BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 001703-EM

In the Matter of

PETITION OF DETERMINATION OF NEED FOR POWER PLANT IN DUVAL COUNTY BY JEA.

______________________________________/

PROCEEDINGS:	**HEARING**
BEFORE:	**CHAIRMAN E. LEON JACOBS, JR.** **COMMISSION LILA A. JABER** **COMMISSIONER BRAULIO L. BAEZ**
DATE:	**Thursday, February 8, 2001**
TIME:	**Commenced at 9:30 a.m.** **Concluded at 9:55 a.m.**
PLACE:	**Betty Easley Conference Center** **Room 148** **4075 Esplanade Way** **Tallahassee, Florida**
REPORTED BY:	**KORETTA E. STANFORD, RPR** **Official FPSC Reporter**

APPEARANCES:

RICHARD D. MELSON, Hopping Green Sams & Smith, Post Office Box 6526, Tallahassee, Florida 32314, appearing on behalf of Jacksonville Electric Authority (JEA).

DEBORAH HART, Florida Public Service Commission, Division of Legal Services, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0870, appearing on behalf of the Commission Staff.

INDEX

WITNESSES

EXHIBITS

NUMBER:		ID.	ADMTD.
JEA-1	Need Application	19	74
JEA-2	Revised Errata Sheet	19	74
3	Staff's Composite	74	74
4	Affidavit of Publication	75	75

PROCEEDINGS

CHAIRMAN JACOBS: Call the hearing to order. Counsel, read the notice.

MS. HART: Pursuant to notice issued December 6th, 2000, and notice published in the "Florida Administrative Weekly" on December 15th, 2000, and published as amended in the "Florida Administrative Weekly" on January 5th, 2001, this time and place have been noticed for hearing in docket number 001703-EM, participation for determination of need for power plant in Duval County by JEA. Also, notice was published in "The Florida Times-Union" in Jacksonville, Duval County, Florida, on December 10th, 2000, pursuant to the requirements of Section 403.519, Florida statutes.

The purpose of this hearing will be for Commission to take final action to determine the need pursuant to Sections 403.501 through 519, Florida statutes, for the conversion to a combined cycle unit of two of the combustion turbines currently under construction at the Brandy Branch generation station in Duval County, Florida.

This proceeding shall allow JEA to present evidence and testimony in support of its petition for a determination of need for its proposed plant and related facilities in Duval County Florida to permit members of the public who are not parties to the need determination preceding the opportunity to present testimony concerning this matter and for such other purposes as the Commission may deem appropriate.

CHAIRMAN JACOBS: Take appearances.

MR. MELSON: Richard Melson of the law firm, Hopping, Green, Sams & Smith, on behalf of JEA.

MS. HART: Deborah Hart, Commission Staff counsel.

CHAIRMAN JACOBS: Very well. Are there any preliminary matters?

MS. HART: We usually ask if there are any members of the public here that are wishing to participate in the proceeding.

CHAIRMAN JACOBS: Let the record reflect, then, there are no members of the public present.

Very well. As I understand it, there has been significant agreement achieved in the docket. Why don't you walk us through how we should proceed this morning.

MS. HART: I think, we should go ahead and let Mr. Melson present his one witness that we have not excused and who has agreed to be here today and is available for Commission questions; and then, stipulate in the rest of the testimony as well as JEA's exhibits, and then Staff has two exhibits to offer as well.

CHAIRMAN JACOBS: Very well. Mr. Melson.

MR. MELSON: Commissioner Jacobs, my understanding is that the Commission had agreed to excuse all of the witnesses, except Mr. Boswell. Given that, I've asked Mr. Boswell not to do a summary this morning. I'm prepared to make a brief opening statement, if you're interested in hearing one. Otherwise, if you just have questions for Mr. Boswell, we can probably proceed more quickly just by putting him on the stand.

CHAIRMAN JACOBS: Okay. I don't have any particular need to hear an opening – unless the other Commissioners do.

MR. MELSON: Okay. JEA calls Randy Boswell.

CHAIRMAN JACOBS: That's because you're so effective.

Would you raise your right hand?

RANDY BOSWELL

Was called as a witness on behalf of the JEA and, having been duly sworn, testified as follows:

CHAIRMAN JACOBS: Thank you. You may be seated.

DIRECT EXAMINATION

BY MR. MELSON:

Q Mr. Boswell, would you state your name and business address, please?

A Randy Boswell, 21 West Church Street,

Jacksonville, Florida.

Q And what is your position with JEA?

A I am the Vice President of Production Services.

Q And have you prefiled direct testimony in this docket consisting of 10 pages?

A Yes, I have.

Q Do you have any changes or corrections to that testimony?

A No, sir.

Q And if I were to ask you the same questions today, would your answers be the same?

A Yes, they would.

MR. MELSON: Mr. Chairman, I'd ask that Mr. Boswell's direct testimony be inserted into the record as though read.

CHAIRMAN JACOBS: Without objection, show the direct testimony entered into the record.

BEFORE THE PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF RANDY BOSWELL

ON BEHALF OF JEA

DOCKET NO. 001703-EM

December 18, 2000

Q. Please state your name and address.

A. My name is Randy Boswell. My business address is 21 West Church Street, Jacksonville, Florida 32202.

Q. By whom are you employed and in what capacity?

A. I am employed by JEA. My current position is Vice President of Production Services.

Q. Please describe your responsibilities in that position.

A. My responsibilities include the overall management of generation expansion planning efforts for JEA and the management of JEA's wholesale full and partial requirements power supply contracts. My responsibilities also include the management of all fuel procurement activities for the JEA system.

Q. Please state your professional experience and educational background.

A. I received a Bachelors degree in Electrical Engineering from Georgia Institute of Technology. I am a registered Professional Engineer in the State of Florida.

I have been employed by JEA for over 27 years During that time I have held the following positions in the organization Engineer in the Transmission and Substation Division, Engineer in the System Planning Division, Division Chief of Energy Dispatch, and Director of System Operations. I assumed my current position as Vice President of Production Services in 1995.

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

A. The purpose of my testimony is to provide an overview of JEA and the Brandy Branch Combined Cycle Conversion Project (the "Brandy Branch Conversion"); to discuss the strategic factors taken into consideration when deciding to pursue the project; and to discuss JEA's plans for financing the project.

Q. **Are there sections of the Need for Power Application identified as Exhibit ___ (JEA-1) that were prepared by you or under your direct supervision?**

A. Yes. Sections 1, 3, 15 and 16 were prepared by me or under my supervision.

Q. **Are you adopting these sections as part of your testimony?**

A. Yes.

Q. **Are there any corrections to these sections?**

A. Yes. Minor corrections to Sections 1 and 3 are shown in Exhibit _____ (JEA-2).

Q. **Please describe JEA.**

A. JEA (formerly known as the Jacksonville Electric Authority) is the largest municipal utility in Florida. We serve approximately 350,000 electric customers in Duval and surrounding counties

The total net generating capability of JEA's system is 2,708 MW (summer). In addition, three simple cycle combustion turbine units are under construction at the Brandy Branch Generating Station ("Brandy Branch") and Northside Units 1 and 2 are being repowered to burn solid fuel.

Q. Please describe the project for which JEA is seeking a determination of need in this proceeding.

A. We are seeking a determination of need for the addition of a 197 MW steam turbine generator and related facilities that will be installed to convert two of the Brandy Branch combustion turbines to combined cycle operation. The planned commercial operation date for the project is June 2004.

In a combined cycle mode, waste heat from the combustion turbines is used to power the new steam turbine generator. The conversion to combined cycle operation thus enables JEA to generate additional electricity for the same amount of fuel, and significantly increases the overall efficiency of the units.

Q. What is the primary driver of the need for additional capacity in 2004?

A. The need for additional capacity in 2004 results from continuing load growth on JEA's system. With this growth, we need additional capacity resources by 2004 in order to maintain a minimum 15% reserve margin.

Q. Please briefly describe the process that led to the selection of the Brandy Branch Conversion as the most cost-effective alternative to meet the 2004 capacity need.

A. The selection of the Brandy Branch Conversion is the result of our on-going generation planning processes. Our 1997 Integrated Resource Plan (IRP) showed a significant increase in JEA's peaking power requirements starting in the 2000 to 2001 time frame. The 1997 IRP concluded that new simple cycle combustion turbines would provide the most economic means to meet those peaking requirements. As a result, JEA installed one combustion turbine at its existing Kennedy Generating Station and is currently installing three combustion turbines at the new Brandy Branch site. Two of the Brandy Branch units are scheduled for completion in May 2001 and the final unit should be in commercial operation by the end of 2001.

The Brandy Branch site was designed with the future in mind. We provided sufficient infrastructure, including transmission and gas pipeline capacity, to support either the addition of a fourth simple cycle combustion turbine or the addition of a steam turbine unit to convert two of the combustion turbines to combined cycle operation.

Q. What was the next step in the decision process?

A. In its 2000 Ten Year Site Plan (TYSP) study, JEA presented its latest evaluation of the future capacity needs of its electric system. This evaluation indicated that additional capacity would be needed to meet system reserve requirements beginning in the year 2004.

JEA undertook an extensive set of analyses to select the most cost-effective alternative for meeting this need. These analyses showed that the Brandy Branch Conversion option is the most cost-effective alternative available to meet our 2004 capacity need. It provides $17 million in Present Worth Revenue Requirement (PWRR) savings over 20 years compared to the best alternative other than the Brandy Branch Conversion. The project was formally approved by JEA's Board on October 17, 2000, and the project has been included in JEA's capital budget.

Other witnesses will provide more detail about JEA's generation planning process, including the wide range of generating technologies that were considered, the sensitivity studies that were performed to ensure that the Brandy Branch Conversion performs well under a variety of generation planning assumptions, and the underlying load and fuel forecasts.

Q. What role do strategic considerations play in the selection of the most cost-effective capacity resource?

A. JEA strives to provide its customers with the lowest rates they can achieve while maintaining sound operating principles and environmentally clean units. This means that in addition to evaluating the cost of any capacity addition, we must consider a variety of other factors to determine whether the least-cost option is in fact our preferred alternative. As I discuss below, in this case a variety of qualitative factors all support the selection of the Brandy Branch Conversion as our most cost-effective capacity addition.

Q. Please summarize the major strategic factors that were considered in the selection of the Brandy Branch Conversion project.

A. One major consideration is fuel diversity on JEA's system. With our ownership interest in the St. Johns River Power Park and Scherer Unit 4, unit power purchases from Southern Company, and the repowering of Northside Units 1 and 2 to burn petroleum coke / coal, JEA is significantly dependent on solid fuel to meet its base load generating requirements. The addition of efficient natural gas fired units that can operate as base load or intermediate generation provides a needed measure of fuel diversity to our system.

The addition of JEA-owned capacity, rather than increased reliance on purchased power, provides two strategic benefits. By controlling the generating capacity, we can maximize operating flexibility by dispatching the units as needed, scheduling maintenance when it best meets our system needs, and taking other steps that increase the value of the capacity. By locating the additional capacity on JEA's transmission system close to the load, we eliminate the risk of transmission issues beyond our control and enhance the certainty of energy delivery.

The use of an existing site minimizes environmental impacts and reduces the time and effort required for licensing. The low level of emissions from the Brandy Branch Conversion gives some protection from the risk of future environmental regulations. Because the conversion provides additional capacity without burning additional fuel, it enables JEA to reduce overall emissions by displacing energy that would otherwise be generated by less efficient units with higher emission rates.

Q. Are there any other strategic factors that favor the Brandy Branch Conversion?

A. Yes. Because infrastructure such as transmission interconnections and a natural gas pipeline are already in place at Brandy Branch, JEA not only avoids the cost of those facilities, but also eliminates the time that would be required to extend such facilities to a new (greenfield) site. Also, since the combustion turbines are already on site at Brandy Branch, JEA avoids the delivery delays that would be associated with construction of similar capacity at a greenfield site. Given our need for capacity by 2004, the ability to minimize the construction schedule is an important consideration.

Finally, given the uncertainty in the merchant power market as the result of the Florida Supreme Court's decision in the Duke case, a JEA-owned and operated project eliminates the risks associated with attempting to license a non-utility owned project.

Q. Are there any other economic benefits from the Brandy Branch Conversion that have not been directly reflected in the economic analysis?

A. Yes. JEA and three other utilities that are constructing combined cycle units based on General Electric combustion turbines are in the process of forming an alliance to minimize their cost of construction, ownership and operation of these units. This alliance, which we call Power Partners, will develop a standardized design for the 2 by 1 combined cycle plants, share project management resources, develop and share common training materials, and share spare parts inventory We expect that this initiative will result in savings in construction, operation and maintenance costs for all of the Power Partners. In addition, through our combined buying power we hope to achieve some capital cost savings as well.

Q. How does JEA intend to finance the construction of the Brandy Branch Conversion?

A. No final decision has been made as to the method of financing. As with other recent projects, JEA will assess whether the project should be financed with long-term debt, short-term debt, internally generated funds, or a combination of these sources. For example, the Brandy Branch combustion turbines were financed with a combination of internally generated funds and variable rate debt.

As a municipality, JEA could finance the project in whole or in part with tax-free debt. There are, however, certain restrictions on the use of capacity funded with tax-exempt sources. With the uncertainty in the industry relative to deregulation, it may be prudent to use taxable bonds. If deregulation were to occur and JEA were to lose some of its customer base, JEA would then be able to sell capacity from Brandy Branch without any restrictions.

Q. **Does JEA have the capability to finance the project with long term debt if required?**

A. Yes. JEA is financially very healthy Our debt service coverage ratio for 2000 is 2.43 and we have strong credit ratings on all of our outstanding debt. In addition, JEA's electric rates in all customer classes continue to be significantly lower than both the Florida average and the Unites States average. In light of this financial health, JEA has the capacity to finance the project entirely through long-term debt if that proves to be the most appropriate option.

Q. **In the absence of a final decision about how JEA will fund the Brandy Branch Conversion, what assumption about cost of money was made in the economic analyses?**

A. In an effort to be conservative, our base case analysis assumed the use of 100% taxable debt. If we choose to use tax exempt financing, the cost of the project would be reduced even further.

Q. **Are you confident that the Brandy Branch Conversion project is the most cost-effective alternative available to JEA to meet its 2004 capacity need?**

A Yes. As I stated earlier, the Brandy Branch Conversion is our least cost option, with $17 million PWRR savings compared to the next best alternative. While they did not change the final decision, the strategic considerations outlined above support the selection of that project as the most cost-effective addition to meet our need. With its relatively low cost, this project will be a good investment for JEA and should provide needed capacity at a reasonable cost for many years into the future.

Q. Does this conclude your testimony?

A. Yes.

MR. MELSON: This might be the appropriate time, if we could have -- we had various witnesses sponsoring different parts of the Need Application.

CHAIRMAN JACOBS: Okay.

MR. MELSON: We'd like to have this document marked, if we could, as Exhibit Number 1.

CHAIRMAN JACOBS: Very well. That is the full --

MR. MELSON: That's the full Need Application.

CHAIRMAN JACOBS: Okay. That is marked as Exhibit 1.

(Exhibit 1 marked for identification.)

MR. MELSON: And then, we handed out this morning a revised errata sheet consisting of five pages that's identified in the upper left-hand corner as JEA-2. We'd like to ask that that be identified as Exhibit 2, if we could.

CHAIRMAN JACOBS: Very well. That is Exhibit 2.

(Exhibit 2 marked for identification.)

BY MR. MELSON:

Q Mr. Boswell, are you sponsoring Sections 1, 13, 15, and 16 of the document that's just been identified as Exhibit 1?

A 1, 3, 15 and 16.

Q I'm sorry. You can read better than I can; 1, 3, 15 and 16. Do you have any changes to your portions of that document, other than those that are shown on the errata sheet that's been identified as Exhibit 2?

A No, I do not.

MR. MELSON: The witness is available to answer questions.

CHAIRMAN JACOBS: Very well.

MS. HART: Staff has no cross.

CHAIRMAN JACOBS: Very well. I think, it was perhaps my question. I don't know if anybody else had any questions. I think, it had to primarily go to the process by which you determine whether or not there were conservation measures that would be applicable. And maybe -- correct me if I'm wrong, but as I understand it, in your analysis, you arrived at the conclusion that there were no conservation programs that would be cost-effective --

THE WITNESS: That's correct.

CHAIRMAN JACOBS: -- under this. And as I understood it, that process -- walk me through that process.

THE WITNESS: Well, the process was the same or similar to the process that we used just this past year in our conservation goals docket where we analyzed or had Black & Veatch, our engineer, analyze the various alternatives that were potentially available to us using the fire model that the Commission typically recognizes as the appropriate model.

We did the goals back last year, and actually had zero goals set, because there just were not any DSM measures that were economic to us. We had Black & Veatch rerun those models against the inputs that are in the need for power application that Mr. Melson has introduced into evidence, and they still showed that there were no economic DSM that we could apply that would work.

We further -- Staff has asked in some of their interrogatories for us to use some higher fuel forecasts to see whether our results would be the same. Staff didn't ask us to do it, but we asked our engineer to run the higher fuel through the model, and we still got the same result.

CHAIRMAN JACOBS: Now, when you say higher fuel, we're talking about natural gas.

THE WITNESS: Yes.

CHAIRMAN JACOBS: And the prices of gas that we use in this second analysis, do you know what the range of those were?

THE WITNESS: Yes. The starting price was $4.98 a million BTUs in the year 2000 escalating over the 20-year horizon.

CHAIRMAN JACOBS: Okay.

THE WITNESS: So, it was a pretty aggressive promise.

