NEED FOR POWER APPLICATION

001703-EU

ORIGINAL

Building Community

JEA Brandy Branch Combined Cycle Conversion

BLACK & VEATCH

Need for Power Application
Brandy Branch Combined Cycle Conversion

November 2000

BLACK & VEATCH

11401 Lamar, Overland Park, Kansas, 66211, USA (913) 458-2000

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1.0 Introduction

JEA is pleased to submit this Need for Power Application for the conversion of Brandy Branch to combined cycle operation. The Brandy Branch Generating Station is currently under construction and will consist of three General Electric PG7241 FA (GE 7 FA) combustion turbine units (Units 1, 2, 3) in simple cycle. Anticipated date of commercial operation for Units 1 and 2 is May 2001. Unit 3 is anticipated to be in commercial operation in December 2001.

JEA proposes to convert two of the three GE 7FA simple cycle units into a combined cycle unit by adding a steam turbine (173 MW ISO rating), electric generator, two heat recovery steam generators (HRSGs) with new exhaust stacks, cooling tower, condenser, and associated balance-of-plant equipment. The addition of the 173 MW steam turbine requires the unit to be certified under the Florida Electrical Power Plant Siting Act, requiring this Need for Power Application. The combined cycle unit will have a nominal rating of approximately 543 MW. Construction of the combined cycle conversion is proposed to start in September 2002. After the conversion, Brandy Branch Generating Station will have a nominal rating of approximately 716 MW, with the proposed commercial operation date of the combined cycle conversion of June 2004.

JEA is seeking a determination of need for the Brandy Branch combined cycle conversion. The need for the conversion is demonstrated for the entire combined cycle unit consisting of the combustion turbines and the 173 MW steam turbine. JEA has concluded that the Brandy Branch conversion is the most cost-effective alternative for meeting JEA's reliability need in 2004. In addition, this conversion project will contribute to JEA's system reliability and integrity and provide power at reasonable costs for many years after 2004.

1.1 Applicant Official Name and Mailing Address

JEA
21 West Church Street, T-11
Jacksonville, Florida 32202

1.2 Business Entity

JEA is a municipal utility, duly organized, and legally existing as part of the government of the City of Jacksonville, engaged in the generation, transmission, and distribution of electric power.

1.3 Official Representative Responsible for Need Application

Charles Bond, P.E.
Manager, Capacity Planning
JEA
21 West Church Street, T-11
Jacksonville, Florida 32202
Phone: (904) 665-6196
Fax: (904) 665-7369

1.4 Site Location

Duval County.

1.5 Nearest Incorporated City

City of Baldwin, Florida.

1.6 Longitude and Latitude

Longitude: 81 degrees, 56 minutes, 55 seconds.
Latitude: 30 degrees, 19 minutes, 14 seconds.

1.7 UTMs (Center of Site)

3,354.4 km North.
408.8 km East.

1.8 Section, Township, Range

Sections 13 and 18, Township 2 South, Ranges 23 East and 24 East.

1.9 Location of Any Directly Associated Transmission Facilities

No directly associated transmission facilities will be constructed for the conversion of Brandy Branch to combined cycle.

1.10 Nameplate Generating Capacity

The nameplate rating of Brandy Branch combined cycle is estimated to be approximately 543 MW at ISO conditions (59° F, 60 percent relative humidity). The exact rating will depend upon the steam turbine vendor selected and cycle configuration. The combined cycle unit will consist of two GE 7FA combustion turbine generators, two

HRSGs with new exhaust stacks, steam turbine, electric generator, cooling tower, condenser, and associated balance-of-plant equipment.

1.11 Commercial Operation

Brandy Branch combined cycle is proposed for commercial operation in June 2004, with a construction schedule of about 21 months. The Brandy Branch combustion turbines will have been installed for about 3 years when the combined cycle conversion becomes commercial.

1.12 Need for Power Application Structure

The following paragraphs describe the general structure of the Need for Power Application and preview the contents of each section.

1.12.1 Description of the Project

Section 2.0 of the Need for Power Application provides details of the proposed project. The section describes the history of the project, the existing facilities, fuel supply to the plant, estimated capital costs, estimated operating and maintenance costs (O&M), heat rate, availability, and the anticipated schedule for commercial operation.

1.12.2 System Description

Section 3.0 describes and details the existing generating and transmission facilities for JEA. The section includes an overview of the JEA system, description of existing power generating facilities, existing transmission details, and maps showing service area and transmission lines.

1.12.3 Methodology

Section 4.0 describes the methodology applied throughout the Need for Power Application to analyze the need for the Brandy Branch combined cycle conversion. This section provides a framework of how the need and the benefits of the Brandy Branch combined cycle conversion were analyzed.

1.12.4 Evaluation Criteria

Section 5.0 designates the economic parameters and evaluation criteria applied throughout the Need for Power Application. This includes escalation rate assumptions, the present worth discount rate, and the evaluation period selected for the economic evaluation.

1.12.5 Fuel Forecast

Section 6.0 provides the fuel forecast applied within the Need for Power Application evaluation. This section details the fuel forecast methodology, assumptions, and results. The fuel forecast consists of a base case forecast, and low and high price fuel forecasts.

1.12.6 Load Forecast

Section 7.0 details JEA's load forecast. This section details the load forecast methodology, assumptions, and results. The load forecast consists of a base case forecast with a high and a low growth case.

1.12.7 Demand-Side Programs

Section 8.0 describes the demand-side programs that JEA has in place today as part of its electric system and identifies demand-side alternatives evaluated.

1.12.8 Reliability Criteria

Section 9.0 addresses the reliability criteria and the need for additional capacity. This includes analysis using the standard reserve margin method.

1.12.9 Invitation for Proposals for Purchase Power

JEA did not issue a Request for Proposal (RFP). Section 10.0 summarizes the reasons JEA did not issue an RFP.

1.12.10 Supply-Side Alternatives

Section 11.0 describes the supply-side alternatives analyzed to determine JEA's most cost-effective option. Supply-side alternatives considered include renewable technologies, waste technologies, advanced technologies, energy storage systems, nuclear facilities, qualifying facilities, conventional alternatives, and purchase power.

1.12.11 Supply-Side Screening

Section 12.0 summarizes the screening analysis conducted to reduce the number of supply-side alternatives to be considered in detailed modeling. The screening analysis considers technical feasibility and busbar economic analysis in a two-phase process.

1.12.12 Economic Analysis

Section 13.0 details the economic analysis for the base case. The economic analysis is based upon the cumulative present worth revenue requirements of the alternatives over the 20 year planning horizon. This section identifies the most cost-effective plan and the cost of alternative plans. This section also presents the economic analyses conducted to determine if there is a cost-effective demand-side management alternative to the identified most cost-effective supply-side alternative.

1.12.13 Sensitivity Analyses

Section 14.0 presents the numerous sensitivity analyses conducted to demonstrate that JEA has selected the most cost-effective plan for its customers. An economic analysis for each of the following sensitivity analyses was conducted and demonstrates that the Brandy Branch combined cycle conversion is the most cost-effective option. The sensitivity analyses consider the high and low load growths, 20 percent reserve margin, high and low fuel prices, and high and low discount rate.

1.12.14 Strategic Considerations

Section 15.0 presents the strategic factors JEA considered in arriving at the selected expansion plan.

1.12.15 Financial Analysis

Section 16.0 outlines JEA's strong financial position and its ability to carry out this project.

1.12.16 Consequences of Delay

Section 17.0 presents the consequences if the Brandy Branch conversion was delayed. These include reliability considerations, capital cost impacts, and economic consequences.

1.12.17 Analysis of 1990 Clean Air Act Amendments

Section 18.0 summarizes the 1990 Clean Air Act Amendments and their impacts on the Brandy Branch combined cycle conversion.

1.12.18 Consistency with Peninsular Florida Needs

Section 19.0 shows that the Brandy Branch combined cycle conversion is consistent with Peninsular Florida needs. This section demonstrates Peninsular Florida's need for power based upon the 2000 Load and Resource Plan published by the Florida Reliability Coordinating Council (FRCC).

2.0 Description of the Project

This section summarizes the details of the Brandy Branch project, including history of the development of the project, a description of the simple cycle units and the conversion to combined cycle, estimated capital cost, O&M cost, fuel supply, heat rate, emissions, availability, and the project schedule.

2.1 History of the Project Development

JEA's 1997 Integrated Resource Plan (IRP) showed the need to increase its peaking power requirements starting in the 2000 to 2001 time frame. The IRP study concluded that new 173 MW simple cycle combustion turbines would provide the most economic means to meet JEA's peaking power system requirements. A purchase specification for the combustion turbines was prepared, issued on March 16, 1998, and bids were received on April 16, 1998. Negotiations were conducted with two bidders: Westinghouse Electric Company and General Electric Company (GE). The cumulative result of the negotiation and the evaluation of the competitive bid price proposals was an award to GE for the purchase of three combustion turbines with an option for a fourth that was subsequently exercised. The award was finalized on May 28, 1998. One combustion turbine has been installed at the Kennedy Generating Station and three are currently being installed at Brandy Branch.

In its 2000 Ten Year Site Plan (TYSP) study, JEA presented its latest evaluation of the future supply capacity needs of its electric system. The evaluation, which was based on peak demand and energy forecasts, existing supply resources and contracts, transmission considerations, and unit retirements, indicated that additional capacity would be needed to meet the system reserve requirements beginning in the year 2004. Tables 2-1 (summer) and 2-2 (winter) display the likely need for capacity when assuming the base case load forecast of JEA's system for a 10 year period beginning in 2000.

To meet future system reserve requirements, JEA developed an expansion plan. Six self-build alternatives were modeled using EPRI's Electric Generation Expansion Analysis System (EGEAS), an optimal generation expansion model, to determine the most cost-effective expansion plan. The most cost-effective expansion plan was identified based on the total present worth costs over a 20 year planning horizon. Several sensitivity analyses were performed to determine the impact on the most cost-effective plan.

Environmental and land use considerations were also factored into the most cost-effective plans. This ensured that the least-cost plans selected were socially and environmentally responsible and demonstrated JEA's total commitment to the community.

Table 2-1
Summer Resource Needs After Committed Units
Forecast of Capacity and Demand at Peak Time

Year	Installed Capacity	Firm Capacity Import	Firm Capacity Export	QF	Available Capacity	Firm Peak Demand	Reserve Margin		Capacity Required for 15 Percent Reserves
	MW	MW	MW	MW	MW	MW	MW	Percent	MW
2000	2,708	468	430	0	2,746	2,384	361	15	0
2001	3,024	298	430	0	2,892	2,461	431	18	0
2002	2,976	299	430	0	2,845	2,539	306	12	75
2003	3,241	207	430	0	3,018	2,619	399	15	0
2004	3,241	207	383	0	3,065	2,700	365	14	40
2005	3,241	207	383	0	3,065	2,782	283	10	135
2006	3,241	207	383	0	3,065	2,866	199	7	231
2007	3,241	207	383	0	3,065	2,952	113	4	330
2008	3,241	207	383	0	3,065	3,039	26	1	430
2009	3,241	207	383	0	3,065	3,128	-63	-2	532

Notes: The committed units are as follows:

1. Kennedy Unit 10 Shutdown – April 2000
2. Kennedy CT 7 – June 2000
3. Brandy Branch CTs 1 and 2 – May 2001
4. Southside Units 4 and 5 Retirement – October 2001
5. Brandy Branch CT 3 – December 2001
6. Northside Unit 1 – Outage for Fuel Conversion – September 2001
7. Northside Unit 2 – April 2002
8. Northside Unit 1 – August 2002

Table 2-2
Winter Resource Needs After Committed Units
Forecast of Capacity and Demand at Peak Time

Year	Installed Capacity	Firm Capacity Import	Firm Capacity Export	QF	Available Capacity	Firm Peak Demand	Reserve Margin		Capacity Required for 15 Percent Reserves
	MW	MW	MW	MW	MW	MW	MW	Percent	MW
2000	2,731	566	445	0	2,852	2,464	388	16	0
2001	2,825	560	445	0	2,940	2,548	392	15	0
2002	2,927	287	445	0	2,769	2,634	134	5	261
2003	3,457	207	445	0	3,219	2,722	497	18	0
2004	3,457	207	383	0	3,281	2,812	469	17	0
2005	3,457	207	383	0	3,281	2,903	378	13	58
2006	3,457	207	383	0	3,281	2,996	285	10	165
2007	3,457	207	383	0	3,281	3,091	190	6	274
2008	3,457	207	383	0	3,281	3,188	93	3	385
2009	3,457	207	383	0	3,281	3,286	-6	0	499

Notes: The committed units are as follows:

1. Kennedy Unit 10 Shutdown – April 2000
2. Kennedy CT 7 – June 2000
3. Brandy Branch CTs 1 and 2 – May 2001
4. Southside Units 4 and 5 Retirement – October 2001
5. Brandy Branch CT 3 – December 2001
6. Northside Unit 1 – Outage for Fuel Conversion – September 2001
7. Northside Unit 2 – April 2002
8. Northside Unit 1 – August 2002

2.2 Description of Brandy Branch Simple Cycle Units

2.2.1 General Description

JEA's Brandy Branch Generating Station consists of three gas/oil fired simple cycle combustion turbine electric generating units. These combustion turbines are GE's advanced class models, rated at 173 MW ISO each. The combustion turbines are dual fuel capable and will be operated with natural gas as the primary fuel and No. 2 oil as the backup fuel. These units were delivered to the Brandy Branch site in late 1999 and early 2000. Construction began in late 1999 and Units 1 and 2 are scheduled for Commercial Operation in May 2001, and Unit 3 in December 2001.

The plant site is a new site near the City of Baldwin. Baldwin is west of Jacksonville on Highway 301, a short distance north of Interstate 10. The plant site is a short distance north of Highway 90 east of Baldwin. The location of the site is shown on Figure 2-1. The generation area will consist of the plant buildings, structures, and equipment required for the power plant.

2.2.2 Combustion Turbine

Each combustion turbine is a General Electric Model PG7241 (FA) with an ISO rating of 173 MW. Each combustion turbine is a 3,600 rpm, 60 hertz heavy-duty industrial combustion turbine unit. The expected performance is shown in Table 2-3.

The primary fuel for the combustion turbines will be natural gas, with No. 2 oil used as a backup fuel. Natural gas will be delivered to the site by a pipeline. No. 2 oil will be delivered by truck and stored in two onsite fuel oil tanks.

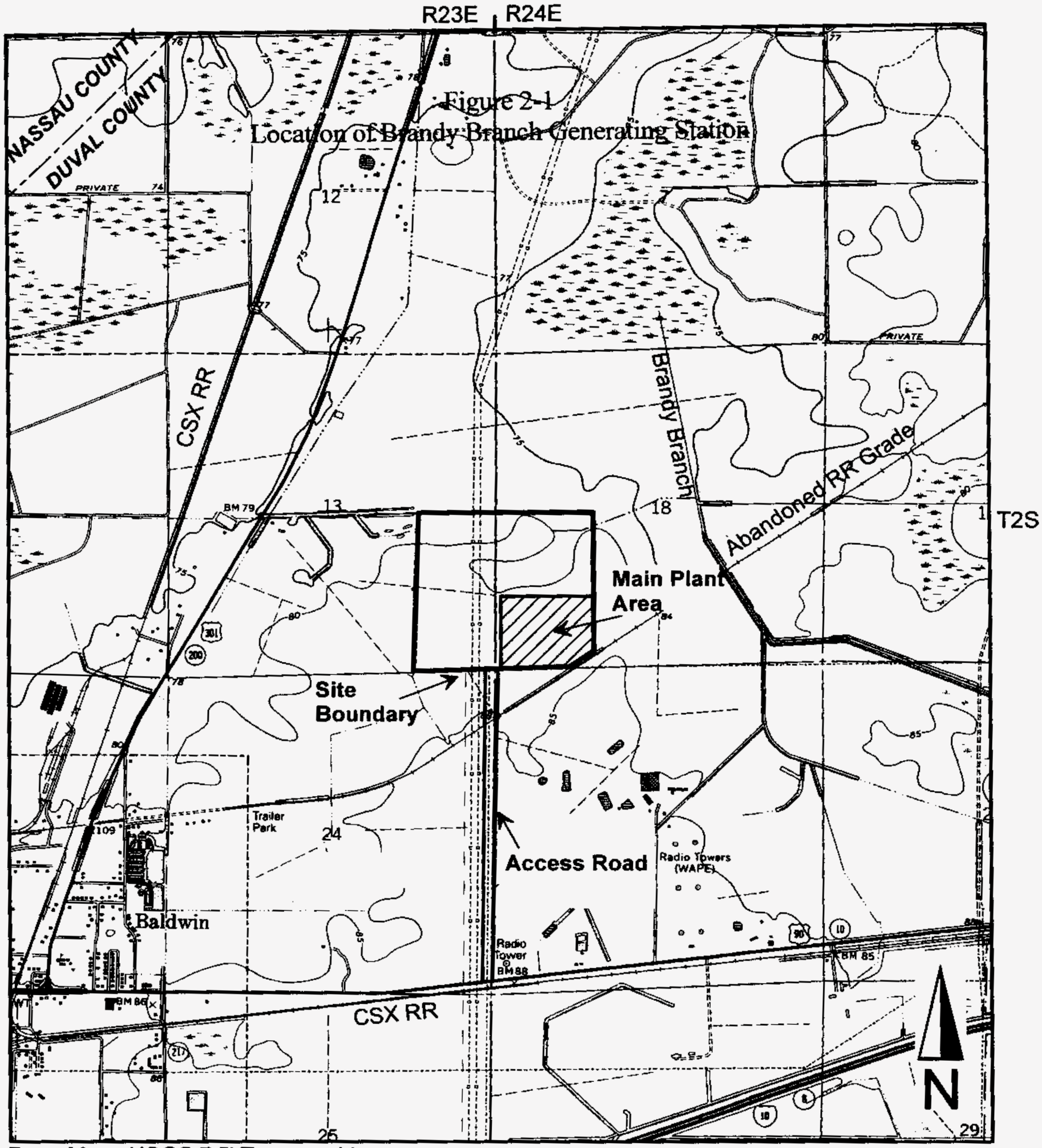
Dry low NO_x combustors will be used to control NO_x emissions for natural gas operation and water injection will be used for No. 2 oil operation.

In order to minimize combustion turbine blade erosion, hot gas part corrosion, and performance loss, inlet air filtration will be provided to remove particles in the inlet airstream.

The combustion control package includes equipment for startup/operation monitoring via a screen and keyboard.

2.2.3 Generator

The generator will be a hydrogen-cooled, synchronous unit rated at 18.0 kV, 60 hertz, three-phase, and approximately 203.8 MVA at 0.90 power factor (lagging) and cold gas temperature of 40° C. The generator will be of the two-pole cylindrical rotor type and use a stator frame with vertical coolers and spring mounted core. The stator and rotor will employ Class F insulation limited to a Class B temperature rise.



Base Map: USGS 7.5' Topographic
Baldwin Quadrangle, Revised 1992

Project Location
Brandy Branch Generating Station

Mile
0 0.5 1

Figure 2-1
Location of Brandy Branch Generating Station

Table 2-3
Brandy Branch Simple Cycle
Preliminary Performance

Baseload Performance	Natural Gas	Fuel Oil
Gross CTG Output, Each, kW	173,200	182,000
Auxiliary Power		
CTG Auxiliary Power, kW	608	1,542
BOP Auxiliary Power, kW	100	150
Transformer Loss, kW	870	910
Total Auxiliary Power, kW	1,578	2,602
Net Plant Output, kW	171,622	179,398
Gross CTG Heat Rate, Btu/kWh (LHV)	9,370	10,010
Gross CTG Heat Rate, Btu/kWh (HHV)	10,391	10,660
Heat Input, MMBtu/h (LHV)	1622.88	1821.82
Heat Input, MMBtu/h (HHV)	1799.72	1940.12
Net Plant Heat Rate, Btu/kWh (LHV)	9,456	10,155
Net Plant Heat Rate, Btu/kWh (HHV)	10,487	10,815
CTG Exhaust Flow, lbm/h	$3{,}542 \times 10^3$	$3{,}683 \times 10^3$
CTG Exhaust Temperature, °F	1,116	1,098
Water Injection, lbm/h	0	119,690

Note: Performance based conditions of 59° F, 60 percent relative humidity, 27 feet elevation with standard inlet/exhaust pressure losses for simple cycle operation, and inlet bleed heating.

The stator winding is designed to meet the requirements of the desired output voltage and kVA rating. The generator is designed to withstand fault forces and normal running vibration while permitting free expansion so that load cycling does not cause damage.

Resistance thermal detectors are used to monitor internal generator temperatures. Terminal bushings are provided to conduct power to the isolated phase ductwork. A digital static exciter system, GE EX2000, is provided for generator voltage regulation.

The hydrogen cooling system includes heat exchangers mounted to the generator and cooled by the closed cycle cooling water system. Carbon dioxide manifolds are provided in order to allow purging of the hydrogen gas in conjunction with generator maintenance activities.

2.2.4 Air Quality Control

The combustion turbine utilizes a dry low NO_x combustion system to regulate the distribution of fuel delivered to a multi-nozzle, total premix combustion arrangement. The fuel flow distribution is calculated to maintain unit load and fuel split for optimal turbine emissions. In addition, when operating on No. 2 oil, demineralized water is injected into the combustion chamber to reduce the firing temperature, which reduces the formation of NO_x. The ratio of the flow rate of demineralized water to No. 2 oil is approximately equal. The NO_x emissions will be controlled to at or below the 10.5 ppmvd permit limit at 15 percent O_2 when firing natural gas and 42 ppmvd at 15 percent O_2 when firing No. 2 fuel oil with water injection.

2.2.5 Water Supply and Treatment

Service and fire water for use at the generating station is normally supplied from onsite wells. Potable water, construction water, and a backup supply for service water will be provided from the City of Baldwin.

The service water will be demineralized using rental filtration and demineralizer equipment to provide high quality water for NO_x water injection. Demineralized water for NO_x injection is stored in onsite tanks.

2.2.6 Wastewater Disposal

Plant and equipment drains and any site runoff from areas where oil contamination is anticipated will be routed through an oil/water separator prior to disposal into a percolation pond. Other site runoff will be collected and routed to a storm water detention pond which will discharge to an existing onsite wetland.

2.2.7 Transmission Systems and Auxiliary Power

The generator output will be fed through step-up transformers to a new onsite 230 kV substation. The substation will be connected to two 230 kV lines in the existing transmission line corridor.

During normal operation of each unit, auxiliary power to operate electrical equipment will be supplied from one full-capacity main auxiliary transformer which receives power from that unit's generator. Each unit's main auxiliary transformer steps generator voltage from 18 kV to 4160 V and distributes the power to the 4160 volt unit auxiliary loads and the 480 volt loads through a unit secondary substation and motor control center. Two full-capacity 230 kV to 4160 V startup/service transformers will provide power to the station common 4160 V bus and to two combustion turbine startup systems, each of which can start up any unit. The 4160 V station bus can provide power to each unit's 4160 V bus, and the common station 480 V loads through two full-capacity common station secondary unit substations and motor control centers.

2.2.8 Controls and Instrumentation

Coordinated control of the operation of the unit will be accomplished in the centralized, air-conditioned main Control Room. Additional control centers will be located throughout the plant as required for locally controlled equipment and systems. Remote operation of the unit will also be possible from the Northside Generating Station control room.

A Mark VI coordinated control system will be provided to regulate the output of each combustion turbine generator and control unit auxiliary systems. A unit safety protective interlock system will be provided to recognize unsafe operating conditions and initiate a unit trip to avoid damage to equipment.

Unit instrumentation and alarm systems will be designed to function independently of control systems. Visual, audible, and recorded alarms will be provided to alert the operator of off-normal operating conditions and to provide a record of operating events.

A station coordinated control system in the Control/Shared Services Building, located between the generating units and the substation, will control and monitor common plant systems and equipment, including the substation. This system will interface with the unit control systems to allow operation of all units from the station coordinated control system. The station administration facilities and station auxiliary electric system will be located in or near the Control/Shared Services Building.

2.2.9 Protection

The sources of water for the fire water systems are the onsite wells and the City of Baldwin water system. The basic fire protection for the plant facilities in different systems is shown in Table 2-4.

2.2.10 Cost Estimate

The total cost of installing the three Brandy Branch simple cycle combustion turbines is estimated to be $193,600,000 including switchyard.

Table 2-4 Brandy Branch Simple Cycle Fire Protection for Different Systems	
Equipment or Area Protected	Type of Protection
Yard and Building Exteriors	Fire hydrants and hose houses
Control Compartment	Portable fire extinguishers and detection system
Combustion Turbine Generator	CO_2 system
Major Transformers	Deluge water spray systems

2.3 Description of Brandy Branch Combined Cycle Conversion

2.3.1 General Description

In order to increase electric power generating capability, JEA is proposing to convert two of the Brandy Branch simple cycle units into a combined cycle unit. The Brandy Branch project was designed with future expansion in mind, namely either the addition of a fourth simple cycle combustion turbine or the addition of the steam turbine unit of a combined cycle to the site. This expansion will occur in the northwest quadrant of the current plant, adjacent to the existing combustion turbine. Adequate space exists for the addition of this equipment. The artist rendering on Figure 2-2 shows how the plant will look after conversion. The site arrangement drawing is shown on Figure 2-3.

The conversion will be accomplished by adding two heat recovery steam generators (HRSGs) and one steam turbine generator to the existing equipment. One HRSG will be added to each of the two combustion turbines and the steam turbine generator will be shared by the two HRSGs. This conversion will create a one-block 2 x 1 combined cycle and leave one simple cycle combustion turbine at the site. The ISO rating of the steam turbine addition is assumed to be 173 MW. The total capacity of the Brandy Branch power plant, including the remaining simple cycle unit and the combined cycle unit after the conversion into combined cycle, will be 716 MW.

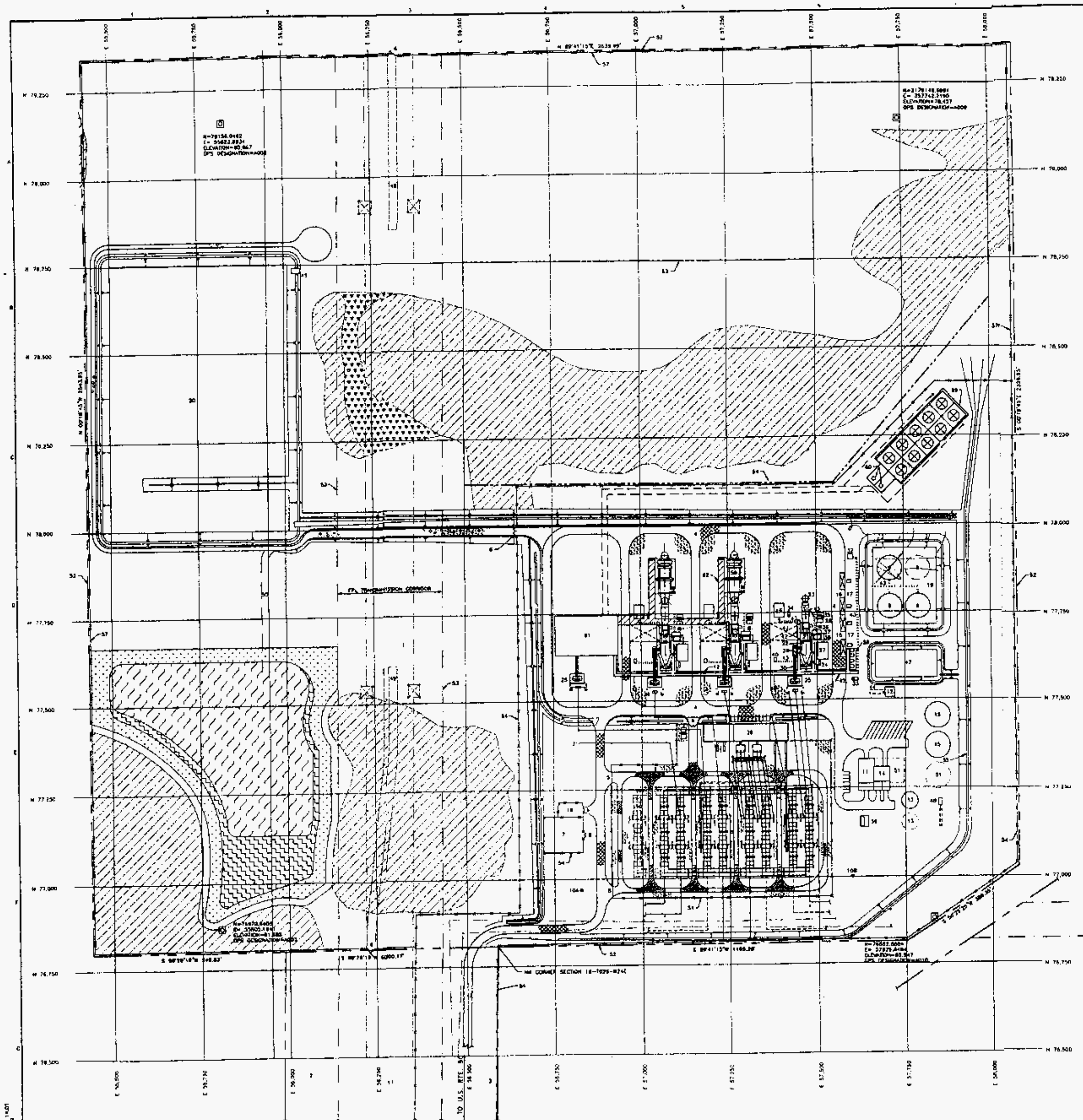
2.3.2 Conversion Modifications and Additions

The following plant modifications and additions are included in the estimate of the conversion from simple cycle to combined cycle:

- Two HRSGs with integral Selective Catalytic Reductions (SCRs), one and associated earthwork, piling, foundations, piping, associated equipment and appurtenances, and electrical and control systems.

Figure 2-2
Artist Rendition of Brandy Branch Power Plant

Figure 2-3
Site Arrangement Drawing
Brandy Branch Power Plant



FACILITIES LEGEND

ITEM NO	DESCRIPTION	LOCATION COORDINATES NORTH	LOCATION COORDINATES EAST	REFERENCE LOCATION
1	F.P.&L. RIGHT-OF-WAY	N/A	N/A	
2	JEA TRANSMISSION CORRIDOR	N/A	N/A	
3	ACCESS ROAD	N/A	N/A	
4	LOOP ROAD	N/A	N/A	
5	SLIDE GATE	N/A	N/A	
6	SWING GATE	N/A	N/A	
7	FUEL GAS METERING STATION	N/A	N/A	
8	SUBSTATION AREA	N/A	N/A	
9	FUEL OIL STORAGE TANK (1,000,000 GALLONS)	N/A	N/A	
10A	WATER SUPPLY WELL	78870.00	56825.00	CL WELL
10B	WATER SUPPLY WELL	77001.92	57597.00	CL WELL
11	SHOP/STORAGE BUILDING	N/A	N/A	
12	WASTEWATER PUMPING STATION	N/A	N/A	
13	RAW WATER/FIRE WATER STORAGE TANK	N/A	N/A	
14	MECHANICAL EQUIPMENT BUILDING	N/A	N/A	
15	DEMINERALIZED WATER STORAGE TANK	N/A	N/A	
16	FUEL OIL UNLOADING AREA	N/A	N/A	
17	FUEL OIL UNLOADING PUMP AREA	N/A	N/A	
18	HYDROGEN STORAGE GAS AREA	N/A	N/A	
19	FUEL OIL STORAGE TANK SECONDARY CONTAINMENT	N/A	N/A	
20	STORM WATER DETENTION POND	N/A	N/A	
21	COMBUSTION TURBINE (CT)	N/A	N/A	
22	CT GENERATOR	N/A	N/A	
23	CT EXHAUST STACK (UNIT 1)	77788.26	57469.00	CL STACK
23	CT EXHAUST STACK (UNIT 2)	N/A	N/A	
23	CT EXHAUST STACK (UNIT 3)	N/A	N/A	
24	CT AIR INLET FILTER	N/A	N/A	
25	GENERATOR STEP-UP TRANSFORMER	N/A	N/A	
26	CT WATER INJECTION SKID	N/A	N/A	
27	CONTROL/ELECTRICAL BUILDING	N/A	N/A	
28	FUEL FORWARDING SKIDS	N/A	N/A	
29	CONTROL/SHARED SERVICES BUILDING	N/A	N/A	
30	UNIT AUXILIARY TRANSFORMER	N/A	N/A	
31	EXHAUST DUCT SILENCER	N/A	N/A	
32	FIRE PROTECTION FOAM HOUSE	N/A	N/A	
33	WASH WATER SKID	N/A	N/A	
34	MISCELLANEOUS DRAIN TANK	N/A	N/A	
35	CT GAS FIRE PROTECTION SKID	N/A	N/A	
36	FALSE START DRAIN TANK	N/A	N/A	
37	LIQUID FUEL/ATOMIZING AIR MODULE	N/A	N/A	
38	CT ACCESSORY MODULE	N/A	N/A	
39	GENERATOR COMPARTMENT	N/A	N/A	
40	FIRE WATER DELUGE HOUSE	N/A	N/A	
41	MAINTENANCE AREA	N/A	N/A	
42	PIPE TRENCH	N/A	N/A	
43	SLEEPER PIPE RACK	N/A	N/A	
44	OIL WATER SEPARATOR	N/A	N/A	
45	STORM WATER DETENTION POND DISCHARGE STRUCTURE	N/A	N/A	
46	COOLER	N/A	N/A	
47	PERCOLATION POND	N/A	N/A	
48	SEPTIC TANK AND DRAINFIELD DETAIL	N/A	N/A	
49	EXISTING ROAD	N/A	N/A	
50	TEMPORARY CONSTRUCTION ACCESS ROAD	N/A	N/A	
51	FUTURE WATER TREATMENT EQUIPMENT EXPANSION	N/A	N/A	
52	PROPERTY BOUNDARY	N/A	N/A	
53	EASEMENT BOUNDARY	N/A	N/A	
54	CHAIN LINK SECURITY FENCE	N/A	N/A	
55	PERIMETER DITCH	N/A	N/A	
56	LUBE OIL STORAGE AREA	N/A	N/A	
57	BARBED WIRE SITE PERIMETER FENCE	N/A	N/A	
58	HEAT RECOVERY STEAM GENERATOR	N/A	N/A	
59	COOLING TOWER	N/A	N/A	
60	CIRCULATING WATER PUMPS	N/A	N/A	
61	STEAM TURBINE GENERATOR BUILDING	N/A	N/A	
62	ABOVE GROUND PIPE RACK	N/A	N/A	
63	CONSERVATION EASEMENT	N/A	N/A	

GENERAL LEGEND

- BENCHMARK
- FUTURE FACILITY
- WETLANDS
- CYPRESS (ZONE 2) AREA
- ASPHALT
- CRUSHED ROCK SURFACING
- HERBACEOUS (ZONE 3) AREA
- UPLAND SEEDING AREA
- RESTORATION MITIGATION AREA
- DEDWEB

NOT TO BE USED
FOR CONSTRUCTION

NO	DATE	REVISIONS AND RECORD OF ISSUE	DR	DES
B	09-19-2000	GENERAL REVISIONS	WC	JKH
A	09-05-2000	ISSUED FOR REVIEW	WC	JKH

SCALE: 1" = 100'

BLACK & VEATCH

JEA

JEA
BRANDY BRANCH COMBINED CYCLE PROJECT

SITE ARRANGEMENT

DRAWING NUMBER: 97990-DS-0001

REV: B

- Removal and replacement of the existing combustion turbine duct and stacks to accommodate the addition of the steam generator, HRSGs, and their stacks.
- Removal and replacement of the chain link security fence in the northeast area of the plant (to include the cooling tower).
- A Distributed Control System/Distributed Control Information System to be located in the existing electrical/control building for the steam side controls.
- Piperacks/sleepers for the HRSGs and steam turbine generator, including the associated earthwork, foundations, and steel.
- The piles included in the estimate are auger cast-in-place piling at 30 feet in length and 14 inches in diameter in accordance with the existing plant.
- A service/fire water storage tank, a neutralization tank, a No. 2 oil storage tank, and a demineralized water storage tank are not included. The existing tanks will be utilized.
- An extension of the existing plant road along the south and west perimeter of the site.
- A generator step-up transformer (GSU) and associated electrical and controls.

2.3.3 Capital Cost

The capital cost estimate is based on the current competitive generation market, and the following assumptions are made for the estimate:

- Direct Cost Assumptions:
  - Direct costs include the costs associated with the purchase of equipment, erection, and contractors' service.
  - Costs are based on an overnight commercial operation date.
  - Construction costs are based on an engineer, procure, and construct (EPC) contracting philosophy.
- Indirect Cost Assumptions:
  - General indirect costs include relay checkouts and testing, instrumentation and control equipment calibration and testing, systems and plant startup including operating crew during test and initial operation period, operating crew training, electricity, water and fuel used during construction; but no local taxes are included in this cost estimate.

- Engineering and related services include A/E services, owner office engineers, outside consultants, and other related costs incurred in the permit and licensing process.
- Field construction management services include field management staff. This includes the support staff personnel, field contract administration, field inspection and quality assurance, project controls, technical direction, and management of startup and testing. Also included is the cleanup expense for the portion not included in the direct-cost construction contracts, safety and medical services, guards and other security services, insurance premiums, other required labor-related insurance, performance bond, and liability insurance for equipment and tools. Local telephone and other utility bills associated with temporary services are also included in the estimate.
- Shipping for equipment and materials is included.
- An allowance of $500,000 is included for spare parts.
- A contingency of 10 percent is included in the estimate.

The estimated total cost for Brandy Branch combined cycle conversion is $107,930,896 in 2000 dollars. A detailed description of the estimated capital cost components is listed in Table 2-5.

2.3.4 O&M Cost

The estimates for fixed and variable nonfuel O&M costs for the Brandy Branch combined cycle unit are 1.86 $/kW-yr and 2.07 $/MWh, respectively. The estimates are made based on the following assumptions:

- All costs are provided in 2000 dollars.
- O&M cycle life: 30 years.
- Variable contingency: 20 percent.
- Fixed contingency: 20 percent.
- Annual capacity factor: 90 percent.
- Primary fuel: Natural gas; secondary fuel: No. 2 oil.
- NO_x control method: Dry low NO_x combustors to meet 10.5 ppmvd at 15 percent O_2 for the GE 7FA combustion turbines with SCR reducing NO_x to 3.5 ppmvd.
- Combustion turbine generator estimated maintenance costs provided by manufacturers.

