissions while ensuring that emissions of carbon monoxide (CO) and volatile organic compounds (VOCs) are within accepted limits. Moreover, SCR will be installed in each HRSG to further reduce NOx emissions when operating in combined cycle mode. Taken together, these design features will make GEC one of the most efficient and lowest polluting power plants in the state of Florida.

5.2.2 Plant Control System

GEC will be designed for control through a plant distributed control and information system (DCIS). A GE Mark VI control system for turbine control will also be included. The DCIS operator control stations will be located in the main plant control room that will be in a new Administration/Control/Maintenance Building.

5.3 Water Use

Water for cooling tower makeup is expected to be reclaim water (treated wastewater). Reclaim water is expected to be supplied from JEA via a pipeline adjacent to the plant site. If needed, municipal water will be used for backup cooling water makeup supply. Cooling water makeup water flow will vary depending upon the plant load and operating conditions.

Service water, potable water, demineralizer water makeup, and fire water will be supplied from the JEA municipal water system. Water will be stored onsite in a fire water/service water storage tank. GEC will include a site fire protection system consisting of a fire/service water storage tank, in addition to the municipal water supplied hydrant system, one diesel engine driven fire water pump, a site hydrant system, and deluge systems as required. A CO_2 fire suppression system will be provided for each CTG as provided in the CTG manufacturer's standard scope of supply.

A new demineralizer system will be installed to provide demineralized water for combustion turbine water injection for NOx control when firing fuel oil and for steam cycle makeup. Two 800,000 gallon demineralized water storage tanks will be provided for a total capacity of approximately 40 hours of storage/makeup capacity under maximum demineralized water demand conditions.

There will be four major sources of wastewater: sanitary waste, oil/water separator effluent, cooling tower blowdown, and treated chemical wastewaters. Cooling tower blowdown will be reblended into the JEA reclaim water distribution system. All other wastewaters will be routed via the adjacent force main to the JEA municipal wastewater treatment plant.

A complete storm water management system will be developed for the site. Storm water system design will be in accordance with FDEP, St. Johns Water Management District (SJWMD), and Duval County requirements. Storm water runoff will be collected in an onsite detention pond for percolation into the ground water.

5.4 Transmission Interconnection

GEC will be interconnected to JEA's existing 230 kV transmission circuits. The GEC site is contiguous with the existing transmission circuits: Southeast-Greenland circuit 922 and Center Park-Greenland circuit 933. Both circuits will be cut-in to the future Greenland Energy Center 230 kV switching station via 0.1 mile transmission line extension per circuit. The CTGs and STG will each connect to separate 18 kV/230 kV generator step-up (GSU) transformers. The CTGs and the STG will each have generator breakers. Auxiliary power will be provided by auxiliary transformers connected to each unit's 18 kV power.

5.5 Site Design

Table 5-1 presents the conceptual site design conditions for the GEC site.

Table 5-1
Conceptual Design Conditions for the Project Site

Condition	Value or Range	Reference
Maximum Temperature	103° F	Weatherbase Web site
Minimum Temperature	7° F	Weatherbase Web site
Average Temperature	69° F	Weatherbase Web site
Wind Loading	Basic Wind Speed: 130 miles per hour (mph), (3 second gust), Occupancy Category IV, Importance Factor: 1.15, Exposure Category C	ASCE 7-05, with applicable addenda
Seismic Loading	Occupancy Category: IV, Seismic Design Category: C, Site Soil Classification (stiff soil): D, Mapped 1 Second Spectral Response Acceleration (S1), g: .06, Mapped Short-Term (0.25 sec) Spectral Response Acceleration (Ss), g: 0.15	ASCE 7-05
Site Elevation	Nominal 30.0 feet above mean sea level (msl)	
Location	Outdoors	

Figure 5-1 is a conceptual drawing that shows the arrangement and locations of the major equipment for each unit at the GEC site.

5.5.1 Cycling Design Features

GEC will include several design features for cycling load operation. The STG will be selected in combination with the HRSGs to provide a reasonable design throttle pressure to ensure satisfactory cycling operation. Because the unit is going to be designed for cycling operation, a nominal throttle pressure of 1,800 psig will be used for design purposes. In comparison to a higher design throttle pressure such as 2,400 psig, a 1,800 psig operating pressure allows reduced wall thicknesses in HRSG drums and piping, thereby reducing thermal stresses and allowing reduced warm-up times. This reduces overall startup time and increases ramp rates when changing loads.