CHAIRMAN JACOBS: Okay. Go ahead. You can finish.

THE WITNESS: Well, that was the basis of our conclusion that there weren't any cost-effective DSM that could offset this need.

CHAIRMAN JACOBS: And the existing programs that you have in place wouldn't be affected. That's something only to offset this project and this conversion, correct?

THE WITNESS: That's correct. The programs we have in place will continue in place.

CHAIRMAN JACOBS: And the thought occurs to me, and here's where I am. In the marketplace that we have right now, and it has been well-documented, and I don't want to interject into the record the whole idea and the specifics of what's happening in the natural gas market, but conceptually, we have a much more volatile marketplace, I think, we would agree.

And rather than coming and doing an analysis, coming back and doing an analysis against projects down the road, it occurs to me that in that event we may want to, on the front end, begin to understand where a trigger line would be; in other words, where would the line of demarcation be for this which would make DSM or any kind of conservation program cost-effective? Do you do something of that analysis of that type?

THE WITNESS: We have not done that analysis.

CHAIRMAN JACOBS: Okay. That's something that we may want to explore in the next conservation docket, because, I think, what it may help us to do from a positive level is to try and ascertain how to manage the goals better.

I would hate for us, for a year's time to forego opportunities to do conservation. Quite frankly, I think, it's becoming much more important to do that. As you may be aware, in California one of the most important things they've done is to go back and reassess what they can do to avoid demand in the midst of the circumstances that are going on there with some pretty impressive results.

So, one of the things I'd like to do is even when we come back and we demonstrate that based on present analysis, there is no program that is cost-effective, I'd like for there to be an understanding where that trigger line is.

That's all the questions I have. I guess, that's it.

MR. MELSON: No redirect.

CHAIRMAN JACOBS: Thank you.

THE WITNESS: You're welcome.

MR. MELSON: Commissioner Jacobs, I guess --

CHAIRMAN JACOBS: Go through the other witnesses now?

MR. MELSON: Go through the other witnesses.

Mr. Bond, Charles Bond, had filed 9 pages of direct testimony. We'd ask that that be inserted into the record as though read.

CHAIRMAN JACOBS: Without objection, show the testimony of Chuck Bond entered into the record as though read.

BEFORE THE PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF CHARLES BOND

ON BEHALF OF JEA

DOCKET NO 001703-EM

DECEMBER 18, 2000

Q. Please state your name and address.

A. My name is Charles Bond. My business address is 21 West Church Street, Jacksonville, Florida 32202.

Q. By whom are you employed and in what capacity?

A. I am employed by JEA. My current position is the Manager of Capacity Planning.

Q. Please describe your responsibilities in your current position.

A. As the Manager of Capacity Planning, I am responsible for capacity planning for JEA's electric system including data collection for the JEA Production Business Unit's monthly electric operating reports; preparation of the annual Ten Year Site Plan for the Florida Public Service Commission; seasonal and long term electric capacity acquisitions through The Energy Authority; load forecasting; economic analysis modeling to support major capital projects such as the Northside Units 1 & 2 Repowering and the Brandy Branch Combustion Turbine and Combined Cycle Conversion Projects; and modeling to support the JEA's annual fiscal budget preparation.

Q. Please state your professional experience and educational background.

A I have a Bachelor of Science Degree in Civil Engineering from Clemson University. I am a Registered Professional Engineer in the State of Florida.

I have been employed by JEA since 1982. I began my career with the utility as a Project Engineer in the Power Engineering Division. In 1984, I assumed the position of Construction Manager in the Power Engineering Division where I was involved in projects involving our large steam powered units. In 1988, I became a Project Manager where I was responsible for project and construction management on various power plant projects. In 1997, I was assigned as the Senior Project Manager for the purchase and installation of four combustion turbines at Kennedy and Brandy Branch. In 1999, I assumed my current position as Manager of Capacity Planning for JEA.

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

A. The purpose of my testimony is to explain the reliability criteria used by JEA for generation resource planning purposes and the impact on JEA if the Brandy Branch Conversion is delayed. I will also explain why JEA believes that its decision not to issue a Request for Proposals (RFP) was prudent. Finally, I will provide an overview of JEA's demand side management (DSM) programs.

Q. Are there sections of the Need for Power Application identified as Exhibit ___ (JEA-1) that were prepared by you or under your direct supervision?

A. Yes. Sections 2, 8.1, 9, 10, and 17 were prepared by me or under my supervision.

Q. Are you adopting these sections as part of your testimony?

A. Yes. I am

Q. Are there any corrections to these sections?

A. Yes. Minor corrections to these sections are included in the errata sheet identified as Exhibit ___ (JEA-2).

Q. Please explain the concept of a "reliability criteria" and why it is important for planning purposes.

A. The mission of JEA is to provide safe, adequate and reliable power to its customers at the lowest reasonable cost in a manner consistent with minimizing environmental impacts. The reliability criteria is associated with the "adequate and reliable power" supply portion of the utility's mission

To serve native load, a utility must have firm capacity resources in excess of its expected firm peak demand. This margin of capacity over firm peak load is needed because factors affecting either demand or supply could cause load to go unserved if a utility maintained only enough resources to meet its expected firm peak demand. On the demand side, higher than expected demand can occur due to a greater number of customers on the system, greater than expected energy usage per customer, extreme weather conditions, or lower than anticipated demand side measure impacts. On the supply side, generation capacity could be unavailable due to factors such as forced or scheduled outages on generation equipment, unanticipated transmission constraints limiting power imports, generator deratings due to equipment failures, and unanticipated constraints on fuel supplies or water supplies.

Due to the uncertainties involved with projecting both demand and available supply, utilities maintain a "margin" of firm capacity resources over and above the anticipated peak level of firm demand. Traditionally in the industry, reserve levels of 15 percent are typical, with some utilities having adopted an even higher reserve margin. The appropriate level of reserve margin varies by utility, but generally, the smaller the utility and the fewer number of interconnections with other utilities, the greater is the reserve margin.

Q. What is the target reserve margin adopted by JEA?

A. JEA has adopted a 15 percent reserve margin level. This is based on the work of the Florida Reliability Coordinating Council which has found that a planned reserve margin criterion of 15 percent is adequate for Peninsular Florida. The 15 percent reserve margin has also been established as a minimum planned reserve margin in Rule 25-6.035(1) Florida Administrative Code. Therefore, JEA believes this to be the minimum level it should maintain, consistent with prudent planning and Florida regulations.

Q. How does the need to meet this reliability criteria impact the timing and need for additional capacity resources for JEA?

A. In order to maintain a 15 percent reserve margin requirement, JEA will need 261 MW of additional capacity resources in the winter of 2002 while Northside Unit 1 is out of service for repowering Because there is insufficient time to meet this

2002 need with new JEA system capacity resources, these capacity needs will be met though seasonal power purchases. Also, this temporary need disappears in 2003 as the repowered Northside Unit 1 is returned to service. However, due to load growth, if no additional capacity is added to the system beyond the currently committed units, a permanent need for additional capacity would arise in 2004 and increase thereafter. In 2004, there would be a summer deficit of 40 MW, increasing to 135 MW in the summer of 2005. Looking at the winter deficit, if no capacity is added beyond the currently committed units, a deficit of 58 MW would arise in the winter of 2004/05 and increase to 169 MW the following year. By the end of the planning horizon in winter 2018/19, JEA will require 2,002 MW of additional capacity to maintain its required reserve margin.

Q. **What would be the consequences of a significant delay or non-approval of the Brandy Branch Conversion?**

A. Mary Guyton-Baker will testify that non-approval would mean that JEA customers would be denied the most cost-effective power supply. A significant delay would mean that from a reliability perspective, JEA's reserves would fall below the minimum reserve level of 15% in 2004. While off-system purchases could perhaps be made to maintain the target reserve margin, there is no assurance that the capacity would be available, or that it would be cost-effective for JEA's ratepayers.

Q. **In your position with JEA, were you involved in the decision not to issue an RFP for capacity to meet the 2004 need?**

A. Yes.

Q. What was the basis of this decision?

A. Rule 25-22.082 of the Florida Administrative Code exempts municipal utilities from being required to conduct a RFP process when construction a new generating unit. JEA is nevertheless intent on providing service to its ratepayers at the lowest possible cost consistent with maintaining reliability and minimizing environmental impacts. JEA would have conducted an RFP process if it believed that there was a realistic chance of securing capacity resources that are more cost-effective than the Brandy Branch Conversion. The decision not to issue an RFP was made based on a number of factors which are summarized below.

JEA has had discussions with developers regarding competitively-procured capacity and has also monitored prices paid for power by other utilities undergoing a competitive bidding process. For example, the recent Panda proposal to Florida Power Corporation for gas-fired combined cycle capacity contained demand charges of \$6.75/kW-month and \$9.10/kW-month, which are roughly 50 to 100 percent higher than the Brandy Branch Combined Cycle demand cost, which is estimated to be \$4.42/kW-month.

One reason for the decided JEA cost advantage is that the combustion turbine units currently under construction at Brandy Branch were placed under contract in 1998, just prior to the significant run-up in price that continues in the combustion turbine market. The contract price for the Brandy Branch combustion turbines was approximately \$30 million for each unit compared to a current price of \$38 to \$39 million.

In addition, there are significant site infrastructure savings associated with the Brandy Branch Conversion. The existing transmission lines, natural gas lateral, substation facilities, and other common facilities such as water and oil storage tanks, buildings for operation and maintenance, and water and wastewater treatment facilities required for the simple cycle combustion turbines will be utilized for the combined cycle plant, resulting in a cost savings.

Finally, while JEA has not made a final decision on the use of tax exempt financing, it has access to such funding. Because JEA conservatively assumed the use of taxable debt in its generation planning analyses, the potential cost savings from the use of tax exempt financing has not been quantified. Even without tax exempt financing, JEA has a lower overall cost of money than privately developed projects.

These cost advantages for the Brandy Branch Conversion make it extremely unlikely that an RFP process would produce any lower cost alternative.

Q. Were there any non-cost considerations in JEA's decision not to issue an RFP?

A. Yes Another significant issue is the uncertainty regarding the merchant power market as the result of the Florida Supreme Court's ruling in the Duke Energy case. This uncertainty will likely postpone any combined cycle merchant plant development until after the 2020 Energy Study Commission makes recommendations and those recommendations are acted on by the Florida

Legislature. These legal issues cast uncertainty on any developer's ability to assure that generating capacity will be available in the time frame required to meet JEA's need.

Finally, JEA is part of The Energy Authority (TEA), along with five other municipal utilities. 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 Mr. Reedy of TEA will testify regarding the market for purchased power.

Q. Has anything occurred since the decision not to issue an RFP was made that would lead you to change your mind about that decision?

A. No. We have seen no information to suggest that any lower cost resource is available to meet the long term reliability need that will be satisfied by the Brandy Branch Conversion.

Q. With regard to demand side management, does JEA currently have any Commission-established conservation goals?

A. No. In the 2000 conservation goals docket the Commission determined that there were no cost-effective conservation measures available to JEA and therefore did not establish goals

Q. Does JEA nevertheless currently offer any conservation programs?

A. Yes. JEA offers a number of conservation programs that are either required by regulation (such as energy audits) or that JEA deems beneficial to the community as a whole (such as information and educational programs) despite the fact that they do not pass traditional cost-effectiveness tests. These programs are described in detail in Section 8.1 of the Need for Power Application, Exhibit ___ (JEA-1).

Q. How has JEA addressed the potential for additional demand side management to affect the need for, or timing of, the Brandy Branch Conversion.

A. An analysis performed by Black & Veatch supports JEA's conclusion that there are no cost-effective measures that would delay or avoid the need for the Brandy Branch Conversion. Mr. Rollins will testify to the details of that analysis.

Q. Does this conclude your testimony?

A. Yes.

MR. MELSON: And just as an overview, none of the witnesses had any exhibits, other than their portions of Exhibit 1 and 2.

CHAIRMAN JACOBS: Very well.

MR. MELSON: So, we'll only be inserting testimony.

We'd ask that 7 pages of direct testimony of Mary Guyton-Baker be inserted into the record as though read.

CHAIRMAN JACOBS: Without objection, show the testimony of Ms. Baker entered into the record.

BEFORE THE PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF MARY GUYTON-BAKER

ON BEHALF OF JEA

DOCKET NO. 001703-EM

DECEMBER 18, 2000

Q. Please state your name and address.

A. My name is Mary Guyton-Baker. My business address is 21 West Church Street, Jacksonville, Florida 32202.

Q. By whom are you employed and in what capacity?

A. I am employed by JEA as an Engineer II in the capacity planning group.

Q. Please describe your responsibilities in that position.

A. I have been with JEA since 1987 and have worked in the area of Generation/Capacity Planning during that time. My primary responsibilities include running and maintaining the production costing simulation models for JEA. These models are used to identify the most cost-effective expansion plan for the utility and have identified the Brandy Branch Conversion as the best option for JEA ratepayers. I am also responsible for performing Integrated Resource Planning (IRP) studies, for the preparation of JEA's Ten Year Site Plan, and for various economic and financial studies for JEA. During my career, I have worked with a number of production costing programs including PROMOD, POWRSYM-Plus, PROSYM, and our current model, the Electric Generation Expansion Analysis System (EGEAS).

Q. **Please state your educational background.**

A. My educational background is in the engineering field. After receiving an Associate of Arts degree in pre-engineering from Polk Community College in 1983, I graduated with a Bachelor of Science degree in Industrial and Systems Engineering from the University of Florida in 1986. In 1987 and 1988, I took a course in Engineering Management offered by the University of South Florida through the University of North Florida in Jacksonville.

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

A. The purpose of my testimony is to explain the economic analysis undertaken by JEA which resulted in the identification of the Brandy Branch Conversion as the most cost-effective capacity resource option for JEA and its ratepayers.

Q. **Are there sections of the Need for Power Application identified as Exhibit ____ (JEA-1) that were prepared by you or under your direct supervision?**

A. Yes. Sections 13 and 14.

Q. **Are you adopting these sections as part of your testimony?**

A. Yes, I am.

Q. **Are there any corrections to these sections?**

A. Yes. Minor corrections to Section 14 are shown in Exhibit _____(JEA-2).

Q. Please describe the process for determining the least cost expansion plan.

A. Expansion planning analysis operates under the economic assumption that because consumers of electricity have scarce resources and a time value of money, they desire to have a safe, adequate, reliable, and environmentally compatible supply of electricity at the minimum possible cost when measured on a Present Worth Revenue Requirements, or PWRR basis.

The development of the least cost expansion plan is an iterative process. JEA uses generation expansion planning computer programs such as EGEAS in this process. EGEAS develops expansion plans in which capacity is added to the system on a year by year basis as needed to serve load and to meet the reserve margin requirements. Expansion plans are developed with various types and sizes of unit additions. Within EGEAS, this process is repeated thousands of times until all realistically feasible expansion plans are evaluated. The system variable costs and incremental fixed costs associated with these expansion plans are then calculated for each year, discounted to the base year, and summed. This results in a cumulative PWRR for each expansion plan. In EGEAS the least cost expansion plan is defined as the plan with the lowest cumulative PWRR.

Once the least cost expansion plan is identified, the first unit in that expansion plan is tentatively identified as the next generating unit addition. This least cost alternative is then evaluated in light of the utility's strategic considerations to determine if it is the most cost-effective alternative when all relevant factors are taken into account.

Q. Please provide more detail on how EGEAS performs its cost calculations.

A. To calculate the variable costs associated with serving load (fuel, variable O&M) EGEAS simulates the dispatch of capacity resources on a merit order (or economic dispatch) basis, while taking into account the characteristics of each unit such as net output, net plant heat rate, forced outage rates and scheduled maintenance requirements. It is also important to accurately estimate the fixed costs (capital and fixed O&M costs) of units under consideration. Once the fixed and variable costs associated with an option are derived for each year, these can be added together and discounted to estimate the net present value of serving load for each year in the planning horizon.

Q. Please describe JEA's planning horizon for evaluating the cost of various resource options.

A. Because of the future uncertainty involved in forecasting, the limited life of generating assets, and the average time that a ratepayer is a customer of a given utility system, it is customary to measure PWRR over a limited planning horizon, usually lasting 15 to 25 years into the future.

JEA uses a 20 year planning period. Therefore, from a cost perspective, JEA's objective is to identify the expansion plan that will minimize the cumulative PWRR over a 20 year planning horizon. Costs included in the analysis are system fuel costs and variable operating and maintenance costs; capital and fixed O&M costs for new units; and purchased power demand and energy costs.

Q. In addition to unit-specific cost and operating data, what other information and assumptions are input into EGEAS?

A. In addition to unit operating data, the inputs into EGEAS include the utility's reliability criteria, its load forecast and fuel forecasts over the planning horizon, and financial assumptions. Other witnesses will provide more detail to support these assumptions.

Q. What generating options did JEA evaluate in EGEAS for meeting its 2004 need?

A. We evaluated the Brandy Branch Conversion, simple cycle combustion turbines, greenfield combined cycle units, pulverized coal units, and atmospheric circulating fluidized bed units.

Q. How was this menu of generating alternatives selected?

A. It was selected through a two stage screening process that is discussed in detail by Mr. Rollins.

Q. What was the conclusion of the detailed economic analysis performed in EGEAS?

A. The conclusion of the detailed production costing analysis was that the Brandy Branch Conversion with commercial operation in 2004 is the most economical option available to meet the 15 percent reserve margin criteria. In fact, it is not until Plan No. 145 that EGEAS produces a plan with something other than the Brandy Branch Conversion as the first unit addition. On a net present value basis, Plan No. 145 is over $17 million more costly than the least cost plan (Plan No. 1). Given the base case assumptions, the Brandy Branch Conversion in 2004 is clearly the first addition of the least cost plan for JEA

Q. Given the many assumptions that are involved with forecasting future conditions, how can a utility be confident that it has actually identified the least cost option?