Table 2-5
Cost Estimate Brandy Branch Conversion to Combined Cycle

Procurement Contracts	
Structural	$306,841
Mechanical	$49,189,714
Electrical	$4,231,606
Control	$1,508,169
Chemical	$2,151,987
Subtotal	$57,388,317
Furnish and Erect Contracts	
Structural	$1,408,569
Mechanical	$2,402,966
Subtotal	$3,811,535
Construction Contracts	
Civil/Structural	$10,347,027
Mechanical	$5,886,500
Electrical/Control	$1,274,509
Chemical	$476,894
Construction Services	$484,447
Subtotal	$18,469,377
Total Contracts, Direct Cost	$79,669,229
Spare Parts	$500,000
Total Direct Cost	$80,169,229
Indirect Cost	
General Indirects	$1,226,220
Engineering	$8,174,802
Field Construction Management	$3,269,921
Owner Admin/Engineering	$611,000
Substation	$1,300,000
Wastewater Pipeline	$1,044,800
Licensing and Permitting	$1,560,000
Contingency	$10,574,924
Total Indirect Cost	$27,761,667
Total Project Cost	$107,930,896

(1) All costs are for the conversion to combined cycle.
(2) All costs are in 2000 dollars.

- Combustion turbine generator technical labor cost estimated at $35/man-hour.
- Combustion turbine generator initial operational, combustion, and hot gas path spares are not included in the O&M cost.
- HRSG annual inspection costs are estimated based on manufacturer input and Black & Veatch experience.
- Steam turbine annual, minor, and major inspection costs are estimated based on Black & Veatch experience. Inspection costs occur every 8,000 hours or 400 starts of operation, minor inspections occur every 24,000 hours or 900 starts of operation, and major inspections occur every 48,000 hours or 2,400 starts of operation.
- Balance-of-plant costs are estimated based on Black & Veatch experience.
- Demineralized and raw water costs are included in the O&M analysis, where applicable.
- Supplies and materials are estimated to be 10 percent of additional staff salary.
- Rental equipment and contract labor costs are estimated by Black & Veatch.
- Fuel costs are not included in the O&M analysis.
- Employee training costs are not included in the O&M analysis.
- The variable O&M analysis is based on a repeating maintenance schedule for the combustion turbine generators and takes into account replacement and refurbishment costs. The annual average cost is the estimated average cost over the 30 year cycle life.
- O&M costs may vary with specific requirements by individual equipment manufacturers.

2.3.5 Fuel Supply

Natural gas will be the primary fuel for the Brandy Branch plant, with No. 2 oil as a backup fuel. Natural gas will be delivered to the site by a pipeline. No. 2 oil will be delivered by truck and stored in two No. 2 oil tanks. JEA currently purchases natural gas transportation from Florida Gas Transmission Company (FGT) under FTS-1. FGT operates the 16 inch Jacksonville Lateral through the Brandy Branch area. JEA has had a 16 inch lateral pipeline installed from the FGT facilities to Brandy Branch. This pipeline will provide adequate natural gas transportation for the Brandy Branch combustion turbines and the combined cycle conversion. JEA's natural gas entitlements include 40,000 decatherms/day for FTS-1, and contract extensions are at JEA's option. JEA has committed to an additional 14,000 decatherms/day of FGT FTS-2 beginning in spring 2002. In addition, JEA is currently negotiating with El Paso Merchant Energy and others for up to 75,000 decatherms/day for additional gas transportation and supply beginning in 2004. No. 2 oil storage facilities at the Brandy Branch site are currently being constructed to provide 2.4 days at full load of backup operation for each combustion turbine located at Brandy Branch.

2.3.6 Heat Rate

The estimates for average net plant heat rate (NPHR) and heat input for the Brandy Branch combined cycle are listed in Table 2-6.

2.3.7 Emissions

The combustion turbines utilize a dry low NO_x combustion system to regulate the distribution of fuel delivered to a multi-nozzle, total premix combustion arrangement. The fuel flow distribution is calculated to maintain unit load and fuel split for optimal combustion turbine emissions. In addition, when operating on No. 2 oil, demineralized water is injected into the combustion chamber to reduce the firing temperature, which reduces the formation of NO_x. The ratio of the flow rate of demineralized water to No. 2 oil is approximately equal. Selective catalytic reduction (SCR) will be utilized to reduce NO_x emissions for the combined cycle configuration. The expected flue gas emissions for the combined cycle are listed in Table 2-7.

Table 2-6
Brandy Branch Combined Cycle
Net Plant Heat Rate (NPHR) and Heat Input

Net Plant Output		NPHR, Btu/kWh (HHV)		Heat Input, MBtu/h (HHV)	
MW	Percentage	Natural Gas	Fuel Oil	Natural Gas	Fuel Oil
135.7	25	8,897	9,137	1,207	1,240
271.5	50	8,362	8,588	2,270	2,332
405.5	75	7,630	7,836	3,094	3,177
543.0	100	7,297	7,494	3,962	4,069

Notes: Includes degradation factor.
Based on 59° F, 60 percent relative humidity.

Table 2-7 Brandy Branch Combined Cycle Estimated Flue Gas Emissions		
Emissions	Natural Gas (lb/MBtu)	Distillate Fuel Oil (lb/MBtu)
SO_2	0.0006	0.21
SO_3	0	0.002
PM	0.0048	0.036
NO_x	0.044	0.15
CO	0.048	0.07
CO_2	130	159.2

A complete summary of emissions levels before and after the conversion is shown in Table 2-8.

Table 2-8 Brandy Branch Estimated Emissions		
Type of Emission	Before Conversion	After Conversion
NO_x	10.5 ppm (gas)	3.5 ppm (gas, w/SCR)
	42.0 ppm (oil)	15.0 ppm (oil, w/SCR)
CO	15.0 ppm (gas)	Same
	20.0 ppm (oil)	Same
SO_2	1.1 lb/h (gas, 2 gr. S/100 cf)	Approximately Same
	98.2 lb/h (oil, 0.05 percent S)	Approximately Same
TSP/PM_{10}	9.0 lb/h and 10 percent opacity (gas, front catch)	11.0 lb/h and 10 percent opacity (gas, front catch)
	17.0 lb/h and 10 percent opacity (oil, front catch)	57.0 lb/h and 10 percent opacity (oil, front catch)

2.3.8 Availability

Availability of the Brandy Branch combined cycle is estimated to be approximately 89 percent per year based on the expected 95 percent availability of the combustion turbine. The availability estimate includes a 4.7 percent forced outage rate and all scheduled maintenance outages as averaged over the life of the unit.

2.3.9 Schedule

The schedule for Brandy Branch combined cycle conversion is based on a 21 month construction period. To meet a June 2004, commercial operation date, construction would start in summer 2002 upon receiving site certification. The detailed schedule is presented on Figure 2-4.

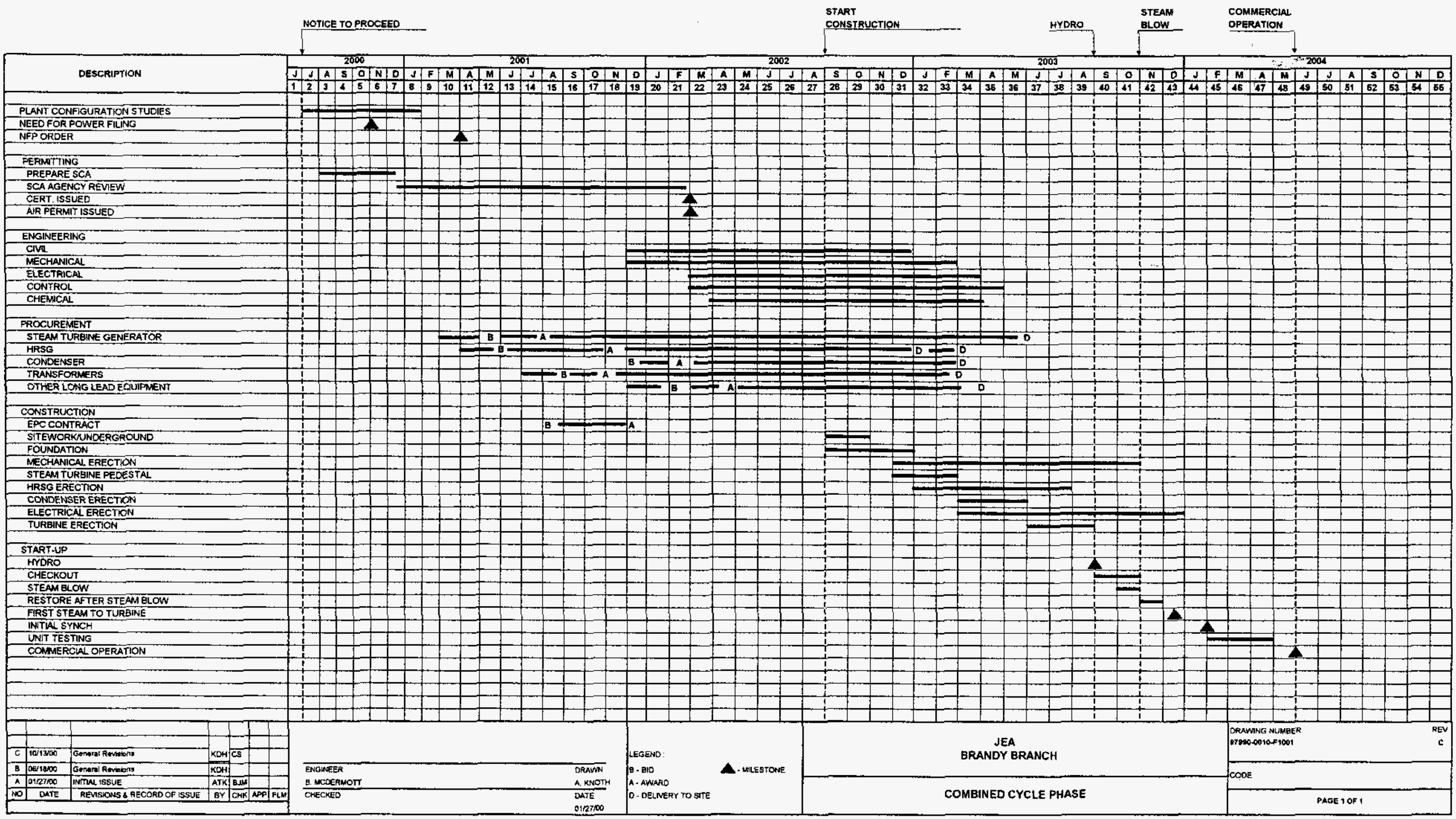


Figure 2-4
JEA Brandy Branch Schedule - Combined Cycle Phase

3.0 System Description

3.1 Generation System

JEA's electric service area covers all of Duval County and portions of Clay County, Nassau County, and St. Johns County. JEA's service area covers approximately 900 square miles.

The generating capability of JEA's system currently consists of Kennedy, Northside, and Southside generating stations, the Girvin Landfill, and joint ownership in St. Johns River Power Park (SJRPP) and Scherer Unit 4 generating stations. The total net capability of JEA's generation system is 2,825 MW in the winter and 2,708 MW in the summer.

3.2 Transmission System

JEA's transmission system consists of bulk power transmission facilities operating at 69 kV or higher. This includes all transmission lines and associated facilities where each transmission line ends at the substations termination structure. JEA owns 684 circuit-miles of transmission lines at five voltage levels: 69 kV, 115 kV, 138 kV, 230 kV, and 500 kV. JEA's transmission system includes a 230 kV loop surrounding JEA's service territory. The existing transmission system is shown on Figure 3-1.

JEA is currently interconnected with Florida Power & Light (FP&L), Seminole Electric Cooperative (SECI), and Florida Public Utilities (FPU). Interconnections with FP&L are at 230 kV, to the Sampson and Duval Substations. The interconnection to SECI is at 230 kV and at 138 kV to FPU. JEA closed Breaker 801 at the Neptune 138 kV Substation to interconnect to the City of Jacksonville Beach (FMPA) through the Jacksonville Beach 138 kV Substation on March 20, 2000.

JEA and FP&L jointly own two 500 kV transmission lines that are interconnected with Georgia Power Company. JEA, FP&L, Florida Power Corporation (FPC), and the City of Tallahassee each own transmission interconnections with Georgia Power Company. JEA's entitlement over these transmission lines is 1,228 out of 3,600 MW import capability. JEA's system is interconnected with the 500 kV transmission lines at FPL's Duval Substation.

3.3 General Description

3.3.1 Existing Generating Units

Kennedy, Northside, and Southside generating stations and the Girvin Landfill make up JEA's generation system. In addition, JEA has joint ownership in SJRPP and Scherer Unit 4 generating stations. Details of the existing facilities are displayed in Table 3-1.

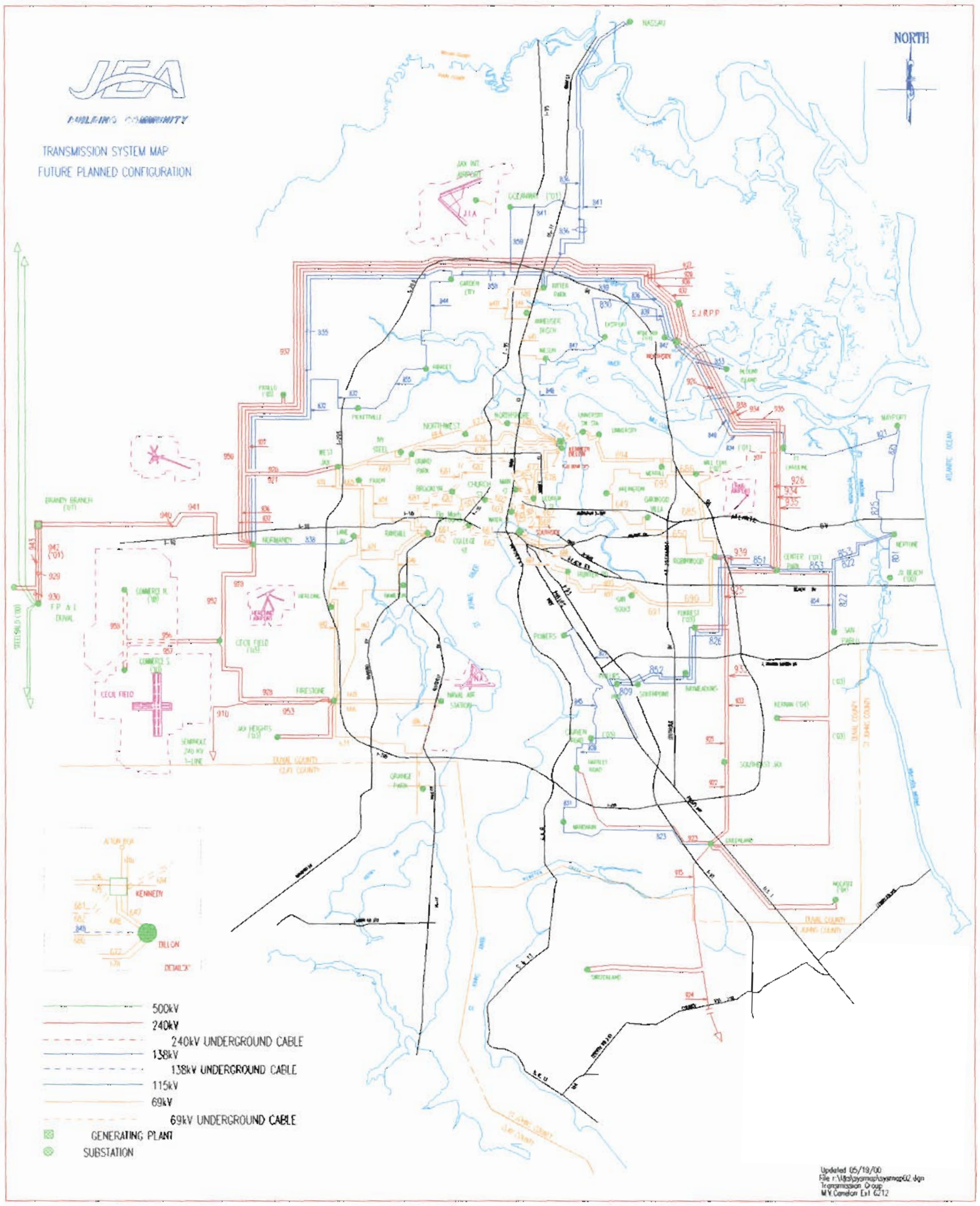


Figure 3-1

JEA Existing Transmission System

General Description Existing Generating Units

Table 3-1
JEA Existing Generating Facilities
(As of November 2000)

Plant Name	Unit Number	Location	Unit Type	Fuel Type		Fuel Transportation		Commercial In-Service, mo/yr	Expected Retirement, mo/yr	Gen. Max. Nameplate, kW	Net MW Capability		Ownership	Status
				Pri.	Alt.	Pri.	Alt.				Summer	Winter		
Kennedy	7	12 – 031	GT	NG	FO2	PL	WA	6/2000	(b)	195,380	158	191	Utility	
	8	12 – 031	ST	FO6		WA		7/1955	(b)	50,000	43	43	Utility	M
	9	12 – 031	ST	NG	FO6	PL	WA	1/1958	(b)	50,000	43	43	Utility	M
	10	12 – 031	ST	NG	FO6	PL	WA	12/1961	4/2000	149,600	97	97	Utility	(e)
	3 - 5	12 – 031	GT	FO2		WA		7/1973	(b)	168,600	153	189	Utility	
Kennedy Total										418,200	311	380		(a)
Northside	1	12 – 031	ST	NG	FO6	PL	WA	11/1966	(b)	297,500	262	262	Utility	
	2	12 – 031	ST	FO6		WA		3/1972	(b)	297,500	262	262	Utility	M
	3	12 – 031	ST	NG	FO6	PL	WA	7/1977	(b)	563,700	505	505	Utility	
	4 - 6	12 – 031	GT	FO2		WA		1/1975	(b)	248,400	199	248	Utility	
Northside Total										1,407,100	967	1,015		(a)
Southside	4	12 – 031	ST	NG	FO6	PL	WA	11/1958	10/2001	75,000	67	67	Utility	
	5	12 – 031	ST	NG	FO6	PL	WA	9/1964	10/2001	156,600	142	142	Utility	
Southside Total										231,600	209	209		(a)
Girvin Landfill	1 - 4	12 - 301	IC	NG		PL		6/1997	(b)	3,000	3	3	Utility	

Table 3-1 (Continued)
JEA Existing Generating Facilities
(As of November 2000)

Plant Name	Unit Number	Location	Unit Type	Fuel Type		Fuel Transportation		Commercial In-Service, mo/yr	Expected Retirement, mo/yr	Gen. Max. Nameplate, kW	Net MW Capability		Ownership	Status
				Pri.	Alt.	Pri.	Alt.				Summer	Winter		
St. Johns River Power Park	1*	12 - 301	ST	BIT/ PC		RR, WA		3/1987	3/2027	679,600	510	510	Joint	(c)
	2*	12 - 301	ST	BIT/ PC		RR, WA		5/1988	5/2028	679,600	510	510	Joint	(c)
St. Johns River Power Park Total										1,359,200	1,021	1,021		(c)
Scherer Unit 4	4	13 - 207	ST	SUB	BIT	RR		12/1989	2/2029	846,000	200	200	Joint	(d)
JEA System Total											2,708	2,825		(a)

Notes:
ST = Steam Turbine, Boiler, Non-nuclear, GT = Combustion Turbine, IC = Internal Combustion
BIT = Bituminous Coal, FO2 = No. 2 Fuel Oil, FO6 = No. 6 Fuel Oil, NG = Natural Gas, SUB = Sub-Bituminous Coal, PC = Petroleum Coke
PL = Pipeline, RR = Railroad, TK = Truck, WA = Water
(a) Plant and System total net capability do not include capacity designated as inactive reserve (M).
(b) Life extension will continue to be an evaluated consideration for future capacity additions.
(c) Net capability reflects JEA's 80 percent ownership of St. Johns River Power Park. Nameplate is original nameplate of the unit.
(d) Nameplate and net capability reflects JEA's 23.64 percent ownership in Scherer Unit 4.
(e) Unit derated from net 129 MW and will be shut down, but not retired in April 2000.
*JEA owns 80 percent of St. Johns River Power Parks 1 and 2, but receives only 50 percent of the output, with the other 30 percent purchased by FP&L.

3.3.1.1 Kennedy Generating Station. Total net MW capability at the Kennedy Generating Station is 311 MW summer and 380 MW winter. These capability values do not include Unit 10, a steam turbine which was shut down in April 2000, or two other steam turbines (Units 8 and 9) which are designated as inactive reserves. It does include combustion turbine Units 3, 4, and 5 fueled by No. 2 oil. Also, included with the Kennedy Generating Station is Unit 7, a new combustion turbine which went into service in June 2000. It operates primarily on natural gas with No. 2 oil backup and has a summer capacity of 158 MW and a winter capacity of 191 MW.

3.3.1.2 Northside Generating Station. Total net MW capability at the Northside Generating Station is 967 MW summer and 1,015 MW winter. These capability values do not include Unit 2, a steam turbine which is designated as inactive reserve. It does include combustion turbine Units 3, 4, 5, and 6 fueled by No. 2 oil, and two steam turbine units. The Northside Units 1 and 2 repowering is under construction. Expected completion date is August 2002. When completed, these units will utilize circulating fluidized bed technology with petroleum coke as the primary fuel.

3.3.1.3 Southside Generating Station. Total net MW capability at the Southside Generating Station is 209 MW summer and winter. There are two steam turbines with natural gas as the primary fuel at Southside. Both of these units have been in operation over 35 years and are scheduled to be retired in October 2001.

3.3.1.4 Girvin Landfill. Total net MW capability at the Girvin Landfill is 3 MW summer and winter. There are four internal combustion units operated on landfill gas which went into service in June 1997.

3.3.1.5 SJRPP Generating Station. 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. Unit 1 began commercial operation in March of 1987 and Unit 2 followed in May of 1988. Both owners are entitled to 50 percent of the output of SJRPP. Since FP&L's ownership is only 20 percent, the remaining 30 percent of capacity and energy output is reflected as a firm sale. The two units have operated efficiently since commercial operation. To reduce fuel costs and increase fuel diversity, a blend of petroleum coke and coal is currently being burned in the units.

3.3.1.6 Scherer Unit 4 Generating Station. JEA and FP&L have purchased an undivided interest in Georgia Power Company's Robert W. Scherer Unit 4. Unit 4 is a coal-fired generating unit with a net output of 846 MW located in Monroe County, Georgia. JEA purchased 150 MW of Scherer Unit 4 in July of 1991 and purchased an additional 50 MW on June 1, 1995. Georgia Power Company delivers the power from the unit to the jointly owned 500 kV transmission lines.

3.3.2 Capacity and Power Sales Contracts

3.3.2.1 Seminole Electric Cooperatives (SECI). JEA returned Kennedy Combustion Turbine Unit 4 (CT4) to service from cold storage status in March 1994. Concurrently, JEA sold to SECI priority dispatch rights for 1/7 of the aggregate CT output capacity of the JEA system. JEA's CTs include Kennedy Units 3, 4, and 5, and Northside Units 3, 4, 5, and 6. For planning purposes, JEA and SECI assume SECI's base committed capacity is 53 MW. Full entitlement sales began in January 1, 1995, and will continue through December 31, 2001. SECI has extended the term through May 21, 2004.

3.3.2.2 Florida Public Utilities Company. JEA also furnishes wholesale power to Florida Public Utilities Company (FPU) for resale to the City of Fernandina Beach in Nassau County, north of Jacksonville. JEA is contractually committed to supply FPU's full requirements until 2007. Sales to FPU in 1999 totaled 454 GWh (3.85 percent of JEA's total system energy requirements).

3.3.3 Capacity and Power Purchase Contracts

3.3.3.1 Southern Company. Southern Company and JEA have entered a unit power sale contract in which JEA purchases 200 MW of firm capacity and energy from specific Southern Company coal units through the year 2010. JEA has the unilateral option, upon 3 years' notice, to cancel 150 MW of the unit power sales.

3.3.3.2 Enron. JEA entered into a purchase power agreement in 1996 with Enron Power Marketing, Inc., for firm power from October 1, 1996, through December 31, 2002. The available capacity varies monthly, ranging from 64 to 85 MW in 1997 to 69 to 92 MW in 2002.

3.3.3.3 The Energy Authority (TEA). JEA entered into an agreement with TEA to purchase 25 MW of annual firm capacity and energy for the term of March 1999 through May 31, 2001. JEA also acquired capacity through TEA to fill the 2001 winter need of 250 MW. JEA has commissioned TEA to fill the short-term seasonal needs of JEA through 2004.

3.3.3.4 Cogeneration. JEA has encouraged and continues to monitor opportunities for cogeneration. Cogeneration facilities reduce the demand from the JEA system and/or provide additional capacity to the JEA system. The JEA purchases power from four customer-owned qualifying facilities (QFs), as defined in the Public Utilities Regulatory Policy Act of 1978, having a total installed summer peak capacity of 17 MW and winter peak capacity of 19 MW. JEA purchases energy from these QFs on as available (nonfirm) basis. Since the capacity is purchased on an as available, nonfirm basis, the capacity is not considered to contribute to JEA's capacity requirements. The following Table 3-2 shows JEA's customers who have QFs located within JEA's service territory.

Table 3-2
JEA's QF Capacity

Name	Unit Type	In-Service Date	Net Capability[1] MW)	
			Summer	Winter
Anheuser Busch	COG[2]	April 1988	8	9
Baptist Hospital	COG	October 1982	7	8
Ring Power Landfill	SPP[3]	April 1992	1	1
St. Vincents Hospital	COG	December 1991	1	1
		Total	17	19

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

3.3.4 Planned Utility Retirements or Shutdowns

The following Table 3-3 shows that three JEA oil/gas steam units are reaching the end of their useful lifetimes and are scheduled for retirement or shutdown:

Table 3-3
Planned Utility Retirements or Shutdowns

Unit	Commercial Operation Date	Change in Status	Date
Kennedy Unit 10	1961	Shutdown	April 2000
Southside Unit 4	1958	Retirement	October 2001
Southside Unit 5	1964	Retirement	October 2001

Upon retirement or shutdown, the units will be over 35 years of age. The units are exhibiting a history of age-related equipment failures. Retirement of the units will allow JEA the opportunity to replace the capacity with newer, more efficient technology that will have lower emissions. JEA has established the above dates for planned retirements.

3.3.5 Total Existing System Resources

JEA's total system resources currently consist of the Kennedy, Northside, and Southside generating stations, the Girvin Landfill, and joint ownership in St. Johns River Power Park and Scherer generating stations. The total net capability of JEA's generation system as of November 2000 is 2,825 MW in the winter and 2,708 MW in the summer.

3.3.6 Committed Generating Unit Additions

Three new simple cycle combustion turbines are currently under construction at the Brandy Branch Generating Station. These combustion turbines are GE PG7241 (FA) units with nominal ISO output of approximately 173 MW.

Northside Units 1 and 2 repowering is under construction at the existing Northside Generating Station. Scheduled for commercial operation in April and August 2002, these units will have a net capacity of approximately 265 MW each. They will use petroleum coke as the primary fuel and employ circulating fluidized bed technology with dry scrubber, baghouse, and SNCR as the air pollution control strategy.

The fluidized bed boiler for Unit 1 will replace the existing natural gas/oil boiler and will not result in additional capacity. The oil-fueled boiler for Unit 2 was dismantled several years ago. The addition of the Unit 2 fluidized bed boiler will return the capacity of the Unit 2 steam turbine to commercial service.

3.3.7 Load and Electrical Characteristics

JEA's load and electrical characteristics have many similarities to other Peninsular Florida utilities. JEA's calendar year 1999 peak demand was 2,427 MW, occurring in August. The net energy for load (NEL) for 1999 was 11,782 GWh. Summer peak demand has increased at an average annual rate of 3.45 percent, winter peak demand 1.99 percent, and net energy for load 3.64 percent over the period from 1990 through 1999.

3.4 Service Area

JEA's electric service area covers all of Duval County and portions of Clay County, Nassau County, and St. Johns County

4.0 Methodology

This section provides a general description of the methodology used to analyze the conversion of the Brandy Branch simple cycle combustion turbines to a combined cycle for JEA's power supply. The purpose of the power supply planning study and determination of need is to develop evaluation criteria and electric system projections to evaluate potential capacity additions that will meet the power generation needs of its consumers in the most cost-effective manner while providing consideration for reliability, fuel diversity, environmental impacts, strategic goals, and regulatory requirements. To this end, JEA has provided in-depth analysis and evaluation of supply-side and demand-side resources to determine the least-cost plan, which is in the collective best interest of JEA customers.

4.1 Economic Parameters

The first step in the power supply planning process is to establish economic parameters. The economic parameters are developed in Section 5.0 and are applied throughout the study. The economic parameters developed include the following:

- Inflation rate.
- O&M escalation rate.
- Capital cost escalation rate.
- Base, low, and high case present worth discount rates.
- JEA municipal bond interest rate.
- Interest during construction interest rate.
- Fixed charge rate.

4.2 Fuel Forecast

The fuel forecast represents a significant factor in the analysis and results of the most cost-effective option for power supply planning analysis. While it is impossible to predict the exact fuel prices in the future, JEA has attempted to forecast fuel prices over the planning period based upon historical and current information about the fuel industry. In an effort to bracket the fuel prices in the future, JEA has forecasted fuel prices for high and low fuel price forecasts. The methodology and the results of JEA fuel price forecasts are discussed in Section 6.0.

4.3 Load Forecast

Forecasts of electrical loads for the JEA system were developed through the year 2019 for use in the assessment of needs and economic analysis. The load forecasts for JEA are summarized in Section 7.0. The load forecasts consist of a base case forecast, and two sensitivity forecasts to bracket the peak demand growth with a high and low forecast. The forecasts are based upon historical information and detailed forecasting methodology.

4.4 Demand-Side Programs

JEA has in place several Demand-Side Management (DSM) programs and has actively pursued additional conservation and DSM programs. JEA evaluated numerous potential DSM programs and the results are summarized in Section 8.0. The evaluations were conducted by applying the Florida Integrated Resource Evaluator (FIRE) model as described in Section 8.0.

4.5 Reliability Criteria

JEA utilizes the Florida Reliability Coordinating Council (FRCC) recommended minimum reserve margin of 15 percent as its planning criteria. The FRCC, municipal utilities in Peninsular Florida, and other regional councils deem this level of reserves adequate for planning purposes. The reliability criteria are discussed in detail in Section 9.0.

4.6 Request for Proposals

JEA did not issue a Request for Proposal (RFP) for purchase power. Section 10.0 discusses the reasons JEA did not issue an RFP.

4.7 Supply-Side Alternatives

Supply-side alternatives were identified that would potentially meet JEA's need for power. The numerous alternatives considered JEA's current system size, potential load growth, and current sites available. Each of these supply-side alternatives is discussed in detail in Section 11.0. The alternatives considered included the following:

- Renewable Technologies
- Waste Technologies
- Advanced Technologies
- Energy Storage Systems
- Nuclear
- Conventional Alternatives

4.8 Supply-Side Screening

JEA has conducted a thorough search for supply-side alternatives that could possibly fit the planning needs for future demands. The numerous supply-side alternatives identified in Section 11.0 have been reduced by screening methods to arrive at an acceptable number of alternatives to model in detail. JEA has conduced a two-phase screening process to reduce the number of alternatives. The first phase of the screening process eliminates alternatives that are not technically or commercially viable for JEA. The second screening phase as outlined in Section 12.0 eliminates alternatives based upon a busbar cost analysis. Alternatives which passed both screening phases were then analyzed using the Electric Generation Expansion Analysis System (EGEAS) modeling software. EGEAS evaluates all combinations of alternatives that exhibit the lowest cumulative present worth revenue requirements while maintaining user-defined reliability criteria. All capacity expansion plans were analyzed over a 20 year period from 2000 to 2019.

4.9 Economic Analysis

The economic evaluations were performed using EPRI's Electric Generation Expansion Analysis System (EGEAS), an optimal generation expansion model to determine the most-cost-effective expansion plan. Based upon all the potential combinations of expansion plans, EGEAS indicates the optimum plans based on the total present worth costs over a 20 year planning horizon. The analysis considers the load forecast, fuel price forecast, existing generating units, potential candidates for expansion, and the reliability criteria. JEA used a 15 percent minimum reserve margin, based on standard methods of calculating the reserve margin, in the identification of feasible expansion plans. The discussion and the results of the economic analyses are presented in Section 13.0.

4.10 Sensitivity Analysis

Several sensitivity analyses were performed to ensure that the expansion plan identified in the base case economic analysis is a robust plan. The sensitivity analyses included high and low load growth, 20 percent reserve margin, high and low fuel prices and high and low discount rates. A detailed discussion and the results of the sensitivity analyses are shown in Section 14.0.

4.11 Strategic Considerations

In selecting a power supply alternative, JEA considered several strategic considerations that reflect long-term ability to provide economical and reliable electric capacity and energy to consumers. Strategic considerations include efficiency, low operating costs, domestically produced fuel, utilization of existing site, environmental benefits, and electric industry deregulation. The discussion on strategic considerations is presented on Section 15.0.

4.12 Financial Analysis

JEA considered the internal ability to finance the Brandy Branch combined cycle conversion. This analysis considered JEA's current financial standing, including out-standing bonds, current cash position, and current credit rating. Section 16.0 of this report discusses the financial analysis.

4.13 Consequences of Delay

The consequences of delay in Section 17.0 considered the impacts on cumulative present worth and reliability needs if the Brandy Branch combined cycle conversion was delayed by one year.

4.14 Analysis of Clean Air Act Amendments

The impacts of the 1990 Clean Air Act Amendments on the most cost-effective expansion plan and the ability of JEA to comply with these regulatory requirements were analyzed in Section 18.0.

4.15 Consistency with Peninsular Florida Needs

JEA looked at the Peninsular Florida need to ensure that the Brandy Branch combined cycle conversion was consistent with that need. While JEA is responsible for planning its own system, it is in the best interest of the state if need is fulfilled with efficient generation. The consistency with Peninsular Florida needs is discussed in Section 19.0.

5.0 Economic Parameters and Evaluation Methodology

5.1 Base Case Economic Parameters

5.1.1 Inflation and Escalation Rates

The general inflation rate applied in this Need for Power Application is 2.3 percent annually, which is based upon the US Consumer Price Index (CPI). A 2.3 percent annual escalation rate is applied to capital costs. Operations and maintenance (O&M) expenses are also assumed to escalate at a 2.3 percent rate.

5.1.2 Present Worth Discount Rate

The present worth discount rate assumed for the Need for Power Application is 7.95 percent. This is equal to JEA's current 20 year taxable bond rate.

5.1.3 JEA Municipal Bond Interest Rate

JEA's current municipal long-term bond interest rate for tax exempt bonds is assumed to be 5.45 percent based upon the current bond rates for JEA. JEA's current municipal long-term bond interest rate for taxable bonds is assumed to be 7.95 percent based upon current bond rates for JEA.

5.1.4 Interest During Construction Interest Rate

The JEA rate for interest during construction is assumed to be 4.00 percent based on using short-term variable rate debt.

5.1.5 Fixed Charge Rate

Based on a 1.0 percent issuance fee, a 1.0 percent insurance annual cost, the taxable bond interest rate of 7.95 percent, and 20 years term, the taxable fixed charge rate for JEA in the base case is assumed to be 11.51 percent.

5.1.6 Present Worth Discount Rate Sensitivity

In Section 14.0 sensitivity analysis is performed to test the expansion plan if the present worth discount rate is raised or lowered. The higher sensitivity assumes a discount rate of 9.95 percent, which is two percentage points higher than the base case present worth discount rate. The low sensitivity assumes a discount rate of 5.95 percent, which is 2 percent lower than the base case present worth discount rate.

5.1.7 Economic Evaluation Criteria

For evaluation purposes in this analysis, JEA has used the taxable financing rates described above; however, JEA has access to tax exempt financing which would result in lower financing costs. While tax exempt financing resultS in lower financing costs, it also presents restrictions on the sale of power from the project should deregulation or some other event reduce JEA's load in the future. The use of the higher cost taxable financing is conservative for evaluation purposes. Final decisions relative to financing of the Brandy Branch conversion will not be made for some time and may result in some flexible arrangements which would allow either taxable or tax exempt financing.

Economic evaluations are conducted over a 20 year period from 2000 through 2019. The economic evaluation is based on the cumulative present worth costs for capital costs, nonfuel O&M costs, fuel costs, and purchase power demand and energy costs. Costs that are common to all expansion alternatives such as administrative and general costs are not included.

6.0 Fuel Forecast

The fuel forecast represents a major economic factor in the selection of resources for future supply to JEA's electrical system. The base case fuel forecast includes low sulfur and medium sulfur coal, natural gas, residual oil (1.8 percent and 1.0 percent sulfur), No. 2 fuel oil, and petroleum coke. High and low case fuel price projections were also developed for sensitivity analyses.

6.1 Base Case Fuel Price Forecast Methodology and Assumptions

The base case forecasts are based on JEA's historical fuel costs together with information on price escalation from the Annual Energy Outlook (AEO) 2000 fuel price data published by the Energy Information Administration (EIA), which is an independent agency of the Department of Energy (DOE). The AEO 2000 energy data is a comprehensive and reliable source of domestic and international energy supply, consumption, and price information.

AEO 2000 provides energy forecast through the year 2020 and takes into account a number of important factors, some of which include:

- Restructuring of the U.S. electricity markets.
- Current regulations and legislation affecting the energy markets.
- Current energy issues:
  - Appliance, gasoline and diesel fuel, and renewable portfolio standards.
  - Expansion of the natural gas industry.
  - Carbon emissions.
  - Competitive electricity pricing.

AEO 2000 energy information is objective and nonpartisan. It is used widely by both government and private sectors to assist in decision-making processes and in analyzing important policy issues.

AEO 2000 publishes 1998, 2005, 2010, 2015, and 2020 fuel price projections. From these projections, real compounded annual escalation rates (CAERs) can be calculated for 1998-2005, 2005-2010, 2010-2015, and 2015-2020 periods. The base case forecasts apply these real CAERs and the assumed annual inflation rate of 2.3 percent to escalate 1999 JEA delivered fuel costs through the year 2019. Table 6-1 shows these base case real CAERs for the various fuel types. Additional assumptions and results of the fuel price forecasts are discussed and presented by fuel types in the next subsections.

Table 6-1
2000 Annual Energy Outlook Real Fuel Price Projections and CAERs

	1998	2005	2010	2015	2020
No. 2 Oil,* $/MBtu	3.19	4.98	5.12	5.10	5.23
Residual Oil,* $/MBtu	2.17	3.11	3.13	3.19	3.30
Coal,* $/MBtu	1.25	1.11	1.07	1.03	0.98
Natural Gas,** $/MBtu	1.96	2.34	2.60	2.71	2.81
	1998-2005	2005-2010	2010-2015	2015-2020	1998-2020
No. 2 Oil* Real CAERs, percent	6.57	0.56	-0.08	0.50	2.27
Residual Oil* Real CAERs, percent	5.28	0.13	0.38	0.68	1.92
Coal* Real CAERs, percent	-1.68	-0.73	-0.76	-0.99	-1.10
Natural Gas** Real CAERs, percent	2.56	2.13	0.83	0.73	1.65

*Delivered price.
**Well head price.
Source: DOE Energy Information Administration website
http://www.eia.doe.gov/oiaf/aeo/index.html.