HRSG design for cycling operation will include nozzle arrangement and connections, use of full penetration welds, separation of headers, and use of higher strength drum and header materials to enable thinner wall construction to reduce stress from temperature gradients. HRSG design will also include a stack damper for heat retention, automated vent and drain valves to control pressure and drain condensate during shutdowns and startups, and 100 percent bypass systems to enable steam/turbine temperature matching.

5.5.2 Ammonia Systems

Ammonia will be required for use in the SCR process for NOx control. Vaporized ammonia is injected into the combustion turbine exhaust gases prior to passage through the catalyst bed, which is installed in the HRSGs. The onsite ammonia system will include unloading facilities, aqueous ammonia storage tank, forwarding system, and vaporizing facilities. Aqueous ammonia will be used and will be delivered to the GEC site by tanker trucks, which include integral unloading pumps. The aqueous ammonia will be stored as a liquid in a nominal 20,000 gallon tank, which provides for two full tanker truck deliveries. The liquid ammonia will be forwarded to the HRSGs, vaporized, and injected upstream of the catalyst.

5.5.3 Future Expansion

The GEC site will have the capability for the future installation of combined cycle and simple cycle units. The site layout and infrastructure will support the future installation of an identical combined cycle power plant and future peaking unit capacity, for an ultimate certification capacity of approximately 1,300 MW.

It is anticipated that the site will be cleared and developed, including the storm water detention pond, for ultimate build out of future units during the construction of the initial simple cycle combustion turbines at GEC. It is also anticipated that most offsite facilities will be sized for ultimate build out including the reclaimed water pipeline, natural gas supply pipelines, wastewater return lines, and potable waterlines.

5.6 Fuel Supply

The primary fuel for GEC will be natural gas, while the backup fuel will be ULSD fuel oil. Natural gas will be delivered to the GEC site through the SeaCoast Pipeline and a distribution lateral utilizing firm transportation service from SeaCoast. The initial phase of the SeaCoast pipeline will extend from interconnections with FGT and SNG Cypress Lateral, near Jacksonville, Florida, to the interconnection between the SeaCoast Pipeline and PGS located in Clay County, Florida. The lateral will extend from the SeaCoast–PGS interconnection to the inlet of the meter located at GEC. SeaCoast's interconnection with both FGT and SNG will allow JEA to utilize a diverse natural gas supply portfolio. It is anticipated that adequate natural gas pressure will be available with no need for the addition of gas compressors.

Natural gas will be delivered to the GEC site by SeaCoast via the GEC Lateral and will be regulated, metered, and conditioned onsite. The pipeline to the site will be sized for ultimate site capacity. Details of this lateral and associated meter station will need to be determined during detailed design. Carbon steel pipe with cathodic protection will be installed underground from the main pipeline to the site. A new meter run and natural gas conditioning equipment is included. The natural gas conditioning equipment includes a fuel gas scrubber, two coalescing gas filters, and a dew point control fuel gas heater.

A complete fuel oil unloading, storage, and supply system will be installed. Two 1,875,000 gallon tanks will be installed that will provide a minimum 5 days of full load operation at minimum ambient conditions for GEC. The tanks will be single wall design fabricated from carbon steel and will be installed inside a dike containment area. Normal fuel oil delivery will be by truck. A truck unloading system will be installed including truck connections. Fuel oil forwarding skids will be included to transfer fuel oil from the storage tanks to the CTGs. Two 100 percent capacity electric motor driven pumps will be included for each skid and the skids will be installed outdoors on concrete pads near the new fuel oil storage tanks.