A. We address uncertainty in our expansion plans by modeling many alternative scenarios in which those assumptions subject to future uncertainty are changed, and a least cost plan under the newly created scenario is determined. In the JEA analysis, sensitivities were run for high and low energy forecasts; for high, low, and alternative fuel forecasts; for high and low net present value discount rates; and for a 20 percent reserve margin case.

Q. What were the results of those sensitivity analyses?

A. These analyses demonstrate the Brandy Branch Conversion in 2004 is very robust. In other words, it is the preferred alternative in most sensitivity simulations, including the high fuel price scenario, the alternative fuel price scenario, the low fuel price scenario, the high discount rate scenario, and the low discount rate scenario. In the low load growth scenario, the Brandy Branch Conversion was also the first unit to be added, although the timing was delayed until 2008.

An option other than the Brandy Branch Conversion was selected as the first unit addition only in the high load forecast scenario and the 20 percent reserve margin scenario. Even in these two cases, the Brandy Branch Conversion becomes part of the least cost expansion plan in 2005 in the high load growth scenario and in 2013 in the 20 percent reserve margin scenario. It should be pointed out that in these two scenarios, the driving factor in selection of the first capacity addition was the need for more capacity to meet the reserve requirements than was provided by the Brandy Branch Conversion.

Q. What conclusions did you draw from this analysis?

A. Based on the results of the extensive screening analysis and production costing analysis, the Brandy Branch Conversion is the least cost option for JEA ratepayers under the most likely future conditions expected on the system. It is also the preferred addition in most of the alternative scenarios that may occur on the system. Therefore, based on the criteria and methods commonly used in the industry, I conclude that the Brandy Branch Conversion is the least-cost option for JEA ratepayers.

Q. Does this conclude your testimony?

A. Yes.

MR. MELSON: Mr. Robert Reedy had prefiled 5 pages of direct testimony. We ask that that be inserted into the record as though read.

CHAIRMAN JACOBS: Without objection, show the testimony of Mr. Reedy entered into the record.

BEFORE THE PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF ROBERT REEDY

ON BEHALF OF JEA

DOCKET NO. 001703-EM

DECEMBER 18, 2000

Q. Please state your name and address.

A. My name is Robert Reedy. My business address is 76 South Laura Street, Jacksonville, Florida.

Q. By whom are you employed and in what capacity?

A. I am employed by The Energy Authority (TEA) in Jacksonville, Florida. My current position is Marketing Manager.

Q. What is TEA?

A. TEA is a not-for-profit wholesale energy marketing company managing about 15,000 megawatts of publicly owned generation capacity nationwide. TEA's members consist of the following utilities.

- JEA
- MEAG Power (Municipal Electric Authority of Georgia)
- Santee Cooper (South Carolina Public Service Authority)
- Nebraska Public Power District
- Gainesville Regional Utilities
- City Utilities of Springfield (Springfield, Missouri)

In addition, TEA provides marketing services to several other publicly owned utilities including Kansas City Kansas Board of Public Utilities, Lafayette Utilities System (Lafayette, Louisiana) and Louisiana Electric Power Authority.

Q. What does TEA do?

A. TEA markets (buys and sells) all the wholesale power for its members.

Q. Please describe your responsibilities as Marketing Manager.

A. I am responsible for origination of long term wholesale power transactions for generating capacity nationwide. I am also responsible for development of relationships with potential alliance partners, and the client relationship with designated owners.

Q. Please state your professional experience and education background.

A. I have a Bachelors of Science and Masters of Science degree in Electrical Engineering, both from Auburn University. I also have an MBA from Florida Southern College.

I have spent the past two and one-half years at TEA where I have served as a Marketing Manager. As a result of my current position, I have a good understanding of the market for energy and capacity sales in the Southeastern United States and the area around and including the City of Jacksonville

Prior to TEA, I worked for approximately 22 years for the Lakeland Department of Electric and Water Utilities (Lakeland). In my first assignments at Lakeland I served as an Electrical Engineer in the System Control and Relay Division, Manager of Engineering, and Director of the Engineering and Operations Group. My last assignment at Lakeland before joining TEA was as the Manager of the Wholesale Energy Business

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

A. The purpose of my testimony is to provide my opinion as to whether the Brandy Branch Conversion is the most cost-effective alternative available to JEA. More specifically, I will provide my opinion as to whether JEA could have obtained more cost-effective purchase power through a Request for Proposal (RFP) process.

Q. In your opinion should JEA have issued an RFP before deciding to proceed with the Brandy Branch Conversion?

A. No. In my opinion, an RFP could not possibly have provided capacity and energy prices for purchased power at a lower cost than would be expected from the Brandy Branch Conversion.

Q. On what basis do you present that opinion?

A. I present my opinion on a number of bases. First, as Marketing Manager, I have access to many bids for buying and selling power. Next, TEA continuously develops forward pricing curves to use in power marketing.

Finally, I have a good general understanding of the cost of power and its pricing in the marketplace.

Q. Have you reviewed the projected costs and parameters in JEA's Need for Power Application for the Brandy Branch Conversion?

A. Yes. I believe that they are reasonable even though fuel prices, especially those for natural gas and oil, are currently different from those projected

Q. Do the current natural gas and oil prices impact your opinion as to whether the Brandy Branch Conversion is the most cost-effective alternative?

A. No. Fuel prices are extremely volatile. To protect themselves from this volatility, bidders require fuel costs to be a pass through, particularly for longer term contracts. Thus, if fuel prices are high for Brandy Branch, they would also be similar for purchased power.

Q. What purchased power arrangements has TEA made on behalf of JEA?

A. Since 1998 TEA has arranged winter and summer seasonal purchases for JEA. While these arrangements are not directly comparable to the long term capacity and energy that will be provided by the Brandy Branch Conversion, their average cost has been higher than the Brandy Branch costs.

Q. Can you share with the Commission some of the bids for purchase power that you have obtained for other members of TEA that you would consider more comparable to the Brandy Branch Conversion?

A. Unfortunately not. The bids provided to TEA are subject to strict confidentiality requirements with the members for whom the bids are obtained. I can, however, say that the lowest cost comparable bids that I have seen are higher priced than the expected cost of power from the Brandy Branch Conversion. Furthermore, the capacity costs from the Panda bid that were presented in the Hines 2 Need for Power public hearing were 50 to 100 percent higher than the corresponding capacity costs associated with the Brandy Branch Combined Cycle.

Q. Can you share TEA's forward pricing curves with the Commission?

A. Again, unfortunately not. TEA's restrictions preclude me from disclosing those curves, but again, the expected cost of power from the Brandy Branch Conversion is below the forward pricing curves

Q. Are you confident that the Brandy Branch Conversion Cycle project is the most cost-effective alternative available to JEA to meet its 2004 capacity requirements?

A. Yes. Based on my experience in the power marketing industry, it is my expert opinion that the Brandy Branch Conversion is the most cost-effective alternative available to JEA to meet its 2004 capacity requirements.

Q. Does this conclude your testimony?

A. Yes

MR. MELSON: Mr. Griffin had 5 pages of direct testimony. We'd ask that it be inserted.

CHAIRMAN JACOBS: Without objection, show the testimony of Mr. Griffin entered into the record.

BEFORE THE PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF BRET L. GRIFFIN

ON BEHALF OF JEA

DOCKET NO. 001703-EM

DECEMBER 18, 2000

Q. Please state your name and address.

A. My name is Bret L. Griffin. My business address is 21 West Church Street, Jacksonville, Florida 32202.

Q. By whom are you employed and in what capacity?

A. I am employed by JEA as a Professional Engineer in the capacity planning group. In that position I am responsible, among other things, for planning, organizing and directing JEA's forecast of demand and energy.

Q. Please state your professional experience and educational background.

A. I have a Bachelors degree in Industrial Engineering from Georgia Institute of Technology. I am also a Registered Professional Engineer in the State of Florida.

I began my career at JEA in 1981 as an Intern Engineer. In 1986 I accepted a position as a Software Developer at Shelby Systems, Inc., of Memphis, Tennessee. I returned to JEA in 1988, where I have held various positions in JEA's fuels, system planning, finance and capacity planning organizations. I have had primary responsibility for JEA's load forecasting for the last five years.

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

A. The purpose of my testimony is to provide a general overview of JEA's load forecast.

Q. Are there sections of the Need for Power Application identified as Exhibit _____ (JEA-1) that were prepared by you or under your direct supervision?

A. Yes, Section 7 and Appendix A.

Q. Are you adopting these sections as part of your testimony?

A. Yes.

Q. Are there any corrections to these sections?

A. No.

Q. Please describe the methodology used in forecasting JEA's energy production.

A. 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. The base case energy forecast is developed from 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 energy 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 to develop the forecast. The base case forecast includes wholesale sales to Florida Public Utilities Company (FPUC). JEA's contract with FPUC extends until December 31, 2007. For planning purposes, it has been assumed that JEA will serve FPUC loads throughout the planning period. The base case energy forecast used in the Need for Power Application is the same as that included in JEA's 2000 Ten Year Site Plan (TYSP).

Q. Please describe the methodology used in developing JEA's peak demand forecast.

A. 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. JEA uses the minimum temperature of the day for the winter season and the 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. The base case demand forecast is also the same as that included in JEA's 2000 TYSP.

Q. How is the impact of conservation reflected in the load forecast?

A. Because JEA uses a trend analysis based on historical data, the effects of existing conservation programs are implicitly included in the forecast.

Q. What are the results of JEA's demand and energy forecasts.

A. JEA's summer peak is forecast to increase from 2,534 MW in 2000 to 2,865 MW in 2004 and 4,365 by 2019, for a compound annual average growth rate of 2.9%.

Similarly, the winter peak is forecast to grow from 2,566 MW in 2000 to 2,924 in 2004 and 4,566 by 2019, or a compound annual average growth rate of 3.1%.

JEA's net energy for load is expected to grow at a compound annual average growth rate of 2.9% over the forecast period.

Q. Did you develop any alternative demand forecasts to be used to perform sensitivity analyses?

A. Yes. In addition to the base case forecast, JEA prepared high and low case load forecasts. The low case forecast represents growth in load at a constant rate of 1.0 percent per year, and the high case forecast assumes a constant growth rate of 5.0 percent per year. The 1.0 percent to 5.0 percent annual constant load growth range represents realistic low and high boundaries of load growth compared to the base case forecast of 2.9 percent. 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.

Q. In your opinion is the base case load forecast reasonable for planning purposes?

A. Yes

Q. Does this complete your testimony?

A. Yes.

MR. MELSON: Mr. John Henry David had 8 pages of testimony. We'd ask that that be inserted.

CHAIRMAN JACOBS: Show the testimony of Mr. David entered into the record.

BEFORE THE PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF JOHN HENRY DAVID

ON BEHALF OF JEA

DOCKET NO. 001703-EM

DECEMBER 18, 2000

Q. Please state your name and address.

A. My name is John Henry David. My business address is 21 West Church Street, Jacksonville, Florida 32202.

Q. By whom are you employed and in what capacity?

A. I am employed by JEA as the Director of Electric System Fuels.

Q. Please describe your responsibilities in that position.

A. My responsibilities include the purchase of coal, residual oil, No.2 fuel oil, natural gas and contracting for natural gas transportation. I have negotiated numerous contracts with natural gas suppliers and transporters. The fuel price forecast in Exhibit___ (JEA-1) was prepared under my direction.

Q. Please state your professional experience and educational background.

A. I graduated with a Bachelor of Industrial Engineering degree from Georgia Institute of Technology in 1970. I am a Registered Professional Engineer in the State of Florida. I have done graduate work in probability and statistics. I have had numerous courses and attended seminars in engineering, statistics, forecasting and fuel related matters.

I joined JEA in 1970 and worked in various construction areas before transferring to system planning in 1980. In system planning, I supervised load research programs and the development of load and energy forecasts. I also participated in the development of state-wide load and energy forecasts. I was appointed to my present fuels position in 1988.

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

A. The purpose of my testimony is to sponsor JEA's fuel price forecast and to discuss natural gas supply and transportation for JEA's system prior to and following the Brandy Branch Conversion.

Q. **Are there sections of the Need for Power Application identified as Exhibit ______ (JEA-1) that were prepared by you or under your direct supervision?**

A. Yes, Section 6.

Q. **Are you adopting this section as part of your testimony?**

A. Yes.

Q. **Are there any corrections to this section?**

A. No.

Q. **What was your participation in development of the fuel price projections used in the Need for Power Application?**

A Black & Veatch developed the fuel price projections at my direction. I provided Black & Veatch with historical JEA fuel price information. Black & Veatch then used this information, together with information from other sources, to develop the base case fuel price projection and two fuel price sensitivity cases for the Need for Power Application. I reviewed the resulting forecasts and concur that they are reasonable for planning purposes.

Q. For what fuels were forecasts developed?

A. Fuel forecasts were developed for low and medium sulfur coal, natural gas, residual oil (1.8 percent and 1.0 percent sulfur), No. 2 fuel oil, and petroleum coke.

Q. What methodology was used to forecast the fuel prices used in the Need for Power Application?

A. The 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). From this information, real compounded annual escalation rates (CAERs) were calculated for the time periods 1998-2005, 2005-2010, 2010-2015, and 2015-2020. The base case forecast was developed by applying these real CAERs, together with an assumed annual inflation rate of 2.3 percent, to escalate 1999 JEA delivered fuel costs through the year 2019.

Q. Is this fuel price forecast methodology appropriate for purposes of this Need for Power Application?

A. Yes. 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 forecasts 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.

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

Q. What fuel will be used by the proposed combined cycle at Brandy Branch?

A. The Brandy Branch combined cycle unit will be dual fuel capable. It will use natural gas as the primary fuel and No. 2 fuel oil as the backup fuel. There are two oil storage tanks at the site which can provide approximately 2.4 days of full load operation of all units at Brandy Branch without resupply

Q. What are the benefits of the combined cycle unit having dual fuel capability?

A. The dual fuel feature increases fuel diversity and protects against short-term natural gas supply interruption. Furthermore, the primary fuel is natural gas which reduces the dependency on foreign oil imports.

Q. What steps has JEA taken to assure that sufficient pipeline capacity will be available to transport natural gas to the combustion turbines at the Brandy Branch site?

A. JEA has taken steps to secure a portion of the pipeline capacity required to support its system needs and is currently engaged in negotiations to finalize the balance of its gas transportation arrangements.

Currently, Florida Gas Transmission Co. (FGT) is the pipeline transportation company for JEA, and Peoples Gas is the local distribution company. Firm natural gas transportation from FGT is currently obtained under two tariffs: FTS-1 and FTS-2. As of today, JEA has 40,000 decatherms per day of firm natural gas transportation under the FTS-1 rate schedule. JEA has contracted for an additional 14,000 decatherms per day of firm transportation capacity under the FTS-2 rate starting in 2002. Thus, JEA will have a combined total of 54,000 decatherms per day of firm natural gas transportation starting in 2002.

Q. Is this amount of transportation sufficient to meet JEA's total system needs for firm gas transportation?

A. No. JEA's total gas requirements by 2004 are projected to be approximately 115,000 decatherms per day. This requires JEA to obtain roughly an additional 61,000 decatherms per day of transportation capacity above what it currently has under contract.

Based on this need, JEA is currently negotiating for additional transportation capacity beginning in 2001. These negotiations will enable JEA to maintain sufficient pipeline capacity throughout the planning horizon by acquiring additional capacity from FGT, another pipeline, or from the secondary market. This additional gas transportation requirement will be served in the secondary market until pipeline construction to meet JEA's needs is completed.

Q. What impact does the conversion of the Brandy Branch combustion turbines to combined cycle operation have on JEA's need for pipeline capacity?

A. The conversion will have no meaningful impact on the amount of gas transportation capacity required by JEA. The addition of the heat recovery steam generators and the steam turbine generator effectively provides "free MW" by enabling JEA to generate additional energy from the same amount of fuel. Thus there is little or no impact on JEA's peak hour gas transportation requirements, which drive the amount of pipeline capacity that JEA must obtain. However, because the combined cycle units are expected to dispatch at a higher capacity factor than the stand-alone combustion turbines, the conversion to combined cycle operation does affect the optimal mix of firm, alternate firm, and interruptible transportation.

Q. Is any upgrade to the pipeline lateral to the Brandy Branch site required to serve the converted unit?

A. No. The pipeline lateral to the Brandy Branch site is permitted and currently under construction. It will be completed before it is needed by the simple cycle units, and it will provide enough capacity to handle the fuel needs of the simple cycle units and the conversion as well.

Q. You have talked about gas transportation, what about gas supply?

A. There are ample supplies of natural gas to meet JEA's system needs for the foreseeable future. Due to the relative volatility of the natural gas market, JEA does not typically enter into long term gas supply contracts. Instead, JEA relies on daily or monthly purchases, and use hedging techniques as appropriate to limit our fuel price exposure. JEA currently has no plans to change this procurement approach.

Q. Will the Brandy Branch Conversion increase JEA's total system requirements for the natural gas commodity?

A. That is difficult to predict. Because the combined cycle unit will operate at a higher capacity factor than the simple cycle combustion turbines, the total volume of gas burned at Brandy Branch will increase. At the same time, the combined cycle unit is more efficient and the "free" MW will displace power that would otherwise have been generated by other JEA units, including other gas-fired units. In any event, there will be adequate gas supplies available to JEA to meet our total system needs

Q. Does this conclude your testimony?

A. Yes.

MR. MELSON: And finally, the direct testimony of Myron Rollins consisting of 10 pages, we'd ask that that be inserted.