6.1.1 Fuel Oil Forecasts

JEA 1999 delivered prices for 1.8 percent sulfur residual, 1.0 percent sulfur residual, and No. 2 fuel oils are $1.94 per MBtu, $2.53 per MBtu, and $4.18 per MBtu, respectively. Table 6-2 shows the base case fuel oil delivered price forecasts for 2000 through 2019.

6.1.2 Natural Gas Forecast

The delivered natural gas price includes the commodity price and the transportation costs. Florida Gas Transmission Co. (FGT) is the pipeline transportation company for JEA. Natural gas transportation from FGT is currently supplied under two tariffs: FTS-1 and FTS-2. FGT's pipeline system has been constructed in phases. One phase (Phase V) is currently under construction and the next phase in the licensing process. Rates for FTS-1 are based on FGT's Phase II expansion, and rates for FTS-2 are based on the Phase III expansion. Rates for the Phase IV, Phase V, and any other future expansions will be set by the Federal Energy Regulatory Commission (FERC) rate cases at the completion of the projects. Peoples Gas Systems (PGS) is the local distribution company serving JEA.

Currently, JEA has 40,000 decatherms per day of firm natural gas transportation under the FTS-1 rate schedule. Starting in 2002, JEA has committed to an additional 14,000 decatherms per day of firm transportation capacity under the FTS-2 rate and is negotiating up to an additional 61,000 decatherms per day of firm transportation capacity. JEA will continue to maintain sufficient pipeline capacity throughout the planning horizon by acquiring additional capacity from FGT, another pipeline, or from the secondary market. The combined total firm natural gas transportation starting in 2002 will be 54,000 decatherms per day and increase to 115,000 decatherms in 2004 to meet JEA's system requirements. Table 6-3 shows the base case natural gas delivered price forecast for 2000 through 2019.

6.1.3 St. John's River Power Park (SJRPP) and Northside Generating Station Coal, Petroleum Coke, and Limestone Forecasts

The 1999 JEA delivered fuel purchase prices for low sulfur (less than 1.0 percent) coal and medium sulfur (1.0 to 2.0 percent) coal, and petroleum coke were $1.47, $1.61, and $0.43 per MBtu, respectively. JEA purchases low sulfur coal offshore from Intercor, a subsidiary of Exxon Coal & Minerals located in Colombia, while the medium sulfur coal is purchased from James River Coal Sales Co. (Kentucky) and Arch Coal Sales (West Virginia). The purchase of off-shore coal delivered by water accounts for the

Table 6-2
Base Case JEA Fuel Oil Delivered Price Forecasts
for 2000 through 2019

Calendar Year	1.8 Percent Sulfur Residual, $/MBtu	1.0 Percent Sulfur Residual, $/MBtu	No. 2 Oil, $/MBtu
2000	2.09	2.72	4.56
2001	2.25	2.93	4.97
2002	2.43	3.16	5.42
2003	2.61	3.40	5.90
2004	2.81	3.66	6.44
2005	2.88	3.75	6.62
2006	2.95	3.84	6.81
2007	3.02	3.94	7.01
2008	3.10	4.03	7.21
2009	3.17	4.13	7.41
2010	3.26	4.24	7.58
2011	3.35	4.36	7.75
2012	3.44	4.47	7.92
2013	3.53	4.59	8.09
2014	3.62	4.72	8.27
2015	3.73	4.86	8.51
2016	3.84	5.00	8.75
2017	3.96	5.15	8.99
2018	4.08	5.31	9.25
2019	4.20	5.47	9.51
Inflated CAER* (2000 – 2019), percent	3.74	3.74	3.95

Notes:
*Inflated CAER takes into account the inflation rate of 2.3 percent.

Table 6-3
Base Case JEA Natural Gas Delivered Price Forecast
for 2000 through 2019

Calendar Year	Commodity Price, $/MBtu	Transportation Costs,* $/MBtu	Delivered Price, $/MBtu
2000	2.17	0.57	2.74
2001	2.27	0.58	2.85
2002	2.39	0.78	3.16
2003	2.50	0.79	3.29
2004	2.63	0.79	3.42
2005	2.74	0.80	3.54
2006	2.87	0.79	3.66
2007	3.00	0.80	3.80
2008	3.13	0.80	3.93
2009	3.27	0.81	4.08
2010	3.37	0.81	4.18
2011	3.48	0.81	4.29
2012	3.59	0.82	4.41
2013	3.70	0.82	4.52
2014	3.82	0.82	4.64
2015	3.93	0.83	4.76
2016	4.05	0.84	4.89
2017	4.18	0.83	5.01
2018	4.30	0.84	5.14
2019	4.44	0.84	5.28
Inflated CAER** (2000 – 2019), percent			3.51

Notes:
*FGT fuel rate is assumed to be 2.75 percent of the natural gas commodity price, and PGS fuel rate is assumed to be 0.1 percent of the sum of the natural gas commodity price, FGT usage rate, and FGT fuel rate.

**Inflated CAER takes into account the inflation rate of 2.3 percent.

lower price of the low sulfur coal price compared to the medium sulfur coal. SJRPP burns approximately 80 percent coal and 20 percent petroleum coke. During the forecast period, SJRPP expects to burn nearly 700,000 tons of petroleum coke per year.

In 2002, JEA will complete the Northside Generating Station Units 1 and 2 repowering project. The units will have circulating fluidized bed (CFB) boilers and will use petroleum coke as a primary fuel. The JEA expects to burn 1,600,000 tons of petroleum coke annually at Northside. In addition, with the CFB technology, JEA will use approximately 700,000 tons of limestone per year to reduce sulfur emissions.

The AEO does not include a fuel price forecast for petroleum coke. For planning purposes, JEA assumes that the price of petroleum coke at Northside will be the same as the price of petroleum coke at SJRPP. JEA projects that petroleum coke will increase at a real escalation rate of 2.50 percent. Limestone cost is assumed to be $11.00 per ton in 2000 and escalates at a nominal rate of 2.0 percent thereafter. Table 6-4 shows the base case delivered price forecasts for low sulfur coal and medium sulfur coal and petroleum coke. Table 6-5 shows the base case limestone delivered price forecast for 2000 through 2019.

6.1.4 Scherer Unit 4 Coal Forecast

In 1999, JEA purchased about 727,290 tons of coal for Scherer Unit 4 at a delivered price of $1.60 per MBtu. Table 6-6 shows the base case Scherer Unit 4 coal delivered price forecast for 2000 through 2019.

6.2 Fuel Price Forecast Sensitivity Analysis Assumptions

The fuel price sensitivity analyses include low and high case forecasts to illustrate the forecast differences resulting from different escalation scenarios. A similar methodology as the base case is employed in the sensitivity analyses. For the low case forecasts, adjusted (Adj.) AEO real CAERs are assumed to be about 2.5 percent lower than the base case AEO real CAERs. The high case Adj. AEO real CAERs are assumed to be about 2.5 percent higher than the base case AEO real CAERs. Table 6-7 lists the low and high case Adj. AEO real CAERs.

6.2.1 Fuel Oil Low and High Case Forecasts

Tables 6-8, and 6-9 display the delivered fuel oil price forecasts for the low and high cases, respectively, for 2000 through 2019.

Table 6-4
Base Case JEA SJRPP and Northside Generating Station
Delivered Fuel Price Forecasts for 2000 through 2019

Calendar Year	Low Sulfur Coal, $/MBtu	Medium Sulfur Coal, $/MBtu	Petroleum Coke, $/MBtu
2000	1.48	1.62	0.46
2001	1.49	1.63	0.49
2002	1.50	1.64	0.51
2003	1.50	1.65	0.53
2004	1.51	1.66	0.56
2005	1.54	1.69	0.59
2006	1.56	1.71	0.62
2007	1.58	1.74	0.65
2008	1.61	1.77	0.68
2009	1.63	1.79	0.71
2010	1.66	1.82	0.74
2011	1.68	1.85	0.78
2012	1.71	1.88	0.82
2013	1.74	1.91	0.86
2014	1.76	1.94	0.90
2015	1.79	1.96	0.94
2016	1.81	1.99	0.99
2017	1.83	2.01	1.04
2018	1.85	2.04	1.09
2019	1.88	2.06	1.14
Inflated CAER* (2000 – 2019), percent	1.27	1.27	4.86

Notes:
*Inflated CAER takes into account the inflation rate of 2.3 percent.

Table 6-5
Base Case JEA Northside Generating Station Limestone Delivered Price Forecasts for 2000 through 2019

Calendar Year	Limestone $/ton
2000	11.00
2001	11.22
2002	11.44
2003	11.67
2004	11.91
2005	12.15
2006	12.39
2007	12.64
2008	12.89
2009	13.15
2010	13.41
2011	13.68
2012	13.95
2013	14.23
2014	14.51
2015	14.81
2016	15.10
2017	15.40
2018	15.71
2019	16.03
Inflated CAER* (2000 – 2019), percent	2.00

Note:
*Inflated CAER takes into account the inflation rate of 2.3 percent.

Table 6-6
Base Case JEA Scherer 4 Unit Coal
Delivered Price Forecast for 2000 through 2019

Calendar Year	Scherer Unit 4 Coal, $/MBtu
2000	1.61
2001	1.62
2002	1.63
2003	1.64
2004	1.65
2005	1.67
2006	1.70
2007	1.72
2008	1.75
2009	1.78
2010	1.81
2011	1.83
2012	1.86
2013	1.89
2014	1.92
2015	1.94
2016	1.97
2017	1.99
2018	2.02
2019	2.04
Inflated CAER,* percent (2000 – 2019)	1.27

Notes:
*Inflated CAER takes into account the inflation rate of 2.3 percent.

Table 6-7
Low and High Case Adj. AEO Real CAERs

	1998-2005	2005-2010	2010-2015	2015-2020	1998-2020
Low Case					
No. 2 Oil Adj. AEO Real CAERs, percent	4.07	-1.94	-2.58	-2.00	-0.23
Residual Adj. AEO Real CAERs, percent	2.78	-2.37	-2.12	-1.82	-0.58
Coal Real Adj. AEO Real CAERs, percent	-4.18	-3.23	-3.26	-3.49	-3.60
Natural Gas Adj. AEO Real CAERs, percent	0.06	-0.37	-1.67	-1.77	-0.85
High Case					
No. 2 Oil Adj. AEO Real CAERs, percent	9.07	3.06	2.42	3.00	4.77
Residual Adj. AEO Real CAERs, percent	7.78	2.63	2.88	3.18	4.42
Coal Real Adj. AEO Real CAERs, percent	0.82	1.77	1.74	1.51	1.40
Natural Gas Adj. AEO Real CAERs, percent	5.06	4.63	3.33	3.23	4.15

Table 6-8
Low Case JEA Fuel Oil Delivered Price Forecasts
for 2000 through 2019

Calendar Year	1.8 Percent Sulfur Residual, $/MBtu	1.0 Percent Sulfur Residual, $/MBtu	No. 2 Oil, $/MBtu
2000	2.09	2.72	4.56
2001	2.20	2.86	4.86
2002	2.32	3.01	5.16
2003	2.43	3.16	5.50
2004	2.56	3.32	5.86
2005	2.55	3.32	5.87
2006	2.55	3.31	5.89
2007	2.55	3.31	5.91
2008	2.54	3.30	5.93
2009	2.54	3.30	5.95
2010	2.54	3.30	5.93
2011	2.55	3.31	5.91
2012	2.55	3.31	5.89
2013	2.55	3.32	5.87
2014	2.56	3.32	5.85
2015	2.57	3.33	5.86
2016	2.58	3.35	5.88
2017	2.59	3.36	5.89
2018	2.60	3.38	5.91
2019	2.61	3.39	5.92
Inflated CAER* (2000 – 2019), percent	1.18	1.18	1.39

Notes:
*Inflated CAER takes into account the inflation rate of 2.3 percent.

Table 6-9
High Case JEA Fuel Oil Delivered Price Forecasts
for 2000 through 2019

Calendar Year	1.8 Percent Sulfur Residual, $/MBtu	1.0 Percent Sulfur Residual, $/MBtu	No. 2 Oil, $/MBtu
2000	2.09	2.72	4.56
2001	2.30	2.99	5.09
2002	2.54	3.30	5.69
2003	2.80	3.65	6.34
2004	3.09	4.02	7.07
2005	3.24	4.22	7.46
2006	3.41	4.43	7.86
2007	3.57	4.65	8.29
2008	3.74	4.88	8.74
2009	3.95	5.13	9.21
2010	4.15	5.39	9.65
2011	4.37	5.67	10.11
2012	4.60	5.98	10.60
2013	4.83	6.29	11.10
2014	5.09	6.62	11.63
2015	5.37	6.98	12.26
2016	5.67	7.37	12.92
2017	5.99	7.78	13.61
2018	6.32	8.22	14.34
2019	6.67	8.67	15.11
Inflated CAER* (2000 – 2019), percent	6.29	6.29	6.51

Notes:
*Inflated CAER takes into account the inflation rate of 2.3 percent.

6.2.2 Natural Gas Low and High Case Forecasts

Tables 6-10 and 6-11 show the low and high case delivered natural gas price forecasts, respectively, for 2000 through 2019.

6.2.3 SJRPP and Northside Generating Station Coal, Petroleum Coke, and Limestone Low and High Case Forecasts

For its petroleum coke price sensitivity forecasts, JEA uses real annual escalation rates of 0 percent for the low case and 5.00 percent for the high case starting in 2002. For its limestone price forecasts, JEA's low case and high case for limestone delivered prices in 2000 are assumed to be $10.00 per ton and $12.00 per ton, respectively. The delivered limestone prices are also assumed to escalate at a nominal rate of 2.00 percent. Tables 6-12 and 6-13 show SJRPP and Northside Generating Station delivered price forecasts for coal and petroleum coke for low and high cases, respectively, for 2000 through 2019. Table 6-14 shows Northside Generating Station low and high case limestone delivered price forecasts for 2000 through 2019.

6.2.4 Scherer Unit 4 Coal Low and High Case Forecasts

Table 6-15 shows the low and high case Scherer Unit 4 coal delivered price forecasts for 2000 through 2019.

6.2.5 Alternative Fuel Price Scenario

This scenario was evaluated to analyze the impact of high current fuel prices. A sensitivity case which incorporates September 2000 fuel prices was evaluated and results are shown in Section 14.0. Prices paid for fuel commodities for September 2000 are as follows:

- Natural Gas- $4.90/MBtu.
- Pet Coke- $1.20/MBtu.
- Coal- $1.65/MBtu.
- Fuel Oil- $5.00/MBtu.

The scenario assumes that these real prices remain constant with the general inflation rate (2.3 percent) used to increase prices each year.

Table 6-10
Low Case JEA Natural Gas Delivered Price Forecast
for 2000 through 2019

Calendar Year	Commodity Price, $/MBtu	Transportation Costs,* $/MBtu	Delivered Price, $/MBtu
2000	2.17	0.57	2.74
2001	2.22	0.57	2.79
2002	2.27	0.78	3.05
2003	2.32	0.79	3.11
2004	2.38	0.78	3.16
2005	2.43	0.78	3.21
2006	2.47	0.79	3.26
2007	2.52	0.79	3.31
2008	2.57	0.79	3.36
2009	2.62	0.79	3.41
2010	2.63	0.79	3.42
2011	2.65	0.79	3.44
2012	2.65	0.79	3.46
2013	2.68	0.79	3.47
2014	2.70	0.79	3.49
2015	2.71	0.79	3.50
2016	2.72	0.79	3.51
2017	2.74	0.79	3.53
2018	2.75	0.79	3.54
2019	2.75	0.79	3.56
Inflated CAER** (2000 – 2019), percent			1.38

Notes:
*FGT fuel rate is assumed to be 2.75 percent of the natural gas commodity price, and PGS fuel rate is assumed to be 0.1 percent of the sum of the natural gas commodity price, FGT usage rate, and FGT fuel rate.

**Inflated CAER takes into account the inflation rate of 2.3 percent.

Table 6-11
High Case JEA Natural Gas Delivered Price Forecast
for 2000 through 2019

Calendar Year	Commodity Price, $/MBtu	Transportation Costs,* $/MBtu	Delivered Price, $/MBtu
2000	2.17	0.57	2.74
2001	2.33	0.58	2.91
2002	2.50	0.78	3.28
2003	2.69	0.79	3.48
2004	2.89	0.80	3.69
2005	3.10	0.80	3.90
2006	3.31	0.81	4.12
2007	3.55	0.81	4.36
2008	3.80	0.82	4.62
2009	4.06	0.83	4.89
2010	4.29	0.84	5.13
2011	4.54	0.84	5.38
2012	4.80	0.85	5.65
2013	5.07	0.86	5.93
2014	5.36	0.87	6.23
2015	5.66	0.88	6.54
2016	5.98	0.89	6.87
2017	6.32	0.89	7.21
2018	6.67	0.90	7.57
2019	7.04	0.92	7.96
	Inflated CAER** (2000 – 2019), percent		5.77

Notes:
*FGT fuel rate is assumed to be 2.75 percent of the natural gas commodity price, and PGS fuel rate is assumed to be 0.1 percent of the sum of the natural gas commodity price, FGT usage rate, and FGT fuel rate.

**Inflated CAER takes into account the inflation rate of 2.3 percent.

Table 6-12
Low Case JEA SJRPP and Northside Generating Station Delivered Fuel Price Forecasts for 2000 through 2019

Calendar Year	Low Sulfur Coal, $/MBtu	Medium Sulfur Coal, $/MBtu	Petroleum Coke, $/MBtu
2000	1.44	1.58	0.46
2001	1.41	1.55	0.47
2002	1.38	1.52	0.48
2003	1.36	1.49	0.50
2004	1.33	1.46	0.51
2005	1.32	1.45	0.52
2006	1.30	1.43	0.53
2007	1.29	1.42	0.54
2008	1.28	1.40	0.56
2009	1.26	1.39	0.57
2010	1.25	1.37	0.58
2011	1.24	1.36	0.59
2012	1.23	1.35	0.61
2013	1.21	1.33	0.62
2014	1.20	1.32	0.64
2015	1.19	1.30	0.65
2016	1.17	1.29	0.67
2017	1.16	1.27	0.68
2018	1.14	1.25	0.70
2019	1.13	1.24	0.71
Inflated CAER* (2000 – 2019), percent	-1.29	-1.29	2.30

Notes:

*Inflated CAER takes into account the inflation rate of 2.3 percent.

Table 6-13
High Case JEA SJRPP and Northside Generating Station Delivered
Fuel Price Forecasts for 2000 through 2019

Calendar Year	Low Sulfur Coal, $/MBtu	Medium Sulfur Coal, $/MBtu	Petroleum Coke, $/MBtu
2000	1.52	1.66	0.46
2001	1.56	1.72	0.50
2002	1.61	1.77	0.53
2003	1.66	1.83	0.57
2004	1.72	1.88	0.62
2005	1.79	1.96	0.66
2006	1.86	2.04	0.71
2007	1.94	2.13	0.76
2008	2.02	2.21	0.82
2009	2.10	2.30	0.88
2010	2.18	2.40	0.95
2011	2.27	2.50	1.02
2012	2.37	2.60	1.09
2013	2.46	2.70	1.17
2014	2.56	2.81	1.26
2015	2.66	2.92	1.35
2016	2.76	3.03	1.45
2017	2.87	3.15	1.56
2018	2.98	3.27	1.68
2019	3.09	3.40	1.80
Inflated CAER* (2000 – 2019), percent	3.83	3.83	7.41

Notes:

*Inflated CAER takes into account the inflation rate of 2.3 percent.

Table 6-14
Low and High Case JEA Northside Generating Station Limestone Delivered Price Forecast for 2000 through 2019

Calendar Year	Low Case $/ton	High Case $/ton
2000	10.00	12.00
2001	10.20	12.24
2002	10.40	12.48
2003	10.61	12.73
2004	10.82	12.99
2005	11.04	13.25
2006	11.26	13.51
2007	11.49	13.78
2008	11.72	14.06
2009	11.95	14.34
2010	12.19	14.63
2011	12.43	14.92
2012	12.68	15.22
2013	12.94	15.52
2014	13.19	15.83
2015	13.46	16.15
2016	13.73	16.47
2017	14.00	16.80
2018	14.28	17.14
2019	14.57	17.48
Inflated CAER* (2000 – 2019), percent	2.00	2.00

Note:

*Inflated CAER takes into account the inflation rate of 2.3 percent.

Table 6-15
Low and High Case JEA Scherer Unit 4
Delivered Coal Price Forecasts for 1999 through 2019

	Low Case	High Case
Calendar Year	$/MBtu	$/MBtu
2000	1.57	1.65
2001	1.54	1.70
2002	1.51	1.76
2003	1.48	1.81
2004	1.45	1.87
2005	1.43	1.94
2006	1.42	2.02
2007	1.40	2.11
2008	1.39	2.19
2009	1.38	2.28
2010	1.36	2.38
2011	1.35	2.47
2012	1.33	2.57
2013	1.32	2.68
2014	1.31	2.79
2015	1.29	2.90
2016	1.27	3.01
2017	1.26	3.12
2018	1.24	3.24
2019	1.23	3.37
Inflated CAER* 2000 – 2019), percent	-1.29	3.83

Notes:

*Inflated CAER takes into account the inflation rate of 2.3 percent.

7.0 Forecasts of Energy Production and Electrical Power Peak Demands

This section discusses the forecast methodologies and assumptions and presents the forecast results of JEA's annual energy production and electrical peak demands from 2000 through 2019. The forecasts do not include the potential impacts of retail wheeling and other results of deregulation as they may occur in the State of Florida over the next 20 years.

The energy production and peak demand forecasts include three scenarios: a base case, a low case, and a high case. The base case is the most probable forecast. The high and low growth cases were developed to illustrate the forecast differences resulting from various growth possibilities.

7.1 Forecast Methodologies, Assumptions, and Results

7.1.1 Energy Production Forecast

JEA utilizes a trend analysis to forecast energy production excluding production for off-system sales. Energy production is commonly referred to as net energy for load (NEL). JEA's experience in using trend analysis is that it provides forecasts with comparable accuracy to econometric and end-use methodologies at far less cost. JEA's forecasts based on those methods were generally biased on the low side. One reason that trend analysis provides comparatively accurate short-term forecasts is the lag in timing of obtaining good quality demographic data for use in econometric and end use forecasts. Furthermore, available economic and demographic data for Jacksonville tended to be low relative to actual results. Table 7-1 demonstrates how the accuracy of the forecast has significantly improved since the forecast methodology was changed to trend analysis beginning with the 1996 forecast. Though there is variability demonstrated in the forecasts, it is clear that the last four forecasts have been more accurate than their predecessors, and the last two forecasts have been very good.

7.1.1.1 Base Case. The base case forecast is the one used in JEA's 2000 Ten Year Site Plan. This analysis, conducted in 1998, is based on the 5, 10, and 15 year historical average energy production growth rates of 3.19, 3.14, and 3.73 percent/year, respectively. The mean of these average production growth rates is 3.35 percent/year or an average constant growth of 368 GWh/year. Both the mean average growth rate and the average constant growth are used as the bases for the forecast calculation. The forecast results for fiscal years for 2000 through 2019 annual energy production, and how they are derived are shown in Table 7-2. The base case forecast includes wholesale sales to Florida Public Utilities Company (FPU). JEA's contract with FPU extends until December 31, 2007. For planning purposes, it has been assumed that JEA will serve FPU loads throughout the planning period.

Table 7-1
JEA Forecast Accuracy - First 12 Months

	Total NEL (GWh)		
Forecast Year	Forecasted	Actual	Error
1990	8,592	8,649	-0.7%
1991	9,034	8,789	2.8%
1992	9,212	8,979	2.6%
1993	8,989	9,452	-4.9%
1994	9,515	9,619	-1.1%
1995	9,961	10,540	-5.5%
1996	10,492	10,433	0.6%
1997	10,954	10,731	2.1%
1998	11,436	11,542	-0.9%
1999	11,747	11,782	-0.3%

7.1.1.2 Low and High Cases. The low case forecast represents growth in energy production at a constant rate of 1.0 percent per year, and the high case forecast assumes a constant growth rate of 5.0 percent. The 1.0 percent and 5.0 percent range represent what was considered realistic low and high boundaries of load growth compared to the base case forecast which has a 2.9 percent growth rate. JEA considers that a long-term sustained growth rate of 1.0 percent would require significant and unprecedented negative economic downturn in Jacksonville which is felt to be very unlikely. Concerning the 5.0 percent upper bound, individual years have shown higher growth, but a sustained growth rate of that magnitude is considered unlikely. The forecast results for the calendar year low and high cases are shown in Table 7-3. Table 7-4 shows the calendar year annual retail and wholesale forecasts.

Table 7-2
JEA Base Case Annual Energy Production Forecast Estimation for 2000 through 2019

Fiscal Year	Forecast GWh: Based on 3.35 Percent/ Year Growth Rate	Forecast GWh: Based on 368 GWh/ Year Constant Growth	Average Forecast,[a] GWh	Average Forecast Growth,[b] GWh	Annual Energy Production,[c] GWh
2000	11,723	11,711	11,717	374	12,038
2001	12,116	12,079	12,097	381	12,418
2002	12,522	12,447	12,485	387	12,805
2003	12,942	12,815	12,879	394	13,199
2004	13,376	13,183	13,280	401	13,600
2005	13,825	13,551	13,688	408	14,009
2006	14,289	13,919	14,104	416	14,425
2007	14,768	14,287	14,527	424	14,848
2008	15,263	14,655	14,959	432	15,280
2009	15,775	15,023	15,399	440	15,720
2010	16,304	15,391	15,848	449	16,168
2011	16,851	15,759	16,305	457	16,626
2012	17,416	16,127	16,772	467	17,092
2013	18,000	16,495	17,248	476	17,569
2014	18,604	16,863	17,734	486	18,054
2015	19,228	17,231	18,230	496	18,550
2016	19,873	17,599	18,736	506	19,057

Table 7-2 (Continued)
JEA Base Case Annual Energy Production Forecast Estimation for 2000 through 2019

Fiscal Year	Forecast GWh: Based on 3.35 Percent/ Year Growth Rate	Forecast GWh: Based on 368 GWh/ Year Constant Growth	Average Forecast,[a] GWh	Average Forecast Growth,[b] GWh	Annual Energy Production,[c] GWh
2017	20,539	17,968	19,253	517	19,574
2018	21,228	18,336	19,782	528	20,103
2019	21,940	18,704	20,322	540	20,643

Notes:
[a] Average Forecast is the average of the forecasts estimated based on 3.35 percent/year and 368 GWh/year.
[b] Average Forecast Growth is the difference between the current year Average Forecast and the previous year Average Forecast.
[c] Annual Energy Production is the sum of the previous year Annual Energy Production and the current year Average Forecast Growth. The 1998 energy production forecast serves as the starting point for the 2000 through 2019 forecast.

Table 7-3
JEA Annual Energy Production Forecast Results for
Calendar Year 2000 through 2019
Base Case, Low Case, and High Case

Calendar Year	Base Case, GWh	Low Case, GWh	High Case, GWh
2000	12,123	11,864	12,334
2001	12,505	11,983	12,951
2002	12,894	12,103	13,599
2003	13,289	12,224	14,279
2004	13,692	12,346	14,992
2005	14,102	12,470	15,742
2006	14,519	12,594	16,529
2007	14,945	12,720	17,356
2008	15,378	12,848	18,223
2009	15,820	12,976	19,135
2010	16,271	13,106	20,091
2011	16,730	13,237	21,096
2012	17,199	13,369	22,151
2013	17,677	13,503	23,258
2014	18,166	13,638	24,421
2015	18,664	13,774	25,642
2016	19,173	13,912	26,924
2017	19,692	14,051	28,271
2018	20,223	14,192	29,684
2019	20,766	14,334	31,168

Notes:
Annual Calendar Year Energy Productions are estimated as the sum of the monthly energy productions (from January through December) for a particular year. The monthly energy productions are estimated as fixed percentages of the Annual Fiscal Year Energy Productions. These fixed percentages are assigned as follow:

8.3 percent for January	10.4 percent for July
7.2 percent for February	10.5 percent for August
7.2 percent for March	9.3 percent for September
7.0 percent for April	7.6 percent for October
8.3 percent for May	7.0 percent for November
9.4 percent for June	7.8 percent for December

Table 7-4
JEA Base Case Annual Retail and Wholesale Forecasts for Calendar Year 2000 through 2019

Calendar Year	Retail, GWh	Wholesale,* GWh	Total, GWh
2000	11,681	442	12,123
2001	12,044	461	12,505
2002	12,414	479	12,894
2003	12,791	498	13,289
2004	13,175	517	13,692
2005	13,567	535	14,102
2006	13,966	554	14,519
2007	14,372	573	14,945
2008	14,787	591	15,378
2009	15,211	610	15,820
2010	15,642	628	16,271
2011	16,083	647	16,730
2012	16,533	666	17,199
2013	16,993	684	17,677
2014	17,463	703	18,166
2015	17,942	722	18,664
2016	18,433	740	19,173
2017	18,934	759	19,692
2018	19,466	777	20,222
2019	19,970	796	20,766

7.1.2 Peak Demand Forecast

The peak demand forecast represents a trend analysis of historical data, weather-normalized to typical temperatures. For each season, winter and summer, a separate model evaluates the effect of weather on historical peak demands and provides weather-normalized peak demands. The weather-normalized peak demands become the basis for the trend analysis.

7.1.2.1 Weather Normalization. JEA uses minimum temperature of the day for the winter season and maximum temperature of the day for the summer season as the weather variables in the normalization methodology. For each individual year of historical data, JEA models the relationship between daily low or high temperature and daily peak demand. JEA evaluates the models at normal temperatures to estimate weather-normalized peak demands. For the purposes of this model, 23° F for the winter and 98° F for the summer are defined to be normal weather. This methodology is outlined in Appendix A, Weather Normalization of Seasonal System Peak Demand and Annual Net Energy Load.

7.1.2.2 Base Case. The summer analysis, conducted in 1998, is based on the five and ten year historical average growth rates of 3.56 and 3.32 percent/year, respectively. The mean of these average summer peak demand growth rates is 3.44 percent/year, equivalent to a constant growth of 77 MW/year beginning in 1998. For the winter historical weather-normalized peak demands, the analysis of the past four and nine periods results in average growth rates of 3.39 and 3.88 percent/year, respectively. This gives a mean average winter peak demand growth rate of 3.63 percent/year, equivalent to a constant growth of 84 MW/year beginning in 1999. Both the mean seasonal average growth rates and average constant growth rate numbers are used as the basis for the forecast calculations. The forecast results for the 2000 through 2019 seasonal peak demands and how they are estimated are shown in Tables 7-5 and 7-6.

JEA has one wholesale customer, Florida Power Utilities Company (FPU). Retail peak demand is calculated by subtracting FPU peak demand from JEA total system peak demand. Retail peak demand is comprised of firm and non-firm customer loads. Non-firm customers are those who have either agreed to allow JEA to interrupt their electric service through the use of remotely operated switches or who have agreed to reduce their electrical consumption to a predetermined level at JEA's request. As a result, these customers have a lower rate and are categorized as Interruptible or Curtailable customers. JEA excludes non-firm customer demand in its determination of the need for new generating capacity. The seasonal retail, wholesale, and interruptible peak demands for the base case are shown in Table 7-7.

Table 7-5
JEA Base Case Summer Peak Demand Forecast Estimation for 2000 through 2019

Year	Forecast MW		Average Forecast,[a] MW	Average Forecast Growth,[b] MW	Summer Peak Demand,[c] MW
	Based on 3.44 Percent/ Year Growth Rate	Based on 77 MW/Year Constant Growth			
2000	2,487	2,480	2,483	79	2,534
2001	2,572	2,556	2,564	81	2,615
2002	2,659	2,633	2,646	82	2,697
2003	2,750	2,709	2,729	83	2,780
2004	2,843	2,786	2,814	85	2,865
2005	2,940	2,862	2,901	87	2,952
2006	3,040	2,939	2,989	88	3,040
2007	3,143	3,015	3,079	90	3,130
2008	3,250	3,092	3,171	92	3,222
2009	3,361	3,168	3,264	94	3,315
2010	3,475	3,245	3,360	95	3,411
2011	3,593	3,321	3,457	97	3,508
2012	3,715	3,398	3,556	99	3,607
2013	3,842	3,474	3,658	101	3,709
2014	3,972	3,551	3,761	104	3,812

Table 7-5 (Continued)
JEA Base Case Summer Peak Demand Forecast Estimation for 2000 through 2019

Year	Forecast MW: Based on 3.44 Percent/ Year Growth Rate	Forecast MW: Based on 77 MW/Year Constant Growth	Average Forecast,[a] MW	Average Forecast Growth,[b] MW	Summer Peak Demand,[c] MW
2015	4,107	3,627	3,867	106	3,918
2016	4,247	3,704	3,975	108	4,026
2017	4,391	3,780	4,086	110	4,137
2018	4,541	3,857	4,199	113	4,250
2019	4,695	3,933	4,314	115	4,365

Notes:
[a] Average Forecast is the average of the forecasts estimated based on 3.44 percent/year and 77 MW/year.
[b] Average Forecast Growth is the difference between the current year Average Forecast and the previous year Average Forecast
[c] Summer Peak Demand is the sum of the previous year Summer Peak Demand and the current year Average Forecast Growth. The trend-line value for 1997 of the 1994-1997 weather normalized summer peak demands, adjussted for the loss of Cecil Field in 1997 and 1998 and for the addition of AmeriSteel in 1999, serves as the starting point for the 2000-2019 forecast.

Table 7-6
JEA Base Case Winter Peak Demand Forecast Estimation for 2000 through 2019

Year	Forecast MW		Average Forecast,[a] MW	Average Forecast Growth,[b] MW	Winter Peak Demand,[c] MW
	Based on 3.63 Percent/ Year Growth Rate	Based on 84 MW/ Year Constant Growth			
2000	2,507	2,504	2,506	86	2,566
2001	2,597	2,588	2,593	87	2,653
2002	2,691	2,672	2,682	89	2,742
2003	2,788	2,756	2,772	90	2,832
2004	2,888	2,841	2,864	92	2,924
2005	2,992	2,925	2,958	94	3,018
2006	3,100	3,009	3,054	96	3,114
2007	3,212	3,093	3,152	98	3,212
2008	3,327	3,177	3,252	100	3,312
2009	3,447	3,261	3,354	102	3,414
2010	3,571	3,345	3,458	104	3,518
2011	3,700	3,429	3,564	106	3,624
2012	3,833	3,513	3,673	109	3,733
2013	3,971	3,597	3,784	111	3,844
2014	4,114	3,682	3,898	114	3,958

Table 7-6 (Continued)
JEA Base Case Winter Peak Demand Forecast Estimation for 2000 through 2019

Year	Forecast MW		Average Forecast,[a] MW	Average Forecast Growth,[b] MW	Winter Peak Demand,[c] MW
	Based on 3.63 Percent/ Year Growth Rate	Based on 84 MW/ Year Constant Growth			
2015	4,262	3,766	4,014	116	4,074
2016	4,415	3,850	4,132	119	4,192
2017	4,574	3,934	4,254	122	4,314
2018	4,739	4,018	4,378	124	4,438
2019	4,909	4,102	4,506	127	4,566

Notes:
[a] Average Forecast is the average of the forecasts estimated based on 3.63 percent/year and 84 GWh/year.
[b] Average Forecast Growth is the difference between the current year Average Forecast and the previous year Average Forecast
[c] Winter Peak Demand is the sum of the previous year Winter Peak Demand and the current year Average Forecast Growth. The trend-line value for 1998 of the 1993-1998 weather normalized winter peak demands, adjusted for the addition of AmeriSteel in 1999, serves as the starting point for the 2000-2019 forecast.

Table 7-7
JEA Base Case Seasonal Retail, Wholesale, and Interruptible Peak Demands for 2000 through 2019

	Summer Peak Demand, MW					Winter Peak Demand, MW				
Year	Retail	Wholesale	Net Firm Demand	Interruptible*	Total Demand	Retail	Wholesale	Net Firm Demand	Interruptible*	Total Demand
2000	2,286	98	2,384	150	2,534	2,366	98	2,464	102	2,566
2001	2,358	103	2,461	154	2,615	2,446	103	2,548	105	2,653
2002	2,431	108	2,539	158	2,697	2,527	108	2,635	107	2,742
2003	2,505	113	2,618	162	2,780	2,610	112	2,722	110	2,832
2004	2,581	118	2,699	166	2,865	2,694	117	2,811	113	2,924
2005	2,659	123	2,782	170	2,952	2,780	122	2,902	116	3,018
2006	2,738	128	2,866	174	3,040	2,868	127	2,996	118	3,114
2007	2,819	133	2,952	178	3,130	2,959	132	3,091	121	3,212
2008	2,901	138	3,039	183	3,222	3,051	137	3,188	124	3,312
2009	2,984	143	3,127	188	3,315	3,145	142	3,286	128	3,414
2010	3,071	148	3,219	192	3,411	3,241	147	3,387	131	3,518
2011	3,158	153	3,311	197	3,508	3,338	152	3,490	134	3,624
2012	3,247	158	3,405	202	3,607	3,439	157	3,596	137	3,733
2013	3,339	163	3,502	207	3,709	3,542	161	3,703	141	3,844
2014	3,432	168	3,600	212	3,812	3,647	166	3,814	144	3,958

Table 7-7 (Continued)
JEA Base Case Seasonal Retail, Wholesale, and Interruptible Peak Demands for 2000 through 2019

	Summer Peak Demand, MW					Winter Peak Demand, MW				
Year	Retail	Wholesale	Net Firm Demand	Interruptible*	Total Demand	Retail	Wholesale	Net Firm Demand	Interruptible*	Total Demand
2015	3,528	173	3,701	217	3,918	3,755	171	3,926	148	4,074
2016	3,625	178	3,803	223	4,026	3,864	176	4,040	152	4,192
2017	3,726	183	3,909	228	4,137	3,978	181	4,159	155	4,314
2018	3,828	188	4,016	234	4,250	4,093	186	4,279	159	4,438
2019	3,932	193	4,125	240	4,365	4,209	191	4,403	163	4,566

Notes:
*Interruptible demands are estimated to grow at a constant rate of 2.5 percent per year.

7.1.2.3 Low and High Cases. The low case forecast represents growth in winter peak demand and summer peak demand of 1.0 percent per year throughout the planning horizon. The high case forecast assumes a constant growth rate of 5.0 percent per year throughout the planning horizon. As discussed in Subsection 7.1.1.2 these ranges of growth are considered to adequately cover the possible range of sustained growth rates. Table 7-8 shows the peak demand forecasts for the base, low, and high cases.