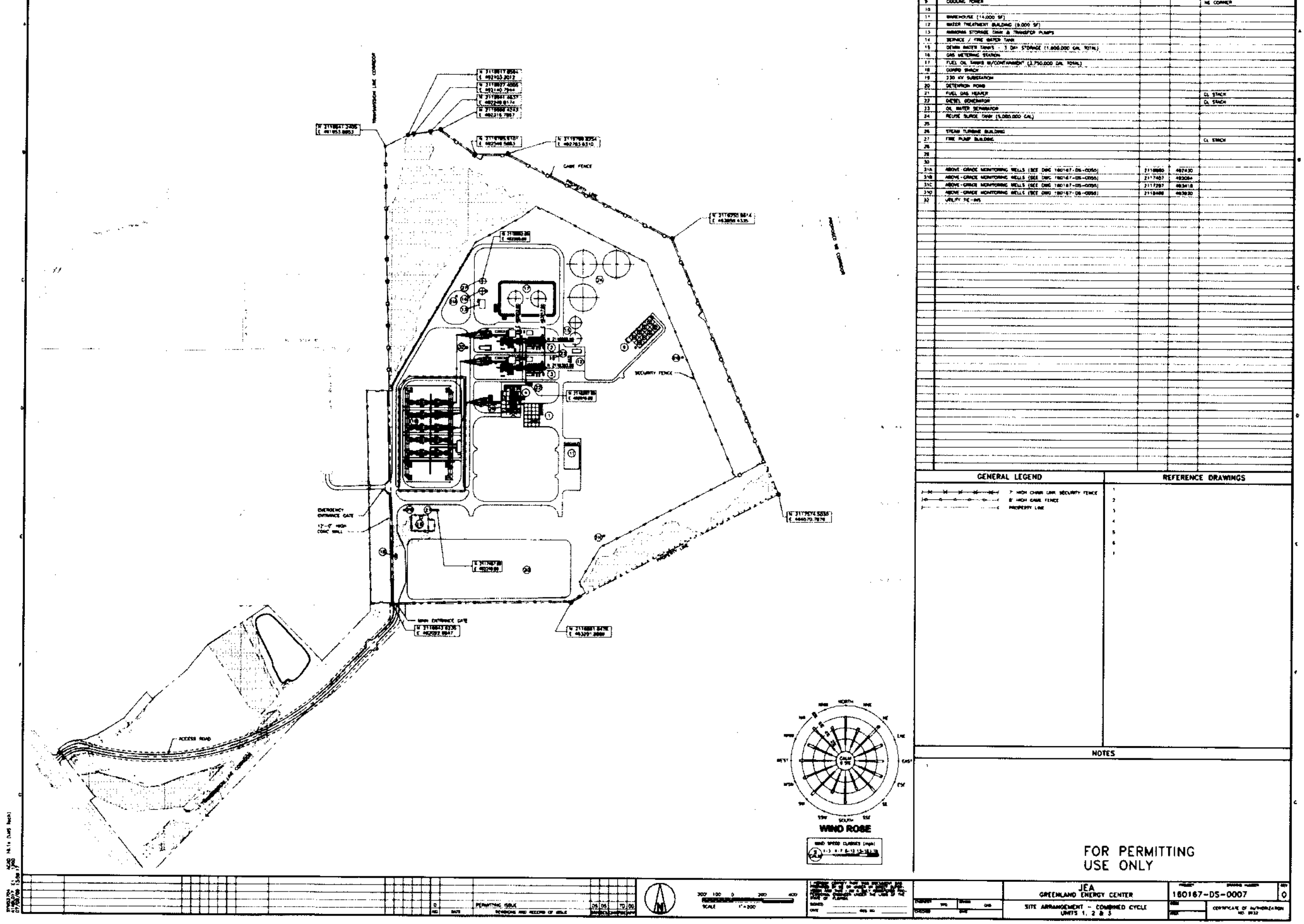
5.7 Project Costs

5.7.1 Capital Cost

The capital cost estimate is based on the conversion of the two GE 7FA simple cycle combustion turbines at GEC to a 2x1 combined cycle configuration. The construction cost includes direct costs for purchased equipment and materials, construction contract costs, and indirect costs. The direct construction cost estimate is based on site development for the ultimate capacity and also sizing interconnecting pipelines for the ultimate capacity. Direct costs include the costs associated with the purchase of equipment, erection, and all contractor services. All direct costs include escalation to spring 2013 commercial operation.

Construction costs are based on an engineering, procurement, and construction (EPC) contracting philosophy. Construction is assumed to be performed based on a 50 hour work week, with some 60 hour work weeks. Local labor craft rates that include payroll, payroll taxes, and benefits were used in developing the estimated construction costs.

Figure 5-1
Conceptual Site Arrangement Drawing



Construction indirects and construction equipment costs are included in the construction and service contracts portion of the estimate.

Indirect costs associated with construction are included in the base cost estimate. General indirect costs include all necessary services required for checkouts, testing services, and commissioning. Insurance for builder's risk and general liability are included. Contractor engineering, contractor field construction management, technical direction, contingency, profit, equipment transportation costs, startup, and commissioning are also included.