CHAIRMAN JACOBS: Without objection, show the direct testimony of Mr. Rollins entered into the record.

BEFORE THE PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF MYRON ROLLINS

ON BEHALF OF JEA

DOCKET NO. 001703-EM

DECEMBER 18, 2000

Q. Please state your name and address.

A. My name is Myron Rollins. My business address is 11401 Lamar Avenue, Overland Park, Kansas.

Q. By whom are you employed and in what capacity?

A. I am employed by Black & Veatch Corporation. My current position is Project Manager.

Q. Please describe your responsibilities in that position.

A. As a project manager, I am responsible for the management of various projects for utility and non-utility clients. These projects encompass a wide variety of services for the power industry The services include load forecasts, conservation and demand-side management, reliability criteria and evaluation, development of generating unit addition alternatives, fuel forecasts, screening evaluations, production cost simulations, optimal generation expansion modeling, economic and financial evaluation, sensitivity analysis, risk analysis, power purchase and sales evaluation, strategic considerations, analyses of the effects of the 1990 Clean Air Act Amendments, feasibility studies, qualifying facility and independent power producer evaluations, power market studies and power plant financing.

Q. Please state your professional experience and educational background.

A. I received a Bachelor of Science degree in Electrical Engineering from the University of Missouri – Columbia. I also have two years of graduate study in nuclear engineering at the University of Missouri – Columbia. I am a licensed professional engineer and a Senior Member of the Institute of Electrical and Electronic Engineers.

I have over twenty-four years of experience in the power industry specializing in generation planning and project development. In the past ten years, I have been the project manager for over 100 projects, the vast majority of which are for Florida utilities. Florida utilities for which I have worked include City of Lakeland – Department of Electric Utilities, Kissimmee Utility Authority, Florida Municipal Power Agency, Orlando Utilities Commission, JEA, City of St. Cloud, Utilities Commission of New Smyrna Beach, Sebring Utilities Commission, City of Homestead, Florida Power Corporation, and Seminole Electric Cooperative.

I was responsible for the development of Black & Veatch's POWRPRO chronological production costing program and RECOM unit commitment program, and POWROPT optimal generation expansion program. I am also responsible for power market analysis and project feasibility studies. I have been responsible for need for power certification on a number of power plants in Florida including Stanton 1 and 2, Cedar Bay, Cane Island 3, and McIntosh 5. I also participated in the need for power certification for the Hardee and Hines Projects. I have presented expert testimony on several occasions before the Missouri and Florida Public Service Commissions and have presented numerous papers on strategic planning and cogeneration.

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

A. The main purpose of my testimony is to address JEA's need for power as it relates to the Brandy Branch Conversion project. In my testimony, I will discuss the methodology used to evaluate the need for the Brandy Branch Conversion. I will also discuss economic assumptions used in the evaluation, other supply-side alternatives, Clean Air Act ramifications, and the consistency of the project with Peninsular Florida's needs. I will show that JEA has adequately explored alternative generating technologies and that the project will provide necessary electricity at the most cost-effective price and will contribute to the electric system reliability and integrity of JEA and Peninsular Florida.

Q. Are there sections of the Need for Power Application identified as Exhibit _____ (JEA-1) that were prepared by you or under your direct supervision?

A. Yes, Sections 4, 5, 8 (except 8.1), 11, 12, 18 and 19.

Q. Are you adopting these sections as part of your testimony?

A. Yes, I am.

Q. Are there any corrections to these sections?

A. Yes. There is a minor correction in Section 5 which is shown in Exhibit ____ (JEA-2).

Q. Are the economic and financial assumptions used by JEA in determining the need for the proposed Brandy Branch Conversion reasonable?

A Yes. A consistent set of economic parameters was assumed for the evaluations. A general inflation rate of 2.3 percent was used which is generally consistent with the US Consumer Price Index (CPI). This rate was applied to capital costs and operation and maintenance costs.

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. A sensitivity analysis was performed which utilized cases which were two percent higher and two percent lower than the base case.

A fixed charge rate of 11.51 percent was used based on the 7.95 percent bond interest rate and applied to capital cost for new unit additions in the evaluations.

Q. Please describe the process and methodology that JEA used to determine the most cost-effective option for meeting its load requirements.

A. First, reasonable and consistent economic parameters were assumed. Next a load forecast was developed and a reserve margin applied to determine JEA's capacity requirements. The capacity requirements were compared to existing capability to determine the need for additional capacity. Fuel price projections were also developed. Cost and performance estimates were developed for generating unit alternatives.

All supply-side generating alternatives were first passed through two different screenings as described in Section 12 of Exhibit _____ (JEA-1). The first phase screening eliminated alternatives that were not technically feasible at the present time, still under commercial development, or not available to JEA due to resource constraints, such as hydroelectric power. Other alternatives were eliminated in the second phase. This second screening utilized a busbar analysis to compare alternatives based on their life cycle levelized costs.

The alternatives that survived the screening from these two phases were evaluated 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 for the system while maintaining the reliability criteria. All potential capacity addition plans were modeled over a twenty-year period.

Q. **What methodology was used to evaluate demand side management (DSM) for JEA?**

A. On the demand-side of the ledger, JEA evaluated in detail the most cost-effective of the Florida Power and Light Company's (FPL's) residential and commercial/industrial demand side management (DSM) measures from FPL's

Conservation Goals Docket No. 991788-EG. FPL evaluated approximately 250 DSM options in that docket. Since the DSM measures found to be most cost-effective by FPL were not found to be cost-effective for JEA, it can be assumed that all the 250 DSM measures evaluated by FPL are not cost-effective for JEA. 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. As shown in Section 8 of Exhibit ___ (JEA-1), all of these items failed to pass the Rate Impact Test and were eliminated as not being cost-effective.

Q. In your opinion, has JEA demonstrated that the Brandy Branch Conversion is the most cost-effective alternative?

A Yes. As described in Section 13 of Exhibit ____ (JEA-1), the evaluations show that the Brandy Branch Conversion in 2004 is more than $17 million lower in present worth revenue requirements than the first plan which did not begin with the Brandy Branch Conversion.

Q. Given the many assumptions that are involved with forecasting future conditions, how can a utility be confident that it has actually identified the most cost-effective option?

A. Because there are assumptions that must be made in such an analysis, one way to mitigate the potential risk is to perform sensitivity analyses on those most important variables. As demonstrated by the sensitivity analyses in Section 14 of Exhibit _____ (JEA-1), the Brandy Branch Combined Cycle Conversion is clearly the most cost-effective supply alternative in 2004.

Q. **Are you confident that all other feasible and economic supply-side options and demand-side options have been considered?**

A. Yes. Cost and performance estimates were developed for conventional, advanced, nuclear, energy storage systems, and renewable and waste energy resources as potential capacity addition alternatives. Although many of the technologies are not viable at this time, cost and performance data were developed in as much detail as possible to provide the most accurate resource planning evaluation. Conventional alternatives were found to be the most technically viable and cost effective through a two-phase screening analysis described in Section 12 of Exhibit ____ (JEA-1).

JEA also evaluated numerous DSM measures. However, as outlined in Section 8.2.4 of Exhibit ____ (JEA-1), there are currently no cost-effective demand-side management measures available that would avoid or defer the need for the Brandy Branch Conversion.

Q. **Is the proposed project consistent with Peninsular Florida's needs?**

A. Yes. The Florida Reliability Coordinating Council (FRCC) is responsible for coordinating power supply reliability in Peninsular Florida for the North American Electric Reliability Council. The FRCC has selected a minimum 15 percent reserve margin criterion to ensure reliability for Peninsular Florida. As part of its reliability coordination activities, the FRCC provides an annual summary and report of Peninsular Florida Ten Year Site Plans. The most recent planning summary conducted by FRCC is the 2000 Load and Resource for the State of Florida.

As shown in Section 19 of Exhibit ____ (JEA-1), Peninsular Florida reserve margins are projected to exceed the 15 percent planning criteria through 2009. Without the inclusion of units that have not yet received certification under the Power Plant Siting Act, including the Brandy Branch Conversion, this reserve margin would drop below 15% in 2004. Thus the Brandy Branch Conversion in 2004 is an important contributor to maintaining Peninsular Florida reliability at acceptable levels.

Q. **In your opinion, will the Brandy Branch Conversion contribute to maintaining reliability and integrity for the JEA and Peninsular Florida systems?**

A. Yes. The Brandy Branch Conversion is based on proven steam technology and will provide a reliable source of power to contribute to the JEA and Peninsular Florida reserve margins. It will be integrated into the electric system through existing transmission facilities and will have no adverse impact on the integrity of the grid.

Q. **What impact will the Brandy Branch Conversion have on the environment?**

A. JEA considers the impacts to the environment, 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 power from the environmental aspects of the facility, the Clean Air Act requirements and other regulations have a significant impact on the power plant's cost and performance. The proposed conversion of two of the Brandy Branch simple cycle combustion turbines to combined cycle would lower emissions on a kilowatt-hour basis and improve fuel utilization. All economic evaluations have included anticipated cost of compliance with environmental regulations.

The Brandy Branch 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 simple cycle units at Brandy Branch. One aspect of the ATC permit is the determination of Best Available Control Technology (BACT). The Brandy Branch Conversion will achieve BACT for NOx through use of dry low NOx combustors and selective catalytic reduction (SCR).

The completed Brandy Branch combined cycle unit will emit small amounts of sulfur dioxide while running on either natural gas or No. 2 fuel 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. JEA has identified two possible sulfur dioxide emissions compliance strategies. The first and preferred compliance strategy involves the reallocation of excess allowances currently maintained by JEA to cover Brandy Branch sulfur dioxide emissions. The other possible compliance strategy involves purchasing allowances. With a maximum of 40 allowances required per year, the cost to purchase allowances would be insignificant.

Q. Does this conclude your testimony?

A. Yes.

MR. MELSON: And then, I would move the admission of Exhibits 1 and 2.

CHAIRMAN JACOBS: Without objection, show Exhibits 1 and 2 admitted.

(Exhibits 1 and 2 admitted into the record.)

CHAIRMAN JACOBS: Staff, I see an exhibit here from you.

MS. HART: Yes, Mr. Chairman. We actually have two exhibits. We have a lengthy composite exhibit, which we'd ask to have marked as Exhibit 3. It consists of JEA's responses to Staff interrogatories as well as to Staff's request for production of documents, and I would move that into the record.

CHAIRMAN JACOBS: Without objection, show Exhibit 3, which is Staff's composite exhibit entered into the record.

(Exhibit 3 marked for identification and admitted into the record.)

MS. HART: Staff's other exhibit consists of the affidavit from "The Florida Times-Union" showing that notice was published as required by 403.519. I'd ask that that be marked as Exhibit 4 and entered into the record.

CHAIRMAN JACOBS: Without objection, show Exhibit 4, the affidavit of publication, entered into the record.

(Exhibit 4 marked for identification and admitted into the record.)

CHAIRMAN JACOBS: That's it?

MS. HART: That's it.

CHAIRMAN JACOBS: Okay. That takes care of the case in proper?

MS. HART: That's correct. Mr. Chairman, at this time, at the pleasure of the panel, Staff is prepared to make an oral recommendation of approval of JEA's application. I think, you have several alternatives. You can --

CHAIRMAN JACOBS: Before you proceed, Commissioners, what's your pleasure?

COMMISSIONER JABER: So, you're asking that we rule on the utility's motion for a bench decision?

MS. HART: Correct.

COMMISSIONER JABER: I can move that we grant the company's motion or request for a bench decision, Mr. Chair.

COMMISSIONER BAEZ: Second.

CHAIRMAN JACOBS: Been moved and seconded. Without objection, show that approved.

COMMISSIONER JABER: And, Staff, unless any other Commissioner needs it, I would like to hear each of your recommendations on each issue, and then maybe make a motion that would handle the entire case.

MS. HART: That's what we're prepared to do, and Mr. Half is ready to do that.

MR. HALF: Good morning, Commissioners. In summary, as we've stated, the Staff recommends that the Commission grant JEA's petition for determination of need.

Issue 1, we recommend that JEA's proposed unit will contribute to the provision of adequate electricity at reasonable cost as stated in Section 403.519 Florida statutes. As discussed in the prefiled testimony of JEA Witness Bond, JEA uses a 15% reserve margin as its planning criteria and, according to Exhibit 1, JEA's need study.

If no capacity is added in 2004, JEA's reserve margin for that year is expected to be 14% summer, 13% winter, which violates the criteria. Those reserve margins reflect the capacity deficiency of approximately 40 megawatts summer and 58 megawatts winter, respectively.

By adding the capacity from the Brandy Branch conversion, JEA will be able to maintain its 15% reserve margin criteria in 2004; thus, the Brandy Branch conversion provides adequate electricity to JEA.

JEA evaluated numerous coal combined cycle and combustion turbine unit options. Coal was excluded as a viable alternative to meet JEA's 2004 need, because of long lead times for permitting and construction. As I'll discuss later in Issue 3 on cost-effectiveness, the combustion turbine option was excluded, because it was not cost-effective.

As shown in Exhibit 1 in JEA's need study, the only viable options available to meet JEA's identified need for the year 2004 at reasonable cost were the Brandy Branch conversion project or a new Greenfield combined cycle unit. The Brandy Branch conversion adds 197 megawatts, approximately, of capacity generated by the waste heat with the combustion turbines that are currently being built at the site. Thus, the Brandy Branch conversion assures reasonable cost to JEA.

COMMISSIONER JABER: Would your recommendations be consistent with the positions that JEA has taken in each of these issues?

MR. HALF: Consistent with, yes.

COMMISSIONER JABER: So, if I made a motion to prove Staff's recommendation on Issues 1 through 5, it would be -- your recommendation would be the positions that JEA has taken?

MR. HALF: Consistent with, yes, basically. That sounds about right.

COMMISSIONER JABER: Mr. Chairman, I'm prepared to make a motion to move Staff's recommendation on Issues

1 through 5.

COMMISSIONER BAEZ: Second.

I have a question. I just wanted to make sure. We had discussed earlier -- I had discussed with Staff the possibility of this project being flexible on fuel source in the future, if necessary. Is that --

MR. HALF: Well --

COMMISSIONER BAEZ: Is that flexibility available?

MR. HALF: There is flexibility with respect to the combustion turbines, but they're not subject to this need hearing. This need hearing is just the heat recovery --

COMMISSIONER BAEZ: Okay. It has nothing to do with this. I just wanted to -- you know, if that flexibility is available in the future, the change.

Okay. Second.

CHAIRMAN JACOBS: I would agree with all of the positions, except I would want to amend Issue 4 in a minor way.

I agree that -- and, I think, the testimony is clear that based on the idea of postponing or deferring this unit that the analysis doesn't show cost-effective DSM or conservation measures, but I would want -- I think, we ought to incur the addition of analyses, as I described, to determine where would be the cost-effective line for new generation, whether it be for JEA or anyone else, to determine where there would be a cost-effective line for DSM or conservation for this plant. I'm not asking the company to go back and do this, but it is to be done in conjunction with the goals docket.

COMMISSIONER JABER: Goals docket, yeah, to apply to every company.

CHAIRMAN JACOBS: Right.

COMMISSIONER JABER: So, that -- perhaps we should handle that separately as just giving direction to Staff.

CHAIRMAN JACOBS: Let's do that. Rather than to amend the position, I'll just give you direction to do that in preparation for the docket. So, we can do that.

COMMISSIONER JABER: And Mr. Chairman, I'm the prehearing officer on that docket, I think, so I'll make sure that we include that in the next issue.

CHAIRMAN JACOBS: Okay. Very well. That being the case, it's been moved and seconded for Issues 1 through 5, Staff will adopt the positions of JEA. All in favor, say aye.

Aye.

COMMISSIONER JABER: Aye.

COMMISSIONER BAEZ: Aye.

CHAIRMAN JACOBS: Opposed? Show Issues 1 through 5 approved.

MS. HART: There is one further matter. You, having completed that vote, the order that we'll issue from this proceeding will be a final order, and so we'll need a motion to close the docket.

COMMISSIONER BAEZ: So moved.

COMMISSIONER JABER: Second.

CHAIRMAN JACOBS: Moved and seconded. All in favor, aye.

Aye.

COMMISSIONER JABER: Aye.

COMMISSIONER BAEZ: Aye.

CHAIRMAN JACOBS: Show it approved. Good work.

MR. MELSON: Thank you very much.

CHAIRMAN JACOBS: Thank you. Is there anything else to come before us today? Great. We're adjourned.

(Hearing concluded at 9:55 a.m.)

- - - - -

STATE OF FLORIDA)

: CERTIFICATE OF REPORTER

COUNTY OF LEON)

I, KORETTA E. STANFORD, RPR, Official Commission Reporter, do hereby certify that the hearing held on Wednesday, February 8th, 2001, Docket Number 001703-EM was heard before the Public Service Commission at the time and place herein stated.

It is further certified that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript, consisting of 80 pages, constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorneys or counsel connected with the action, nor am I financially interested in the action.

DATED this 9th day of February, 2001.