Table 7-8
JEA Seasonal Peak Demand Forecasts for 2000 through 2019
Base Case, Low Case, and High Case

Year	Summer Peak Demand, MW			Winter Peak Demand, MW		
	Base Case	Low Case	High Case	Base Case	Low Case	High Case
2000	2,534	2,480	2,578	2,566	2,505	2,604
2001	2,615	2,504	2,707	2,653	2,530	2,734
2002	2,697	2,529	2,842	2,742	2,555	2,871
2003	2,780	2,555	2,984	2,832	2,581	3,014
2004	2,865	2,580	3,133	2,924	2,607	3,165
2005	2,952	2,606	3,290	3,018	2,633	3,323
2006	3,040	2,632	3,454	3,114	2,654	3,490
2007	3,130	2,658	3,627	3,212	2,685	3,664
2008	3,222	2,685	3,809	3,312	2,712	3,847
2009	3,315	2,712	3,999	3,414	2,739	4,040
2010	3,411	2,739	4,199	3,518	2,767	4,242
2011	3,508	2,766	4,409	3,624	2,795	4,454
2012	3,607	2,794	4,629	3,733	2,822	4,676
2013	3,709	2,822	4,861	3,844	2,851	4,910
2014	3,812	2,850	5,104	3,958	2,879	5,156
2015	3,918	2,879	5,359	4,074	2,908	5,414

Table 7-8 (Continued)
JEA Seasonal Peak Demand Forecasts for 2000 through 2019
Base Case, Low Case, and High Case

	Summer Peak Demand, MW			Winter Peak Demand, MW		
Year	Base Case	Low Case	High Case	Base Case	Low Case	High Case
2016	4,026	2,907	5,627	4,192	2,937	5,684
2017	4,137	2,937	5,908	4,314	2,966	5,968
2018	4,250	2,966	6,204	4,438	2,996	6,267
2019	4,365	2,996	6,514	4,566	3,026	6,580

8.0 Demand-Side Analysis

According to Section 403.519, Florida Statutes, in its determination of need, the Florida Public Service Commission (PSC) must take into consideration conservation measures that could mitigate or delay the need of the proposed plant. Based on this requirement, JEA has tested potential demand-side management (DSM) measures for cost effectiveness. Measures were evaluated using the PSC approved Florida Integrated Resource Evaluator (FIRE) model. The FIRE model evaluates the economic impact of existing and proposed conservation measures by determining the relative cost effectiveness of the measures versus an avoided supply-side resource. The FIRE model was designed by Florida Power Corporation and is used by several utilities in Florida.

In addition to testing potential DSM programs for cost-effectiveness, JEA actually offers several DSM programs which, although they may not pass the cost-effectiveness test, are deemed overall to be beneficial to JEA's customers or are required by various rules and regulations. Section 8.1 presents a description of JEA's existing residential and commercial programs. Section 8.2 describes the FIRE model methodology, inputs, outputs, and analysis of the results.

8.1 Existing DSM Programs

The following subsections describe JEA's existing residential and commercial programs.

8.1.1 Residential Programs

8.1.1.1 Contractor, Building Inspector, and Architect Continuing Education.

This program provides education and training to building contractors, architects, building inspectors, and homeowners to encourage energy conservation. The classes are approved as continuing education courses for those contractors and inspectors licensed by the Construction Industry Licensing Board (CILB). The Board of Architecture and Interior Design has approved these courses as continuing education for architects. The courses are listed and described below.

"Constructing an Energy Efficient Home" - This class addresses all aspects of constructing an energy efficient home, including site inspection, design principles, thermal and mechanical systems, construction details, energy code requirements, heating and air conditioning equipment, duct sizing, and landscaping. Economic assessments are made of all energy features commonly offered by builders. This class is being offered four times per year at the JEA training auditorium and averages 40 to 90 attendees per session.

"Improving Energy Efficiency and Indoor Air Quality in Homes" - This course teaches a system strategy for enhancing energy efficiency and indoor air quality, as well as the cost of implementing the techniques discussed. A review of such elements as drainage, filtration, and return air ducts is included. This seminar is presented annually to 15 to 25 students at the JEA Training Center.

"Load and Duct Sizing Calculations: Computer Solutions" - This class explains the state requirements for heating and air conditioning equipment and duct systems for residential and small commercial buildings. The computer software allows the user to quickly and inexpensively calculate the load, size the duct, and select the heating and air conditioning equipment. This course is offered at the JEA Training Center computer lab room when enough interest is generated to justify a class. JEA's goals for this course are to raise the requirements for duct systems.

The courses comprising this program are offered to homeowners, licensed contractors, building inspectors, engineers, or architects. Upon completion of any of these courses, a certificate of continuing education will be issued to the applicable participants. The certificate for continuing education credits meets licensee state board requirements.

JEA has developed additional seminars that are minor variants of the original seminar themes. In the case of residential airflow seminars, JEA has developed commercial alternates that address uncontrolled airflow in nonresidential buildings. JEA continually updates, revises, and implements educational measures based on recent developments, research, and customer demand. Each year new programs are addressed to increase the public's knowledge of energy efficiency.

JEA customers will benefit from the availability of more informed and educated contractors, building inspectors, and architects. The education courses will encourage energy efficient building practices, correct sizing of duct systems and heating and air conditioning equipment. System improvements will lower energy bills, increase homeowner comfort, and improve indoor air quality. Properly sized equipment saves energy over the life of the system. Duct and equipment systems installed correctly will save energy and minimize air quality problems. Due to a more efficient system, the household will use less energy and make more efficient use of the energy it does use. This creates less of a demand on the electric utility. The customers and contractors will pay all installation costs. Participants eligible for continuing education credits pay a class registration fee.

In 1998, JEA initiated a more vigorous marketing effort to attain even greater attendance by construction professionals. The popular "Constructing an Energy Efficient Home" seminar was increased from 11 credit hours to 12.5 credit hours, and a free 2 hour Work Place Safety/Workers Compensation course was added for a total of 14.5 available credit hours. The 12.5 credit hour course with the two credit hour option made the class more attractive to licensees of the Construction Industry Licensing Board, which requires 14 credit hours for license renewal.

8.1.1.2 Energy Audits.

8.1.1.2.1 Energy Audits for Low Income Customers. This program targets low income residential customers. Every customer is eligible for an energy audit. Audit recommendations usually require the customer to spend money replacing or adding energy conservation measures. Low income customers may not have the discretionary income to make these changes. To alleviate this barrier, two types of low income audits are offered.

One type of low income audit is performed by the local weatherization agency, The Jacksonville Housing Partnership (JHP). JHP is under contract to JEA to perform this audit. During the audit, a conservation measure is installed or performed consistent with a priority list of measures established by JEA. Unfortunately, JHP can only perform 120 installations per year since its overall mission is to perform a collection of major repairs on a limited number of owner-occupied dwellings. The purpose of the weatherization program is to reduce the energy cost for low income households, particularly those households with elderly persons, disabled persons, and children, by improving the energy efficiency of their homes and ensuring a safe and healthy environment.

To supplement the 120 JHP audits, the JEA staff began to perform low income audits on dwellings supervised by the local public housing agency, the Jacksonville Housing Authority (JHA). Eighty additional audits were performed in 1999 by JHA. This type emphasizes behavioral solutions to high energy use, and sometimes involves educational presentations to large audiences.

The Department of Community Affairs (DCA) has administered the state weatherization program since 1978. The DCA's local designated weatherization provider determines eligibility of low income JEA residential customers. Both owner-occupied and rental properties are eligible.

Customers will be able to participate in conservation measures that they might not be able to otherwise afford. Low income customers will benefit from the customized weatherization of their homes which will decrease their electric bills.

JEA will be helping to lower the bills of low income customers who may have more difficulty paying their bills. Reducing the bill of the low income customer may improve the customer's ability to pay the bill, thereby decreasing costly service disconnect fees and late charges. JEA believes this will help to achieve and maintain high customer satisfaction.

The DCA provides program oversight, development, program delivery, fiscal training, and monitoring for the weatherization providers. Each local agency is field monitored at least once a year. The local agencies must comply with federal and state program requirements. Each agency must provide the DCA with an agency audit once a year. The DCA receives monthly work reports from all weatherization providers, with detailed information about weatherization services provided, costs, and an estimate of the pre-weatherization monthly energy expenditures.

8.1.1.2.2 Residential Energy Audits. JEA's objective for offering a Standard Energy Audit Program, a Landscape Audit Program, and a Water Audit Program is to lower kW and kWh usage in residential buildings by providing information and recommendations to homeowners regarding increasing energy efficiency in a manner that is cost effective for the homeowner. Typically, energy and demand savings are not directly attributed to audits. An estimated 3,000 audits are performed per year for this program.

8.1.1.2.3 Multi-Check. In 1990, JEA began offering a short version of the residential energy survey to each customer who requested a meter re-read. JEA looks for causes of high consumption and offers suggestions on how customers can better manage their energy resources. JEA offers this program for both electric and water services. Typically, energy and demand savings are not directly attributed to audits. An estimated 4,000 meter checks resulting in 2,000 multi-checks take place per year.

8.1.1.2.4 Energy Star. This is an Environmental Protection Agency (EPA) program intended to reduce energy consumption in new homes by 30 percent compared to the national Model Energy Code. The Florida Energy Efficiency Code is more stringent than the Model Energy Code, so savings will be less than the 30 percent. Upgrades include higher R-value insulation, tighter construction, more efficient windows, and properly sized and installed duct systems and HVAC equipment.

JEA is implementing this program as a 2 day workshop. JEA is presently planning a joint presentation with the Northeast Florida Builders Association.

8.1.1.2.5 Building Energy Efficiency Rating System (BERS). In accordance with Rule 25-17.003, Florida Administrative Code, JEA is required to perform "Building Energy Efficiency Rating System" (BERS) Energy audits. JEA is implementing the program by training raters certified by the Department of Community Affairs (DCA). JEA will confirm the certification of each rater once per year and send the list of names and certification to FPSC. Beginning in early 2001, JEA will be distributing brochures to potential customers every 6 months describing the auditing program. JEA will maintain records of audits for at least 3 years.

The training class for Class 1 raters was completed on October 27, 2000. Once certificates are received, JEA will begin to promote the BERS program.

8.1.2 Commercial/Industrial Programs.

8.1.2.1 Contractor, Building Inspector, and Architect Continuing Education.

JEA's positive experience with residential educational activities has supported the value of offering similar programs for commercial customers. In 1997 JEA began offering an educational seminar addressing energy issues related to nonresidential buildings.

This program provides education and training to contractors, architects, engineers, and facilities owners and managers to encourage conservation while improving occupant comfort or enhancing manufacturing processes. The classes are or will be approved by the Construction Industry Licensing Board (CILB) for contractors and the Board of Architecture and Interior Design for architects. Presently, the state of Florida has no continuing education requirements for registered engineers. The Board of Professional Engineers is expected to add this requirement for engineering licensing renewals within the next few years. The courses offered are listed and described below.

"Uncontrolled Airflow in Non-Residential Buildings" - This class teaches the students ways to reduce energy use, reduce building degradation, and improve indoor air quality caused by uncontrolled airflow. Details include discussion of leaky ducts, building cavities and ceilings, misplaced vapor barriers, airflow imbalances, and the transport of contaminants into the structure. This course is offered every other year at the JEA Training Center to a group of 25 in number. This course began in 1997 with an attendance of 36 participants.

"Uncontrolled Airflow: Field Studies" - This training will be at a field site at which a problem building will be tested and evaluated. The objective is to link uncontrolled airflow to problems of high energy bills, pollutants, moisture accumulation, comfort conditions, mold and mildew, and ventilation quantities. The student learns about the test equipment used to make the assessments, how to evaluate the data derived, remediation measures, and possible outcomes of the suggested corrections. The training is held at a customer site and is now limited to 10 people. This course began in 1998 and 21 participants attended.

"Energy Efficient Ventilation for Commercial Buildings: ASHRAE 62-1989 Fundamentals, Applications and Field Studies" – This course offers an extensive look at the ASHRAE 62-1989 standard and the energy efficient ways of applying the standard in the design and operation of HVAC systems in commercial buildings. It includes a thorough review of dehumidification technologies related to ventilation. Case studies are discussed, with special attention on designs and operational guidelines which minimize energy consumption while achieving an indoor air quality that is healthy and conducive to productivity. This course will be held every 3 years at the JEA Training Center and will be offered to a group of 10 students. The first course was held in October of 1999.

"High Performance Commercial Buildings Designs for Florida's First Coast" - Topics include economics of building design, the building envelope, HVAC systems design for minimal life cycle operating costs while meeting the unique climate of North Florida, designing for power quality, using day-lighting techniques to minimize lighting and HVAC operating costs, optimal building maintenance, avoiding common design oversights which result in excessive rework and operating costs, and the use of available, proven, cutting-edge technologies in the design of the building systems. This seminar will be held annually at a local conference center, which will accommodate 50 building owners, property mangers, architects, engineers, and suppliers. The first course was held May of 1999.

"Industrial Technology Update" - The agenda includes new technologies and processes being applied in industry; proven new technologies and processes that reduce costs and environmental concerns; avoiding costly, nonproductive and energy wasting manufacturing technologies; and increasing the reliability of the processes. Topics to be discussed are technology transfer (ozone use, electro-technologies, product substitution, etc.); onsite power generation, including solar photovoltaic and fuel cells; and resources for learning about technology transfer. This annual event will be held at a local conference center and will be offered to a group of 50 plant engineers, plant managers and owners, consulting engineers, architects, contractors, and suppliers. The first course was held in September of 1999.

In 2000, a continuing education class was taught and engineers, contractors, and building officials were trained in the Windows version of the 1998 State of Florida Commercial Energy Code, combined with use of the ACCA Manual N commercial heat loss/heat gain form. Engineers, architects, and contractors benefit from these courses.

Recent studies of 70 Florida buildings found only one with proper airflow. This is the first time that the findings of this new research have been presented in the State of Florida. Conditions in many buildings were so catastrophic, according to the researchers, that if not corrected, immense building repair costs and possible litigation could result. Uncontrolled airflow exists when air is forced across the building envelope, through building components or between building zones in a manner never intended by designers and builders.

The addition of the continuing education class will greatly assist those building officials responsible for plan review, and will increase the likelihood that the structure will be built energy efficient in accordance with the 1998 State of Florida Commercial Energy Code.

Participants will be surveyed at the end of the session and at a later date to measure the effectiveness of the course material. The survey will focus on the extent that the material was applied to the design and operation of structures under the participants' authority. The course will be modified or new seminars developed to better meet the customer needs for energy conservation.

8.1.2.2 Energy Audits. An estimated 100 commercial/industrial audits take place per year.

8.1.2.2.1 Commercial Energy Audits. Commercial Energy Audits are provided to all commercial customers upon customer request. Audits are performed by trained energy analysts who consider cost-effective conservation measures relating to thermal insulation, heating and air conditioning, and lighting. The customer receives a written report on the findings of the analysis, including a description of recommended measures.

8.1.2.2.2 Industrial Energy Audits. Industrial Energy Audits are performed by professional engineers and specifically address the industrial customer's unique energy conservation opportunities. Opportunities include thermal improvements, space conditioning, lighting, cogeneration, process, and any new efficient electro-technology. The customer receives written recommendations describing each recommendation, initial cost, and projected annual savings.

8.1.2.3 Community Conservation Programs.

8.1.2.3.1 Street Light Efficiency Program. JEA has converted nearly all of the approximately 60,000 mercury vapor illuminaries owned by the City of Jacksonville to the more energy efficient high-pressure sodium luminaries that use less electricity.

8.1.2.3.2 Community Information/Energy Education. This is a multifaceted program aimed at promoting energy conservation awareness of the general public. This is accomplished through the following agenda.

First, "Speakers' Bureau" is a program aimed at satisfying ongoing requests from the public and specialized groups in four main categories:

- Speakers with energy conservation expertise (residential conservation and commercial/industrial energy management), address business, professional, civic, and church groups.
- Energy information specialists discuss energy conservation on radio and television talk shows and in media interviews.
- Professional engineers address management and personnel at large industrial sites.
- Energy educators or speakers coach teachers and address students at elementary, high school, and college levels.

The speakers have a broad knowledge of energy curriculum, energy education material content, and sources. In 1999, the speakers' bureau was utilized on 61 occasions reaching a total of 26,250 people.

Second, "Media Contact" energy conservation events and developments are promoted through print and electronic media. In 1999, approximately 106 energy conservation radio spots aired on six radio stations, reaching approximately 525,000 members of the target audience (18 years and older). Three television public service announcements were distributed to local stations during the third and fourth quarters of 1999. Because television stations air PSAs on a best time available basis, audience data and times aired cannot be determined. A total of 52 Power for Pennies segments aired on WTLV TV-12.

Third, "Special Promotions and Special Events are sponsored by JEA." JEA supports special energy awareness observances and special events. National Energy Awareness Month, Energy Week, Public Power Week, and Electrical Safety Week are promoted through the media, businesses, school, and special events including the following:

- Energy Week held at Naval Bases and at Vistakon in October (National Energy Awareness Month).
- Home & Patio Spring and Fall Shows.
- Eartha M. White Nursing Home Health Fair.
- Earth Day.

Fourth, JEA produced a series of printed Bill Inserts and Brochures to highlight seasonal energy conservation tips and JEA energy conservation services. A total of 700,000 inserts promoting energy conservation were placed in customer bills in 1999. In total, JEA distributed more than one million statements, brochures, and fact sheets promoting energy conservation.

Fifth, tours of JEA power plants and facilities are open to students grade six and up and adults. The tours provide a foundation for energy awareness.

Sixth, the Energy Conservation Division reviews product listings in appropriate magazines, such as ASHRAE Journal and Building Design and Construction as well as new products appearing on the local market. The Energy Product Reviews and fact sheets keep customers abreast of developments in energy technology.

Seventh, a selection of technically accurate attractive booklets, brochures, posters, and multi-part kits is made available for customers of all ages.

Eighth, Video Series/Public Service Video are videos, slides, films, and filmstrips seeking to improve the effectiveness of energy conservation messages, with or without personal JEA representation.

Ninth, Model Energy Curriculum is an educational tool developed and used to coach teachers in knowledge of energy facts and teaching methods.

Tenth, the Tree Hill Outreach is an outreach to educators, students, senior citizens, and other adults. The education is provided under contract with PATH Inc. through the Tree Hill Nature Center. Energy education or information is provided to approximately 10,000 consumers annually in Tree Hill programs. The JEA maintains a working photovoltaic demonstration at Tree Hill. In 1999, 224 Tree Hill Tours were given reaching an estimated 4,337 people.

Eleventh, JEA has a Key Accounts program to serve the needs of its largest customers. JEA is systematically contacting all of its Key Account customers to identify their energy related needs and concerns and develop mechanisms to respond to issues raised by the customers. The Key Account program includes energy audits, power conditioning audits, power conditioning supply analysis, bill and rate analysis, problem resolution, and cogeneration services.

8.1.2.3.3 Tree Power Program. JEA will continue to participate in the American Public Power Association's Tree Power program. JEA distributed over 27,945 trees during the current reporting period. This is done to help reduce greenhouse gases and to lower homeowners' cooling costs due to lack of shading.

8.2 DSM Program Analysis

The FIRE model evaluates the economic impact of conservation measures by determining the relative cost effectiveness of the measures versus an avoided supply-side resource. The FIRE model was designed by Florida Power Corporation and is used by several utilities in Florida.

8.2.1 Fire Model Assumptions

Assumptions inherent in the FIRE model include:

- System demand is growing. Demand reductions due to DSM will result in reduced need for system expansion.
- Individual demand reductions can be related to reduced need for system generation expansion.
- The generation reduction will be evaluated with respect to specified generation.
- Decreases or increases in revenue due to demand-side programs will impact rate levels and will be passed on to all customers.
- Additional conservation taking place after the next deferred generating unit will affect subsequent units.

8.2.2 FIRE Model Inputs

There are two types of FIRE model input files. The first input file contains data specific to the utility's next proposed unit, the avoided unit. The second input file contains data specific to the DSM measure being tested for cost effectiveness. Input data for the avoided unit is placed on a per kW basis. Because the avoided unit data is input on a per kW basis, the potential DSM measures can be tested individually to determine cost effectiveness.

8.2.2.1 Avoided Unit. The avoided unit is the utility's next planned capacity addition. The Brandy Branch combined cycle conversion is JEA's avoided unit. The conversion of simple cycle combustion turbines to combined cycle as an avoided unit presents an interesting quandary with respect to the cost and performance of the avoided unit. JEA has taken a very conservative approach by including the entire cost for the combined cycle as the avoided unit capital cost and O&M costs. Obviously, the true avoided capital cost is only the capital cost associated with the conversion.

8.2.2.2 DSM Measures. Demand-Side Management measures selected for cost effective analyses were identified based on the potential to be cost effective. This approach allowed JEA to focus on alternatives that were expected to have the highest potential for being cost effective if added to its existing DSM program portfolio.

The DSM measures analyzed were compiled from the residential and commercial measures deemed cost effective in Florida Power and Light's 2000 Demand-Side Management Plan. According to this document, FPL's most cost-effective residential measure is Direct Load Control, and its most cost-effective commercial/industrial measure is Off-Peak Battery Charging.

The residential Direct Load Control program allows participants to receive rebates in exchange for surrendering control of major appliances during peak periods of high energy consumption by FPL customers. Appliances include air conditioners, central heaters, water heaters, and pool pumps. The commercial Off-Peak Battery Charging Program allows participants to receive a one time rebate for every kilowatt the participant shifts from on-peak to off-peak. The program was designed for electric carts and the eligible participants are limited to golf courses with electric golf carts.

Based on a telephone survey of golf courses in the JEA service territory, it has been concluded that the facilities are already charging their electric carts at night. Based on this conclusion, there is no customer base for the Off-Peak Battery Charging program and JEA evaluated FPL's next most cost-effective commercial DSM measure, commercial Direct Load Control. An added benefit to testing the commercial Direct Load Control program is the greater number of eligible customers potentially resulting in a greater demand reduction compared to the Off Peak Battery Charging Program. The results can be found in Section 8.2.4.

By testing the most cost-effective measures from FPL, the assumption was made that if the most cost-effective measures from FPL did not prove cost effective for JEA, then FPL's lesser cost-effective measures would also fail the analysis.

8.2.3 FIRE Model Output

FIRE model results are presented in the form of three cost-effectiveness tests. All the DSM cost-effectiveness tests are based on the comparison of discounted present worth benefits to costs for a specific DSM measure. Each test is designed to measure costs and benefits from a different perspective.

The Total Resource Cost Test measures the benefit/cost ratio by comparing the total program benefits (both the participant's and utility's) to the total program costs (equipment costs, supply costs, and participant costs).

The Participant's Test measures the impact of the DSM program on the participating customer. Benefits to the participant may include bill reductions, incentives paid, and tax credits. Participant's costs may include equipment costs, operation and maintenance expenses, equipment removal, etc. The Participant's Test is important because customers will not participate in a program if it is not beneficial to them.

The Rate Impact Test is a measure of the expected impact on customer rates resulting from a DSM program. The test statistic is the ratio of the utility's benefits (avoided supply costs and increased revenues) compared to the utility's costs (program costs, incentives paid, increased supply costs, and revenue losses). A value of less than one indicates an upward pressure on electricity rates as a result of the DSM program. JEA views the Rate Impact Test as the primary test for determining the cost effectiveness of a DSM measure on its system.

8.2.4 FIRE Model Output Analysis

JEA requires all measures to pass the Rate Impact Test to be considered cost effective. Of the potential DSM measures tested, none passed the Rate Impact Test. Thus, JEA has concluded that there are no cost-effective DSM measures reasonably available that would avoid or defer the need for the Brandy Branch conversion project. Table 8-1 presents the FIRE model results of the DSM analysis.

Table 8-1
FIRE Model Results

Program Description	Rate Impact Test	Participant's Test	Total Resource Cost Test
Residential			
Direct Load Control	0.44	1.0	21.89
Commercial			
Off-PeakBattery Charging	0.32	1.0	14.38

The results of the DSM analysis are not surprising due to previously performed analysis for similarly situated utilities. The failing cost effectiveness of DSM has been exhibited in the Need for Power Dockets for Kissimmee Utility Authority (KUA) and Florida Municipal Power Agency (FMPA) for Cane Island Unit 3 (Docket No. 980802) and Lakeland Electric conversion of McIntosh Unit 5 (Docket No. 990023), and in recent Demand Side Management Ten Year Plans for Orlando Utilities Commission (OUC) (Docket No. 990722-EG) and JEA (Docket No. 990720-EG).

The decrease in the cost effectiveness can be attributed to the decreased price of installing new generation, the higher efficiency of new generation, relatively low interest rates, and the general increase in the efficiency of appliances and dwellings.

JEA's recent 2000 Demand-Side Management Plan and proposed numeric conservation goals (Docket No. 990720-EG) were approved in Order No. PSC-00-0588-FOF-EG by the Florida Public Service Commission. JEA's approved goals for residential, commercial, and industrial conservation are zero based on the results of the DSM analysis. JEA has voluntarily opted to continue its existing programs based on the importance of energy conservation to the community.

9.0 Reliability Criteria and Need for Capacity

This section presents the reliability criteria used by JEA and the forecast of JEA's capacity needs to maintain the reliability requirement for the period of 2000 through 2019.

9.1 Reliability Criteria

The Florida Reliability Coordinating Council (FRCC) has found that a planned reserve margin criterion of 15 percent is adequate for Peninsular Florida. The Florida Public Service Commission (FPSC) has also established a minimum planned reserve margin criterion of 15 percent in Rule 25-6.035 (1) Fla. Admin. Code, for the purposes of sharing responsibility for grid reliability. The 15 percent minimum planned reserve margin criteria is generally consistent with the practice throughout the industry.

JEA has been using 15 percent for its planning reserve margin as a single criterion for providing reliable electricity to its customers. The planning reserve margin covers uncertainties in extreme weather, forced outages for generators, and uncertainty in load projections. JEA plans to maintain the 15 percent reserve margin only for firm load obligations. Interruptible and curtailable load is not considered in the 15 percent reserve margin.

9.2 JEA's Seasonal Capacity Needs

Based on the firm peak demand and energy forecasts, existing supply-side capacity resources and contracts, and unit retirements, JEA has forecasted future supply capacity needs for its electric system.

Tables 9-1 and 9-2 display the likely base case capacity needs for the summer and winter, respectively, to maintain the 15 percent reserve margin requirement for a 20 year period beginning in 2000. The forecasts in Tables 9-1 and 9-2 indicate that JEA will experience a capacity need of about 261 MW in the winter of 2002 and 75 MW in the summer of 2002. These capacity needs must be offset by power purchases, as time is too short to install any capacity addition.. The forecasts in Table 9-1 and Table 9-2 also show that JEA will experience capacity needs of about 40 MW starting in the summer of 2004 and about 58 MW in the winter of 2005. The average annual summer and winter increase is approximately 130 MW.

Table 9-1
JEA Base Case Capacity Need After Committed Units* for 2000 through 2019
Summer

Year	Installed Capacity** MW	Firm Capacity** MW		QF MW	Available Capacity MW	Firm Peak Demand MW	Reserve Margin		Capacity Required for 15 Percent Reserve Margin MW
		Import	Export				MW	Percent	
2000	2,708	468	430	0	2,746	2,384	361	15	0
2001	3,024	298	430	0	2,892	2,461	431	18	0
2002	3,236	299	430	0	2,845	2,539	306	12	75
2003	3,241	207	430	0	3,018	2,619	399	15	0
2004	3,241	207	383	0	3,065	2,700	365	14	40
2005	3,241	207	383	0	3,065	2,782	283	10	135
2006	3,241	207	383	0	3,065	2,866	199	7	231
2007	3,241	207	383	0	3,065	2,952	113	4	330
2008	3,241	207	383	0	3,065	3,039	26	1	430
2009	3,241	207	383	0	3,065	3,128	-63	-2	532
2010	3,241	0	383	0	2,858	3,219	-360	-11	842
2011	3,241	0	383	0	2,858	3,311	-453	-14	950
2012	3,241	0	383	0	2,858	3,405	-548	-16	1,058
2013	3,241	0	383	0	2,858	3,502	-644	-18	1,169
2014	3,241	0	383	0	2,858	3,600	-742	-21	1,282
2015	3,241	0	383	0	2,858	3,701	-843	-23	1,398
2016	3,241	0	383	0	2,858	3,803	-946	-25	1,516

Table 9-1 (Continued)
JEA Base Case Capacity Need After Committed Units* for 2000 through 2019
Summer

Year	Installed Capacity** MW	Firm Capacity** MW		QF MW	Available Capacity MW	Firm Peak Demand MW	Reserve Margin		Capacity Required for 15 Percent Reserve Margin MW
		Import	Export				MW	Percent	
2017	3,241	0	383	0	2,858	3,908	-1,054	-27	1,637
2018	3,241	0	383	0	2,858	4,016	-1,162	-29	1,777
2019	3,241	0	383	0	2,858	4,125	-1,271	-31	1,923

Notes:
*Committed Units:
1. Kennedy Unit 10 Shutdown – April 2000
2. Kennedy CT 7 On Line – June 2000
3. Brandy Branch CTs 1 and 2 – May 2001
4. Southside Units 4 and 5 Retirement – Oct 2001
5. Brandy Branch CT 3 – December 2001
6. Northside Unit 1 – Outage for Fuel Conversion – September 2001
7. Northside Unit 2 – April 2002
8. Northside Unit 1 – August 2002

**The generating units and firm import and export capacities make up JEA's supply-side capacity resources. In the past, JEA has set each unit's summer capability using SERC guidelines. These values were verified twice a year using either a 2 hour test under normal operation or a 2 hour period of actual generation as measured at the dispatch center. Since the SERC guidelines are no longer a requirement, JEA runs a special test only when normal operation indicates that a unit is degrading.

Table 9-2
JEA Base Case Capacity Need After Committed Units* for 2000 through 2019
Winter

Year	Installed Capacity** MW	Firm Capacity** MW		QF MW	Available Capacity MW	Firm Peak Demand MW	Reserve Margin		Capacity Required for 15 Percent Reserve Margin MW
		Import	Export				MW	Percent	
2000	2,731	566	445	0	2,852	2,464	388	16	0
2001	2,825	560	445	0	2,940	2,548	392	15	0
2002	2,927	287	445	0	2,769	2,635	134	5	261
2003	3,457	207	445	0	3,219	2,722	497	18	0
2004	3,457	207	383	0	3,281	2,811	469	17	0
2005	3,457	207	383	0	3,281	2,902	378	13	58
2006	3,457	207	383	0	3,281	2,996	285	10	169
2007	3,457	207	383	0	3,281	3,091	190	6	274
2008	3,457	207	383	0	3,281	3,188	93	3	385
2009	3,457	207	383	0	3,281	3,286	-6	0	499
2010	3,457	207	383	0	3,281	3,387	-106	-3	614
2011	3,457	0	383	0	3,074	3,490	-417	-12	940
2012	3,457	0	383	0	3,074	3,596	-522	-15	1,061
2013	3,457	0	383	0	3,074	3,703	-630	-17	1,185
2014	3,457	0	383	0	3,074	3,814	-740	-19	1,312
2015	3,457	0	383	0	3,074	3,926	-852	-22	1,441
2016	3,457	0	383	0	3,074	4,040	-967	-24	1,573

Table 9-2 (Continued)
JEA Base Case Capacity Need After Committed Units* for 2000 through 2019
Winter

Year	Installed Capacity** MW	Firm Capacity** MW		QF MW	Available Capacity MW	Firm Peak Demand MW	Reserve Margin		Capacity Required for 15 Percent Reserve Margin MW
		Import	Export				MW	Percent	
2017	3,457	0	383	0	3,074	4,159	-1,085	-26	1,709
2018	3,457	0	383	0	3,074	4,279	-1,205	-28	1,847
2019	3,457	0	383	0	3,074	4,403	-1,340	-30	2,002

Notes:
*Committed Units:
1. Kennedy Unit 10 Shutdown – April 2000
2. Kennedy CT 7 On Line – June 2000
3. Brandy Branch CTs 1 and 2 – May 2001
4. Southside Units 4 and 5 Retirement - October 2001
5. Brandy Branch CT 3 – December 2001
6. Northside Unit 1 – Outage for Fuel Conversion - September 2001
7. Northside Unit 2 – April 2002
8. Northside Unit 1 – August 2002

**The generating units and firm import and export capacities make up JEA's supply-side capacity resources. In the past, JEA has set each unit's summer capability using SERC guidelines. These values were verified twice a year using either a 2 hour test under normal operation or a 2 hour period of actual generation as measured at the dispatch center. Since the SERC guidelines are no longer a requirement, JEA runs a special test only when normal operation indicates that a unit is degrading.

10.0 Request for Proposal

The Commission's Rules (Rule 25-22.082, Florida Administrative Code) exempts municipal utilities from being required to conduct a Request for Proposal process when constructing a new generating unit requiring certification under the Florida Electrical Power Plant Siting Act. JEA did not issue a Request for Proposal (RFP) for the following reasons.

10.1 Current Market Condition

JEA has had formal discussions with active merchant plant developers who have proposed charges in the \$8.00-\$9.00/kW-mo range for their capacity. It was documented in the October 2000 Florida Power Corporation (FPC) Hines 2 Need for Power hearings that FPC received a proposal from a bidder for two 250 MW blocks of power priced at \$6.75/kW-mo and \$9.10/kW-mo purchase power demand charge. Based on JEA's economic information included in this application, the equivalent demand charge for the Brandy Branch Combined Cycle is estimated to be \$4.42/kW-mo. Based on this information, it is anticipated that purchase power proposals from bidders would include demand charges that would be 50-100% higher than JEA's costs for the Brandy Branch facility. JEA's superior financial bond ratings coupled with having no obligation to produce a Return on Investment for investors comprise the majority of these savings.

10.2 Economic Benefits Resulting from Existing Infrastructure

10.2.1 Combustion Turbine Cost

Two combustion turbine units at the Brandy Branch site are under construction and scheduled for commercial operation in May 2001. A third unit is under construction and scheduled for Commercial Operation in December 2001. These units have been under contract since 1998 with General Electric and the contract was signed before the recent price increases impacted the market. The contractual price for the Brandy Branch combustion turbines was approximately \$30 Million for each unit compared to the current price range of \$38-\$39 Million.

10.2.2 Existing Site/Substation/Transmission Line

Site availability and the existing infrastructure greatly improve the economics of this project relative to other options resulting from an RFP. The Brandy Branch site was originally configured to incorporate either a fourth combustion turbine or the additional heat recovery steam generators and steam turbine required for the combined cycle conversion.

The Brandy Branch substation has been designed with a bay for a breaker position for the Brandy Branch Combined Cycle Conversion. Therefore, only the breaker and associated relaying needs to be added. A proposal from a Greenfield site would require three breakers to be installed.

Cost of land and right-of-way costs for transmission lines and natural gas pipelines would also be significant additional costs in any proposed Greenfield project.

10.2.3 Gas Transportation

An 18.2 mile, 16 inch diameter pipeline lateral has been constructed from the FGT system to Brandy Branch. This pipeline has adequate capacity to serve up to four simple cycle combustion turbines at Brandy Branch. No new pipeline lateral improvements are required to service the combined cycle conversion project. JEA has a long term need for gas transportation for its simple cycle turbines and the Northside Generating Station No. 3 steam unit. As discussed in Section 6.1.2, the firm transport required by JEA for those units is partially contracted already with final negotiations underway for the remaining portion. This firm amount is fully adequate to supply the Brandy Branch conversion project, so no incremental firm obligations are incurred for the conversion. A proposal from a Greenfield project would need to include natural gas transportation costs.

10.3 Florida Supreme Court Ruling

The recent ruling by the Florida Supreme Court which overturned the PSC's March 1999 decision allowing Duke Energy to partner with the New Smyrna Beach Utilities Commission on a combined cycle plant and the Supreme Court's ruling on reconsideration will likely postpone any merchant plant development. This postponement will likely continue until the Florida Legislature makes changes to the Power Plant Siting Act. Governor Bush has appointed the 2020 Commission to study energy policy in Florida. The 2020 Commission's findings are not due until December 2001, with findings on wholesale power due in January 2001. The Florida Legislature may not act on the Power Plant Siting Act until the 2020 Commission's findings are available, which would be the 2002 legislative session. Even if the Florida Legislature acted during the 2001 legislative session after the 2020 Commission's findings on wholesale power are available, it is unlikely that sufficient time would be available for merchant projects to be developed in time to meet JEA's need for capacity in the summer of 2004. In any event, the uncertainty of the situation of merchant plants precludes JEA from depending upon merchant plants to meet JEA's immediate capacity needs and obligation to serve load.

10.4 Time and Expense Considerations

Costs which are often overlooked when considering a RFP process are those incurred by bidders. Bidders often spend millions of dollars developing a project and can spend thousands or hundreds of thousands in providing a bid in response to an RFP. The costs associated with an unsuccessful project have to be ultimately recovered by the bidders on successful projects. Even though nothing requires bidders to bid, JEA feels that it is not appropriate to exercise the bidding process when the cost structure of the Brandy Branch Conversion project is such that bidders cannot successfully compete.

10.5 Purchase Power Alternatives

JEA, along with South Carolina Public Service Authority (Santee Cooper), Municipal Electric Agency of Georgia (MEAG), Nebraska Public Power District (NPPD), Gainesville Regional Utilities, and the City of Springfield Missouri are members of The Energy Authority (TEA).

TEA is a wholesale marketing company that purchases all its members wholesale purchase power requirements and markets all its members excess power at wholesale. TEA is active in pursuing short and long term power supply arrangements on behalf of its members resulting in contracts of up to five years. TEA has not seen any available purchase opportunities that would economically compete with the Brandy Branch Combined Cycle Conversion.

11.0 Supply-Side Alternatives

The first step in the development of generation expansion alternatives involves the identification of generic generation technologies whose technical and cost characteristics cause them to be worthwhile candidates for inclusion in full-fledged alternative plans. The primary criteria for including a technology in the planning process are cost, commercial viability, and technical feasibility.

The commercial viability of a technology relates to the degree to which it has been demonstrated in utility applications. In general, a commercial scale demonstration unit must have been built and operated before this criteria is fully met.

Technical feasibility refers to the likelihood that the technology can be applied to meeting generation requirements in a manner that: 1) is likely to be cost effective, given current economic projections; and 2) permits the electrical system to continue to operate in an integrated, efficient manner. For example, if a particular technology was low in cost, but not suitable for system load characteristics that technology would not be useful to the electrical system at this time. To fully examine the issue of technical feasibility, it is necessary to factor into account the size, fuel type, construction requirements, and ability to match the technology to the service it must perform.