5.7.2 Operations and Maintenance Costs

O&M costs include fixed and variable costs. Fixed costs are independent of plant operation while variable costs are directly related to the plant operation. The O&M cost estimates were based on the following assumptions:

- Primary fuel is natural gas.
- Potable water will be provided by JEA, cooling tower makeup water will be provided by JEA as reclaimed water, and service water will be provided by JEA's municipal water supply. JEA's municipal water supply will also provide an emergency source of makeup water.
- A full-time plant staff of 22 personnel consisting of a plant manager, three administrative staff, and 18 O&M personnel.
- An operating profile consisting of up to 300 starts per year, weekly starts during the summer months, and daily starts during the non-summer months with an average capacity factor ranging from 20 to 95 percent.

5.7.2.1 Fixed O&M Costs

Fixed costs include labor, payroll burden, fixed routine maintenance, and administration costs. The incremental fixed O&M costs associated with the GEC combined cycle conversion are estimated to be $3.38 million per year in 2008 dollars.

5.7.2.2 Nonfuel Variable O&M Cost

Nonfuel variable O&M costs include consumables, chemicals, lubricants, water, and major inspections and overhauls. Major inspection and overhaul costs can be covered under long-term service agreements with the turbine manufacturer, or each overhaul can be subcontracted to the turbine supplier or a third party maintenance provider. Because the plant is not staffed to fully perform these major inspections, it is assumed that these will be subcontracted to the turbine supplier or a third party O&M provider. Nonfuel variable O&M costs vary as a function of plant generation. The incremental nonfuel variable O&M costs associated with the GEC combined cycle conversion are estimated to be $2.28 million per year in 2008 dollars. The estimated nonfuel variable O&M costs assume operation on natural gas.

5.8 Other Information

5.8.1 Heat Rate

Based on the heat balances developed for the project, Table 5-3 presents a summary of the estimated performance for the GEC combined cycle. Nonrecoverable performance degradation factors of 2.7 percent for output and 1.5 percent for heat rate have been included in the estimated performance.

Table 5-3
Estimated Greenland Energy Center Combined Cycle Performance

Performance Point	Net Plant Output (kW)	Net Plant Heat Rate (Btu/kWh, [HHV])
95° F, Full Load with Supplemental Firing	491,346	7,280
24° F, Full Load with Supplemental Firing	562,423	7,159
69° F, Full Load with Supplemental Firing	522,190	7,136
69° F, Full Load without Supplemental Firing	490,314	7,019
69° F, 2 CTGs at 80% Load without Supplemental Firing	405,420	7,226
69° F, 2 CTGs at 50% Load without Supplemental Firing	284,534	7,908
69° F, 1 CTG at 100% Load without Supplemental Firing	240,136	7,165
69° F, 1 CTG at 80% Load without Supplemental Firing	197,091	7,432
69° F, 1 CTG at 50% Load without Supplemental Firing	134,644	8,355

5.8.2 Emissions

The estimated emissions for the GEC combined cycle are presented in Table 5-4. The estimated emissions include operation of SCR and DLN burners.

5.8.3 Availability

Equivalent availability is a measure of the capacity of a generating unit to produce power considering operational limitations such as equipment failures, repairs, routine maintenance, and scheduled maintenance activities. Equipment outages and forced outages are not predictable and, as a result, a forced outage of 3 percent is assumed for each year. Scheduled outages will be determined by the hours of operation and number of starts. The CTG maintenance program typically consists of combustion inspections, hot gas path inspections, and major overhauls. Typical durations for these outages have been assumed as follows: 7 days for a combustion inspection, 14 days for a hot gas path inspection, and 25 days for a major overhaul. Based on the expected operating profile for the plant, the equivalent availability for GEC is estimated to be 94 percent. On average, 7 maintenance days per year and a 3 percent forced outage rate have been assumed.

Table 5-4
Greenland Energy Center Combined Cycle Estimated Emissions [1]

NO_x, parts per million volumetric dry (ppmvd) at 15% Oxygen (O_2)	2.0
NO_x, lb/MBtu	0.0072
SO_2, lb/MBtu	0.0004
Hg, lb/MBtu	Negligible
CO_2, lb/MBtu	114.8
CO, ppmvd at 15% O_2	7.6
CO, lb/MBtu	0.0166

[1] Emissions are at full load at average ambient conditions, reflect operation on natural gas, and include the effects of SCR and DLN burners.

5.9 Schedule

The GEC combined cycle conversion is planned for commercial operation beginning in June 2013. In order to achieve the planned commercial operation date, detailed engineering activities will be required in advance of the June 2011 start of initial construction. These activities are planned to commence during the first quarter of 2010. Similarly, procurement activities such as specification, equipment proposal solicitation, and contract negotiation for the STG and HRSGs, which are all long lead equipment items, will occur starting in 2009 to allow for delivery of this equipment to support the schedule.