Koretta E. Stanford

KORETTA E. STANFORD, RPR
Official Commission Reporter
(850) 413-6734

NEED FOR POWER APPLICATION

JEA

Building Community

JEA Brandy Branch Combined Cycle Conversion

BLACK & VEAT

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 0001703-EM EXHIBIT NO. 1
COMPANY/
WITNESS: JEA
DATE 2-8-01

JEA

Need for Power Application Brandy Branch Combined Cycle Conversion

November 2000

BLACK & VEATCH

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

Contents

Contents (Continued)

Contents (Continued)

Contents (Continued)

Contents (Continued)

Contents (Continued)

Contents (Continued)

Tables

Contents (Continued)

Tables (Continued)

Contents (Continued)

Tables (Continued)

Contents (Continued)

Tables (Continued)

Contents (Continued)

Figures

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.

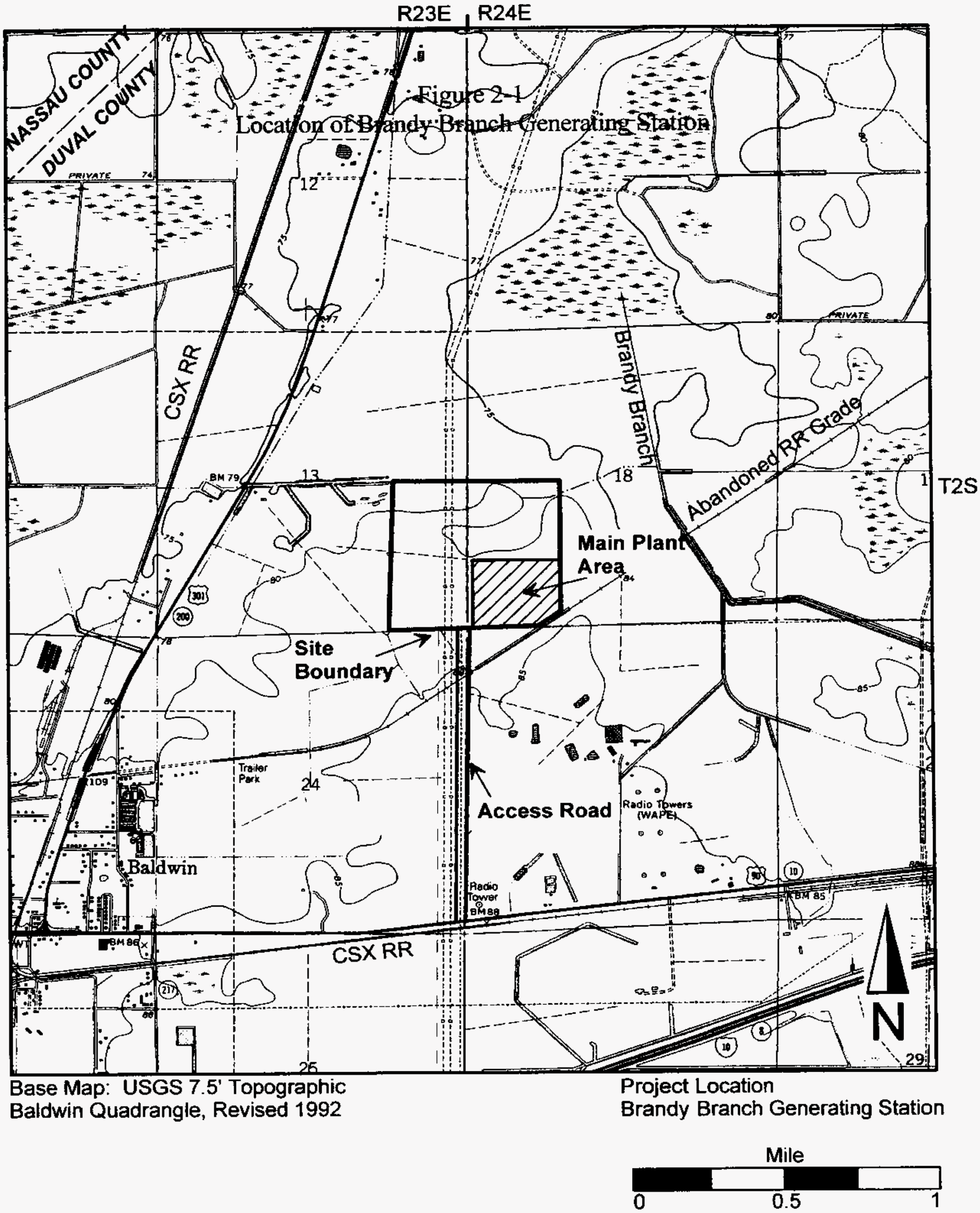


Figure 2-1
Location of Brandy Branch Generating Station

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.

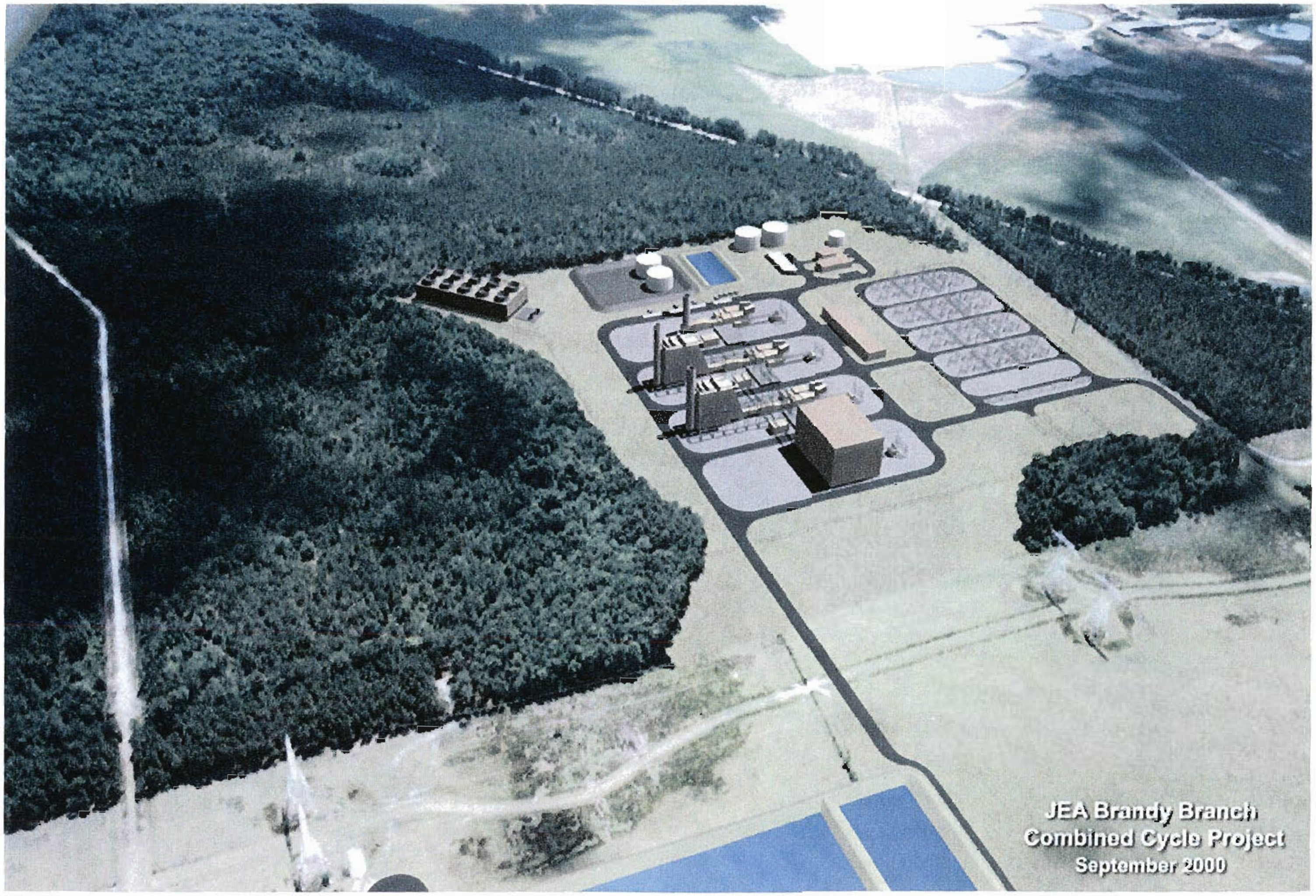
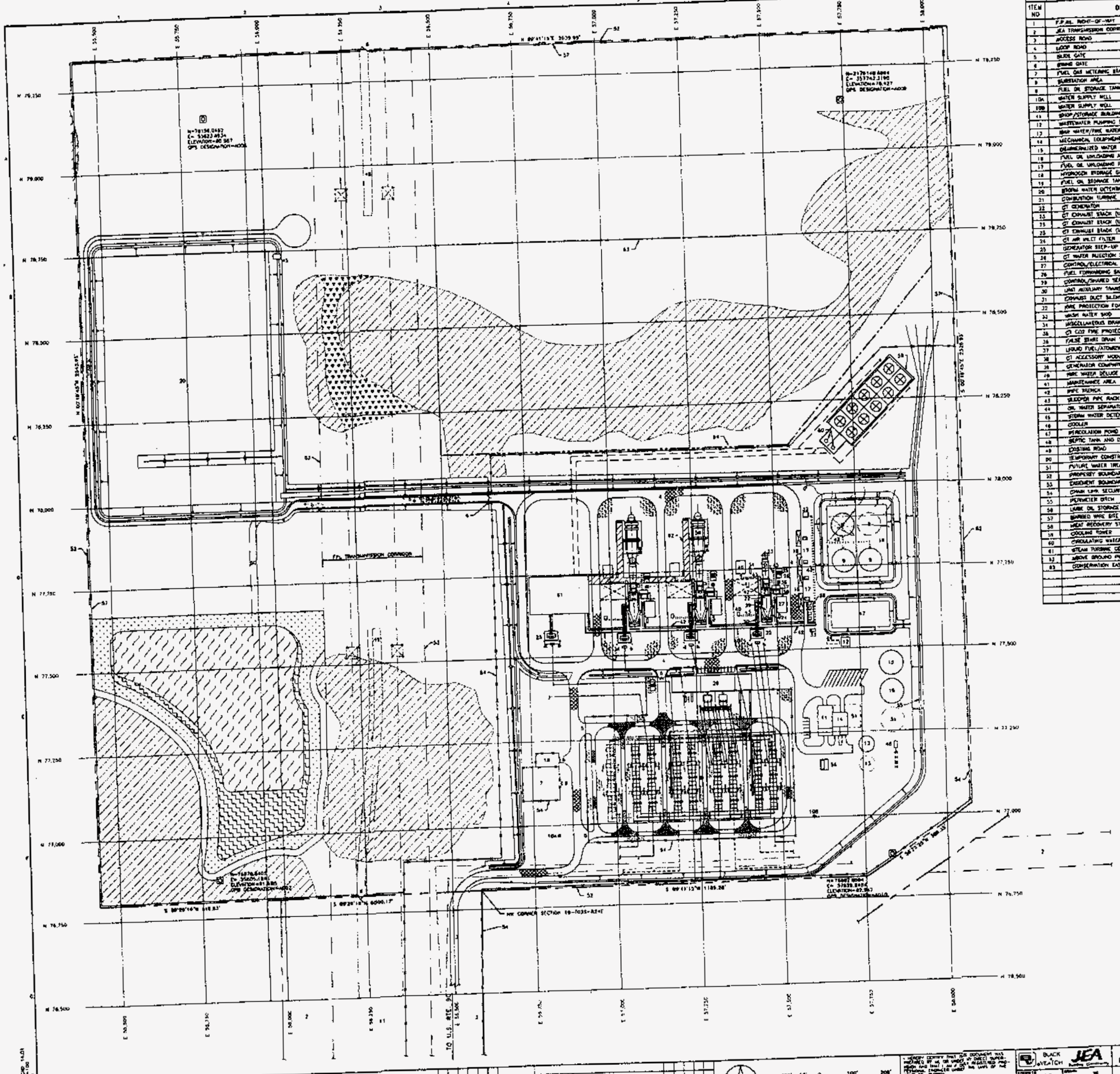


Figure 2-2
Artist Rendition of Brandy Branch Power Plant

Figure 2-3
Site Arrangement Drawing
Brandy Branch Power Plant



FACILITIES LEGEND

ITEM NO	DESCRIPTION	LOCATION COORDINATES NORTH	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)	76870.00	56825.00	CL WELL
10A	WATER SUPPLY WELL	77001.92	57587.00	CL WELL
10B	WATER SUPPLY WELL	N/A	N/A	
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	77768.28	57469.00	CL STACK
23	CT EXHAUST STACK (UNIT 1)	N/A	N/A	
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 CO2 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			

GENERAL LEGEND

- BENCHMARK
- FUTURE FACILITY
- WETLANDS
- CYPRESS (ZONE 2) AREA
- ASPHALT
- CRUSHED ROCK SURFACING
- HERBACEOUS (ZONE 1) AREA
- UPLAND SEEDING AREA
- RESTORATION MITIGATION AREA
- GEOWEB

NOT TO BE USED FOR CONSTRUCTION

REV	DATE	REVISIONS AND RECORD OF ISSUE
B	09-13-2000	GENERAL REVISIONS
A	08-05-2000	ISSUED FOR REVIEW

BLACK & VEATCH

JEA

BRANDY BRANCH COMBINED CYCLE PROJECT

SITE ARRANGEMENT

97990-DS-0001 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.

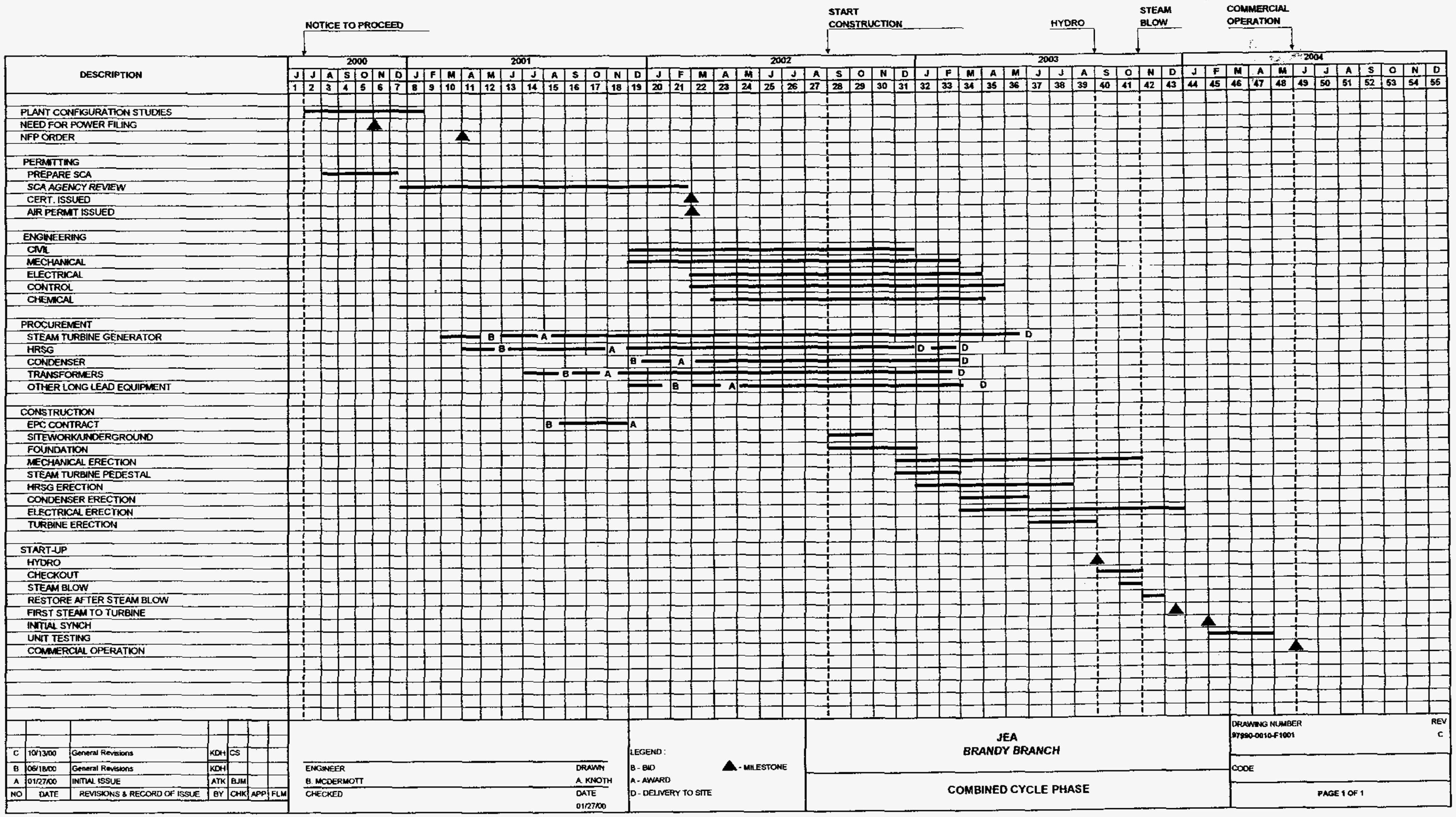


Figure 2-4
JEA Brandy Branch Schedule - Combined Cycle Phase

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.