This section presents a review of the conventional, advanced, and renewable energy resources evaluated as potential capacity addition alternatives. Although many technologies are not commercially viable at this time, cost and performance data were developed in as much detail as possible to provide an accurate resource planning evaluation. In addition, due to the dependent nature of some technologies on site characteristics and resources, it is difficult to accurately estimate performance and costing information. For this reason, some of the options have been presented with a typical range for performance and cost. For most technologies, the performance and costs are based on a specified size. In addition, an overall levelized cost range for the general technology type is provided. This levelized cost of energy production accounts for capital, fuel, operations, maintenance, and other costs over the typical life expectancy of the unit. The following alternatives are addressed in the subsequent sections:

- Renewable technologies.
- Waste technologies.
- Advanced technologies.
- Energy storage systems.
- Nuclear (fission).
- Other conventional alternatives.

11.1 Renewable Technologies

Renewable energy technologies are based on energy sources that are practically inexhaustible in that they are usually solar derivatives. Such technologies are often favored by the public over conventional fossil fuel technologies because of the perception that renewable technologies are more environmentally benign. Renewable technologies evaluated in this section include wind, solar thermal, solar photovoltaic, biomass, geothermal, hydroelectric, and ocean energy technologies.

11.1.1 Wind

Wind power systems convert the movement of the air to power by means of a rotating turbine and generator. Wind power was the fastest growing energy source of the last decade in percentage terms and enjoyed a 36 percent growth in capacity in 1999. Installed worldwide wind capacity at the end of 1999 is estimated by the American Wind Energy Association to be 13,400 MW. * The United States, with a total installed capacity of about 2,500 MW, no longer leads the world in wind power installations. The lead is held by Germany, with just over 4,000 MW installed. Denmark, Spain, and India are other active international markets. Domestic markets are no longer limited to California, and large wind farms have been installed in Iowa, Minnesota, and Texas in the past few years. Much of the recent growth in domestic capacity was spurred by fear that the US federal production tax credit would not be renewed when it expired July 1, 1999 (the application period for the credit has since been extended to January 1, 2002).

Utility scale wind energy systems consist of multiple wind turbines that range in size from 100 kW to 1,600 kW. Typically sized energy system installations may total 5 to 200 MW. Wind is an intermittent resource with average capacity factors of 15 to 40 percent, depending on the wind regime in the area and energy capture characteristics of the wind turbine. To provide a peaking resource, wind energy systems may be coupled with battery energy storage to provide power when required, but this is not usually done. Table 11-1 provides wind energy characteristics for a 10 MW wind farm with an average yearly wind speed of 18 miles per hour (8 m/s).

In general, wind resources in the southeastern United States, including Florida, are limited and not economically recoverable. Average wind speeds in Florida are typically below 14 miles per hour (6.2 m/s at a 50 meter hub height) and are not sufficient to support economical wind power generation. (Wind turbine power output rises with the cube of wind speed, making small differences in wind speed very significant.) The

*American Wind Energy Association, "Global Wind Energy Market Report," December 23, 1999, from: http://www.awea.org/faq/global99.html.

central plain states offer the greatest potential for large scale wind development in the United States.

Table 11-1
Wind Energy Conversion--Performance and Costs

Commercial Status	Commercial
Performance*:	
Plant Capacity (MW)	10
Capacity Factor (percent)	35
Economics:	
Capital Cost ($/kW)	1,000-1,200
Fixed O&M ($/kW-yr)	10.5
Variable O&M ($/MWh)	5.0
Levelized Cost (cents/kWh)	5.1-6.0

Note:
*Performance calculations based on a Rayleigh wind speed distribution with an average annual wind speed of 18 m/s at 50 m hub height. (The Rayleigh wind speed distribution is a mathematical function in common use in the wind industry to provide a convenient, approximate method of summarizing wind regimes.)

11.1.2 Solar Thermal

Solar energy consists of capturing the sun's energy and converting it to either thermal energy (solar thermal) or electrical energy (photovoltaic). Solar thermal systems convert solar insulation to high temperature thermal energy, usually steam, which is then used to drive heat engines, turbine/generators, or other devices for electricity generation. Commercial solar thermal plants in the U.S. currently generate more than 350 MW. Solar thermal technologies are appropriate for a wide range of intermediate and peak load applications, including central power station power plants and modular power stations in both remote and grid-connected areas.

In order to achieve the high temperature needed for solar thermal power systems, the sunlight is usually concentrated with mirrors or lenses. Three concentrating solar thermal collector technologies have been developed. The shape of the mirrored surface on which the sunlight is concentrated characterizes each. They are parabolic trough, parabolic dish, and central receiver. Of the three, parabolic trough represents the vast majority of installed capacity. The US government has funded two utility-scale central receiver power plants: Solar One and its successor/replacement, Solar Two. Solar Two is no longer operating due to reduced federal support. A few companies have developed small parabolic dish systems, which are typically below 50 MW in size. They are now actively marketing their modular technology.

Representative characteristics for an 80 MW parabolic trough solar thermal plant are represented in Table 11-2.

Table 11-2
Solar Thermal--Performance and Costs

Commercial Status	Commercial
Performance:	
Plant Capacity (MW)	80
Capacity Factor (percent)	34
Economics:	
Capital Cost ($/kW)	2,700-4,000
Fixed O&M ($/kW-yr)	24-46
Variable O&M ($/MWh)	3-5
Levelized Cost (cents/kWh)	12.7-19.3

11.1.3 Photovoltaics

Photovoltaic cells convert sunlight directly into electricity by the interaction of photons and electrons within the semiconductor material. To create a photovoltaic cell, a material such as silicon is doped with atoms from an element with one more or less electron than occurs in its matching substrate (e.g., silicon). A thin layer of each material is joined to form a junction. Photons, striking the cell, cause this mismatched electron to be dislodged, creating a current as it moves across the junction. Through a grid of physical connections, the current is gathered. Various currents and voltages can be supplied through series and parallel cell arrays.

The dc current produced depends on the material involved and the intensity of the solar radiation incident on the cell. Most widely used today is the single crystal silicon cell. The source silicon is highly purified and sliced into wafers from single-crystal ingots or is grown as thin crystalline sheets or ribbons. Polycrystalline cells are another alternative. These are inherently less efficient than single crystal solar cells, but are less expensive to produce. Gallium arsenide cells are among the most efficient solar cells and have many other advantages, but they are also expensive.

Thin film cells are another approach to producing solar cells that show great promise. Commercial thin films are principally made from amorphous silicon; however, copper indium diselenide and cadmium telluride also show promise as low-cost solar cells. Thin film solar cells require very little material and can be easily manufactured on a large scale. Manufacturing lends itself to automation and the fabricated cells can be flexibly sized and incorporated into building components.

Current utility grid connected photovoltaic systems are generally below 1 MW. However, several larger projects ranging from 1 to 50 MW have been proposed. One of the more recent project announcements is a 2.5 MW installation to be constructed on an industrial brownfield site in Chicago.

Numerous variations in photovoltaic cells are available, such as single crystalline silicon, polycrystalline, thin film silicon, etc., and several structure concepts are available (fixed-tilt, one-axis tracking, two-axis tracking). For representative purposes, a fixed-tilt, single crystalline photovoltaic system is characterized in Table 11-3.

Table 11-3
Solar Photovoltaic--Performance and Costs

Commercial Status	Commercial
Performance*:	
Plant Capacity (MW)	0.01-10
Capacity Factor (percent)	20-22
Economics:	
Capital Cost ($/kW)	3,600-7,000
Fixed O&M ($/kW-yr)	5.7-8.2
Variable O&M ($/MWh)	0.5-1.5
Levelized Cost (cents/kWh)	23.5-50.2

Note:
*Performance calculations based on use of a single crystalline, fixed-tilt array.

11.1.4 Biomass

Electricity generation from biomass, which is any material of recent biological origin, is the second most prolific source of renewable energy generation after hydro. Biomass includes materials as diverse as urban wood waste, agricultural residues, and yard waste. Direct biomass combustion power plants in operation today essentially use the same steam Rankine cycle introduced into commercial use 100 years ago. Pressurized steam is produced in a boiler and then expanded through a turbine to produce electricity. Prior to combustion in the boiler, the biomass fuel may require some processing to improve the physical and chemical properties of the feedstock. Furnaces used in the combustion of biomass include spreader stoker-fired, suspension-fired, fluidized bed, cyclone, and pile burners. Advanced integrated biomass gasification combined cycles are under development.

The capacity of biomass plants is usually less than 50 MW because of the large quantities and dispersed nature of the feedstock. Furthermore, biomass plants will commonly have lower efficiencies as compared to modern coal plants. The low efficiency is due to the lower heating value and higher moisture content of the biomass fuel compared to coal. Finding sufficient sources of fuel within a 100 mile radius may also limit the size of plant because of high transportation costs associated with the low density fuel.

Wood is the most common biomass fuel. There are around 1,000 wood-fired plants in the country, with typical sizes ranging from 10 to 25 MW. Only a third are commercially operated, with the rest being owned and operated by the forest products industry for self-generation. Table 11-4 provides typical characteristics of a 50 MW biomass plant using urban wood waste as fuel.

Table 11-4
Biomass--Performance and Costs

Commercial Status	Commercial
Performance:	
Plant Capacity (MW)	50
Net Plant Heat Rate (Btu/kWh)	13,500-15,000
Capacity Factor (percent)	60-80
Economics:	
Capital Cost ($/kW)	2,000-3,000
Fixed O&M ($/kW-yr)	50-70
Variable O&M ($/MWh)	6-10
Levelized Cost* (cents/kWh)	6.6-11.6

Note:
*Assumes fuel cost of $0.75/MBtu.

11.1.5 Geothermal

Geothermal power plants use heat from the earth to generate steam and drive turbine generators for the production of electricity. The production of geothermal energy in the US currently ranks third in renewable energy sources, following hydroelectric power and biomass energy. In the United States, the electrical generation industry has an installed capacity of 2,800 megawatts of electricity (MWe) from geothermal energy, and direct applications have an installed capacity in excess of 2,100 thermal megawatts (MWt). Approximately 8,000 MWe are currently being generated in some 20 countries from geothermal energy, and there are 12,000 MWt of installed capacity worldwide for direct heat applications.*

Geothermal power is limited to locations where geothermal pressure reserves are found. In the United States, most of these reserves can be found in the western portion of the country. No known geothermal reservoirs suitable for power production are located in the state of Florida. Four types of geothermal power conversion systems are in common use. They are dry steam, single-flash, double-flash, and binary cycle power plants. For representative purposes, a binary-cycle power plant is characterized in Table 11-5. Capital costs of geothermal facilities can vary widely, as the drilling of wells can cost as much as 4 million dollars, and the number of wells drilled depends on the success of finding the resource. Variable O&M costs include the replacement of production wells.

Table 11-5
Geothermal – Performance and Costs

Commercial Status	Commercial
Performance*:	
Plant Capacity (MW)	25-50
Capacity Factor (percent)	85-93
Economics:	
Capital Cost ($/kW)	1,800-4,000
Fixed O&M ($/kW-yr)	30-90
Variable O&M ($/MWh)	2-6
Levelized Cost (cents/kWh)	3.5-9.0

Note:
*Performance calculations based on use of a binary cycle geothermal plant.

* University of Utah Energy & Geoscience Institute, "Geothermal Energy Brochure," accessed June, 2000, from: http://www.egi.utah.edu/geothermal/brochure/brochure.htm.

11.1.6 Hydroelectric

Hydroelectric generation is usually regarded as a mature technology that is unlikely to advance. Turbine efficiency and costs have remained somewhat stable; however, construction techniques and cost have and are changing. Capital costs are highly dependent on site characteristics and may vary widely. To be able to predict performance and cost, site and river resource data would be required. Table 11-6 has typical ranges for performance and cost estimates.

Table 11-6
Hydroelectric--Performance and Costs

Commercial Status	Commercial
Performance:	
Plant Capacity (MW)	50-1,500+
Capacity Factor (percent)	Resource dependent
Economics:	
Capital Cost ($/kW)	1,300-5,200
Fixed O&M ($/kW-yr)	5-20
Variable O&M ($/MWh)	0.25-2.0
Levelized Cost (cents/kWh)	2.4-13.0

New, large, domestic hydro installations are unlikely due to long construction times and environmental concerns.

11.1.7 Ocean Wave Energy

Ocean wave energy systems convert the kinetic and potential energy contained in the natural oscillations of ocean waves into electricity. A variety of proposed mechanisms for the utilization of this energy source exist, most of which are still in the demonstration or prototype testing stage. Wave energy research was intensive in 1970s and 1980s. Research funding has slowed and wave energy applications are not likely to be competitive in the near future. The optimal regions for wave power applications typically occur between 40 and 60 degrees latitude, although seas that consistently experience trade winds can also produce sufficient wave energy for power applications. The potential for offshore/deep wave plants is large, but the technical barriers and associated costs are also considerably high. Surge devices and oscillating water column devices are the primary technologies for converting wave energy to electricity.

The technical problems of dealing with adverse sea conditions, complexity and difficulty of electricity interconnection and transmission, and low reliability have kept wave energy systems from being developed commercially. Furthermore, the high capital costs of such systems have deterred the implementation of wave energy systems. Table 11-7 presents typical performance and cost characteristics of wave energy systems.

Table 11-7
Ocean Wave Energy--Performance and Costs

Commercial Status	Developmental
Performance:	
Plant Capacity (MW)	0.1-1
Capacity Factor (percent)	25
Economics:	
Capital Cost ($/kW)	2,600-6,000
Fixed O&M ($/kW-yr)	55-110
Variable O&M ($/MWh)	N/A
Levelized Cost (cents/kWh)	18.0-40.5

11.1.8 Ocean Tidal Energy

The generation of electrical power from ocean tides is very similar to traditional hydroelectric generation. A tidal power plant consists of a tidal pond created by a dam, a powerhouse in the dam containing a turbogenerator, and a sluice gate in the dam to allow the tidal flow to enter and leave. By opening the sluice gate in the dam, the rising tidal waters are allowed to fill the tidal basin. At high tide these gates are closed and the tidal basin behind the dam is filled to capacity. After the ocean waters have receded, the tidal basin is released through a turbogenerator in the dam. Power may be generated during ebb tide, flood tide, or both. The capacity factor of such a facility is around 24 percent. Times and amplitudes of high and low tide are predictable, although these characteristics will vary considerably from region to region. Commercial tidal plants have been developed; a 240 MW plant in France and an 18 MW plant in Canada are the two largest plants in the world.

Economic studies suggest that tidal power will be most economical at sites where mean tidal range exceeds about 16 feet. In North America, the northeast and northwest coasts of Canada are generally considered the only regions where tidal energy plants would be economically feasible. Tidal amplitudes as high as 50 feet are experienced on the east coast of Canada in the Bay of Fundy. Tidal energy plants are not likely economically feasible in the coastal Florida region.

Utilization of tidal energy for power generation has the environmental advantage of a zero emission technology. At the same time, the environmental impact that the facility has on the coastline must be carefully evaluated. The main barriers to the increased use of tidal energy are the high cost and long period for the construction of the tidal generating system. As noted previously, the economic viability of this option is highly dependent on the location chosen for application. Table 11-8 presents typical performance and cost characteristics for tidal energy plants.

Table 11-8
Ocean Tidal Energy--Performance and Costs

Commercial Status	Commercial
Performance:	
Plant Capacity (MW)	18-240
Capacity Factor (percent)	20-25
Economics:	
Capital Cost ($/kW)	1,600-4,500
Fixed O&M ($/kW-yr)	5-25
Variable O&M ($/MWh)	0.5-2.5
Levelized Cost (cents/kWh)	9.4-33.9

11.1.9 Ocean Thermal Energy

The temperature of the ocean may differ up to 40° F from the surface to a depth of 3,000 feet. The idea of utilizing this temperature difference for energy production has existed for over a century. Ocean thermal energy conversion (OTEC) concepts have been developed by using three basic types of cycles: closed cycles, open cycles, and hybrid cycles. Closed cycle plants use a low boiling point working fluid such as ammonia. The working fluid is heated and vaporized by the warm surface water, expanded in a turbine generator, and condensed by the deep cold water. Open cycle plants use warm surface water itself as the working fluid. The water vaporizes in a near vacuum at surface water temperatures. The expanding vapor drives a low-pressure turbine generator and is condensed by the deep cold water. As the condensed vapor no longer contains salt, it may be used for drinking, irrigation, and mariculture (i.e., sea farming, which also benefits from the nutrient-rich deep ocean water). Hybrid OTEC cycles use parts of both the closed and open cycles to optimize production of electricity and fresh water.

In OTEC systems, the relatively small temperature difference between the warm and cold thermal reservoirs and the large pumping power required combine for a very low overall system efficiency. Commercial OTEC plants must be located in an environment that is suitable for efficient system operation. The temperature of the warm surface seawater should differ at least 36° F from that of the cold deep water, and the extraction depth should not be more than about 3,280 feet below the surface. The best thermal gradients for OTEC sites are in tropical and subtropical areas.

OTEC systems are still in the development stage and current research efforts focus on cold water pipe technology, heat exchanger systems to improve heat transfer performance and decrease costs, and innovative turbine concepts for the large machines required for open cycle systems. A few 50-200 kW demonstration systems are being designed and/or tested in Hawaii. The high capital costs of OTEC systems are expected to delay their implementation. Furthermore, some environmental questions remain regarding the effect of high pumping flow rates and local temperature changes on the surrounding aquatic environment. Because the current low price of fossil fuels makes OTEC uneconomic, funding for OTEC research has been limited. Levelized costs for OTEC systems have been estimated at 10 to 22 cents/kWh.

11.2 Waste Technologies

Waste to energy (WTE) technologies can utilize a variety of refuse types to produce electrical power. The use of municipal solid waste (MSW), refuse derived fuel (RDF), landfill gas (LFG), tire derived fuel (TDF), and sewage sludge to generate power will be addressed in this section. Florida has grown from having one small WTE power plant in 1980 to 13 operating WTE facilities in 1997. These plants have a total capacity to burn nearly 19,000 tons of waste per day to generate about 500 MW of electrical power. Florida has established the largest capacity to burn MSW of any state in the US.*

It should be noted that economic feasibility of refuse to energy facilities is difficult to assess in general. Costs are highly dependent on transportation, processing, and tipping fees associated with a particular location. Values given in this section should be considered representative of the technology at a generic site.

* Florida Division of Waste Management, "1999 Solid Waste Management in Florida Annual Report," 1999, from: http://www.dep.state.fl.us/dwm/documents.htm.

11.2.1 Municipal Solid Waste to Energy Conversion

Converting refuse or municipal solid waste (MSW) to energy can be accomplished by a variety of technologies. These technologies have been developed and implemented as a means of reducing the quantity of municipal and agricultural solid waste. The avoided cost of disposal is primarily what will determine whether a waste to energy facility is economically feasible.

The degree of refuse processing determines the method used to convert municipal solid waste to energy. Unprocessed refuse is typically combusted in a water wall furnace (mass burning). After only limited processing to remove noncombustible and oversized items, the MSW is fed on to a reciprocating grate in the boiler. The combustion generates steam in the walls of the furnace, which is converted to electrical energy via a steam turbine generator system. Other furnaces used in mass burning applications are refractory furnaces and rotary kiln furnaces, which use other means to transfer the heat to the steam cycle or add a mixing process to the combustion. For smaller modular units, controlled air furnaces, which utilize two-stage burning for more efficient combustion, can be used in mass burning applications.

Large MSW facilities typically process 500 to 3,000 tons of MSW per day (the average amount produced by 200,000 to 1,200,000 residents). Table 11-9 has typical ranges of performance and cost for a facility burning 2,000 tons of MSW per day.

Table 11-9
MSW Mass Burning Unit--Performance and Costs

Commercial Status	Commercial
Performance:	
Plant Capacity (MW)	50
Net Plant Heat Rate (Btu/kWh)	16,000
MSW Tons per Day	2,000
Capacity Factor (percent)	60-80
Economics:	
Capital Cost ($/kW)	2,500-4,000
Fixed O&M ($/kW-yr)	100-175
Variable O&M ($/MWh)	25-50
Levelized Cost (cents/kWh)	4.0-14.8*

Note:
*Includes tipping fee of $25/ton.

11.2.2 Refuse Derived Fuel to Energy Conversion

Refuse derived fuel (RDF) is preferred in many refuse to energy applications because it can be combusted with technology traditionally used for coal. Spreader stoker fired boilers, suspension fired boilers, fluidized bed boilers, and cyclone furnace units have all been utilized to generate steam from RDF. Fluidized bed combustors are often preferred for RDF energy applications due to their high combustion efficiency, capability to handle RDF with minimal processing, and inherent ability to effectively reduce nitrous oxide and sulfur dioxide emissions. In all boiler types, the combustion temperature for MSW or RDF must be kept at a temperature less than 800° F in order to minimize boiler tube degradation due to chlorine compounds in the flue gas. Table 11-10 has typical ranges for performance and costs for a 50 MW RDF facility.

Table 11-10
RDF Stoker-Fired Unit--Performance and Costs

Commercial Status	Commercial
Performance:	
Plant Capacity (MW)	50
Net Plant Heat Rate (Btu/kWh)	17,000
MSW Tons per Day	2,000
Capacity Factor (percent)	60-80
Economics:	
Capital Cost ($/kW)	3,000-4,200
Fixed O&M ($/kW-yr)	150-225
Variable O&M ($/MWh)	25-50
Levelized Cost (cents/kWh)	5.4-16.2*

Note:
*Includes tipping fee of $25/ton.

11.2.3 Landfill Gas to Energy Conversion

Landfilled waste can be converted to energy by collecting the gases generated by the decomposition of waste in landfills. To reduce smog production and the risk of explosion, many landfills are currently required to collect landfill gas (LFG) and either flare or generate energy. The major constituents released from LFG wells are carbon dioxide and methane. The methane concentration is typically around 50 percent. To convert this clean burning, low heating value gas to electricity, the gas is piped from wells, filtered, compressed, and typically used in internal combustion engine generation sets. Depending on the scale of the gas collection facility, it may be feasible to generate power via a combustion turbine generator.

LFG was first used as a fuel in the late 1970s. Since then, there has been a steady development of the technology for its collection and use. LFG energy recovery is now regarded as one of the more mature and successful of the waste to energy technologies. There are more than 600 LFG energy recovery schemes in 20 countries, spanning five continents.

In general, landfills that have over one million tons of waste, more than 30 acres available for gas recovery, a waste depth greater than 40 feet, and the equivalent of 25+ inches of annual precipitation are sites at which LFG recovery is economically feasible. In many cases, the payback period of LFG energy facilities is between 2 and 5 years. The capital costs will be highly dependent on the conversion technology and landfill characteristics. Table 11-11 has typical ranges for performance and costs.

Table 11-11
Landfill Gas IC Engine--Performance and Costs

Commercial Status	Commercial
Performance:	
Plant Capacity (MW)	10
Net Plant Heat Rate (Btu/kWh)	8,500-13,000
Capacity Factor (percent)	60-80
Economics:	
Capital Cost ($/kW)	1,000-1,500
Fixed O&M ($/kW-yr)*	1.0-1.35
Variable O&M ($/MWh)	6-20
Levelized Cost (cents/kWh)	2.6-6.2

JEA currently has four internal combustion engines with a total generating capability of 3,000 kW producing power using LFG at the Girvin Landfill.

11.2.4 Tire Derived Fuel to Energy Conversion

The conversion of used tires to energy via combustion is attractive due to the high heating value (15,000 - 17,000 Btu/lb), low ash and sulfur content, and low cost of tire derived fuel (TDF). The co-firing of TDF with coal can be done in either a cyclone or conventional stoker boiler without system modification. TDF at co-firing percentages of 2 to 20 percent has been utilized by eight utilities in the US on a regular basis. In cyclone plants, the NO_x emissions and trace metal emissions have actually been reduced when burning TDF. On an energy basis, the cost of TDF (processed to 1 inch mesh) can be almost half that of coal. A new facility designed to co-fire TDF with coal would likely be a fluidized bed unit. Fluidized bed systems provide multi-fuel capability, in-situ sulfur removal, high combustion efficiencies, and low NO_x emissions. The estimated cost and performance of a 100 MW multi-fuel (10 percent TDF co-fire) circulating fluidized bed system are shown in Table 11-12.

Table 11-12
TDF Multi-Fuel CFB (10 Percent Co-Fire)--Performance and Costs

Commercial Status	Commercial
Performance:	
Plant Capacity (MW)	100
Net Plant Heat Rate (Btu/kWh)	13,300
TDF Tons per Day	100
Capacity Factor (percent)	60-80
Economics:	
Capital Cost ($/kW)	1,800-2,200
Fixed O&M ($/kW-yr)	40-75
Variable O&M ($/MWh)	3.0-6.5
Levelized Cost (cents/kWh)	4.3-7.9

11.2.5 Sewage Sludge to Energy Conversion

The disposal of sewage sludge is a significant environmental problem. The combustion of these materials to convert them into thermal energy is one solution that has been proposed. Dewatered sewage sludge has a heating value of up to 7,000 Btu/lb. Typically, the sludge has been co-fired with coal in a fluidized bed combustor. Some problems with fluidized bed agglomeration have been realized when utilizing large amounts of sludge. In addition to this operational problem, the low heating value of this waste has impeded the development of sludge combustion. Dewatered sewage sludge can also be burned with municipal solid waste (MSW), but the kinetics of combustion require that the ratio of sludge to MSW remain low (2 percent to 3 percent). A research project of the US Department of Energy (DOE) shows that the combination of enhanced combustion kinetics and combustion temperature control could increase the sludge/MSW ratios to 10 percent.* Other waste to energy methods are currently being investigated that involve digestion, fermentation, or gasification of the sludge to produce a higher grade fuel or gas for energy conversion. There are also a number of sewage recycling methods that convert sludge to soil, fertilizer, or building materials. These applications compete with energy conversion methods.

11.3 Advanced Technologies

Advanced technologies include developmental and near commercial technologies that offer significant potential for cost and efficiency improvements over conventional technologies. These include advanced gas and coal technologies, magnetohydrodynamics, fuel cells, and nuclear fusion.

11.3.1 Advanced Gas Technologies

Combined cycle combustion turbines have many advantages, including low capital cost, high efficiency, and short construction periods. Operation of an actual combustion turbine approaches that of an idealized thermodynamic cycle called the air-standard Brayton cycle. The Brayton cycle is based on an all gas cycle that uses air and combustion gases as the working fluid, as opposed to the Rankine cycle, which is a vapor-based cycle. Three Brayton cycles show promise as advanced technologies: the humid air cycle, Kalina cycle, and Cheng cycle. These cycles are discussed in this section.

11.3.1.1 Humid Air Cycle. The humid air turbine (HAT) cycle is an intercooled, regenerative cycle burning natural gas with a saturator that adds considerable moisture to the compressor discharge air so that the combustor inlet flow contains 20 to 40 percent water vapor. The warm humidified air from the saturator is then further heated by the turbine exhaust in a recuperator before being sent to the combustor. The water vapor adds to the turbine output while intercooling reduces the compressor work requirement. The heat addition in the recuperator reduces the amount of fuel heat input required. Table 11-13 presents typical performance and cost characteristics for the HAT cycle.

11.3.1.2 Kalina Cycle. The Kalina cycle is a combined cycle plant configuration that injects ammonia into the vapor side of the cycle. The ammonia/water working fluid provides thermodynamic advantages based on the non-isothermal boiling and condensing behavior of the working fluids two-component mixture, coupled with the ability to alter

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*National Renewable Energy Laboratory, "Oxygen-Enriched Co-combustion of Sewage Sludge and Municipal Solid Waste," Advances in Industrial Energy-Efficiency Technologies, from: http://es.epa.gov/techinfor/facts/kocmbust.html.

the ammonia concentration at various points in the cycle. This capability allows more effective heat acquisition, regenerative heat transfer, and heat rejection.

Table 11-13
Humid Air Turbine Cycle--Performance and Costs

Commercial Status	Development
Performance:	
Plant Capacity (MW)	250-650
Net Plant Heat Rate (Btu/kWh)	6,500
Capacity Factor (percent)	60-80
Economics:	
Capital Cost ($/kW)	400-600
Fixed O&M ($/kW-yr)	5.0-9.0
Variable O&M ($/MWh)	1.5-4.0
Levelized Cost (cents/kWh)	3.8-4.9

The cycle is similar in nature to the combined cycle process except exhaust gas from the combustion turbine enters a heat recovery vapor generator (HRVG). Fluid (70 percent ammonia, 30 percent water) from the distillation condensation subsystem (DCSS) enters the HRVG to be heated. A portion of the mixture is removed at an intermediate point from the HRVG and is sent to a heat exchanger, where it is heated with vapor turbine exhaust from the intermediate-pressure vapor turbine. The moisture returns to the HRVG, where it is mixed with the balance of flow, superheated, and expanded in the vapor turbine generator (VTG). Additional vapor enters the HRVG from the high-pressure vapor turbine, where it is reheated and supplied to the inlet of the intermediate-pressure vapor turbine. The vapor exhausts from the vapor turbine and condenses in the DCSS. Table 11-14 presents typical performance and cost characteristics for the Kalina cycle.

11.3.1.3 Cheng Cycle. The Cheng cycle, which is similar to the steam-injected gas turbine, increases efficiency over the gas turbine cycle by injecting large volumes of steam into the combustor and/or turbine section. The basic Cheng cycle is composed of a compressor, combustor, turbine, generator, and heat recovery steam generator (HRSG). The HRSG provides injection steam to the combustor as well as process steam. The amount of steam injection is limited to the allowable loading of the turbine blades.

Table 11-14 Kalina Cycle--Performance and Costs	
Commercial Status	Development
Performance:	
Plant Capacity (MW)	50-500
Net Plant Heat Rate (Btu/kWh)	6,700
Capacity Factor (percent)	60-80
Economics:	
Capital Cost ($/kW)	600-750
Fixed O&M ($/kW-yr)	4-10
Variable O&M ($/MWh)	1.5-4.0
Levelized Cost (cents/kWh)	4.2-5.4

The typical application of the Cheng cycle is in a cogeneration plant where increased power can be produced during low cogeneration demand and/or peak demand periods. Since 1984, over 50 small cogeneration plants have applied the Cheng cycle in California, Japan, Australia, and Europe. The Cheng cycle has also been proposed as a retrofit for simple cycle combustion turbines. Table 11-15 presents typical performance and cost characteristics for the Cheng cycle.

Table 11-15 Cheng Cycle--Performance and Costs	
Commercial Status	Development (larger units)
Performance:	
Plant Capacity (MW)	25-250
Net Plant Heat Rate (Btu/kWh)	8,000-9,000
Capacity Factor (percent)	60-80
Economics:	
Capital Cost ($/kW)	700-1,100
Fixed O&M ($/kW-yr)	6-10
Variable O&M ($/MWh)	1.5-4.0
Levelized Cost (cents/kWh)	5.0-7.2

11.3.2 Advanced Coal Technologies

Coal continues to supply a large portion of the energy demand in the US. Current research is focused on making the conversion of energy from coal more clean and efficient. Supercritical pulverized coal boilers and pressurized fluidized bed systems are two systems that have been developed to improve coal conversion efficiency.

11.3.2.1 Supercritical Pulverized Coal Boilers. New generation pulverized coal boilers can be designed at supercritical steam pressures of 3,000 to 4,500 psig, compared to the conventional 2,400 psig subcritical boilers. This increase in pressure can bring the overall efficiency of the unit from below 40 percent to nearly 45 percent. This efficiency increase, coupled with the latest in emissions control technologies, is expected to keep pulverized coal systems environmentally and economically competitive with other generation technologies. Further significant advances in supercritical steam conditions depend on the availability of fully tested and approved advanced steel alloys. It is currently envisaged that supercritical power plants with an efficiency of 48 percent might be in operation by 2005, with 50 percent possible by 2015.* Table 11-16 presents typical performance and cost characteristics of supercritical pulverized coal power plants.

11.3.2.2 Pressurized Fluidized Bed Combustion. Pressurized fluidized bed combustion (PFBC) is a variation of fluid bed technology in which combustion occurs in a pressure vessel at 10 to 15 atm. The PFBC process involves burning crushed coal in a limestone or dolomite bed. High combustion efficiency and excellent sulfur capture are advantages of this technology. In combined cycle configurations, PFBC exhaust is expanded to drive both the compressor and gas turbine generator. Heat recovery steam generators transfer heat from this exhaust to generate steam in addition to the steam generated from the PFBC boiler. Overall thermal efficiencies of PFBC combined cycle configurations are 45 to 47 percent. These second-generation PFBC systems are in the development stage. Table 11-17 presents typical performance and cost characteristics for pressurized fluidized bed combustion.

11.3.3 Magnetohydrodynamics

Magnetohydrodynamic (MHD) generators produce electrical power by passing a high velocity conducting fluid through a very strong magnetic field. The conducting fluid is an ionized gas (plasma) or a liquid metal. Current prototypes and conceptual designs typically use the high temperature combustion of coal to produce a partially ionized flue gas, which can be passed through a magnetic field. When this highly conductive plasma-like flue gas is accelerated in a nozzle and then passed through a

*International Energy Agency, "Competitiveness of Future Coal-Fired Units in Different Countries," January 1999.

Table 11-16
Supercritical Pulverized Coal--Performance and Costs

Commercial Status	Commercial
Performance:	
Plant Capacity (MW)	300-1,000
Net Plant Heat Rate (Btu/kWh)	7,500-9,500
Capacity Factor (percent)	60-80
Economics:	
Capital Cost ($/kW)	1,200-1,450
Fixed O&M ($/kW-yr)	18-24
Variable O&M ($/MWh)	3.0-4.0
Levelized Cost (cents/kWh)	4.3-6.4

Table 11-17
Pressurized Fluidized Bed Combustion--Performance and Costs

Commercial Status	Development
Performance:	
Plant Capacity (MW)	150-350
Net Plant Heat Rate (Btu/kWh)	8,000-9,000 (6,700 2nd generation)
Capacity Factor (percent)	60-80
Economics:	
Capital Cost ($/kW)	1,350-1,600
Fixed O&M ($/kW-yr)	20-35
Variable O&M ($/MWh)	3.8-5.0
Levelized Cost (cents/kWh)	4.8-7.1

channel perpendicular to a magnetic field, an electric field is induced. To successfully ionize the flue gas, the combustion temperatures must be around 5,000° F. A seed material such as potassium is added to the flue gas flow to increase gas conductivity.

An MHD system in simple cycle configuration only converts a portion of the flue gas energy to electricity. To optimize the performance of an MHD system, the energy in the hot flue gas exiting the MHD generator can be utilized to generate steam for additional power generation. This combined cycle configuration can result in an efficiency increase of 15 to 30 percent over conventional steam plant efficiencies. The overall thermal efficiency could potentially be as high as 60 percent.

Emission levels can be effectively controlled in MHD systems. NO_x levels are controlled by designing time-temperature profiles within the radiant boiler that promote the decomposition of NO_x formed in the combustion process. The potassium seed in the flue gas reacts with the sulfur compounds to produce a solid potassium sulfate. The spent seed is regenerated and converted to nonsulfur containing potassium species. Particulate emissions can be controlled by a electrostatic precipitator.

Currently, MHD power generation technology is still in the development stage. Although a variety of the individual subcomponents of this technology have been developed and tested, the operation of a fully integrated system has not been demonstrated. The driving force behind MHD combined cycle technology is improved performance. Currently, there are no commercial applications of MHD that demonstrate that this improved performance is feasible. The disadvantages of MHD power plants are their complexity compared to standard steam plants, longer construction times, higher capital costs, and their generation of direct current, which must be converted to alternating current to be compatible with most grid systems. Further development work is required.

11.3.4 Fuel Cells

Fuel cells convert hydrogen-rich fuel sources directly to electricity through an electrochemical reaction. Fuel cell power systems have the capability of high efficiencies because they are not limited by the Carnot efficiency that limits thermal power systems. Commercial stationary fuel cell plants are fueled by natural gas. There are four major fuel cell types under development: phosphoric acid, molten carbonate, solid oxide, and proton exchange membrane. The most developed fuel cell technology for stationary power is the phosphoric acid fuel cell (PAFC). Currently, PAFC plants have efficiencies on the order of 40 percent. Fuel cells can sustain high efficiency operation even under part load conditions and they have a rapid response to load changes. The construction of fuel cells is inherently modular, making it easy to size plants according to power requirements. Current PAFC plants range from around 200 kW to 10 MW in size. PAFC cogeneration facilities can attain efficiencies approaching 88 percent when the thermal energy from the fuel cell is utilized. Also, the potential development of fuel cell/gas turbine combined cycles could reach electrical conversion efficiencies of 60 to 70 percent.

In addition to the potential for low heat rates and low O&M costs, the environmental benefits of fuel cells remain one of the primary reasons for their development. With natural gas as the fuel source, carbon dioxide and water are the only emissions. High capital costs are the primary disadvantage of fuel cell systems. These costs are expected to drop significantly in the future as development efforts continue, partially spurred on by interest by the transportation sector. Fuel cell plants are typically less than 10 MW in size. The performance and costs of a 200 kW unit are shown in Table 11-18.

Table 11-18
Fuel Cell--Performance and Costs

Commercial Status	Development/Commercial
Performance:	
Plant Capacity (MW)	0.20-13
Net Plant Heat Rate (Btu/kWh)	7,000-9,500
Capacity Factor (percent)	60-80
Economics:	
Capital Cost ($/kW)	3,200-5,000
Fixed O&M ($/kW-yr)	275-325
Variable O&M ($/MWh)	0.78-0.84
Levelized Cost (cents/kWh)	13.9-24.1

Note:
Evaluation based on phosphoric acid fuel cell.

11.3.5 Nuclear Fusion

Theoretically, the potential for nuclear fusion power is great. Energy is released when two light nuclei such as deuterium and tritium undergo fusion to form heavier nuclei such as helium. This new nuclei has less mass than the total of the two original nuclei, resulting in a release of energy. Large amounts of energy are released if this fusion reaction can be sustained, but fusion also has high initiation energy requirements. A temperature greater than 50 million Kelvin is required to sustain a deuterium-tritium reaction.

The concept of a fusion power plant is appealing not only because huge amounts of energy can be produced from relatively small amounts of readily available resources (water and lithium), but also because the fusion process has only a very limited impact on the environment. In contrast to conventional nuclear fission, the fusion power plant is not likely to undergo an uncontrolled meltdown situation. Furthermore, the minimal amount of radioactive fusion waste does not emit strong radiation during its moderate half-life of approximately 12 years.

Despite the attractive possibilities of fusion, it has yet to yield a net energy output. At the current level of development, the energy required to sustain the fusion reaction is still over twice the amount produced. Recently, fusion research funding has been cut dramatically in the US. The Princeton Tokamak Fusion Test Reactor was decommissioned in the spring of 1997 due to cuts in federal funding of the program. Alternative basic research on various aspects of fusion continues, and the international effort to develop a viable fusion power facility is still significant. Nonetheless, it is likely to be well into the next century before fusion develops to the point of commercial viability.