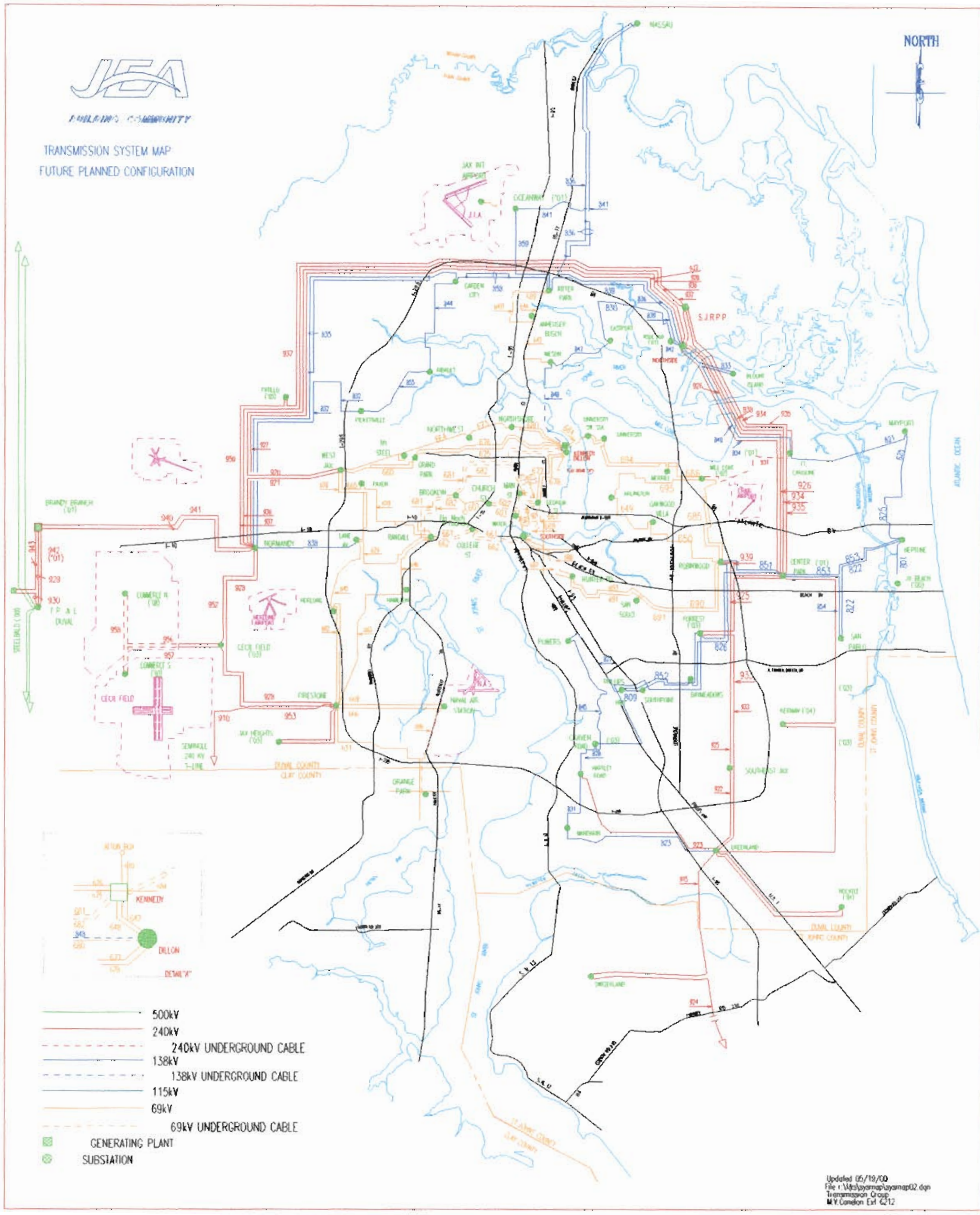


Figure 3-1

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

			Net Capability[1] MW)	
Name	Unit Type	In-Service Date	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 outstanding 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

Calendar Year	Low Case	High Case
	$/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		Average Forecast,[a] GWh	Average Forecast Growth,[b] GWh	Annual Energy Production,[c] GWh
	Based on 3.35 Percent/ Year Growth Rate	Based on 368 GWh/ Year Constant Growth			
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		Average Forecast,[a] GWh	Average Forecast Growth,[b] GWh	Annual Energy Production,[c] GWh
	Based on 3.35 Percent/ Year Growth Rate	Based on 368 GWh/ Year Constant Growth			
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

Year	Summer Peak Demand, MW					Winter Peak Demand, MW				
	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

Year	Summer Peak Demand, MW			Winter Peak Demand, MW		
	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

*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.

* 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.

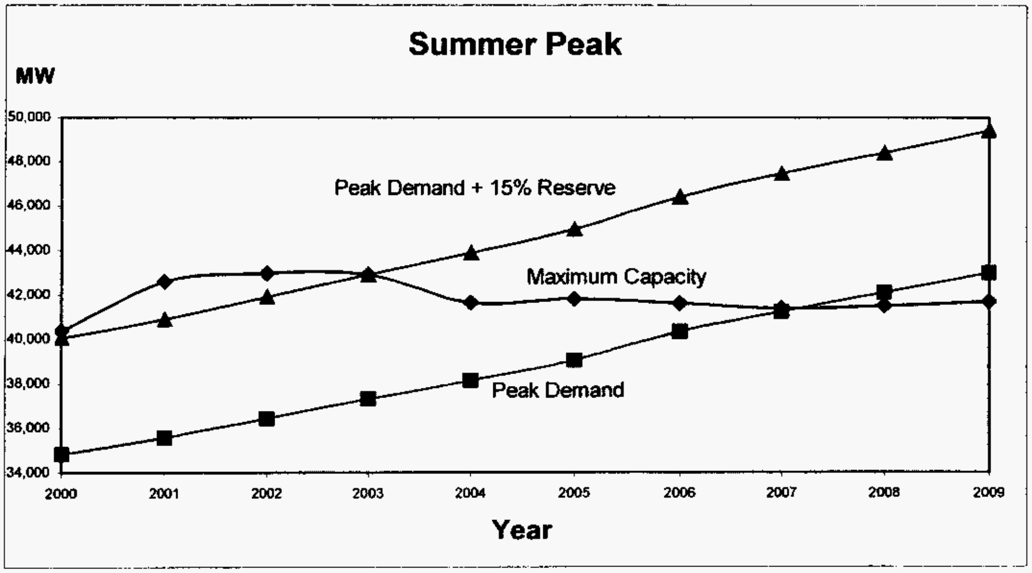
Table 19-2 represents the summer and winter peak demand and available capacity by excluding the capacity required to be approved under the Florida Electrical Power Plant Siting Act, but not yet approved. The available capacity consists of existing capacity, capacity changes that have been approved under 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%



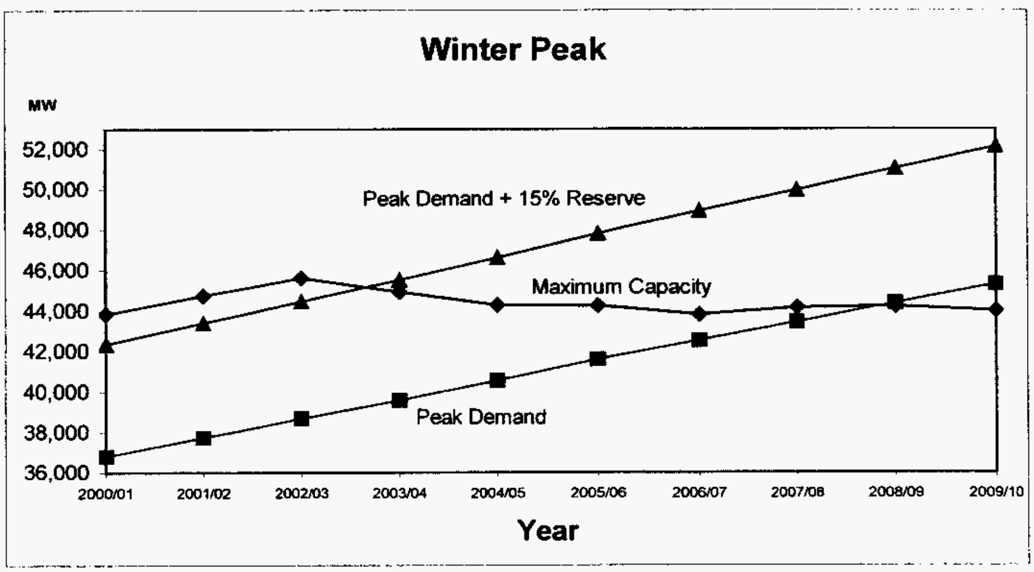


Figure 19-1
2000 Load and Resource Plan--Peak Demand and Reserve Margin
Excluding Approved Capacity Required to be Approved Under the
Florida Electrical Power Plant Siting Act but Not Yet Approved

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.

---

[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.

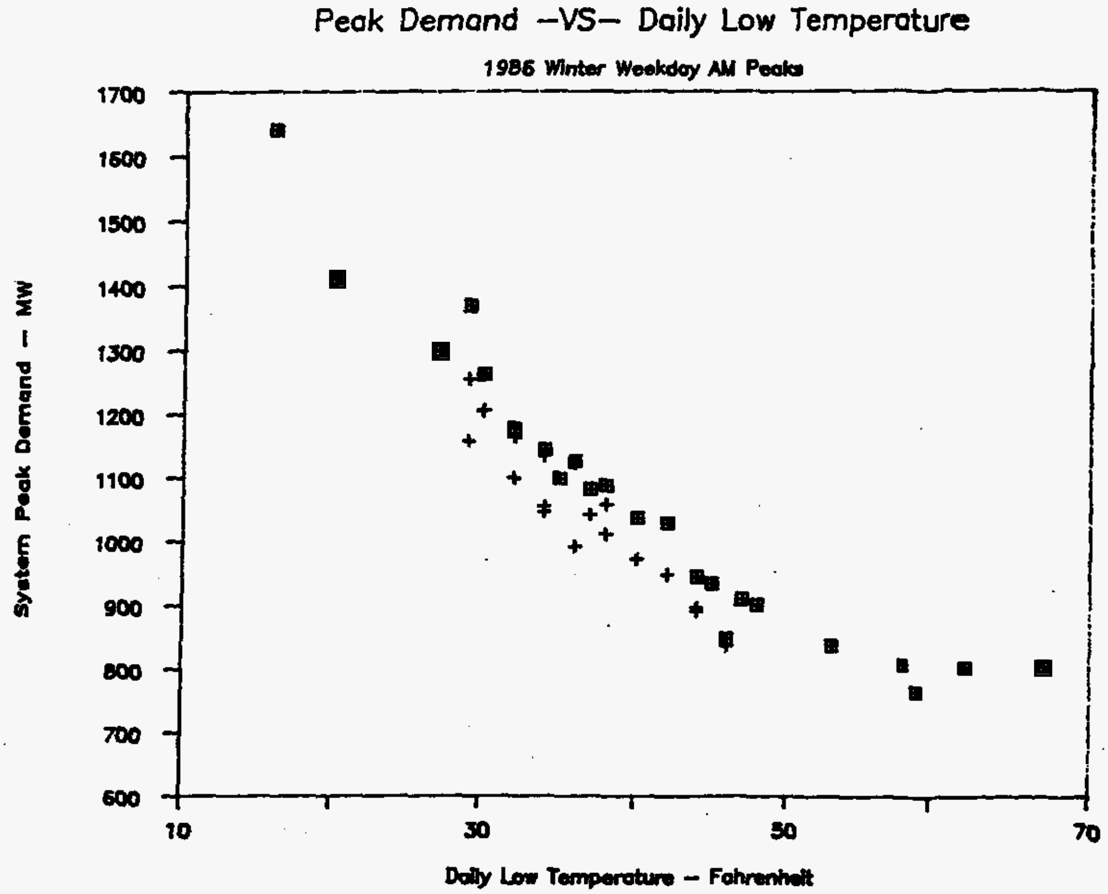


Figure 1

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.

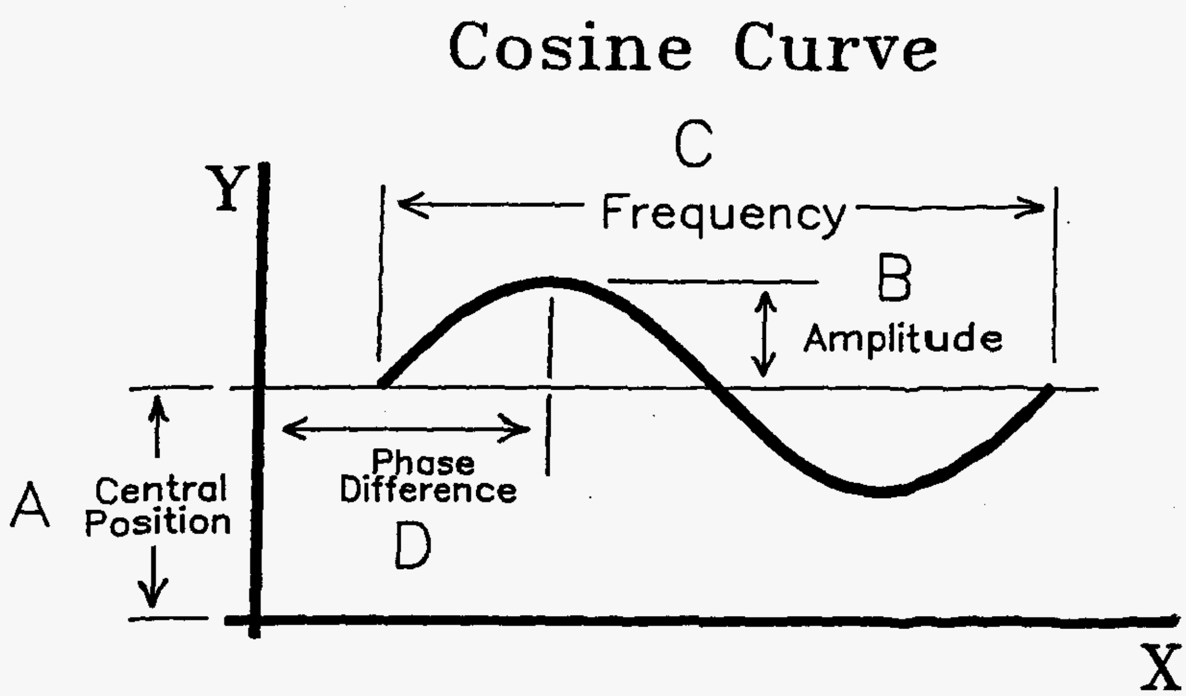


Figure 2

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

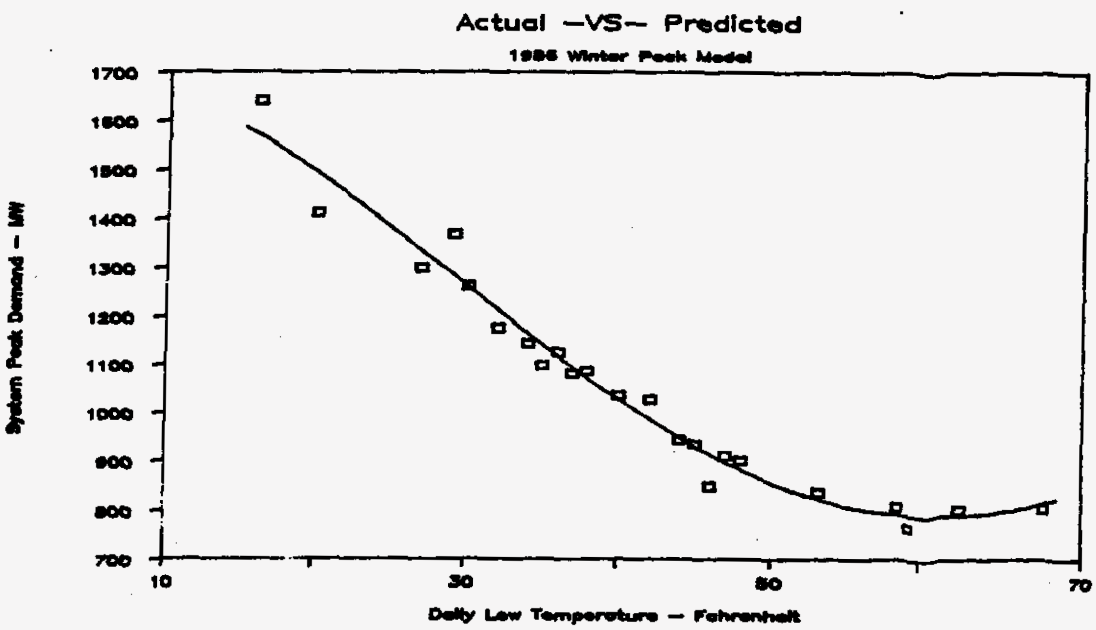


Figure 3

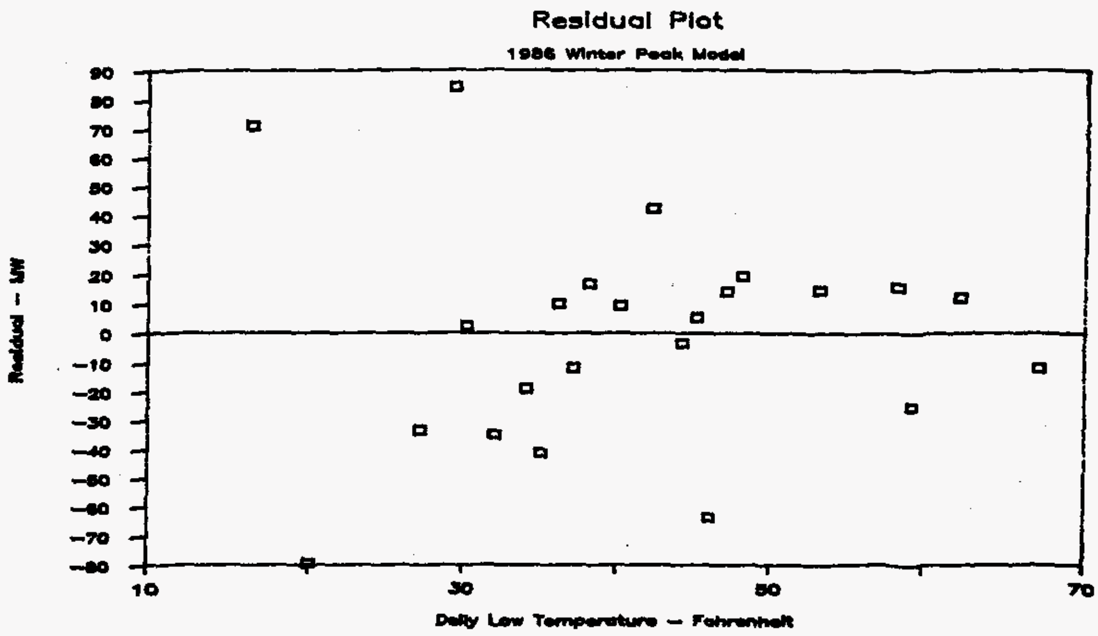


Figure 4

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.