11.4 Energy Storage Systems

Energy storage technologies convert and store electricity to help alleviate disparities between electricity supply and demand. Energy storage systems increase the value of power by allowing better utilization of off-peak baseload generation and through mitigation of instantaneous power fluctuations. Different types of technologies are available to provide for a variety of storage durations. Durations range from microseconds (superconducting magnets, flywheels, and batteries), to minutes (flywheels and batteries), to hours and seasonal storage (batteries, compressed air, and pumped hydro). These technologies are discussed in this subsection.

11.4.1 Pumped Hydro Energy Storage

Pumped hydro energy storage is the oldest and most prevalent of the central station energy storage options. More than 22 GW of pumped storage generation is installed in the United States.* A pumped storage hydroelectric facility requires a reservoir/dam system similar to a conventional hydroelectric facility. Excess energy from the grid (available at low cost) is used to pump water from a lower reservoir to an upper reservoir above a dam. When this energy is required during high electrical demand periods, the potential energy of the water in the upper reservoir is converted to electricity as the stored water flows through a turbine to the lower reservoir.

*US Department of Energy, EPRI, "Renewable Energy Technology Characterizations," December 1997.

Capital cost and lead time are the primary considerations in implementing this storage technology. Furthermore, without careful siting, planning, and construction, the environmental impact of this technology can be significant. Geographic and geologic conditions largely preclude many areas, including Florida, from consideration of this technology. Table 11-19 presents typical performance and cost estimates for pumped hydro energy storage.

11.4.2 Battery Energy Storage

A battery energy storage system consists of the battery, dc switchgear, dc/ac converter/charger, transformer, ac switchgear, and a building to house these components. During peak power demand periods, the battery system can discharge ac power to the utility system for around 4 to 5 hours. The batteries are then recharged during nonpeak hours. In addition to the high initial cost, a battery system will require replacement every 4 to 10 years, depending on the duty cycle.

Currently, the only commercially available utility-size battery systems are lead-acid systems. Research to develop better performing and lower cost batteries such as sodium-sulfur and zinc-bromine batteries is currently underway. More than 70 MW of battery energy storage systems have been installed by utilities in ten states.* The largest facility is a 21 MW lead-acid system with 140 MWh of storage capability. The overall efficiency of battery systems averages 72 percent from charge to discharge. The cost and performance of a 5 MW (15 MWh) system are provided in Table 11-20.

11.4.3 Compressed Air Energy Storage

Compressed air energy storage (CAES) is a technique used to supply electrical power to meet peak loads within an electric utility system. This method uses the power surplus from baseloaded coal and nuclear plants during off-peak periods to compress and store air in an underground formation. The compressed air is later heated (with a fuel) and expanded through a gas turbine expander to produce electrical power during peak power demand. A simple compressed air storage plant consists of an air compressor, turbine, motor/generator unit, and a storage vessel, typically underground. Exhaust gas heat recuperation may be added to increase cycle efficiency.

*US Department of Energy, EPRI, "Renewable Energy Technology Characterizations," December 1997.

Table 11-19
Pumped Hydro Energy Storage--Performance and Costs

Commercial Status	Commercial
Performance:	
Plant Capacity (MW)	30-1,500+
Capacity Factor (percent)	10-25
Economics:	
Capital Cost ($/kW)	800-1600
Fixed O&M ($/kW-yr)	3-8
Variable O&M ($/MWh)	0.5-2.0
Levelized Cost (cents/kWh)	7.6-26.9

Table 11-20
Lead-Acid Battery Energy Storage--Performance and Costs

Commercial Status	Commercial
Performance:	
Plant Capacity (MW)	5
Energy Capacity (MWh)	15
Capacity Factor (percent)	10-25
Economics:	
Capital Cost ($/kW)	800-1,400
Fixed O&M ($/kW-yr)	13.5
Variable O&M ($/MWh)	310
Levelized Cost (cents/kWh)	49.4-65.8

The theoretical basis associated with the thermodynamic cycle for a compressed air storage facility is that of a simple gas turbine system. Typically, gas turbines will consume 50 to 60 percent of their net power output to operate the air compressor. In a compressed air storage generating plant, the air compressor and the turbine are not connected, and the total power generated from the gas turbine is supplied to the electrical grid. By using off-peak energy to compress the air, the need for expensive natural gas or imported oil is reduced by as much as 2/3 compared with conventional gas turbines.* This results in a very attractive heat rate for CAES plants, ranging from 4,000 to 5,000 Btu/kWh. Because fuel (typically natural gas) is supplied to the system during the energy generation mode, CAES plants actually provide more electrical power to the grid than was used during the cavern charging mode.

The location of a CAES plant must be suitable for cavern construction or for the reuse of an existing cavern. However, suitable geology is widespread throughout the United States, with over 75 percent of the land area containing appropriate geological formations.† There are three types of formations that can be used to store compressed gases: solution mined reservoirs in salt, conventionally mined reservoirs in salt or hard rock, and naturally occurring porous media reservoirs (aquifers).

The basic components of a CAES plant are proven technologies and CAES units have a reputation for achieving good availability. The first commercial scale CAES plant in the world is a 290 MW plant in Huntorf, Germany. This plant has been operated since 1978, providing 2 hours of generation with 8 hours of charging. In 1991, a 110 MW CAES facility in McIntosh, Alabama, began operation. This plant remains the only US CAES installation, although several new plants have been recently announced. Table 11-21 shows the performance and cost characteristics of a CAES system.

11.4.4 Flywheel Energy Storage

The flywheel provides a means to store energy in the form of rotational inertia. Flywheels have a number of advantages as energy storage devices. First, compared to other storage technologies, such as lead-acid batteries or pumped storage hydro systems, they are very compact, have a high energy density, and can transfer large amounts of energy very quickly. They have very long life cycles and low operating and maintenance costs. These advantages make flywheel systems particularly advantageous to the transportation industry, where weight reduction and quick energy transfer (fast acceleration) are important parameters.

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* Nakhamkin, M., Anderson, L., Swenson, E., "AEC 110 MW CAES Plant: Status of Project," Journal of Engineering for Gas Turbines and Power, October 1992, Vol. 114.

† Mehta, B., "Compressed Air Energy Storage: CAES Geology," EPRI Journal, October/November 1992.

Table 11-21
Compressed Air Energy Storage--Performance and Costs

Commercial Status	Commercial
Performance:	
Plant Capacity (MW)	100-500
Net Plant Heat Rate (Btu/kWh)	4,000-5,000
Capacity Factor (percent)	10-25
Economics:	
Capital Cost ($/kW)	400-600
Fixed O&M ($/kW-yr)	3-6
Variable O&M ($/MWh)	3-6
Levelized Cost (cents/kWh)	6.4-14.2

Although high tech prototype flywheels can exceed 80 percent efficiency from storage to release, they are still in the research and development stage. In order for flywheels to be economically viable for general purpose energy storage, capital cost must be reduced, performance must be enhanced with new materials and low friction bearings, and motor/generator controls need to be enhanced to better utilize flywheel energy under the always changing flywheel speed. Current research is focusing on the development of magnetic bearings using high temperature superconductor technology. At this point in flywheel development, flywheels cannot compete against battery systems, particularly in the power industry. Conventional battery energy storage systems have significantly lower costs on a price per unit of stored energy.

11.4.5 Superconducting Magnetic Energy Storage

Superconducting magnetic energy storage (SMES) stores energy by allowing a current to pass through a "zero resistance" toroidal winding, storing the energy in a magnetic field. SMES systems for power industry storage applications are still in the research and development stage. The cost of these high tech systems must be reduced significantly before they will become commercially viable for large energy storage. Smaller SMES systems are commercially available. Such systems are practical for eliminating power surges and dips in industries where these brief discontinuities can be harmful to sensitive equipment and processes. Typically, they can store only a few seconds of energy at full load.

11.5 Nuclear (Fission)

The environmental and safety issues (and associated costs) involved with producing power from nuclear reactors has kept new nuclear plants from being constructed in the US. Table 11-22 provides a rough estimate of nuclear power plant costs.

Table 11-22
Nuclear Power Plant Performance and Costs

Commercial Status	Commercial
Performance:	
Typical Plant Capacity (MW)	>600
Net Plant Heat Rate (Btu/kWh)	10,500
Capacity Factor (percent)	65 - 80
Economics:	
Capital Cost ($/kW)	3,300
Fixed O&M ($/kW-yr)	95
Variable O&M ($/MWh)	13.0
Levelized Cost (cents/kWh)	5.8 - 15.0

11.6 Conventional Technologies

Several conventional capacity addition alternatives were selected for consideration. The size of the alternatives selected considered the need for capacity. Conventional generating unit alternatives considered for capacity expansion included the following:

- Pulverized coal.
- Atmospheric circulating fluidized bed.
- Combined cycle.
- Simple cycle combustion turbine.

Combustion turbine based alternatives were based on the size and performance of specific machines, but were not intended to limit consideration to only those machines. There are a number of combustion turbines available from different manufacturers with similar sizes and performance characteristics. The pulverized coal and fluidized bed units are assumed to be located at a generic Greenfield site. Combined cycle units were assumed to be installed at a generic Greenfield site. Simple cycle combustion turbines were assumed to be installed at a generic Greenfield site, except that one additional simple cycle General Electric 7FA combustion turbine was assumed to be installed at

Brandy Branch to take advantage of existing infrastructure. The Brandy Branch site was originally designed to allow for either the addition of a fourth additional simple cycle F Class combustion turbine or conversion of two of the existing simple cycle F class combustion turbines to combined cycle operation.

Performance and O&M cost estimates have been compiled for each capacity addition alternative. The estimates provide representative values for each generation alternative and show expected trends in performance and costs within a given technology as well as between technologies. Degradation is also included. Actual unit performance and availability will vary based on site conditions, regulatory requirements, and operation practices. Capital costs for conventional technology alternatives are in 2000 dollars.

11.6.1 Performance Estimates

11.6.1.1 Net Plant Output. Net plant output is equal to the gross turbine output less auxiliary power.

11.6.1.2 Equivalent Availability. Equivalent availability is a measure of a generating unit's capacity to produce power considering limitations such as equipment failures, repairs, and maintenance activities. The equivalent availability is equal to the maximum possible capacity factor for a unit as limited by forced, scheduled, and maintenance outages and deratings. The equivalent availability is the capacity factor that a unit would achieve if the unit were to generate every megawatt-hour it was available to generate.

11.6.1.3 Equivalent Forced Outage Rate. Equivalent forced outage rate is a reliability index, which reflects the probability that a unit will not be capable of providing power when called upon. It is determined by dividing the sum of forced outage hours plus equivalent forced outage hours, by the sum of forced outage hours plus service hours. Equivalent forced outage hours take into account the effect of partial outages and are equal to the number of full forced outage hours that would result in the same lost generation as actually experienced during partial outage hours.

11.6.1.4 Planned Maintenance Outage. Estimates are provided for the time required each year to perform scheduled maintenance on an average annual basis.

11.6.1.5 Startup Fuel. Estimates for startup fuel, where applicable, in MBtu, are based on the fuel required to bring the unit from a cold condition to the speed at which synchronization is first achievable under normal operation conditions.

11.6.1.6 Net Plant Heat Rate. Estimates for net plant heat rates are based on the higher heating value of the fuel. Heat rate estimates are provided for summer (97 F ambient) and winter (23 F ambient) conditions for combustion turbines and combined cycle units. Allowance for heat rate degradation over time because of aging has been included. Heat rates may vary as a result of factors such as turbine selection, fuel properties, plant cooling method, auxiliary power consumption, air quality control system, and local site conditions.

11.6.2 Cost Estimates

11.6.2.1 Capital Costs. Total capital cost is the summation of direct and indirect cost and interest during construction for commercial operation. The construction period is the time from start of construction to commercial operation. The construction period was used to estimate costs for interest during construction (IDC). Capital costs were developed on the basis of the current competitive generation market. Additional direct costs are outlined as follows:

- Substation costs.
- Direct costs for the combined cycle alternatives include continuous emissions monitoring equipment. Combined cycles include a selective catalytic reducer (SCR).
- Direct costs for natural gas alternatives are based on using No. 2 oil as a backup fuel and include fuel oil storage tanks for a 3 day supply.
- Direct costs for the circulating fluidized bed include dry scrubber and a selective noncatalytic reduction (SNCR).
- Direct cost for the pulverized coal unit includes dry scrubber, fabric filter, and SCR.
- Makeup water treatment.
- Wastewater treatment.
- Startup spare parts.

The following lists the indirect costs included in the capital cost estimates.

- General indirects.
- Relay checkouts and testing.
- Instrumentation and control equipment calibration and testing.
- Systems and plant startup.
- Operating crew during test and initial operation period.
- Operating crew training.
- Electricity, water, and fuel used during construction. Fuel used during startup by the generating unit is assumed to be offset by the value of startup energy produced.
- Insurance.
  - General liability.

  - Builder's risk.
  - Liquidated damages.
- Engineering and related services.
- Owner office engineers.
- Outside consultants.
- Other related costs incurred in the permit and licensing process.
- Field construction management services.
- Field management staff, including supporting staff personnel.
- Field contract administration.
- Field inspection and quality assurance.
- Project control.
- Technical direction.
- Management of startup and testing.
- Miscellaneous.
- Cleanup expense for the portion not included in the direct cost construction contracts.
- Safety and medical services.
- Guards and other security services.
- Insurance premiums.
- Other required labor related to insurance.
- Performance bond and liability insurance for equipment and tools.
- Telephone and other utility bills associated with temporary services.
- Permitting and licensing.
- Owners cost.

11.6.2.2 O&M Costs. For simple and combined cycle units, O&M estimates are based on a unit life of 30 years. A baseload capacity factor of 90 percent was assumed for combined cycle units and a peak load capacity factor of 10 percent was assumed for simple cycle units. O&M estimates for coal units are based on a unit life of 30 years and a baseload capacity factor of 90 percent.

Fixed O&M costs are those that are independent of plant electrical production. The largest fixed costs are wages and wage related overheads for the permanent plant staff. Fuel costs typically are determined separately and are not included in either fixed or variable O&M costs. The O&M costs presented are typically referred to as nonfuel O&M costs. Variable O&M costs include disposal of combustion wastes and consumables such as scrubber additives, chemicals, lubricants, water, and maintenance repair parts. Variable O&M costs vary as a function of plant generation.

11.6.2.3 Coal/Petcoke-Fueled O&M. O&M and performance estimates for the coal/petcoke-fueled alternatives were based on the following assumptions:

- Fixed O&M costs include operating staff salary costs, basic plant supplies, and administrative costs. Staffing estimates provided are based on recent utility experience with modern facilities. Variable operations costs include an assumed lime cost for flue gas desulfurization (FGD) and waste disposal. Variable maintenance costs are the costs associated with the inspection/maintenance of plant components based on the operating time of the plant, such as steam turbine inspection costs.
- Additional variable O&M costs have been included on each coal unit for emissions control equipment. The pulverized coal unit requires additional costs for an SCR and dry scrubber. The fluidized bed unit requires additional variable costs for the operation of an SNCR and dry scrubber.

11.6.2.4 Combined Cycle and Simple Cycle O&M. O&M and performance estimates for the combined cycle and simple cycle units were based on the following assumptions:

- Primary fuel--Natural gas.
- NO_x control method--Dry low NO_x combustors for combustion turbine generation (CTG).
- NO_x control method--(SCR) for combined cycle units.
- Capacity and heat rate degradation has been included in the performance estimates.
- CTG specialized labor cost estimated at $38/man-hour for Siemens-Westinghouse and $35/man-hour for General Electric (provided by manufacturers).
- CTG operational spares, combustion spares, and hot gas path spares are not included in the O&M cost.
- Heat recovery steam generator (HRSG) annual inspection costs are estimated based on manufacturer input and Black & Veatch data.
- Steam turbine annual, minor, and major inspection costs are estimated based on Black & Veatch data. Inspections occur every 8,000 hours of operation, minor overhauls occur every 24,000 hours of operation, and major overhauls occur every 48,000 hours of operation.
- The costs for demineralizer cycle makeup water and cooling tower raw water are included.

The variable O&M analysis is based on a repeating maintenance schedule for the CTG and includes replacement and refurbishment costs. The annual average cost is the estimated average cost over the 30 year cycle life.

Variable O&M costs are based on 200 starts per year and 10 percent capacity factor for simple cycle combustion turbines, and 30 starts per year and 90 percent capacity factor for combined cycles.

11.6.3 Pulverized Coal

A 250 MW pulverized coal unit with dry scrubber, fabric filter and SCR was selected as a solid fueled alternative. The unit is assumed to be located at a generic Greenfield site. Coal is assumed to be delivered by rail, and cooling is achieved with mechanical draft cooling towers. Table 11-23 presents the cost summary and operating characteristics of the 250 MW pulverized coal unit.

11.6.4 Atmospheric Circulating Fluidized Bed

A 250 MW atmospheric circulating fluidized bed unit (CFB) with dry scrubber, fabric filter, and SNCR was selected as another solid fuel alternative. The CFB is capable of burning a wide range of fuels. For expansion planning purposes, the CFB is assumed to burn petroleum coke. Like the pulverized coal unit, the CFB is assumed to be located at a generic Greenfield site. Petroleum coke is assumed to be delivered by rail and cooling is achieved with mechanical draft cooling towers. Table 11-24 presents the cost summary and operating characteristics of the 250 MW CFB unit.

11.6.5 Combined Cycle

Three combined cycle units were selected as generating unit alternatives:

- 1 x 1 General Electric 7FA.
- 2 x 1 General Electric 7FA.
- 1 x 1 Siemens-Westinghouse 501G.

The combined cycles all utilize conventional, heavy-duty, industrial type combustion turbines. Several other vendors provide combustion turbines with similar performance characteristics. The combined cycles would be dual fueled with natural gas as the primary fuel. Specifications for performance and operating costs are based on natural gas fuel and baseload operation. The combined cycles assume that emission requirements will be met with dry low NO_x combustors and SCR. The units would be located at a generic Greenfield site. Natural gas compressors are not included in the cost estimates because natural gas pipeline pressure is assumed adequate. Tables 11-25 through 11-27 present the cost summary and operating characteristics of the combined cycle units alternatives.

11.6.6 Simple Cycle Combustion Turbine

Two simple cycle combustion turbines were selected as generating unit alternatives:

- GE 7FA at Brandy Branch.
- GE 7FA at Greenfield site.

The 7FA combustion turbines are heavy-duty, industrial combustion turbines. The combustion turbines are dual fueled with specifications for performance and operating costs based on natural gas operation. Tables 11-28 and 11-29 present the cost summary and operating characteristics for the simple cycle alternatives.

Table 11-23
250 MW Pulverized Coal
Cost Summary and Operating Characteristics

Generating Unit Characteristics		
Steam pressure, psia	2,535	
Steam temperature, °F	1,000	
Reheat steam temperature, °F	1,000	
Direct capital cost, 2000 $1,000	205,421	
Indirect capital cost, 2000 $1,000	70,396	
Total capital cost, 2000 $1,000	275,817	
O&M cost baseload duty:		
Fixed O&M cost, 2000 $/kW-yr	26.76	
Variable O&M cost, 2000 $/MWh	3.67	
Equivalent availability, percent	85	
Equivalent forced outage rate, percent	7	
Planned maintenance outage, weeks/year	4	
Startup fuel (cold start), MBtu:	1,500	
Construction period, months	30	
Load points at 59° F, percent	Net Plant Output, kW	Net Plant Heat Rate Btu/kWh (HHV)
100	250,000	10,141
75	187,000	10,317
50	125,000	10,878
25	62,500	13,062

Table 11-24
250 MW Fluidized Bed Coal
Cost Summary and Operating Characteristics

Generating Unit Characteristics		
Steam pressure, psia	2,535	
Steam temperature, °F	1,000	
Reheat steam temperature, °F	1,000	
Direct capital cost, 2000 $1,000	211,314	
Indirect capital cost, 2000 $1,000	70,220	
Total capital cost, 2000 $1,000	281,534	
O&M cost baseload duty:		
Fixed O&M cost, 2000 $/kW-yr	30.15	
Variable O&M cost, 2000 $/MWh	5.97	
Equivalent availability, percent	85	
Equivalent forced outage rate, percent	7	
Planned maintenance outage, weeks/year	4	
Startup fuel (cold start), MBtu (HHV)	2,670	
Construction period, months	30	
Load points at 59 °F, percent	Net Plant Output kW	Net Plant Heat Rate Btu/kWh (HHV)
100	250,000	10,543
75	187,500	10,803
50	125,000	11,593
25	62,500	14,516

Table 11-25
General Electric 7FA 1 by 1 Combined Cycle
Cost Summary and Operating Characteristics

Generating Unit Characteristics		
Steam pressure, psia	1,815	
Steam temperature, °F	1,050	
Reheat steam temperature, °F	1,050	
Direct capital cost, 2000 $1,000	114,851	
Indirect capital cost, 2000 $1,000	22,428	
Total capital cost, 2000 $1,000	137,279	
O&M cost-baseload duty:		
Fixed O&M cost, 2000 $/kW-y	7.38	
Variable O&M cost, 2000 $/MWh	2.22	
Equivalent availability, percent	93	
Equivalent forced outage rate, percent	2.86	
Planned maintenance outage, weeks/y	2.14	
Startup fuel (cold start), MBtu	3,649	
Construction period, months	23	
	Net plant output, kW[1]/Net plant heat rate, Btu/kWh[1] (HHV)	
Load points, percent	97° F	30° F
100	256,201/7,402	282,099/7,364
75	192,157/7,766	211,580/7,765
50	128,101/8,540	141,049/8,500
25	64,056/11,250	70,530/11,146

Note:
[1]Includes output and heat rate degradations.

Table 11-26
General Electric 7FA 2 by 1 Combined Cycle
Cost Summary and Operating Characteristics

Generating Unit Characteristics		
Steam pressure, psia	1,815	
Steam temperature, °F	1,050	
Reheat steam temperature, °F	1,050	
Direct capital cost, 2000 $1,000	202,450	
Indirect capital cost, 2000 $1,000	32,306	
Total capital cost, 2000 $1,000	234,756	
O&M cost-baseload duty:		
Fixed O&M cost, 2000 $/kW-y	4.86	
Variable O&M cost, 2000 $/MWh	2.07	
Equivalent availability, percent	89	
Equivalent forced outage rate, percent	4.57	
Planned maintenance outage, weeks/y	3.71	
Startup fuel (cold start), MBtu	10,729	
Construction period, months	25	
	Net plant output, kW[1]/Net plant heat rate, Btu/kWh[1] (HHV)	
Load points, percent	97° F	30° F
100	510,070/7,370	575,917/7,223
75	379,113/7,726	431,935/7,534
50	255,006/8,487	287,964/8,236
25	127,503/9,051	143,982/8,743

Note:
[1]Includes output and heat rate degradations.

Table 11-27
Siemens-Westinghouse 1 by 1 501G Combined Cycle
Cost Summary and Operating Characteristics

Generating Unit Characteristics		
Steam pressure, psia	1,815	
Steam temperature, °F	1,050	
Reheat steam temperature, °F	1,050	
Direct capital cost, 2000 $1,000	137,740	
Indirect capital cost, 2000 $1,000	50,669	
Total capital cost, 2000 $1,000	188,409	
O&M cost-baseload duty:		
Fixed O&M cost, 2000 $/kW-y	2.68	
Variable O&M cost, 2000 $/MWh	2.71	
Equivalent availability, percent	92	
Equivalent forced outage rate, percent	3.32	
Planned maintenance outage, weeks/y	2.43	
Startup fuel (cold start), MBtu	4,511	
Construction period, months	25	
	Net plant output, kW[1]/Net plant heat rate, Btu/kWh[1] (HHV)	
Load points, percent	97° F	30° F
100	295,310/6,987	351,806/6,704
75	221,488/7,571	263,859/7,034
50	147,655/8,327	175,903/7,699
25	73,832/10,970	87,956/10,095

Note:
[1]Includes output and heat rate degradations.

Table 11-28
General Electric 7FA Simple Cycle at Brandy Branch
Cost Summary and Operating Characteristics

Generating Unit Characteristics		
Steam pressure, psia	--	
Steam temperature, °F	--	
Reheat steam temperature, °F	--	
Direct capital cost, 2000 $1,000	43,189	
Indirect capital cost, 2000 $1,000	17,560	
Total capital cost, 2000 $1,000	60,749	
O&M cost-baseload duty:		
Fixed O&M cost, 2000 $/kW-y	1.32	
Variable O&M cost, 2000 $/MWh	11.68	
Equivalent availability, percent	96	
Equivalent forced outage rate, percent	1.96	
Planned maintenance outage, weeks/y	0.86	
Startup fuel (cold start), MBtu	224	
Construction period, months	12	
	Net plant output, kW[1]/Net plant heat rate, Btu/kWh[1] (HHV)	
Load points, percent	97° F	30° F
100	145,926/11,200	174,167/10,616
75	109,442/12,333	130,630/11,482
50	72,968/14,807	87,084/13,839
25	36,484/20,840	43,547/18,968

Note:
[1]Includes output and heat rate degradations.

Table 11-29
General Electric 7FA Simple Cycle at Greenfield Site
Cost Summary and Operating Characteristics

Generating Unit Characteristics		
Steam pressure, psia	--	
Steam temperature, °F	--	
Reheat steam temperature, °F	--	
Direct capital cost, 2000 $1,000	52,805	
Indirect capital cost, 2000 $1,000	22,770	
Total capital cost, 2000 $1,000	75,575	
O&M cost-baseload duty:		
Fixed O&M cost, 2000 $/kW-y	2.63	
Variable O&M cost, 2000 $/MWh	11.68	
Equivalent availability, percent	96	
Equivalent forced outage rate, percent	1.96	
Planned maintenance outage, weeks/y	0.86	
Startup fuel (cold start), MBtu	224	
Construction period, months	12	
	Net plant output, kW[1]/Net plant heat rate, Btu/kWh[1] (HHV)	
Load points, percent	97° F	30° F
100	145,926/11,200	174,167/10,616
75	109,442/12,333	130,630/11,482
50	72,968/14,807	87,084/13,839
25	36,484/20,840	43,547/18,968

Note:
[1]Includes output and heat rate degradations.

12.0 Supply-Side Screening

JEA has conducted a thorough search for supply-side alternatives that could possibly fit the planning needs for future demands. The numerous supply-side alternatives identified in Section 11.0 have been reduced by screening methods to arrive at an acceptable number of alternatives to model in detail. JEA has conducted a two-phase screening process to reduce the number of alternatives. The first phase of the screening process eliminates alternatives that are not technically or commercially viable for JEA. The second phase eliminates alternatives based upon a busbar analysis.

12.1 Phase I Screening

This phase eliminated alternatives that were not technically feasible or are still under commercial development at this time. Alternatives that were eliminated for technical feasibility were based upon JEA's ability to support the proposed technology. Instances where JEA could not support the resources necessary for the technology include: wind, hydrology, and additional refuse derived fuels. Below is a discussion of why each alternative or alternative group was eliminated from the study.

12.1.1 Renewable Technologies

The six renewable technologies identified in Section 11.1, including: wind energy, solar thermal, photovoltaics, wood chips, geothermal, and hydroelectric were reviewed to determine if JEA could support the technical feasibility and provide the available resources needed for these alternatives. JEA could not support the wind generation technologies due to the wind conditions necessary for generation. Geothermal and hydroelectric alternatives were eliminated due to a lack of natural resources to support these technologies. Solar thermal, wood chips (biomass) and photovoltaics were considered for Phase II.

It should be pointed out that JEA has embarked on an aggressive Clean Power Program (CPP) to place into service up to 7.5 percent of its installed generation as clean power. The CPP consists of a combination of practices, technologies, fuel and energy sources that minimize the impact of electric power generation on human health and the environment. The CPP will consist of 80 percent as green/renewable energy sources and 20 percent as equivalent clean energy. The total capacity goal of 250 MW is scheduled for completion within the next 15 years. The challenge that JEA faces in implementing the CPP is that these generation alternatives are not competitive with conventional alternatives at this time.

12.1.2 Waste Technologies

Waste technologies evaluated include mass burn units, refuse derived fuel (RDF), landfill gas, sewage sludge, and used tire fueled generating units. All waste technology alternatives were considered in Phase II.

12.1.3 Advanced Technologies

Advanced technologies evaluated include humid air turbine (HAT), Kalina and Cheng cycles, advanced coal technologies, magnetohydrodynamics, fuel cells, fusion, and ocean wave and ocean tidal systems. Only fuel cell and supercritical coal technologies are considered commercially viable at this time. Therefore, the other alternatives are eliminated from further consideration.

12.1.4 Energy Storage Systems

Energy storage systems evaluated include pumped storage, battery storage, compressed air energy storage, flywheel storage, and super conducting magnetic energy storage. Pumped storage and compressed air are commercially proven resources, but JEA's natural resources do not provide access to these technologies. Battery storage, flywheel storage, and super conducting magnetic storage were eliminated from further consideration since the status of these alternatives is experimental.

12.1.5 Nuclear

Nuclear power represents a capital-intensive technology and has been eliminated from consideration because of high capital cost and uncertain licensing requirements and feasibility. Current public concern and environmental aspects also factored into elimination of this alternative.

12.1.6 Conventional Alternatives

Conventional generating unit alternatives considered for capacity expansion include pulverized coal, fluidized bed, combined cycle, and simple cycle combustion turbines. These alternatives were all included in Phase II of the screening analysis.

12.2 Phase II Screening

The alternatives that passed the initial screening analysis of Phase I are included in the Phase II screening analysis, which considers the capital and operating costs of the units on a busbar level. Supply-side alternatives that pass the Phase II screening will be modeled in detail for the economic evaluation of supply-side alternatives.

12.3 Phase II Results

A busbar analysis was utilized to eliminate additional alternatives via comparison of levelized costs. The results of this analysis are shown in Tables 12-1 and 12-2. Solar thermal, fuel cells, wood chips (biomass), and photovoltaics were eliminated due to significantly higher levelized costs. Supercritical pulverized coal was eliminated due to the fact that there are less expensive coal technologies available. Waste technologies were eliminated due to expected fuel unavailability and higher levelized costs with the exception of landfill gas. JEA currently utilizes landfill gas at the Girvin facility for generating capacity and also utilizes landfill gas in Northside Generating Station Units. Since JEA is already utilizing landfill gas to the extent practical, it was not considered further. The remaining six alternatives are included in the detailed economic analysis in Section 13.0.

Table 12-1 Comparison of Selected Alternative Technology Levelized Costs (Base Loaded Units)	
Alternative Technology	Levelized Costs, cents/kW
7FA 2x1 Combined Cycle	3.24-4.05
501 G 1x1 Combined Cycle	3.31-4.14
7FA 1x1 Combined Cycle	3.43-4.28
250 MW Pulverized Coal	3.78-4.73
250 MW Fluidized Bed Coal	4.19-5.24
Supercritical Pulverized Coal Boilers	4.30-6.40
Waste Technologies	2.60-16.20
Wood chips (Biomass)	6.60-11.60
Fuel Cells	13.90-24.10

Table 12-2 Comparison of Selected Alternative Technology Levelized Costs (Peaking Units)	
Alternative Technology	Levelized Costs, cents/kW
7FA Simple Cycle	7.53-9.41
Solar Thermal	12.70-19.30
Photovoltaics	23.50-50.20

13.0 Economic Analysis

The economic analysis for the cost effectiveness of the project consists of several evaluations to arrive at the most cost-effective plan to meet the growing needs of JEA's customers in a reliable manner. The methodology of the analyses, the expansion candidates evaluated, and the results of the base case evaluations are discussed in detail in this section.

13.1 Introduction

A three phase economic analysis was conducted to determine JEA's optimum capacity expansion plan. The three phases included supply-side evaluations, demand-side evaluations, and sensitivity analyses. The results of the supply-side and demand-side analyses are included in this section and discussed in detail. The sensitivity analyses are discussed in Section 14.0.

13.2 Supply-Side Economic Analysis

13.2.1 Methodology

The supply-side evaluations of generating unit alternatives were performed using the Electric Generation Expansion Analysis System (EGEAS) modeling software. EGEAS evaluates all combinations of alternatives to determine the lowest cumulative present worth revenue requirements while maintaining user-defined reliability criteria. All capacity expansion plans were analyzed over a 20 year period from 2000 to 2019. All cases incorporate the 3 Simple Cycle Combustion Turbines at Brandy Branch. Units 1 and 2 are scheduled for commercial operation in May 2001 and Unit 3 in December 2001.

All of the generation alternatives that passed the two phase screening process discussed in Section 12.0 were considered. The cost and performance characteristics of these options are summarized in Table 13-1.

13.2.2 Results of Supply-Side Economic Analysis

Table 13-2 shows the top five expansion plans from EGEAS ranked based upon minimum cumulative present worth revenue requirements. In each of these cases, the Brandy Branch Conversion option was selected by EGEAS as the most cost-effective alternative in order to maintain a 15 percent reserve margin in 2004. It was not until EGEAS generated plan Number 145 in cost ranking that something other the Brandy Branch Combined Cycle Conversion alternative appears in 2004. This plan is over $17 million more expensive than the base case. The Brandy Branch Combined Cycle Conversion in 2004 is clearly the most cost-effective supply alternative.

Table 13-1
Summary of Generation Alternatives

Description	Capital Costs ($ in 2000), $1,000	Capacity		O&M Costs		Primary Fuel Type	Full Load Heat Rate Summer, Btu/kWh	Full Load Heat Rate Winter, Btu/kWh	Forced Outage Rate, percent	Planned Maintenance, weeks	First Year Available
		Summer, MW	Winter, MW	Variable, $/MWh	Fixed, $/kW-Y						
Greenfield Pulverized Coal	275,817	250	250	3.67	26.76	Coal	10,141	10,141	7.0	4.0	2006
Greenfield Fluidized Bed Coal	281,534	250	250	5.97	30.15	Pet Coke	10,543	10,543	7.0	4.0	2006
Brandy Branch 2x1 CC Conversion (1)	107,931 (2)	510.1	575.0	2.07	1.86	Natural Gas	7,370	7,223	4.6	3.7	2004
Brandy Branch 7FA Combustion Turbine	60,749	145.9	174.2	11.68	1.32	Natural Gas	11,200	10,616	2.0	1.0	2004
Greenfield 7FA Combustion Turbine	75,575	145.9	174.2	11.68	2.63	Natural Gas	11,200	10,616	2.0	1.0	2004
Greenfield 1x1 7FA Combined Cycle	137,279	256.2	282.1	2.22	7.38	Natural Gas	7,402	7,364	2.9	2.1	2004
Greenfield 1x1 501G Combined Cycle	188,409	295.3	351.8	2.71	2.68	Natural Gas	6,987	6,704	3.3	2.4	2004
Greenfield 2x1 7FA Combined Cycle	234,756	510.1	575.0	2.07	4.86	Natural Gas	7,370	7,223	4.6	3.7	2004

Notes:
1. Performance is provided for combined cycle operation.
2. Capital cost is for steam side of combined cycle.

Table 13-2
Supply-Side Economic Analysis

Year	Plan No. 1	Plan No. 2	Plan No. 3	Plan No. 4	Plan No. 5	Plan No. 145 First Case Without Conversion
2001	3 – CTs (1)	3 – CTs (1)	3 – CTs (1)	3 – CTs (1)	3 – CTs (1)	3 – CTs (1)
2002						
2003						
2004	BB CC Conv. 2x1	BB CC Conv. 2x1	BB CC Conv. 2x1	BB CC Conv. 2x1	BB CC Conv. 2x1	Greenfield 501G CC 1x1
2005						
2006	Greenfield 7FA CC 1x1	Greenfield 7FA CC 1x1	Greenfield 7FA CC 1x1	Greenfield 501G CC 1x1	Greenfield 501G CC 1x1	
2007						Greenfield 501G CC 1x1
2008	Greenfield CT 7FA	Greenfield CT 7FA	Greenfield CT 7FA			
2009				Greenfield CT 7FA	Greenfield CT 7FA	
2010	Greenfield 7FA CC 2x1	Greenfield 7FA CC 2x1	Greenfield 7FA CC 2x1	Greenfield 7FA CC 2x1	Greenfield 7FA CC 2x1	Greenfield 7FA CC 2x1
2011						
2012						BB CC Conv. 2x1
2013	Greenfield 7FA CC 1x1	Greenfield 7FA CC 1x1	Greenfield 7FA CC 1x1	Greenfield 501G CC 1x1	Greenfield 501G CC 1x1	Greenfield 501G CC 1x1
2014						
2015	Greenfield CFB	Greenfield 501G CC 1x1	Greenfield 501G CC 1x1			Greenfield 7FA CC 1x1
2016				Greenfield 7FA CC 1x1	Greenfield 7FA CC 1x1	
2017	Greenfield 7FA CC 1x1					Greenfield 7FA CC 1x1
2018		Greenfield CFB	Greenfield CT 7FA	Greenfield CFB	Greenfield Coal	
2019	Greenfield CT 7FA	Greenfield CT 7FA	Greenfield Coal			Greenfield Coal
Summary of Units Needed	BB CC Conv. 2x1	BB CC Conv. 2x1	BB CC Conv. 2x1	BB CC Conv. 2x1	BB CC Conv. 2x1	BB CC Conv. 2x1
	5- CTs	5- CTs	5- CTs	4- CTs	4- CTs	4- CTs
		1-Greenfield 501G CC 1x1	1-Greenfield 501G CC 1x1	2-Greenfield 501G CC 1x1	2-Greenfield 501G CC 1x1	2-Greenfield 501G CC 1x1
	3-Greenfield 7FA CC 1x1	2-Greenfield 7FA CC 1x1	2-Greenfield 7FA CC 1x1	1-Greenfield 7FA CC 1x1	1-Greenfield 7FA CC 1x1	1-Greenfield 7FA CC 1x1
	1-Greenfield 7FA CC 2x1	1-Greenfield 7FA CC 2x1	1-Greenfield 7FA CC 2x1	1-Greenfield 7FA CC 2x1	1-Greenfield 7FA CC 2x1	1-Greenfield 7FA CC 2x1
	1-Greenfield CFB	1-Greenfield CFB	1-Greenfield Coal	1-Greenfield CFB	1-Greenfield Coal	1-Greenfield Coal

Table 13-2 (Continued)
Supply-Side Economic Analysis

Year	Plan No. 1	Plan No. 2	Plan No. 3	Plan No. 4	Plan No. 5	Plan No. 145 First Case Without Conversion
Cumulative Present Worth (1,000 $)	4,431,688	4,431,709	4,431,729	4,432,190	4,432,255	4,448,858
CPW Difference (1,000 $)		21	41	502	567	17,170
Percent More Expensive Than Plan No. 1		0.00%	0..00%	0.01%	0.01%	0.39%
Total Capacity Added (MW)	2,647	2,701	2,701	2,581	2,581	2,581

(1) The 3 CTs are the simple cycle units currently under construction at Brandy Branch

13.3 Demand-Side Economic Analysis

As outlined in Section 8.0, JEA has many residential, commercial/industrial, and community demand-side management (DSM) programs. The effect of these existing programs is embedded in JEA's load forecast. On February 21, 2000, the Florida Public Service Commission (FPSC) approved zero conservation goals for JEA and JEA's accompanying DSM plan based on evaluations which indicated no DSM programs were cost effective. The primary reasons that DSM programs are not cost effective are the increase in efficiency of appliances and building designs, lower cost and higher efficiency of new generating units, and lower financing costs.

Nevertheless, JEA has evaluated in detail the most cost effective of the Florida Power and Light Company (FPL) residential and commercial/industrial DSM programs from FPL's Conservation Goals Docket No. 991788-EG. These programs were evaluated for JEA using the PSC-approved Florida Integrated Resource Evaluator (FIRE) model which provides output in the form of the Rate Impact Test, the Total Resources Test, and the Participant's Test. The FIRE model results are shown in Section 8.0. None of these plans were cost effective and therefore, are not included in the generation plan.

14.0 Sensitivity Analyses

JEA performed several sensitivity analyses to measure the impact of important assumptions on the most cost-effective identified in Section 13.0. These include:

- High Load and Energy Forecast
- Low Load and Energy Forecast
- High Fuel Price Forecast
- Alternative Fuel Price Forecast
- Low Fuel Price Forecast
- High Discount Rate
- Low Discount Rate
- 20 Percent Reserve Margin

Identical to the Base Case, the sensitivity analyses were also performed over a 20 year planning horizon with the projection of annual costs and cumulative present worth costs. The results of optimum expansion plan for each of these cases are shown in Table 14-1.

14.1 High Load and Energy Forecast

The high case represents higher than normal economic growth over the forecast horizon. This case assumes a 5.0 percent per year constant growth rate starting in 1999. This case requires additional capacity almost every year of the plan and is almost 40 percent more expensive than the Base Case. As shown in Table 14-1, due to the large capacity required, a Greenfield Combined Cycle 2x1 is selected in 2004. The Brandy Branch Combined Cycle Conversion is selected in 2005.

14.2 Low Load and Energy Forecast

The low case represents lower than normal economic growth over the forecast horizon. This case assumes a 1.0 percent per year constant growth rate starting in 1999. This case requires six less capacity additions than the Base Case with 27 percent lower costs. As shown in Table 14-1, the Brandy Branch Combined Cycle Conversion is selected as the first additional resource beginning operation in 2008.

14.3 High Fuel Price Forecast

The high case represents higher escalation in fuel costs over the forecast horizon which are shown in Tables 6-9, 6-11, 6-13, 6-14, and 6-15. This case has higher costs of almost 24 percent. As shown in Table 14-1, the Brandy Branch Combined Cycle Conversion is selected as the first additional resource beginning operation in 2004.

Table 14-1
Results of Sensitivity Analysis

Year	Base Case (Plan No. 1)	High Load/ Energy Forecast	Low Load/ Energy Forecast	High Fuel Price Forecast	Alternative Fuel Price Forecast	Low Fuel Price Forecast	High Discount Rate	Low Discount Rate	20% Reserve Margin
2001	3 – CTs (1)	3 – CTs (1)	3 – CTs (1)	3 – CTs (1)	3 – CTs (1)	3 – CTs (1)	3 – CTs (1)	3 – CTs (1)	3 – CTs (1)
2002									
2003									
2004	BB CC Conv. 2x1	Greenfield 7FA CC 2x1		BB CC Conv. 2x1	BB CC Conv. 2x1	BB CC Conv. 2x1	BB CC Conv. 2x1	BB CC Conv. 2x1	Greenfield 7FA CC 2x1
2005		BB CC Conv. 2x1							
2006	Greenfield 7FA CC 1x1	Greenfield 501G CC 1x1		Greenfield 501G CC 1x1	Greenfield 501G CC 1x1	Greenfield 7FA CC 1x1	Greenfield 7FA CC 1x1	Greenfield 501G CC 1x1	
2007									
2008	Greenfield CT 7FA	Greenfield 501G CC 1x1	BB CC Conv. 2x1			Greenfield CT 7FA	Greenfield CT 7FA		Greenfield 7FA CC 1x1
2009				Greenfield CT 7FA	Greenfield CFB			Greenfield CT 7FA	
2010	Greenfield 7FA CC 2x1	Greenfield 7FA CC 2x1	Greenfield 7FA CC 2x1	Greenfield 7FA CC 2x1	Greenfield CFB	Greenfield 7FA CC 2x1	Greenfield 7FA CC 2x1	Greenfield 7FA CC 1x1	Greenfield 7FA CC 1x1
2011		Greenfield CT 7FA							
2012		Greenfield 7FA 2x1			Greenfield CFB				
2013	Greenfield 7FA CC 1x1			Greenfield 501G CC 1x1		Greenfield 7FA CC 1x1	Greenfield 7FA CC 1x1	Greenfield 501G CC 1x1	BB CC Conv. 2x1
2014		Greenfield 501G CC 1x1			Greenfield 7FA CC 1x1				Greenfield CT 7FA
2015	Greenfield CFB	Greenfield 7FA CC 1x1				Greenfield 501G CC 1x1	Greenfield CFB		
2016		Greenfield 7FA CC 1x1		Greenfield 7FA CC 1x1	Greenfield 7FA CC 1x1	Greenfield 7FA CC 1x1		Greenfield 7FA CC 1x1	Greenfield 7FA CC 1x1
2017	Greenfield 7FA CC 1x1	Greenfield 7FA CC 1x1 Greemfield CT 7FA					Greenfield 7FA CC 1x1		

Table 14-1 (Continued)
Results of Sensitivity Analysis

Year	Base Case (Plan No. 1)	High Load/ Energy Forecast	Low Load/ Energy Forecast	High Fuel Price Forecast	Alternative Fuel Price Forecast	Low Fuel Price Forecast	High Discount Rate	Low Discount Rate	20% Reserve Margin
2018		Greenfield 7FA CC 1x1		Greenfield 7FA CC 1x1	Greenfield Coal	Greenfield 501G CC 1x1	Greenfield CT 7FA	Greenfield CFB	Greenfield CT 7FA
2019	Greenfield CT 7FA	Greenfield 7FA CC 1x1 Greenfiled CT 7FA							Greenfield CT 7FA
Summary of Units Needed	BB CC Conv. 2x1	BB CC Conv. 2x1	BB CC Conv. 2x1	BB CC Conv. 2x1	BB CC Conv. 2x1	BB CC Conv. 2x1	BB CC Conv. 2x1	BB CC Conv. 2x1	BB CC Conv. 2x1
	5- CTs	6- CTs	3- CTs	4- CTs	3- CTs	3- CTs	6- CTs	4- CTs	6- CTs
	3-Greenfield 7FA CC 1x1	3-Greenfield 501G CC 1x1	1-Greenfield 7FA CC 1x1	2-Greenfield 501G CC 1x1	1-Greenfield 501G CC 1x1	2-Greenfield 501G CC 1x1		2-Greenfield 501G CC 1x1	
	1-Greenfield 7FA CC 2x1	5-Greenfield 7FA CC 1x1		2-Greenfield 7FA CC 1x1	2-Greenfield 7FA CC 1x1	3-Greenfield 7FA CC 1x1	3-Greenfield 7FA CC 1x1	1-Greenfield 7FA CC 1x1	2-Greenfield 7FA CC 1x1
	1-Greenfield CFB	3-Greenfield 7FA CC 2x1		1-Greenfield 7FA CC 2x1	3-Greenfield CFB	1-Greenfield 7FA CC 2x1	1-Greenfield 7FA CC 2x1	1-Greenfield 7FA CC 2x1	2-Greenfield 7FA CC 2x1
					1-Greenfield Coal			1- Greenfield CFB	
Cumulative Present Worth (1,000 $)	4,431,688	6,101,977	3,239,378	5,488,938	5,317,895	3,852,189	3,765,418	5,549,674	4,494,681
CPW Difference (1,000 $)		1,670,289	(1,192,310)	1,057,250	866,207	(579,499)	(666,270)	1,117,986	62,993
Percent More Expensive Than Plan No. 1		37.69%	-26.90%	23.86%	20.00%	-13.08%	-15. 03%	25.23%	1.41%
Total Capacity Added (MW)	2,647	5,165	967	2,600	2,560	2,695	2,571	2,581	2,845

(1) The 3 CTs are the simple cycle units currently under construction at Brandy Branch

14.4 Alternative Fuel Price Forecast

This case was evaluated to test the impact of current high fuel prices on the results. Prices paid for all fuel commodities in September 2000 were used as the starting price (see Section 6.2.5). Real prices were assumed to remain constant with the general inflation rate (2.3%) used to increase prices each year. This results in 20 percent higher costs than the base case. Again, the Brandy Branch Combined Cycle Conversion is selected as the first additional resource beginning operation in 2004.

14.5 Low Fuel Price Forecast

The low case represents lower escalation in fuel costs over the forecast horizon. These values are shown in Tables 6-8, 6-10, 6-12, 6-14, and 6-15. This case results in lower costs of almost 13 percent relative to the base case. As shown in Table 14-1, the Brandy Branch Combined Cycle Conversion is selected as the first additional resource beginning operation in 2004.

14.6 High Discount Rate

A two percent higher present worth discount rate of 9.95 percent was evaluated. The Brandy Branch Combined Cycle Conversion was the first additional resource beginning operation in 2004.

14.7 Low Discount Rate

A two percent higher present worth discount rate of 9.95 percent was evaluated. The Brandy Branch Combined Cycle Conversion was the first additional resource beginning operation in 2004

14.8 Twenty Percent Reserve Margin

This case assumes that a 20 percent reserve margin is maintained each year of the 20 year planning horizon. This results in an additional $63 million in costs relative to the base case which maintains a 15 percent reserve margin. Due to the significantly higher capacity needed, a larger Greenfield Combined Cycle 2x1 is the first additional resource beginning operation in 2004.

14.9 Sensitivity Summary

The Brandy Branch Conversion project was selected early in all sensitivity runs regardless of the scenario. The only cases where the Brandy Branch Conversion was not selected in 2004 was the High Load and Energy Forecast and the 20 Percent Reserve

Margin cases due to the fact that more capacity is immediately needed for those cases than the Brandy Branch Conversion can provide.

As shown in Table 14-1, the Brandy Branch Conversion performs well under all of the sensitivity cases studied, and is clearly the most cost-effective alternative.

15.0 Strategic Considerations

In selecting a power supply alternative, a utility must consider certain strategic factors, which reflect the utility's long-term ability to provide economical and reliable electric capacity and energy to its consumers. A number of strategic considerations favor the conversion of Brandy Branch to combined cycle. These strategic factors include exceptional efficiency; consistency with reliability need; least-cost supply plan; merchant power plant development in Florida; personnel requirement; domestically produced fuel; and environmental benefits and risks.

15.1 Efficiency

JEA strives to provide its customers with the lowest rates they can achieve while maintaining sound operating principles and environmentally clean units. The General Electric 7FA combustion turbines represent the best technology available to accomplish this goal. With the conversion of the Brandy Branch from simple cycle to combined cycle, the plant will achieve a very high efficiency and provide a very clean burning solution to meet JEA's load growth. The efficiency of the combined cycle for natural gas combustion will be 47 percent (net plant heat rate of 7,297 Btu/kWh for high heating value at 59° F and 60 percent relative humidity). This high efficiency ensures that the Brandy Branch combined cycle unit will produce competitively priced generation for many years.

15.2 Reliability Need

JEA will not be able to maintain the minimum reserve margin if it does not install generation or purchase power by the summer 2004. The Brandy Branch conversion to combined cycle offers the most cost-effective solution for meeting JEA's expected load growth and reserve margin requirement of 15 percent.

JEA has analyzed many potential expansion plans (supply-side alternatives) using Electric Generation Expansion Analysis System (EGEAS), and the conversion of Brandy Branch from simple cycle to combined cycle proves to be the most cost effective alternative available to JEA.

A significant factor contributing to the reliability need is the uncertainty associated with the delivery schedules for combustion turbines. Based on current delivery schedules, it is unlikely that combustion turbines could be delivered on a schedule that would allow for commercial operation in time to meet the summer 2004 peak either as simple cycle or combined cycle. The equipment necessary for the combined cycle conversion of the Brandy Branch combustion turbines can be obtained in a time frame that meets the summer 2004 capacity need.

15.3 Least-Cost Supply Plan

The Brandy Branch combined cycle conversion is the most cost-effective alternative for JEA to add new generation. The conversion of the combustion turbine to combined cycle is slightly more costly on a $/kW basis in comparison to other resource additions because the steam portion of a combined cycle unit has a higher $/kW cost relative to the combustion turbine portion. However, the steam side of the combined cycle requires no fuel and the slightly higher incremental cost of the capital to convert the unit from simple cycle to combined cycle is more than made up for in operational savings.

Site availability and the existing infrastructure greatly improve the economics of this project compared with other expansion options. The Brandy Branch site was originally configured to incorporate either a fourth simple cycle F class combustion turbine or conversion of two of the existing F class combustion turbines to combined cycle. Cost of land and right-of-way costs for transmission lines would be significant additional costs in any proposed Greenfield project. Relative to the existing substation which will be upgraded for the conversion project, the substation for a Greenfield project would require at least two additional breaker positions and substantial other electrical equipment.

The sensitivity analysis section of this Application has shown how a Greenfield 2x1 combined cycle plant or a coal unit does not compete economically with the Brandy Branch conversion. Benefits occur in the Brandy Branch conversion not only from the increased capacity of the expanded station, but also increased the energy utilization of the existing simple cycle capacity which occurs with improvement in operating efficiency.

15.4 Power Plant Development in Florida

The recent ruling by the Florida Supreme Court which overturned the PSC's March 1999 decision allowing Duke Energy to partner with the New Smyrna Beach Utilities Commission on a combined cycle plant will likely postpone any power plant development until changes to the Power Plant Siting Act are made by the Florida legislature.

This is not likely to occur until recommendations are obtained from the 2020 Commission. These recommendations for wholesale power are expected at the earliest by January 2001 and may not be completely provided until the Commission finishes its work in December 2001. The speed at which the legislature takes action would then be uncertain. In any case, it is highly unlikely that merchant capacity will be allowed to be developed in a time frame which would provide capacity to meet JEA's capacity requirements for the summer of 2004. This uncertainty necessitates JEA proceeding to convert the Brandy Branch combustion turbines to combined cycle.

15.5 Personnel Required

The conversion of the Brandy Branch combustion turbines to combined cycle offers the advantage of being able to utilize the operation and maintenance personnel being used for the simple cycle operation for the combined cycle operation, thus reducing the number of personnel required. While JEA plans to initially remotely operate the simple cycle combustion turbines, there are operation and maintenance personnel mobilized for unit starts and the use of these personnel will reduce the incremental operations and maintenance personnel costs for the combined cycle conversion.

15.6 Fuel Risk

Brandy Branch will utilize domestic natural gas, which minimizes risks from imported fuels. The unit is also capable of burning No. 2 oil for generation, thus providing JEA with fuel diversity in situations in which natural gas supply may be interrupted.

15.7 Emission Impacts

The use of the existing site minimizes environmental impacts and reduces the time and effort required for licensing. The low level of emissions with the Brandy Branch conversion provides assurance from risk of future environmental regulations while reducing emissions within the state by displacing energy generated by less efficient units with higher emissions.

15.8 Greenfield Site Availability

For analysis purposes, a Greenfield site was assumed for other alternatives to the Brandy Branch Combined Cycle Conversion. In fact, JEA has not yet identified or determined a suitable Greenfield site at this time.

16.0 Financial Analysis

JEA is a municipal utility operating in Jacksonville, Florida. The operation is comprised of two enterprise funds--the Electric Enterprise Fund and the Water and Sewer Enterprise Fund. The Electric Enterprise Fund is comprised of the JEA Electric System, Bulk Power Supply System (Scherer), and St. Johns River Power Park System (SJRPP).

The total operating revenues of the Electric Enterprise Fund were $794.3 Million for fiscal year 2000. The total operating expenses for the same year were $632.4 Million.

The combined senior and subordinated Electric System debt service coverage for fiscal year 2000 was 2.43x.

JEA's financial strength is illustrated in its strong credit ratings on all of its outstanding debt. JEA's senior Electric System/SJRPP debt is rated AA+ from Fitch, Inc., AA from Standard & Poor's Rating Services and Aa2 from Moody's Investors Service.

Table 16-1 shows that rates for all of JEA's customer classes were lower than other major Florida and US utilities based on the latest data available from Resource Data International (RDI).

Table 16-1
Comparison of Electricity Rates 1998

	State Average Rate (cents/kWh)	US Average (cents/kWh)	JEA Average (cents/kWh)
Residential Sector	7.9	8.3	6.9
Commercial Sector	6.4	7.4	5.5
Industrial Sector	4.8	4.5	4.1

Source: RDI - Powerdat 3.1.

As shown above, JEA's strong financial position allows the Brandy Branch conversion to be easily financed and will not have adverse effect on JEA's financial position.

17.0 Consequences of Delay

The initial consequences of delaying the proposed combined cycle conversion are related to the need to supply an alternative resource or purchase to maintain the same level of system reliability at a competitive cost.

17.1 Reliability

If the Brandy Branch combined cycle conversion is delayed, JEA's reserve margin is projected to decrease to 13 percent in 2004. A reserve margin of 13 percent would be in violation of both FRCC and FPSC requirements as well as violate JEA's reserve margin criteria. Reserve margins below JEA's criteria increase JEA's probability of not being able to serve load. Opportunities to mitigate this reduced reliability level are at best, very limited. The opportunities to purchase power, especially for the summer season in which the reserve margin deficit occurs, are expected to be very limited and costly.

The other potential way to mitigate the reduced reliability level would be to install a simple cycle combustion turbine at Brandy Branch or install generation at another site. JEA does not have purchase options for additional combustion turbines past the third combustion turbine at Brandy Branch. While for evaluation purposes, additional simple cycle combustion turbines are shown to be available in 2003, and additional combined cycle units are shown to be available in 2004; in reality, neither is probable due to the delivery schedules for combustion turbines. Currently, delivery schedules for new combustion turbines from Siemens Westinghouse and General Electric are the fourth quarter 2003 and first quarter 2004 which would not support installation for summer 2004 commercial operation. Thus, the inability to obtain equipment would likely limit JEA's ability to maintain an acceptable reliability level unless the conversion of the Brandy Branch combustion turbines occurs on schedule.

17.2 Economic Benefits

If the Brandy Branch combined cycle conversion is delayed, costs to JEA's ratepayers would increase. A sensitivity study was conducted in which the EGEAS model was set up to not allow the Brandy Branch conversion before 2005, a 1 year delay of implementation. The model selected a Greenfield 1x1 combined cycle unit in 2004 to satisfy reserve margin requirements. As is shown in Table 17-1, this delay of the Brandy Branch project by 1 year adds $6.572 million in cumulative worth cost. In addition, this sensitivity analysis ignores potential effects of equipment prices escalating faster than

Table 17-1
Consequences of Delay

Year	Base Case (Plan No. 1)	Brandy Branch CC Delayed Until 2005
2004	BB CC Conv. 2x1	Greenfield 7FA CC 1x1
2005		BB CC Conv. 2x1
2006	Greenfield 7FA CC 1x1	
2008	Greenfield CT 7FA	Greenfield CT 7FA
2010	Greenfield 7FA CC 2x1	Greenfield 7FA CC 1x1
2013	Greenfield 7FA CC 1x1	Greenfield 7FA CC 1x1
2014		Greenfield CT 7FA
2015	Greenfield CFB	Greenfield 501G CC 1x1
2017	Greenfield 7FA CC 1x1	
2018		Greenfield 501G CC 1x1
2019	Greenfield CT 7FA	
Summary of Units Needed	BB CC Conversion 2x1 2- Greenfield CT 7FA 3-Greenfield 7FA CC 1x1 1-Greenfield 7FA CC 2x1 1-Greenfield CFB	BB CC Conversion 2x1 2-Greenfield CT 7FA 2-Greenfield 7FA CC 1x1 1-Greenfield 7FA CC 2x1 2-Greenfield 501G CC 1x1
Cumulative Present Worth (1,000 $)	4,431,688	4,438,260
CPW Difference (1,000 $)		6,572
% More Expensive Than Plan No. 1		0.15%
Total Capacity Added (MW)	2,647	2,775

inflation and the fact that delivery schedule (as mentioned above), would not be adequate to allow for the 2004 combined cycle installation date. In reality, the cost of a 1 year delay would likely be significantly higher than $6.57 million.

18.0 Clean Air Act Considerations

JEA considers the impacts to its community and Peninsular Florida a vital portion of its strategic planning. While the Florida Electrical Power Plant Siting Act carefully bifurcates the need for the power plant from the environmental impacts of the facility, the Clean Air Act requirements have a significant impact on the power plant's cost and performance. The conversion of Brandy Branch simple cycle Units 2 and 3 to combined cycle would lower emissions on a kilowatt hour basis from the current simple cycle machines and improve fuel utilization. All economic evaluations of the Brandy Branch Combined Cycle Conversion included anticipated costs of compliance with environmental regulations.

18.1 History of the Clean Air Act

The Clean Air Act of 1970 was designed to protect human health and the environment by regulating the amount of pollutants released to the atmosphere. The major regulated air pollutants include carbon monoxide (CO), nitrogen oxides (NO_x), sulfur dioxide (SO_2), hydrocarbon compounds (or volatile organic compounds, VOC), ozone, lead, and suspended particulates (PM/PM_{10}). The listed pollutants, commonly referred to as criteria pollutants, have been regulated primarily through National Ambient Air Quality Standards (NAAQS) and the respective state implemented programs that support the NAAQS.

In the late 1980s, as it came time for Congress to reauthorize the Clean Air Act, air quality had improved, but it was clear that continuing the improvement was becoming more costly per unit of pollution removed. Under the 1990 Clean Air Act amendments, Congress required the EPA to establish an emissions trading program that would cut the emissions of sulfur dioxide in half by the year 2000. Under the program established by the EPA, existing power plants were allocated sulfur dioxide allowances with a given number of additional allowances auctioned each year. An allowance holder can emit 1 ton of sulfur dioxide for each allowance. Firms holding the allowances can use the allowances to emit pollutants, bank the allowances for the next year, or sell the allowances to other firms. Total emissions will fall because the sulfur dioxide emissions associated with the number of allowances available are less than existing emissions.

18.2 Authority to Construct

Brandy Branch combined cycle conversion must comply with the Clean Air Act and the current Florida air quality requirements stemming from the Act. An Authority to Construct (ATC) permit has been obtained for the Brandy Branch simple cycle units.

One aspect of the ATC permit is the determination of Best Available Control Technology (BACT). Major criteria pollutants included in the BACT analysis are NO_x, VOC, CO, and PM/PM_{10}. The Brandy Branch combined cycle unit is proposed to achieve BACT for NO_x through the use of dry low NO_x combustors and selective catalytic reduction (SCR). For natural gas combustion, the NO_x emissions will be controlled to 10.5 ppmvd at 15 percent O_2 by dry low NO_x combustors, and SCR will further reduce NO_x emissions to 3.5 ppmvd. When firing No. 2 oil, the NO_x emissions of the unit will be limited to 42 ppmvd with water injection and further reduced to 15 ppmvd with the installation of the SCR. The cost of the SCR has been included in the capital cost for conversion for evaluation purposes.

18.3 Title V Operating Permit

Along with the ATC, the unit will be required to obtain an operating permit under Title V of the Clean Air Act. All units at the Brandy Branch site will be ultimately included in a single Title V permit. Requirements under the Title V permit for Brandy Branch combined cycle conversion will require similar emissions control and operations as those required under the ATC and BACT determinations.

18.4 Title IV Acid Rain Permit

In addition to the construction and operating permit requirements of the unit, the regulations implementing the Acid Rain provisions of the Clean Air Act Amendments require that electric utility units obtain acid rain permits.

18.5 Compliance Strategy

Brandy Branch combined cycle will emit small amounts of sulfur dioxide while running on either natural gas or No. 2 oil. As an affected unit, Brandy Branch must have allowances available for emissions of sulfur dioxide to comply with its Title IV Acid Rain permit. JEA is proposing to limit sulfur dioxide emissions to 40 tons per year (40 tpy combined for Units 2 and 3). The current operating plan for Brandy Branch includes operation on No. 2 oil only during emergency situations. JEA has identified two possible sulfur dioxide emissions compliance strategies. The first and preferred compliance strategy involves reallocation of excess allowances currently maintained by JEA to cover Brandy Branch sulfur dioxide emissions. The second possible compliance strategy involves purchasing allowances. Purchasing allowances will be the compliance strategy utilized if, for any reason, reallocation does not supply sufficient quantities of allowances. The recent price for purchasing allowances is about 140 to 200 \$/ton-year and thus would be less than \$8,000 per year if all allowances for the permitted operation were purchased. All costs associated with the conversion of Brandy Branch to combined cycle have been included in the evaluations.

19.0 Peninsular Florida Needs

The Florida Reliability Coordinating Council (FRCC) is responsible for coordinating power supply reliability in Peninsular Florida for the North American Reliability Council (NERC). As part of its reliability coordination activities, the FRCC provides an annual summary and report of Peninsular Florida Ten Year Site Plans. The annual summary is then analyzed by PSC staff and utility members during annual workshops. The most recent planning summary conducted by FRCC is the 2000 Load and Resource Plan for the State of Florida. Published in July 2000, this Load and Resource Plan summarizes utility loads and resources by type of capacity through the year 2009. The summary also includes utility load forecast data and proposed generation expansion plans, retirements, and capacity re-rates. The following section summarizes the results of the FRCC's reliability analysis in the determination of future capacity requirements for Peninsular Florida according to the State of Florida 2000 Load and Resource Plan.

19.1 Peninsular Florida Capacity and Reliability Need

Table 19-1 represents the peak demand and available capacity for summer and winter as presented by FRCC. As Table 19-1 indicates, reserve margins are projected to exceed the 15 percent criteria required by FRCC. Closer inspection, however, indicates that reserve margins before exercising load management and interruptible loads only range between 7 to 14 percent.

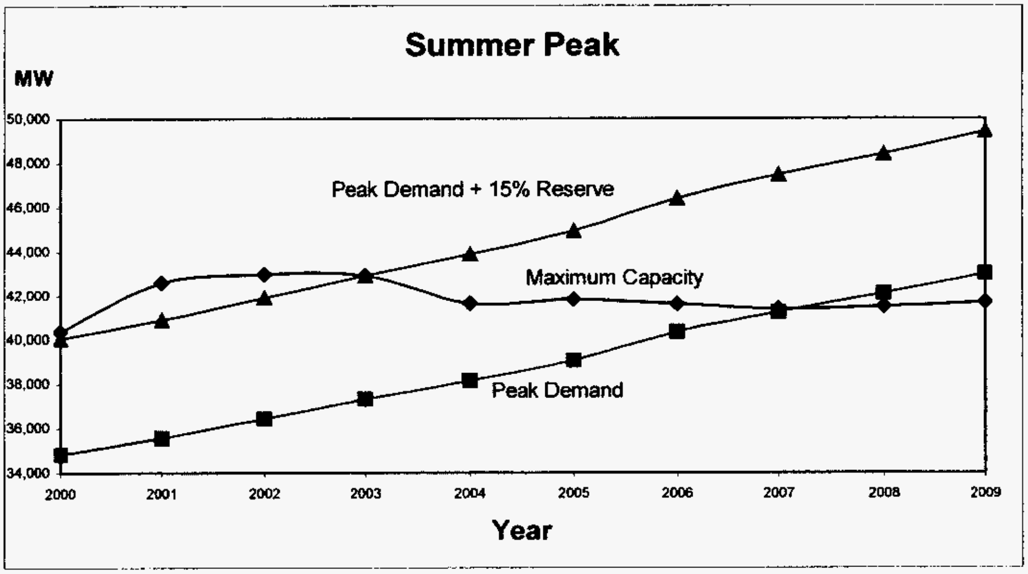
Table 19-2 represents the summer and winter peak demand and available capacity by excluding the capacity required to be approved under the Florida Electrical Power Plant Siting Act, but not yet approved. The available capacity consists of existing capacity, capacity changes that have been approved under the Florida Electrical Power Plant Siting Act, and capacity changes not requiring certification under the Florida Electrical Power Plant Siting Act. Planned capacity changes which are not approved under the Florida Electrical Power Plant Siting Act have not been included in the available capacity shown in Table 19-2. Figure 19-1 shows the curves of peak demand, available capacity, and peak demand plus 15 percent reserve margin. Table 19-2 and Figure 19-1 shows that, beginning with the winter period of 2003/04, there is insufficient capacity to meet the required 15 percent reserve margin.

Table 19-1
2000 Load and Resource Plan -- Peninsular Florida Peak Demand and Available Capacity

Calendar Year	Installed Capacity (MW)	Net Contracted Firm Interchange (MW)	Projected Firm Net to Grid from NUG (MW)	Total Available Capacity (MW)	Total Peak Demand (MW)	Reserve Margin w/o Exercising Load Management and Int. (MW)	Reserve Margin w/o Exercising Load Management and Int. % of Peak	Load Management (MW)	Interruptible Load (MW)	Firm Peak Demand (MW)	Reserve Margin with Exercising Load Management & Int. (MW)	Reserve Margin with Exercising Load Management & Int. % of Peak
Summer Peak Demand												
2000	36,033	1,697	2,653	40,383	37,728	2,655	7%	1,584	1,312	34,832	5,551	16%
2001	38,244	1,699	2,653	42,596	38,445	4,151	11%	1,565	1,320	35,560	7,036	20%
2002	38,903	1,675	2,906	43,484	39,282	4,202	11%	1,517	1,333	36,432	7,052	19%
2003	41,007	1,583	3,221	45,811	40,157	5,654	14%	1,485	1,359	37,313	8,498	23%
2004	42,138	1,583	2,768	46,489	41,004	5,485	13%	1,464	1,376	38,164	8,325	22%
2005	42,734	1,583	2,658	46,975	41,905	5,070	12%	1,445	1,395	39,065	7,910	20%
2006	44,174	1,583	2,525	48,282	43,190	5,092	12%	1,430	1,413	40,347	7,935	20%
2007	44,887	1,583	2,220	48,690	44,097	4,593	10%	1,416	1,426	41,255	7,435	18%
2008	45,916	1,583	2,205	49,704	44,926	4,778	11%	1,408	1,424	42,094	7,610	18%
2009	46,623	1,583	2,096	50,302	45,810	4,492	10%	1,400	1,430	42,980	7,322	17%
Winter Peak Demand												
2000/01	39,342	1,786	2,717	43,845	40,894	2,951	7%	2,864	1,216	36,814	7,031	19%
2001/02	40,075	1,688	3,002	44,765	41,811	2,954	7%	2,835	1,223	37,753	7,012	19%
2002/03	42,943	1,583	3,365	47,891	42,739	5,152	12%	2,812	1,248	38,679	9,212	24%
2003/04	44,759	1,583	2,912	49,254	43,663	5,591	13%	2,810	1,261	39,592	9,662	24%
2004/05	45,311	1,583	2,802	49,696	44,638	5,058	11%	2,814	1,273	40,551	9,145	23%
2005/06	46,275	1,583	2,669	50,527	45,694	4,833	11%	2,823	1,286	41,585	8,942	22%
2006/07	47,607	1,583	2,324	51,514	46,668	4,846	10%	2,831	1,296	42,541	8,973	21%
2007/08	48,950	1,583	2,309	52,842	47,573	5,269	11%	2,839	1,289	43,445	9,397	22%
2008/09	49,559	1,583	2,200	53,342	48,531	4,811	10%	2,850	1,295	44,386	8,956	20%
2009/10	50,746	1,583	1,778	54,107	49,478	4,629	9%	2,858	1,304	45,316	8,791	19%

Table 19-2
2000 Load and Resource Plan -- Peninsular Florida Peak Demand and Available Capacity
Excluding Capacity Required to be Approved Under the Florida Electrical Power Plant Siting Act but Not Yet Approved

Calendar Year	Installed Capacity	Net Contracted Firm Interchange	Projected Firm Net to Grid from NUG	Total Available Capacity	Total Peak Demand	Reserve Margin w/o Exercising Load Management & Int.		Load Management	Interruptible Load	Firm Peak Demand	Reserve Margin with Exercising Load Management & Int.	
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	% of Peak	(MW)	(MW)	(MW)	(MW)	% of Peak
Summer Peak Demand												
2000	36,033	1,697	2,653	40,383	37,728	2,655	7%	1,584	1,312	34,832	5,551	16%
2001	38,244	1,699	2,653	42,596	38,445	4,151	11%	1,565	1,320	35,560	7,036	20%
2002	38,373	1,675	2,906	42,954	39,282	3,672	9%	1,517	1,333	36,432	6,522	18%
2003	38,097	1,583	3,221	42,901	40,157	2,744	7%	1,485	1,359	37,313	5,588	15%
2004	37,278	1,583	2,768	41,629	41,004	625	2%	1,464	1,376	38,164	3,465	9%
2005	37,586	1,583	2,658	41,827	41,905	-78	0%	1,445	1,395	39,065	2,762	7%
2006	37,503	1,583	2,525	41,611	43,190	-1,579	-4%	1,430	1,413	40,347	1,264	3%
2007	37,578	1,583	2,220	41,381	44,097	-2,716	-6%	1,416	1,426	41,255	126	0%
2008	37,718	1,583	2,205	41,506	44,926	-3,420	-8%	1,408	1,424	42,094	-588	-1%
2009	38,031	1,583	2,096	41,710	45,810	-4,100	-9%	1,400	1,430	42,980	-1,270	-3%
Winter Peak Demand												
2000/01	39,342	1,786	2,717	43,845	40,894	2,951	7%	2,864	1,216	36,814	7,031	19%
2001/02	40,075	1,688	3,002	44,765	41,811	2,954	7%	2,835	1,223	37,753	7,012	19%
2002/03	40,677	1,583	3,365	45,625	42,739	2,886	7%	2,812	1,248	38,679	6,946	18%
2003/04	40,439	1,583	2,912	44,934	43,663	1,271	3%	2,810	1,261	39,592	5,342	13%
2004/05	39,903	1,583	2,802	44,288	44,638	-350	-1%	2,814	1,273	40,551	3,737	9%
2005/06	40,012	1,583	2,669	44,264	45,694	-1,430	-3%	2,823	1,286	41,585	2,679	6%
2006/07	39,916	1,583	2,324	43,823	46,668	-2,845	-6%	2,831	1,296	42,541	1,282	3%
2007/08	40,263	1,583	2,309	44,155	47,573	-3,418	-7%	2,839	1,289	43,445	710	2%
2008/09	40,443	1,583	2,200	44,226	48,531	-4,305	-9%	2,850	1,295	44,386	-160	0%
2009/10	40,634	1,583	1,778	43,995	49,478	-5,483	-11%	2,858	1,304	45,316	-1,321	-3%



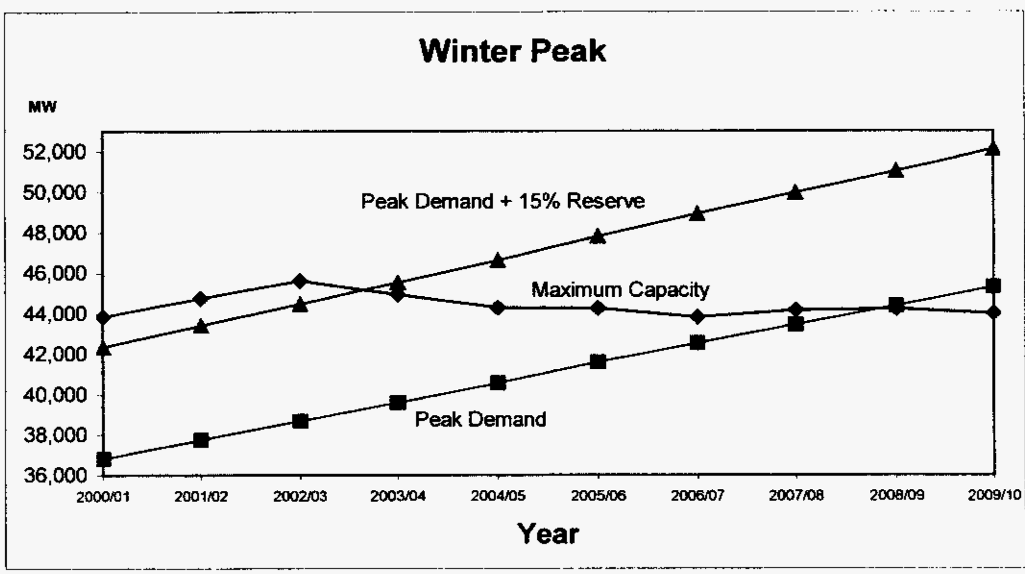


Figure 19-1
2000 Load and Resource Plan--Peak Demand and Reserve Margin
Excluding Approved Capacity Required to be Approved Under the
Florida Electrical Power Plant Siting Act but Not Yet Approved

19.2 Impact to Transmission System

The Florida Regional Coordinating Council (FRCC) maintains a generation and transmission system database for Peninsular Florida in which FRCC attempts to identify planned generating and transmission additions that the FRCC feels are highly likely to occur. The Brandy Branch simple cycle combustion turbines have been included in FRCC's database the last 2 years.

The transmission lines at Brandy Branch were originally sized to handle either four simple cycle F class combustion turbines or a simple cycle combustion turbine along with a 2 on 1 combined cycle configuration which is being proposed here. As a result, JEA does not foresee any transmission additions as a result of the Brandy Branch Combined Cycle Conversion.

Weather Normalization of Seasonal System Peak Demand and Annual Net Energy for Load

Presented at

Southeast Regional
Association of Edison Illuminating Companies
Load Research Conference

August 16-18, 1989

Bret L. Griffin
Jacksonville Electric Authority

ABOUT THE JACKSONVILLE ELECTRIC AUTHORITY

The Jacksonville Electric Authority (JEA) serves over 280,000 customers in portions of Duval, Clay, and St. Johns Counties in Northeast Florida. JEA is a dual peaking utility, whose summer peak demand reached 1714 MW in 1989. Annual sales in fiscal year 1987-88 totaled 7,744 GWH, producing revenues exceeding $494 million. JEA has the lowest residential rates in the State of Florida at $67.70 per 1000 kWh, including base rate, fuel adjustment charge, and franchise fees. JEA recently completed construction of the St. Johns River Power Park (SJRPP), a jointly owned 1248 MW coal-fired generating plant. Commercial operation of SJRPP Unit 2 on March 24, 1988 marked the end of the construction project -- 5 months ahead of schedule and $150 million under budget ($1.6 billion budget).