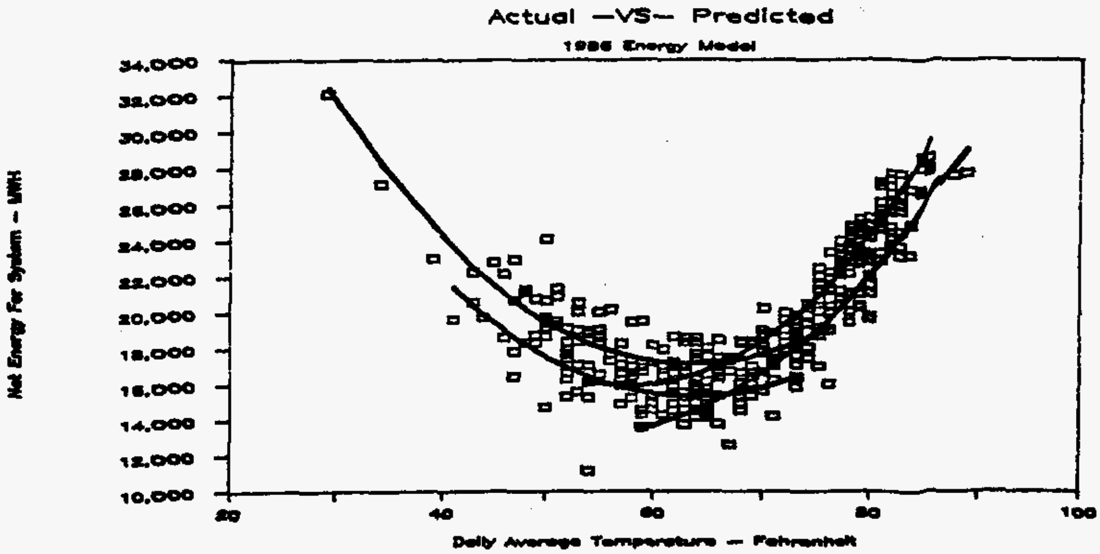


Figure 5

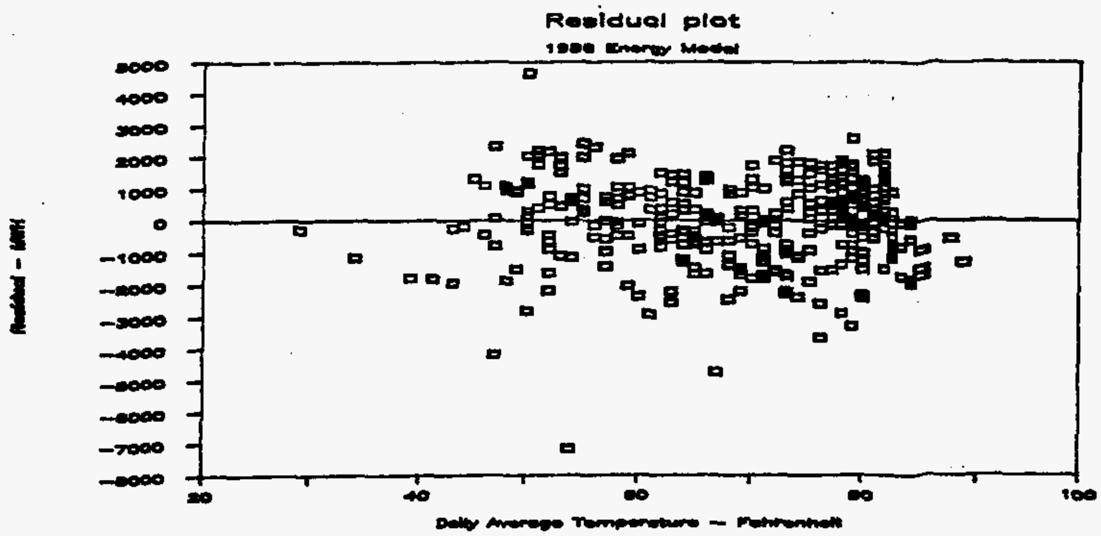


Figure 6

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.

Step 1

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,
Δ MINTEMP 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.

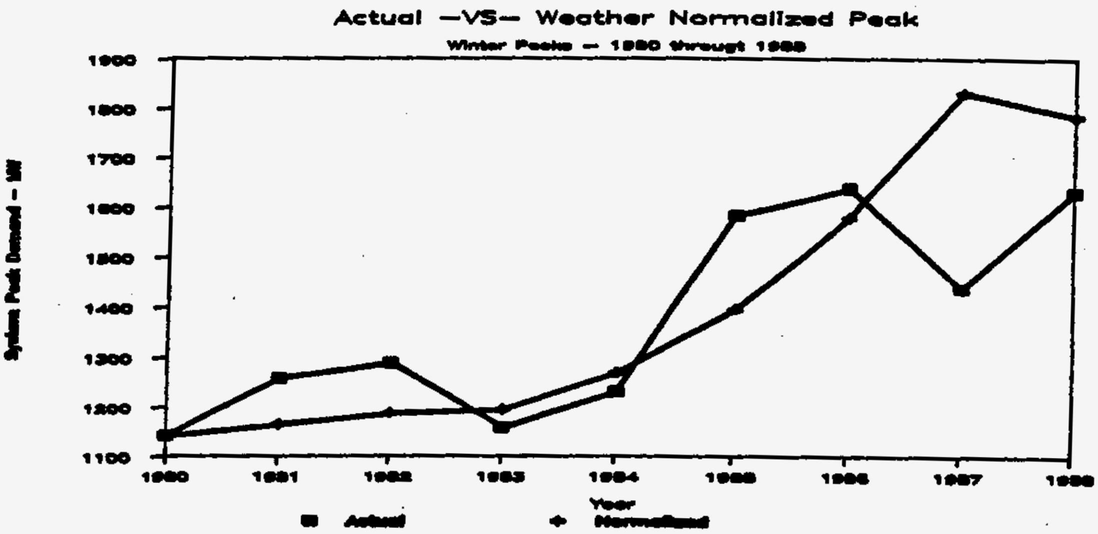


Figure 7

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.

Exhibit No. ______ (JEA-2)
Docket No. 001703-EM
Page 1 of 1
REVISED 2/7/01

CHANGES TO JEA NFP APPLICATION

Section	Page No.	Change
Table of Contents	TC-8	Table 2-8 should read: "Brandy Branch Estimated Emissions"
Table of Contents	TC-9	Table 7-4 should read: "JEA Base Case Annual Retail and Wholesale Forecasts for Calendar Year 2000 through 2019"
Table of Contents	TC-9	Table 7-7 should read: "JEA Base Case Seasonal Retail, Wholesale, and Interruptible Peak Demand for 2000 through 2019"
Table of Contents	TC-10	Table 19-1 should read: "2000 Load and Resource Plan - ….. but Not Yet Approved"
Table of Contents	TC-10	Table 19-2 should read: "2000 Load and Resource Plan - ….. but Not Yet Approved"
1.0 Introduction	1-1	In three (3) instances on this page, the output for the steam turbine should be 197 MW rather than 173 MW
2.0 Description of the Project	2-9	The output for the steam turbine should be 197 MW rather than 173 MW
2.0 Description of the Project	2-18	The comma after 2004 should be removed. Summer 2002 should be changed to Fall 2002.
3.0 System Description	3-8	In section 3.3.7, winter peak demand should be 3.63 percent, not 1.99 percent.
5.0 Economic Parameters and Evaluation Methodology	5-2	"resultS" should be changed to "results"
8.0 Demand Side Programs	8-12	In Table 8-1, "Off-Peak Battery Charging" should be changed to read "Direct Load Control"
9.0 Reliability Criteria and Need for Capacity	9-1	Remove one of periods after "addition.."
9.0 Reliability Criteria and Need for Capacity	9-2	In Table 9-1, the installed capacity in 2002 should be changed from "3236" to "2976"
13.0 Economic Analysis	13-3 to 13-4	Substitute attached Table 13-2 (Revised)
14.0 Sensitivity Analysis	14-4	In section 14.7, the first sentence should be changed to: "A two percent lower present worth discount rate of 5.95 percent was evaluated."
14.0 Sensitivity Analysis	14-2 to 14-3	Substitute attached Table 14-1 (Revised)
16.0 Financial Analysis	16-1	On line 6, change "$632.4 Million" to "$639.9 Million"

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 001703-EM EXHIBIT NO. 2
COMPANY/
WITNESS: JEA
DATE: 2-8-01

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	3- CTs
		1-Greenfield 501G CC 1x1	1-Greenfield 501G CC 1x1	2-Greenfield 501G CC 1x1	2-Greenfield 501G CC 1x1	3-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	2-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	2,999

(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.

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 2x1
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 Greenfield 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	5- 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	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

EXHIBIT NO. ________

Docket No. 001703-EM

Party: JEA

Description: COMPOSITE EXHIBIT

(1) JEA's Response to Staff Interrogatory Nos. 1-9

(2) JEA's Response to Staff Request for Production of Documents Nos. 5-7

Proffered By: Commission Staff

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 001703-EM EXHIBIT NO. 3
COMPANY/
WITNESS: FPSC Staff
DATE: 2-8-01

STAFF COMPOSITE EXHIBIT
TABLE OF CONTENTS

JEA's Response to Staff Interrogatories

JEA's Response to Staff Request for Production of Documents

JEA's RESPONSE TO
STAFF'S FIRST SET OF INTERROGATORIES
DOCKET NO. 001703-EM

1. Provide on an annual and cumulative basis, the present worth revenue requirements (PWRR) associated with the proposed steam cycle addition. Please break down the analysis by capital, operations and maintenance (O & M), and fuel costs.

   See attached table.

   This answer was provided by: Mary Guyton-Baker.

JEA's RESPONSE TO
STAFF INTERROGATORY NO. 1
DOCKET NO. 001703-EM

JEA Need For Power Application
Cumulative Present Worth Revenue Requirements
(Million $)

Discount Factor: 7.95%

Year	Fuel	O&M Variable	O&M Fixed	Capital	Total	Cumulative	Present Worth Total	Present Worth Cumulative
2000	228.39	1.02	91.49	0.00	320.90	320.90	320.90	320.90
2001	232.80	9.35	47.18	11.24	300.56	621.46	278.43	599.32
2002	193.89	13.12	38.56	11.24	256.80	878.26	220.37	819.69
2003	191.96	15.99	50.69	11.24	269.88	1,148.13	214.54	1,034.23
2004	198.29	13.10	35.56	25.43	272.38	1,420.51	200.58	1,234.80
2005	219.05	14.06	36.38	25.43	294.92	1,715.43	201.18	1,435.98
2006	221.92	14.18	39.61	44.30	320.00	2,035.43	202.22	1,638.20
2007	244.90	15.58	40.52	44.30	345.30	2,380.73	202.13	1,840.33
2008	263.27	17.46	42.00	55.17	377.89	2,758.63	204.92	2,045.26
2009	287.48	19.38	42.96	55.17	404.99	3,163.62	203.44	2,248.70
2010	325.26	23.97	47.47	90.56	487.26	3,650.87	226.74	2,475.44
2011	354.84	26.39	48.56	90.56	520.34	4,171.22	224.31	2,699.75
2012	393.83	29.69	49.67	90.56	563.76	4,734.98	225.12	2,924.87
2013	400.80	29.54	53.61	112.69	596.64	5,331.61	220.71	3,145.58
2014	439.41	33.13	54.85	112.69	640.08	5,971.69	219.34	3,364.92
2015	421.76	45.38	66.71	160.13	693.98	6,665.67	220.30	3,585.21
2016	450.67	46.07	68.24	160.13	725.12	7,390.79	213.23	3,798.44
2017	481.36	48.76	72.88	184.36	787.35	8,178.14	214.48	4,012.92
2018	520.25	51.83	74.55	184.36	831.00	9,009.13	209.70	4,222.61
2019	562.71	56.40	76.98	198.32	894.40	9,903.53	209.07	4,431.69

2

2. Provide on an annual and cumulative basis, the present worth revenue requirements (PWRR) associated with each resource alternative to the proposed steam cycle addition. Break down by capital, operations and maintenance (O & M), and fuel costs.

Attached is a table providing the requested information for Plan 145, which is the first alternative in which some resource other than the Brandy Branch Conversion was selected as the preferred unit addition for 2004. (See Table 13-2 on page 13-3 of the Need Application for a listing of the unit additions that comprise Plan 145.)

As can be seen by comparing this table and the table provided in response to Interrogatory No. 1, Plan 1 beginning with the Brandy Branch Conversion has a lower cost than Plan 145 on a cumulative PWRR basis during each year of the planning horizon. Through 2019, Plan 1 is \$17.2 million (PWRR) lower cost than Plan 145.

EGEAS is limited to producing a maximum of 200 alternative plans. Out of these 200 plans, 188 plans showed the Brandy Branch Conversion as the first unit addition and 12 plans showed the Greenfield 501G 1x1 Combined Cycle (first selected in Plan 145) as the first unit addition. None of the 200 plans selected any other resource addition to meet the 2004 reliability need. JEA is therefore unable to provide a PWRR associated with any other resource addition for 2004.

It should be noted that Plan 200 has a total cumulative PWRR of \$4453.89 million, or \$22.2 million higher than the cost of Plan 1. Any plan that begins with a resource addition other than the Greenfield 501G 1x1 Combined Cycle would by definition be even more costly than Plan 200, and therefore would be <u>at least</u> \$22.2 million higher cost than the Brandy Branch Conversion.

This answer was provided by: Mary Guyton-Baker.

JEA's RESPONSE TO
STAFF INTERROGATORY NO. 2
DOCKET NO. 001703-EM

JEA Need For Power Application
Cumulative Present Worth Revenue Requirements
(Million $)

Discount Factor: 7.95%

		O&M					Present Worth	
	Fuel	Variable	Fixed	Capital	Total	Cumulative	Total	Cumulative
2000	228.39	1.02	91.49	0.00	320.90	320.90	320.90	320.90
2001	232.80	9.35	47.18	11.24	300.56	621.46	278.43	599.32
2002	193.89	13.12	38.56	11.24	256.80	878.26	220.37	819.69
2003	191.96	15.99	50.69	11.24	269.88	1,148.13	214.54	1,034.23
2004	193.79	15.28	36.13	35.98	281.18	1,429.31	207.06	1,241.28
2005	213.57	16.96	36.96	35.98	303.46	1,732.77	207.01	1,448.29
2006	229.73	18.27	37.81	35.98	321.79	2,054.56	203.34	1,651.63
2007	236.97	18.06	39.79	62.47	357.28	2,411.84	209.15	1,860.78
2008	259.59	19.81	40.70	62.47	382.57	2,794.41	207.46	2,068.24
2009	282.72	22.34	41.64	62.47	409.16	3,203.57	205.54	2,273.78
2010	319.29	27.48	46.11	97.86	490.74	3,694.32	228.36	2,502.14
2011	348.27	30.48	47.17	97.86	523.78	4,218.10	225.79	2,727.93
2012	371.22	30.12	48.81	114.89	565.05	4,783.14	225.64	2,953.57
2013	396.34	31.29	49.94	114.89	592.46	5,375.60	219.16	3,172.73
2014	432.76	34.65	51.09	114.89	633.38	6,008.98	217.05	3,389.77
2015	458.86	37.17	55.19	138.05	689.26	6,698.24	218.80	3,608.57
2016	487.36	38.01	56.46	138.05	719.87	7,418.11	211.68	3,820.26
2017	515.58	41.08	60.82	162.28	779.75	8,197.86	212.41	4,032.66
2018	557.31	43.65	62.22	162.28	825.45	9,023.31	208.30	4,240.96
2019	551.58	50.62	73.96	213.22	889.37	9,912.68	207.90	4,448.86

3. Reconstruct the 1999 generation expansion plan (the plan leading to the construction of the three Brandy Branch combustion turbine units) using the most recent fuel price forecast. Based on this sensitivity, explain whether the Brandy Branch combustion turbine units are still the most cost effective alternative available to JEA.

It was JEA's 1998 generation expansion plan, not the 1999 generation expansion plan, that led to the selection of the Brandy Branch combustion turbine units. Based on a clarification by staff, JEA has reconstructed the 1998 generation expansion plan using the updated base case fuel price forecast identified in response to Interrogatory No. 7.