BACKGROUND

In 1980 the Florida Legislature passed the Florida Energy Efficiency and Conservation Act (FEECA) which called for a reduction in the growth rates of weather sensitive seasonal peak demands and annual energy consumption. FEECA authorized the Florida Public Service Commission (FPSC) to adopt rules to implement the act. In 1984 the FPSC adopted rules which called for weather normalizing seasonal system peak demand and annual net energy for load (NEL).

The FPSC rules state that, "Load data shall be normalized for the effect of changes in weather variables including at least temperature, heating degree days, and cooling degree days, or surrogates for those variables." Normal weather is to be "derived from statistical analysis of a minimum of ten consecutive years of weather data," or, "the typical meteorological year as defined by the National Weather Service."

In response to these rules, JEA developed a normalization methodology that related winter peak demand to daily low temperature, summer peak demand to daily high temperature, and energy consumption to daily average temperature. Normal weather was defined using the ten most recent years of historical weather as a base.

OVERVIEW

The purpose of weather normalization is to estimate summer and winter system peak demand and annual NEL had "typical" weather conditions occurred. JEA's weather normalization efforts are simplified because JEA serves primarily one county, and therefore experiences relatively homogeneous weather conditions within its service territory. JEA's methodology correlates hourly loads (EEI data) and National Weather Service data to create regression models of the system's response to actual weather conditions. Once the parameters of the regression models are produced, the models use weather data as input to estimate the system's response to both actual and typical weather conditions. The weather adjustment, for reporting purposes, is the difference between a model's response to actual weather and its response to typical weather. As required by the FPSC, the weather adjustment is applied to actual data to obtain weather adjusted data.

LOAD DATA

Prior to 1985, JEA collected hourly load data from hand-written Generating Station Log Sheets and entered the data manually into a computer. In 1985, JEA implemented an electronic metering and data transfer system to collect hourly station loads. This section describes both methods and highlights some of the problems and solutions involved with each.

Log sheets are generated by an employee who, once an hour, records by hand the values from each of the station's MWH meters. The mathematical difference between two consecutive hourly readings is the average system demand for that generator. Average loads summed for each generator, less house load, is the average system demand for that hour.

This method of collecting data has several weaknesses. First, problems result because the meters are not read at precisely the same time each hour, resulting in over-reporting one hour, and under-reporting the next. Second, a station's meters are frequently not read at all for several hours. This occurs, for example, in emergencies when all available personnel are needed on other more important tasks. Finally, because of the quantity of hand-entered data, errors are also generated in data entry.

To account for these problems, JEA "smooths" the data. "Smoothing" is a technique in which plot of system load by hour is viewed, and outliers are identified and corrected. JEA is careful to preserve monthly peak demands and annual NEL. Smoothing produces load shapes superior to unsmoothed data, but quality is still poor.

In 1985, JEA implemented a system of electronic monitoring load data. With this system, load data is collected electronically at each generating station, then transferred by microwave to the control center for tabulation. The data is stored monthly on diskette, and annually manipulated into EEI format. Electronic monitoring has dramatically improved the quality of the data.

Virtually all of the problems with the old method were eliminated, but several new ones have emerged. First, house load is not monitored. In response, JEA developed a house load formula[1] based on historical house load data from the log sheets. The accuracy of the formula is annually reviewed, and updated as necessary.

Lost data is another problem with monitored data. Each year, several hours of data are lost due to electronic equipment failure. Occasionally, however, several month's worth of data are lost, as happened when JEA's control center relocated to a new building. For these and other reasons, JEA has maintained the log sheet system of collecting data and uses it when monitored data is not available.

WEATHER DATA

The National Oceanographic and Atmospheric Administration (NOAA) is the source of JEA's weather data. Historical data on tape and diskette as well as printed monthly reports are utilized as sources of weather data. The final product, after initial processing and manipulation, is a database of temperatures for 8760 (or 8784) hours each year.

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[1] The house load formula is:

$$HL = 3.1608 + 0.051946*(GROSS) - 0.000015277*(GROSS)^2,$$

Where,
HL is house load, and
GROSS is gross generation for the hour.

Raw data is collected from three reports:

1. *TDF-14 Surface Observations*,
2. *TD-3200 Summary of the Day*, and
3. *Local Climatological Data Monthly Summary*.

TDF-14 Surface Observations is a database of hourly weather data including temperature, humidity, barometric pressure, cloud cover, wind speed, and other surface observations. *TD-3200 Summary of the Day* is a database summarizing daily weather conditions. In Jacksonville's case, only daily maximum and minimum temperatures are available. The *Local Climatological Monthly Summary* is a hard-copy report of daily and hourly weather conditions, including averages and monthly totals.

NOAA weather data is processed by JEA staff using Statistical Analysis System (SAS) software on a time-shared mainframe at the University of Florida's Northeast Regional Data Center (NERDC). The *TDF-14 Surface Observations*, provided on tape, is read directly into the mainframe. The *TD-3200 Summary of the Day* database, provided on diskette, is read into a PC, manipulated by spreadsheet, and uploaded to NERDC via modem. Data in the *Local Climatological Data Monthly Summary* reports is manually keyed into the PC and uploaded annually to update the database.

Some NOAA weather data (including parts of the *TDF-14 Surface Observations* data and all of the *Local Climatological Data Monthly Summary* data) reports tri-hourly temperatures (one reading every three hours). Since these values are collected at specific time intervals, the data does not necessarily contain the high or the low temperature of the day. JEA overcomes this problem with a two step process. First, daily high and low temperatures in the *TDF-14 Surface Observations* data are replaced with the *TD-3200 Summary of the Day* daily high and low temperatures. Second, the missing data is estimated by interpolation. Admittedly, this method does not accurately correlate time and temperature, but does produce acceptable results concerning the variables of interest; namely, daily high, low, and average temperatures.

TDF-14 Surface Observations and *TD-3200 Summary of the Day* databases can be obtained from NOAA at the cost of reproduction (approximately \$300 and \$150 respectively). These databases contain historical weather data as far back as 1948 in Jacksonville's case. Subscriptions to the *Local Climatological Data Monthly Summary* report can be obtained for less than \$10 per year. NOAA weather data can be obtained from:

National Climatic Data Center
Federal Building
Asheville, NC 28801
(704) 259-0682

PEAK MODELS

JEA typically experiences hot summers and mild winters. High temperatures in the summer typically reach 95 °F to 103 °F, an 8 °F range. Low temperatures in the winter typically reach 26 °F to 7 °F, a 19 °F range. As would be expected from these ranges, JEA experiences relatively stable and predictable summer peak demands, but unstable and unpredictable winter peak demands. For that reason, this discussion will focus on the winter peak model. The summer model is similar to the winter model, however, and where appropriate, the differences will be discussed.

The winter peak model is an "extreme response" model. "Extreme response" means that when daily winter peak demand is plotted against low temperature for the day, only the highest, or most extreme, demand at any temperature is used as a data point for the regression model. This is pictured graphically in Figure 1.

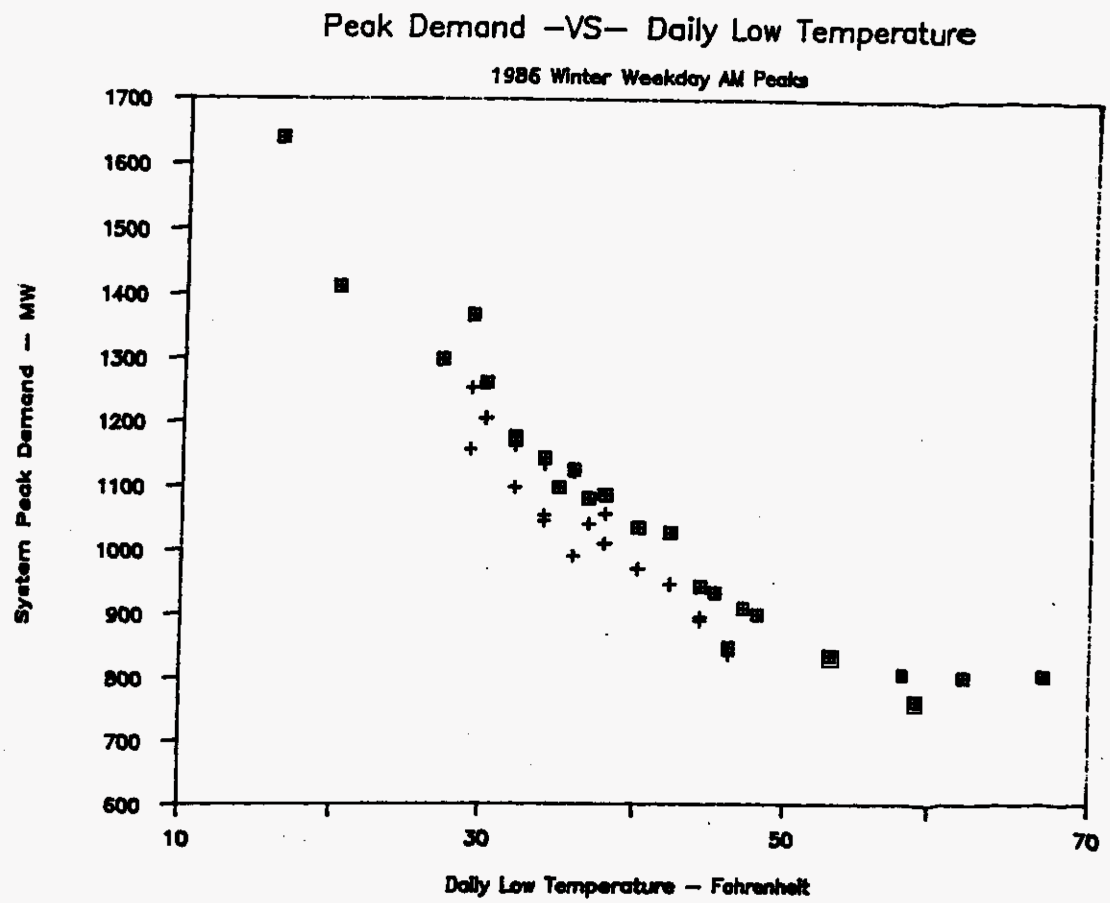

Figure 1

Figure 1 shows JEA's 1986 daily winter peaks plotted against low temperature of the day. Extreme responses are represented as filled in squares.

It should be noted from Figure 1 that only weekday peaks and peaks before 1:00 PM are considered (only weekday peaks after 12 NOON are considered in the summer model). The other data was excluded because JEA experiences load shapes typical of summer[2] in what the FPSC defines as winter. Since the winter load shape peaks in the morning and in the afternoon, this screening process excludes some legitimate winter peak data from consideration. JEA tolerates the exclusion of afternoon winter peaks by considering the historical evidence that afternoon winter peaks do not produce system peaks.

[2] Summer load shapes are typified by low early morning loads, rising gradually by mid-morning, and peaking in late afternoon.

Extreme responses are modeled by a regression equation of the form,

$$PEAK_i = A + B*COS(C*(MINTEMP_i-D)),$$

Where,

$PEAK_i$ is the system peak demand in day i,
$MINTEMP_i$ is the minimum temperature in day i, and
A, B, C & D are constants to be estimated.

The cosine curve exhibits predictable patterns based on the values of A, B, C, and D. The value of A gives the central position of the curve, B gives the amplitude, $2\pi/C$ gives the frequency, and D gives the phase difference. Figure 2 illustrates this graphically.

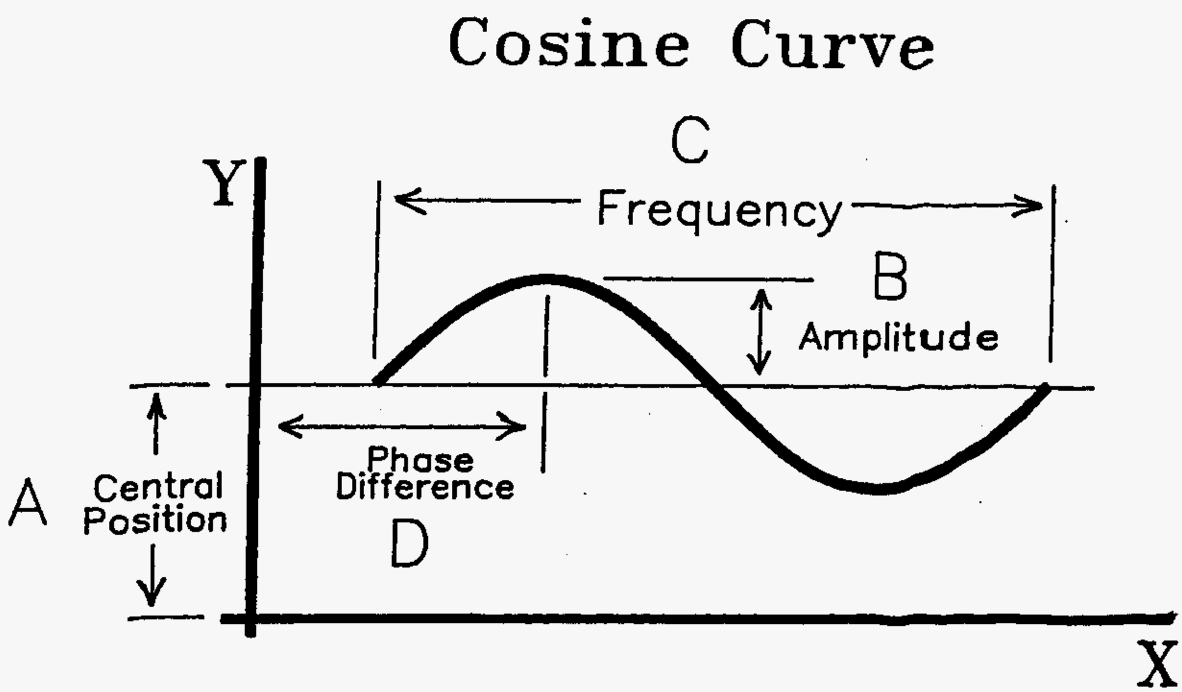

Figure 2

In practical terms, the sum of A and B is the maximum value that the model will produce. In addition, π/C is the temperature range between the maximum and minimum points on the curve. D is the phase constant, and indicates the temperature at which the curve reaches its maximum value. A SAS procedure, PROC NLIN (a non-linear regression procedure), is utilized to estimate the values of A, B, and C for each year. D has been chosen by the utility to be equal to 0 °F for the winter model and 105 °F for the summer model[3]. Table 1 gives the values of each parameter for years 1980 through 1988.

[3] Choosing a value of D outside the range of possible temperatures assures that the function will not decrease unexpectedly at higher load levels.

Peak Demand Parameters								
	WINTER				SUMMER			
YEAR	A	B	C	D	A	B	C	D
1980	1033	296	0.0562	0	1027	327	0.0934	105
1981	782	458	0.0327	0	981	307	0.0861	105
1982	930	432	0.0434	0	1011	325	0.0851	105
1983	1081	362	0.0538	0	1090	393	0.0838	105
1984	983	331	0.0436	0	1102	376	0.0834	105
1985	1213	439	0.0554	0	1119	377	0.0791	105
1986	1255	467	0.0521	0	1230	412	0.0874	105
1987	1489	517	0.0612	0	1314	438	0.0922	105
1988	1383	563	0.0502	0	1282	404	0.0793	105

Table 1

Two statistics, R^2 and the coefficient of variation (CV), were calculated for each equation in Table 1. Every equation has an R^2 over 0.99 and a CV under 10. R^2 indicates the amount of variability in the data that is explained by the model, and ranges from 0.0 to 1.0, 1.0 representing complete explanation. CV can be viewed as the average residual expressed as a percent of predicted value, and has a minimum of 0 and no maximum. Values of CV under 30 are acceptable, and values under 20 are good. These two statistics indicate that the models perform well.

It is possible for the statistics to look good and the model be poor. Here is where "a picture is worth a thousand words". One can get a good "feel" for the validity of a model by looking

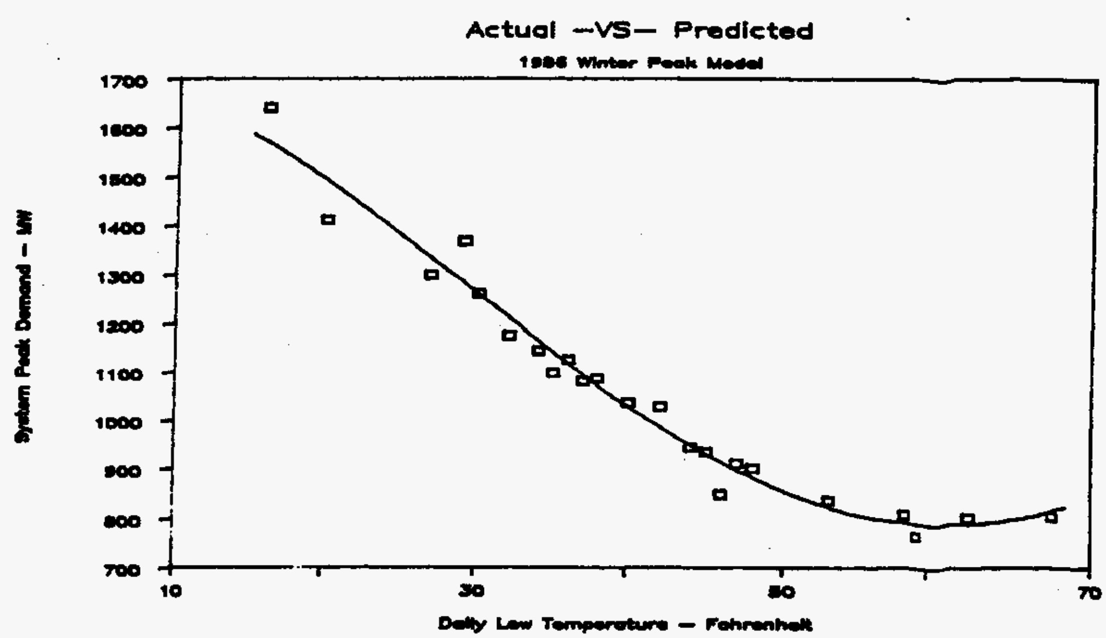

Figure 3

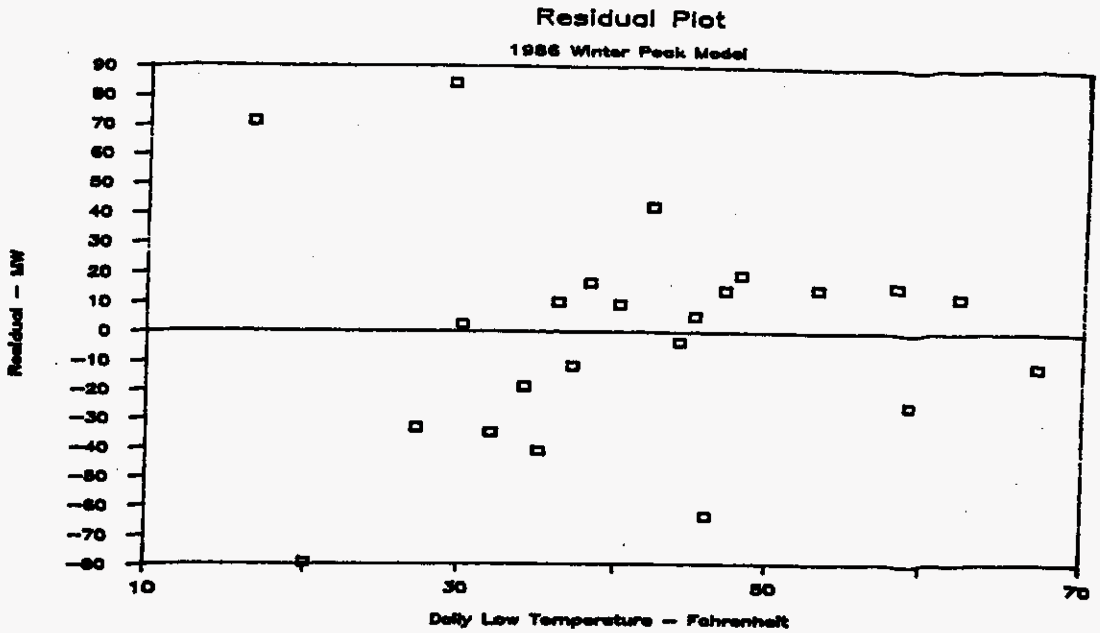

Figure 4

at two plots, an actual versus predicted value plot, and a residual plot. Figures 3 and 4 illustrate these for JEA's 1986 winter data.

Actual versus predicted value plots are useful in letting the modeler visually check to see if the model accurately represents the data. Closeness of fit at the low end of the temperature range is of particular importance for winter peak modeling. Runs-of-the-same-sign analysis of residual plots can help to identify autocorrelation in errors[4]. Both plots are useful in identifying outliers and influential points.

JEA's review of the validity of the peak models indicates that some autocorrelation in errors is exhibited, but that, generally, the regression equations adequately model the effects of weather on system peak, especially at low temperatures in the winter and high temperatures in the summer. In addition, JEA is committed to reviewing the adequacy of the models and making changes as necessary.

ENERGY MODEL

The NEL model is a set of four regression equations that relate daily NEL sales to average temperature of the day. One equation models each of the following:

winter weekday NEL sales,
winter weekend day NEL sales,
summer weekday NEL sales, and
summer weekend day NEL sales.

[4] Autocorrelation in errors means that errors are distributed non-randomly, showing up as predictable patterns in the residual plot. Autocorrelated errors usually indicate the need for a regression equation of a different form.

Each model is a simple quadratic equation of the form,

$$NEL_i = A + B*AVGTEMP_i + C*AVGTEMP_i^2,$$

Where,

NEL_i is the total energy sales in day i,
$AVGTEMP_i$ is the average temperature in day i, and
A, B, & C are constants to be estimated.

JEA uses PROC REG, SAS's simple linear regression procedure, to estimate A, B, and C for each equation for each year, and the results are shown in Tables 2 and 3.

Winter NEL Parameters						
	Weekday			Weekend Day		
YEAR	A	B	C	A	B	C
1980	43950	-829	5.67	42834	-864	6.11
1981	49113	-999	7.10	46040	-932	6.32
1982	51964	-1134	8.62	56418	-1328	10.09
1983	43333	-787	5.32	35529	-566	3.37
1984	53669	-1140	8.46	60761	-1439	10.96
1985	54733	-1141	8.53	54313	-1200	9.06
1986	69093	-1639	12.94	63996	-1532	12.07
1987	71195	-1635	12.52	52044	-959	6.13
1988	74695	-1694	12.81	76576	-1835	14.14

Table 2

Summer NEL Parameters						
	Weekday			Weekend Day		
YEAR	A	B	C	A	B	C
1980	76825	-2076	17.98	73022	-1990	16.13
1981	65056	-1727	14.47	112647	-3050	23.25
1982	83610	-2245	18.15	76331	-2074	16.79
1983	86867	-2395	19.74	72546	-2036	17.11
1984	79143	-2128	17.65	102456	-2871	23.00
1985	72550	-1939	16.42	57871	-1596	14.11
1986	72342	-1955	16.95	45642	-1248	11.93
1987	92395	-2466	20.38	95978	-2622	21.42
1988	84076	-2228	18.81	91032	-2479	20.49

Table 3

Analysis of variance reveals that all but 3 of the 36 equations have an R^2 above 0.8. However, every equation has a CV of under 10. Figures 5 and 6 show, respectively, the actual versus predicted value plot and the residual plot. Please note that data from all four models for 1986 have been combined.

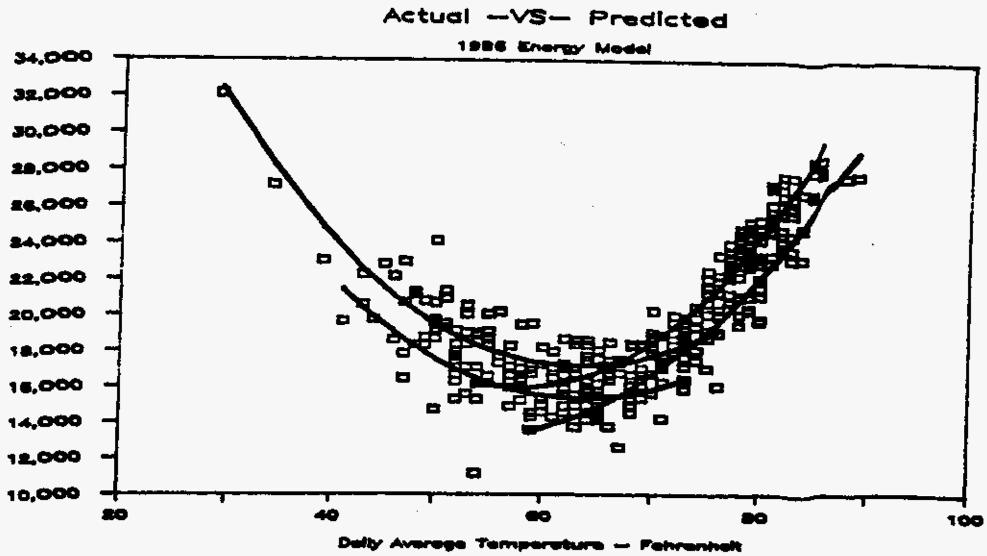

Figure 5

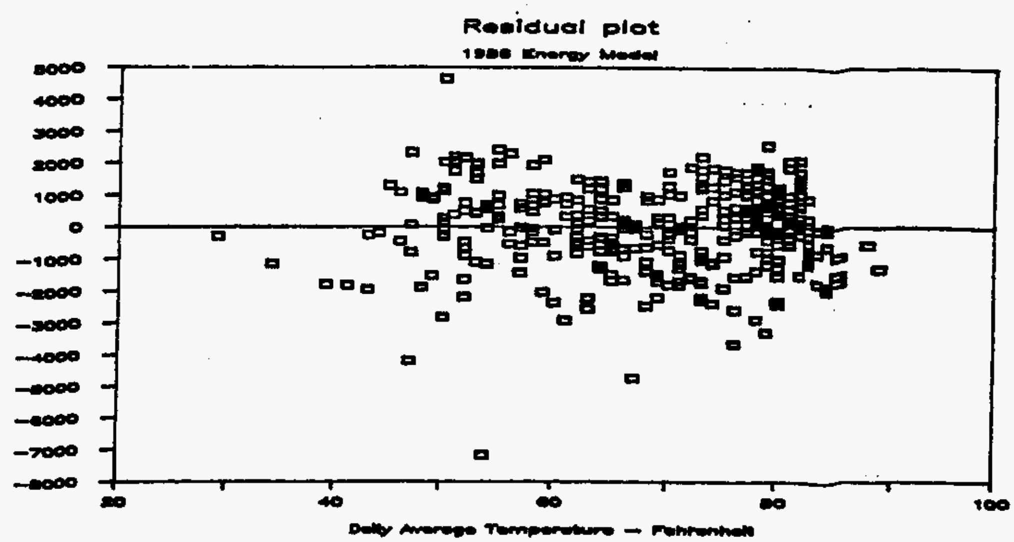

Figure 6

The top two curves on the actual versus predicted value plot represent the predicted values of weekday energy consumption during winter and summer. Weekend day consumption is distinctively lower in both seasons as is shown by the bottom two curves. Although not evident in the 1986 data, other actual versus predicted value plots indicate less of a difference between weekday and weekend day energy consumption as average temperature approaches extreme values. Explanations for this will be left up to the reader's imagination. The residual plot indicates no significant problems with the data.

TYPICAL WEATHER

As was mentioned above, JEA defines typical weather using the ten most recent years of historical weather as a base. The goal is to select the most typical January, the most typical February, the most typical March, and so on through December to be the typical year. Three steps outline the process:

1) Rank the months from hottest to coldest,
2) Calculate targets for each month, and
3) Select twelve typical months.

<u>Step 1</u>
The months are ranked from hottest to coldest based on average weather. Four variables define "hot" and "cold" -- heating degree days (HDD), cooling degree days (CDD), minimum temperature for the month (MINTEMP), and maximum temperature for the month (MAXTEMP)[5]. The rank of each month is based on the formula:

$$RANK = (HDD-CDD)/DAYS + 200/MINTEMP - MAXTEMP/10,$$

Where,
DAYS is the number of days in month.

The ranking formula puts degree days and temperature on the same scale. By dividing HDD and CDD by the number of days, degree days never contribute more than 20 points to the rank. By dividing MINTEMP into 200, MINTEMP's contribution increases as temperature decreases and seldom exceeds 10. Likewise, by dividing MAXTEMP by 10, MAXTEMP's contribution increases as temperature increases and seldom exceeds 10. Table 4 shows the months ranked based on Jacksonville's 1979-1988 weather data.

Months Ranked From Hottest to Coldest		
Month	Rank (1=hot)	Relative Position
July	1	-22.7
August	2	-21.8
June	3	-20.6
September	4	-18.1
May	5	-13.3
October	6	-8.4
April	7	-6.3
November	8	1.7
March	9	3.0
December	10	9.9
February	11	10.0
January	12	17.2

Table 4

[5] It is important to consider degree days and temperature when defining typical weather, because degree days affect energy consumption while high and low temperatures affect peak demand.

Step 2

The second step is to calculate the target values of HDD, CDD, MINTEMP, and MAXTEMP for each month. These targets will be used in step 3 to determine which months in the historical data are most typical. The goal in this step is to combine the data in a manner such that the most harsh months from each year are analyzed together.[6]

To combine the most harsh months, JEA uses a method similar to the one described in step 1 to rank the months within each year from hottest to coldest. The months within each year with the same rank are analyzed together. The analysis consists of calculating the targets -- the median values of HDD, CDD, MINTEMP, and MAXTEMP.[7] The targets for the 1988 typical weather year are shown in Table 5.

1988 Typical Weather Year Targets				
Month	HDD	CDD	MINTEMP	MAXTEMP
January	477	3	18	79
February	377	5	26	81
March	189	26	32	84
April	47	113	40	89
May	1	251	48	93
June	0	434	65	95
July	0	496	66	99
August	0	477	67	98
September	0	349	58	94
October	24	155	45	91
November	115	56	33	86
December	267	20	28	82

Table 5

Step 3

The final step is the selection of the typical weather year. As indicated above, the typical weather year consists of 12 typical months. A month is selected as typical if it's data most closely matches the targets for that month. The typical January, for example, is the January out of the last 10 years whose HDD, CDD, MINTEMP, and MAXTEMP most closely match the January targets.

Mathematically, closeness, or deviation from target, is calculated by summing the absolute values of the differences between the targets and the actual values. A seasonal weighting factor places emphasis on HDD and MINTEMP in winter and on CDD and MAXTEMP in summer according to the following formula:

6 The purpose of processing the months together in this manner is to reduce the dampening effect of a simple averaging methodology. For example, suppose the high temperature for the year reached 100 °F three years in a row, but occurred in three different months. The high temperature in the hottest month may have averaged 99 °F in the same three year period. A simple average would indicate that the average high temperature is 99 °F, when in fact it typically reaches 100 °F.

7 The median is used instead of the mean in order to dilute the effects of abnormally high or low values and is necessary because only 10 data points are used.

$$\begin{aligned} DEV = \; & ABS(\Delta HDD) * WT_{HDD} + \\ & ABS(\Delta CDD) * WT_{CDD} + \\ & ABS(\Delta MINTEMP) * WT_{MINTEMP} + \\ & ABS(\Delta MAXTEMP) * WT_{MAXTEMP}, \end{aligned}$$

Where,

DEV is the total deviation from target for the month,
ABS is the absolute value function,
ΔHDD is the difference between actual HDD and the target,
ΔCDD is the difference between actual CDD and the target,
ΔMINTEMP is the difference between actual MINTEMP and the target,
ΔMAXTEMP is the difference between actual MAXTEMP and the target,
WT_{HDD} is the seasonal weight for HDD,
WT_{CDD} is the seasonal weight for CDD,
$WT_{MINTEMP}$ is the seasonal weight for MINTEMP, and
$WT_{MAXTEMP}$ is the seasonal weight for MAXTEMP.

Weighting factors vary by season.[8] In winter, the weights for HDD and MINTEMP are 2 and 20, respectively. In summer, the weights for CDD and MAXTEMP are 2 and 20, respectively. In spring and fall, the weights for MINTEMP and MAXTEMP are both 10. Weights not mentioned have a value of 1.

Table 6 shows JEA's 1988 typical weather year.

1988 Typical Weather Year					
Month	YEAR	HDD	CDD	MINTEMP	MAXTEMP
January	1979	523	2	19	78
February	1988	382	7	25	82
March	1981	203	23	32	81
April	1988	54	122	41	91
May	1982	0	244	48	95
June	1987	0	433	58	95
July	1987	0	498	67	99
August	1982	0	478	68	97
September	1985	0	343	59	94
October	1979	23	141	46	87
November	1982	102	56	33	84
December	1987	269	20	28	83

Table 6

[8] For the purpose of calculating weighting factors, winter is defined as December through February, summer is defined as May through September, and Spring and Fall are defined by default.

WEATHER ADJUSTMENT

The FPSC defines the weather adjustment as, "...changes made [to actual data] to mathematically adjust...for differences in weather conditions between the test year and the normal weather year...". JEA calculates the weather adjustments to seasonal peak demand and annual NEL by, first, evaluating the models using as input actual weather conditions, second, evaluating the models using as input typical weather, and third, calculating the differences between the models' responses to actual weather and their respective responses to typical weather. Table 7 exhibits the procedure for the winter system peak:

A	B	C	D	E	F
			Winter Peak Model Evaluated at		
Year	Actual MINTEMP	Typical MINTEMP	Actual MINTEMP	Typical MINTEMP	Weather Adjustment (E-D)
1980	23	23	1115	1115	0
1981	13	24	1199	1106	-93
1982	17	24	1249	1148	-102
1983	26	24	1142	1180	38
1984	26	23	1123	1161	38
1985	7	19	1619	1430	-189
1986	16	19	1568	1511	-58
1987	29	16	1384	1777	393[9]
1988	25	19	1558	1709	151

Table 7

Column B is the minimum temperature on the winter peak day. Column C is the minimum temperature of the typical weather year. Note that typical MINTEMP changes several times from 1980 to 1988. This is due to re-defining typical weather every year. Columns D and E are the values of the regression equations (defined in the peak model section) evaluated at actual MINTEMP and typical MINTEMP, respectively. Column F, the weather adjustment is the difference between columns D and E.

The weather adjustment for annual NEL is calculated in a similar way, except that the regression equations are used to estimate MWH sales for each day based on average temperature of the day. Annual NEL is the sum of the daily NELs. The weather adjustment is the difference between the model evaluated using typical weather and the model evaluated using actual weather.

[9] The weather adjustment seems to be out of the range of reasonableness for 1987. Two factors produce these results. First, there are no actual data points below 29 °F in 1987. This may cause the regression model to perform poorly at 16 °F, typical MINTEMP. Second, 16 °F was chosen as typical for MINTEMP in 1987. This is significantly lower than was chosen for any other year, and does cause the adjustment to be higher.

PERFORMANCE

Tables 8, 9, and 10 show, respectively, the weather adjusted winter peak demand, summer peak demand, and annual NEL for years 1980 through 1988.

Weather Adjusted Winter Peak Demand			
Year	Actual Peak (MW)	Weather Adjustment (MW)	Weather Adjusted Peak (MW)
1980	1143	0	1143
1981	1260	-93	1167
1982	1291	-102	1189
1983	1159	38	1197
1984	1233	38	1271
1985	1586	-189	1397
1985	1640	-58	1582
1987	1439	393	1832
1988	1633	151	1784

Table 8

Weather Adjusted Summer Peak Demand			
Year	Actual Peak (MW)	Weather Adjustment (MW)	Weather Adjusted Peak (MW)
1980	1296	-59	1237
1981	1306	-60	1246
1982	1238	38	1276
1983	1389	41	1430
1984	1335	85	1420
1985	1479	-27	1452
1985	1553	22	1575
1987	1628	23	1651
1988	1655	54	1709

Table 9

Weather Adjusted Annual Net Energy For Load			
Year	Actual NEL (GWH)	Weather Adjustment (GWH)	Weather Adjusted NEL (GWH)
1980	6051	-311	5740
1981	6089	-182	5907
1982	6076	20	6096
1983	6348	7	6355
1984	6453	170	6623
1985	6996	-64	6932
1985	7337	0	7337
1987	7729	34	7763
1988	8065	7	8072

Table 10

JEA's analysis of the data presented in Tables 8, 9, and 10 indicates that all three models reduce the variability in the data and therefore make seasonal peak demands and annual NEL more predictable. The most dramatic improvement, however, is made in the winter peak. Figure 7 shows this graphically.

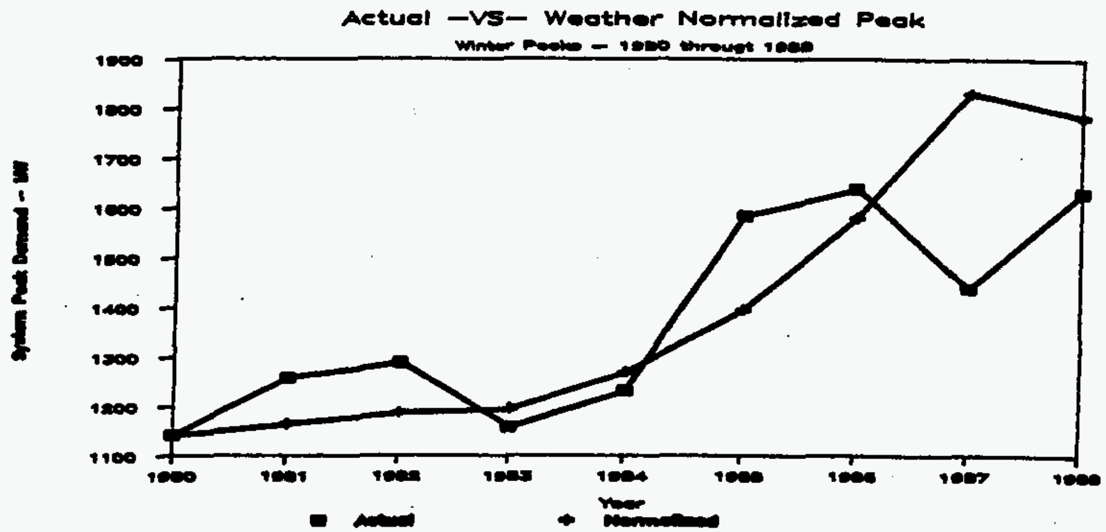

Figure 7

FUTURE ACTIVITIES

JEA is aware that its weather normalization procedure is not perfect, and is therefore committed to improving it. Probable items for future consideration include selection of new functions to model summer and winter peak demand, the addition of other variables (such as humidity) to the NEL model, and development of a method to produce more consistent typical weather years.