The 1998 expansion plan analyzed several purchase power options obtained by JEA through an Invitation for Bids (IFB) process. These purchase power options included firm capacity and energy for unit and system capacity, included winter and annual capacity and included resources in and out-of-state from new, existing and repowered units. In reconstructing the 1998 expansion plan using the most recent fuel price forecast, JEA did not take into consideration how the current fuel market would affect these purchase power bids. The reconstructed plan therefore contains more purchased power than would likely be selected based on the current market for such power.

As shown on the attached table, the Branch combustion turbine units are the most cost-effective alternative available to JEA in 2001 under either the original 1998 expansion plan or the reconstructed 1998 expansion plan. Overall, the reconstructed plan includes more purchased power than the original 1998 expansion plan, which results in the deferral of other self build options.

Answer provided by: Mary Guyton-Baker

JEA Response to
Staff Interrogatory No. 3
Docket No. 001703-EM

JEA Summary of Results

Need For Power Application
Interrogatory 3

Year	[redacted]	[redacted]
1998		
1999		
2000	1-168 MW CT	100 MW Purch
2001	3-168 MW CT	4-168 MW CT
2002		
2003		
2004	1-168 MW CT	1-168 MW CT
2005	1-115 MW CT	100 MW Annual Purchase
2006	100 MW Annual Purchase	200 MW Annual Purchase
2007	200 MW Annual Purchase	300 MW Annual Purchase
Rundown	6 - CTs Annual Purchases	5 - CTs Annual Purchases
Cumulative Present Worth (1000 $)	9,929,749	10,713,653
CPW Difference (1000 $)	[redacted]	783,904
Percent More Expensive Than Base Case		7.9%
Total Capacity Added (MW)	955	840

Note:

1. Analysis was for a 10 year study period with a 10 year extension period.
   Load was frozen after 10 years and no additional capacity additions were made.
2. Purchases are for a 1 year period only.
3. In the original analysis, the Brandy Branch Conversion was not modeled and all self-build alternatives were assumed to be at existing sites; Northside, Southside or Kennedy.
4. Although not shown above, Northside Units 1 and 2 CFBs were part of the expansion plan. These units and any short-term purchases in the early years were left out for consistency with the other need filings.

JEA's RESPONSE TO
STAFF'S FIRST SET OF INTERROGATORIES
DOCKET NO. 001703-EM

4. Explain why JEA assumed a 7.95% present worth discount rate for the proposed steam cycle addition, and how this discount rate is applied in JEA's analysis of alternative resource plans.

As of September 30, 2000, a theorectical 20 year taxable bond rate for JEA taxable debt was 7.95%, which is viewed as a representative value for determining JEA's expected return on investment. The 7.95% average annual rate was used to discount streams of revenue requirements nominal dollars into current year dollars.

Answer provided by: Myron Rollins

5. Explain why JEA assumed a 2.3% annual escalation rate for capital cost and expense, and how the escalation rate applied in JEA's analysis of alternative resource plans.

JEA uses a forecast of the Gross Domestic Product (GDP) Deflator as a base measure of general inflation to derive relative escalation rates for use in resource planning analysis. This rate, 2.3%, was the approximate average annual value for twenty years for GDP Deflator from data supplied by the United States Bureau of Labor Statistics. This figure is used as the general inflation rate component and combined with real inflation rates to compute the overall yearly escalation of capital costs, fuel expense, etc.

Answer provided by: Myron Rollins

6. Explain why JEA assumed a 4.00% interest during construction rate for the proposed steam cycle addition.

> As of September 30, 2000, 4.00% was the rate of JEA's short term variable rate debt. JEA prefers to use short term variable rate debt to finance generation related construction projects, such as the Brandy Branch Combined Cycle Conversion.

Answer provided by: Myron Rollins

7. The U.S. Energy Information Agency's *2001 Annual Energy Outlook (2001 AEO)* was made available on December 22, 2000. Compare the base case fuel price forecasts contained in the *2001 AEO* to JEA's base case fuel price forecasts used in the need application.

The base case fuel price forecast used in the need application was developed by applying escalation rates derived from the *2000 AEO* base case forecast to JEA's average fuel prices for 1999. The high and low fuel price forecasts in the need application similarly were developed by applying escalation rates derived from the *2000 AEO* high and low forecasts to JEA's average fuel prices for 1999.

Pursuant to a clarification from staff regarding the intent of this interrogatory, JEA updated this approach by one year and applied escalation rates derived from the *2001 AEO* forecast to JEA's average fuel prices for 2000.

The resulting comparisons for the base, high and low cases for each fuel are included in the attached tables.

The tables originally filed in response to this Interrogatory on January 18, 2001 contained some inadvertent errors in the updated fuel price columns. Attached is a revised table. The error affected only the tables attached to this interrogatory response; the correct numbers were used in the EGEAS model runs based on the updated fuel forecast.

Answer provided by: John Henry David

JEA **REVISED** Response to Staff
Interrogratory Nos. 7 and 9
Docket No. 001703-EM

Residual and Distillate Fuel Oil ($/MBtu)

	Base Case Delivered Prices ($/MBtu)					
	1.8 % Sulfur		1.0 % Sulfur		Distillate # 2	
Year	Table 6.2 NFP Application	Utilizing AEO 2001	Table 6-2 NFP Application	Utilizing AEO 2001	[redacted]	[redacted]
2000	2.09	4.09	2.72	4.63	[redacted]	[redacted]
2001	2.25	4.35	2.93	5.04	[redacted]	[redacted]
2002	2.43	4.63	3.16	5.49	[redacted]	[redacted]
2003	2.61	4.93	3.40	5.98	[redacted]	[redacted]
2004	2.81	5.25	3.66	6.51	[redacted]	[redacted]
2005	2.88	5.35	3.75	6.79	[redacted]	[redacted]
2006	2.95	5.46	3.84	7.08	[redacted]	[redacted]
2007	3.02	5.57	3.94	7.39	[redacted]	[redacted]
2008	3.10	5.68	4.03	7.71	[redacted]	[redacted]
2009	3.17	5.79	4.13	8.04	[redacted]	[redacted]
2010	3.26	5.82	4.24	8.27	[redacted]	[redacted]
2011	3.35	5.86	4.36	8.52	[redacted]	[redacted]
2012	3.44	5.89	4.47	8.77	[redacted]	[redacted]
2013	3.53	5.93	4.59	9.02	[redacted]	[redacted]
2014	3.62	5.97	4.72	9.29	[redacted]	[redacted]
2015	3.73	5.99	4.86	9.53	[redacted]	[redacted]
2016	3.84	6.01	5.00	9.79	[redacted]	[redacted]
2017	3.96	6.03	5.15	10.05	[redacted]	[redacted]
2018	4.08	6.05	5.31	10.31	[redacted]	[redacted]
2019	4.20	6.07	5.47	10.59	[redacted]	[redacted]

	Low Case Delivered Prices ($/MBtu)					
	1.8 % Sulfur		1.0 % Sulfur		Distillate # 2	
Year	Table 6-8 NFP Application	Utilizing AEO 2001	Table 6-8 NFP Application	Utilizing AEO 2001	[redacted]	[redacted]
2000	2.09	4.09	2.72	4.63	[redacted]	[redacted]
2001	2.20	4.25	2.86	4.92	[redacted]	[redacted]
2002	2.32	4.42	3.01	5.24	[redacted]	[redacted]
2003	2.43	4.59	3.16	5.57	[redacted]	[redacted]
2004	2.56	4.77	3.32	5.92	[redacted]	[redacted]
2005	2.56	4.75	3.32	6.02	[redacted]	[redacted]
2006	2.56	4.72	3.31	6.13	[redacted]	[redacted]
2007	2.55	4.70	3.31	6.24	[redacted]	[redacted]
2008	2.54	4.67	3.30	6.35	[redacted]	[redacted]
2009	2.54	4.65	3.30	6.46	[redacted]	[redacted]
2010	2.54	4.56	3.30	6.48	[redacted]	[redacted]
2011	2.56	4.47	3.31	6.50	[redacted]	[redacted]
2012	2.55	4.39	3.31	6.53	[redacted]	[redacted]
2013	2.56	4.31	3.32	6.55	[redacted]	[redacted]
2014	2.56	4.23	3.32	6.58	[redacted]	[redacted]
2015	2.57	4.13	3.33	6.58	[redacted]	[redacted]
2016	2.58	4.05	3.35	6.59	[redacted]	[redacted]
2017	2.59	3.96	3.36	6.60	[redacted]	[redacted]
2018	2.60	3.87	3.38	6.60	[redacted]	[redacted]
2019	2.61	3.79	3.39	6.61	[redacted]	[redacted]

	High Case Delivered Prices ($/MBtu)					
	1.8 % Sulfur		1.0 % Sulfur		Distillate # 2	
Year	Table 6-9 NFP Application	Utilizing AEO 2001	Table 6-9 NFP Application	Utilizing AEO 2001	[redacted]	[redacted]
2000	2.09	4.09	2.72	4.63	[redacted]	[redacted]
2001	2.30	4.46	2.99	5.16	[redacted]	[redacted]
2002	2.54	4.85	3.30	5.75	[redacted]	[redacted]
2003	2.80	5.29	3.65	6.41	[redacted]	[redacted]
2004	3.09	5.76	4.02	7.14	[redacted]	[redacted]
2005	3.24	6.28	4.22	7.63	[redacted]	[redacted]
2006	3.41	6.84	4.43	8.16	[redacted]	[redacted]
2007	3.57	7.45	4.65	8.72	[redacted]	[redacted]
2008	3.74	8.12	4.88	9.32	[redacted]	[redacted]
2009	3.95	8.84	5.13	9.96	[redacted]	[redacted]
2010	4.15	9.63	5.39	10.60	[redacted]	[redacted]
2011	4.37	10.49	5.67	11.08	[redacted]	[redacted]
2012	4.60	11.43	5.96	11.69	[redacted]	[redacted]
2013	4.83	12.46	6.29	12.33	[redacted]	[redacted]
2014	5.09	13.57	6.62	13.00	[redacted]	[redacted]
2015	5.37	14.78	6.98	13.68	[redacted]	[redacted]
2016	5.67	16.11	7.37	14.39	[redacted]	[redacted]
2017	5.99	17.55	7.78	15.15	[redacted]	[redacted]
2018	6.32	19.12	8.22	15.93	[redacted]	[redacted]
2019	6.67	20.83	8.67	16.77	[redacted]	[redacted]

JEA **REVISED** Response to Staff
Interrogratory Nos. 7 and 9
Docket No. 001703-EM

Natural Gas Delivered Prices ($/MBtu)

	Base Case ($/MBtu)		Low Case ($/MBtu)		High Case ($/MBtu)	
Year	Table 6-3 NFP Application	Utilizing AEO 2001	Table 6-10 NFP Application	Utilizing AEO 2001	Table 6-11 NFP Application	Utilizing AEO 2001
2000	2.74	4.98	2.74	4.98	2.74	4.98
2001	2.85	5.22	2.79	5.11	2.91	5.34
2002	3.16	5.68	3.05	5.44	3.28	5.93
2003	3.29	5.95	3.11	5.58	3.48	6.34
2004	3.42	6.23	3.16	5.72	3.69	6.79
2005	3.54	6.45	3.21	5.78	3.90	7.18
2006	3.66	6.67	3.26	5.85	4.12	7.60
2007	3.80	6.90	3.31	5.92	4.36	8.04
2008	3.93	7.14	3.36	5.99	4.62	8.51
2009	4.08	7.39	3.41	6.06	4.89	9.02
2010	4.18	7.62	3.42	6.10	5.13	9.51
2011	4.29	7.85	3.44	6.14	5.38	10.03
2012	4.41	8.09	3.46	6.19	5.65	10.58
2013	4.52	8.33	3.47	6.23	5.93	11.16
2014	4.64	8.59	3.49	6.27	6.23	11.77
2015	4.76	8.93	3.50	6.38	6.54	12.54
2016	4.89	9.29	3,.51	6.48	6.87	13.36
2017	5.01	9.67	3.53	6.58	7.21	14.24
2018	5.14	10.06	3.54	6.69	7.57	15.18
2019	5.28	10.47	3.56	6.80	7.96	16.18

JEA **REVISED** Response to Staff
Interrogatory Nos. 7 and 9
Docket No. 001703-EM

SJRPP FUEL FORECAST

Year	Base Case Delivered Prices SJRPP Coal Low Sulfur		Low Case Delivered Prices SJRPP Low Sulfur		High Case Delivered Prices SJRPP Low Sulfur	
	[redacted]		[redacted]		[redacted]	
2000	1.48	1.47	1.44	1.47	1.52	1.47
2001	1.49	1.48	1.41	1.45	1.56	1.52
2002	1.50	1.50	1.38	1.42	1.61	1.58
2003	1.50	1.52	1.36	1.40	1.66	1.63
2004	1.51	1.53	1.33	1.38	1.72	1.70
2005	1.54	1.55	1.32	1.36	1.79	1.75
2006	1.56	1.56	1.30	1.34	1.86	1.81
2007	1.58	1.57	1.29	1.31	1.94	1.87
2008	1.61	1.58	1.28	1.29	2.02	1.94
2009	1.63	1.60	1.26	1.27	2.10	2.00
2010	1.66	1.62	1.25	1.25	2.18	2.08
2011	1.68	1.65	1.24	1.24	2.27	2.17
2012	1.71	1.67	1.23	1.23	2.37	2.25
2013	1.74	1.70	1.21	1.22	2.46	2.35
2014	1.76	1.72	1.20	1.20	2.56	2.44
2015	1.79	1.75	1.19	1.19	2.66	2.55
2016	1.81	1.78	1.17	1.18	2.76	2.65
2017	1.83	1.81	1.16	1.17	2.87	2.77
2018	1.85	1.84	1.14	1.16	2.98	2.88
2019	1.88	1.87	1.13	1.15	3.09	3.01

13

JEA **REVISED** Response to Staff
Interrogatory Nos. 7 and 9
Docket No. 001703-EM

SJRPP FUEL FORECAST

Year	Base Case Delivered Prices SJRPP Coal Medium Sulfur		Low Case Delivered Prices SJRPP Medium Sulfur		High Case Delivered Prices SJRPP Medium Sulfur	
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2000	1.62	1.65	1.58	1.65	1.66	1.65
2001	1.63	1.67	1.55	1.62	1.72	1.71
2002	1.64	1.69	1.52	1.60	1.77	1.77
2003	1.65	1.71	1.49	1.58	1.83	1.84
2004	1.66	1.72	1.46	1.56	1.88	1.91
2005	1.69	1.74	1.45	1.53	1.96	1.97
2006	1.71	1.75	1.43	1.50	2.04	2.04
2007	1.74	1.77	1.42	1.48	2.13	2.10
2008	1.77	1.78	1.40	1.45	2.21	2.18
2009	1.79	1.80	1.39	1.43	2.30	2.25
2010	1.82	1.82	1.37	1.41	2.40	2.34
2011	1.85	1.85	1.36	1.40	2.50	2.44
2012	1.88	1.88	1.35	1.38	2.60	2.53
2013	1.91	1.91	1.33	1.37	2.70	2.64
2014	1.94	1.93	1.32	1.35	2.81	2.74
2015	1.96	1.97	1.30	1.34	2.92	2.86
2016	1.99	2.00	1.29	1.33	3.03	2.98
2017	2.01	2.03	1.27	1.32	3.15	3.11
2018	2.04	2.07	1.25	1.31	3.27	3.24
2019	2.06	2.10	1.24	1.29	3.40	3.38

JEA **REVISED** Response to Staff
Interrogatory Nos. 7 and 9
Docket No. 001703-EM

SJRPP FUEL FORECAST

Year	Base Case Delivered Prices SJRPP Petroleum Coke		Low Case Delivered Prices SJRPP Petroleum Coke		High Case Delivered Prices SJRPP Petroleum Coke	
	[redacted]		[redacted]		[redacted]	
2000	0.46	0.65	0.46	0.65	0.46	0.65
2001	0.49	0.66	0.47	0.64	0.50	0.67
2002	0.51	0.67	0.48	0.63	0.53	0.70
2003	0.53	0.68	0.50	0.63	0.57	0.73
2004	0.56	0.69	0.51	0.62	0.62	0.76
2005	0.59	0.71	0.52	0.63	0.66	0.81
2006	0.62	0.74	0.53	0.64	0.71	0.86
2007	0.65	0.77	0.54	0.64	0.76	0.91
2008	0.68	0.80	0.56	0.65	0.82	0.97
2009	0.71	0.83	0.57	0.66	0.88	1.03
2010	0.74	0.86	0.58	0.67	0.95	1.09
2011	0.78	0.89	0.59	0.67	1.02	1.16
2012	0.82	0.92	0.61	0.68	1.09	1.23
2013	0.86	0.95	0.62	0.68	1.17	1.31
2014	0.90	0.98	0.64	0.69	1.26	1.39
2015	0.94	1.02	0.65	0.70	1.35	1.47
2016	0.99	1.06	0.67	0.71	1.45	1.56
2017	1.04	1.09	0.68	0.71	1.56	1.66
2018	1.09	1.13	0.70	0.72	1.68	1.76
2019	1.14	1.17	0.71	0.73	1.80	1.87

JEA **REVISED** Response to Staff
Interrogatory Nos. 7 and 9
Docket No. 001703-EM

Scherer Unit 4 Coal ($/MBtu)

Year	Base Case Delivered Prices		Low Case Delivered Prices		High Case Delivered Prices	
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2000	1.61	1.66	1.57	1.66	1.65	1.66
2001	1.62	1.68	1.54	1.64	1.70	1.72
2002	1.63	1.70	1.51	1.61	1.76	1.79
2003	1.64	1.72	1.48	1.59	1.81	1.85
2004	1.65	1.74	1.45	1.57	1.87	1.92
2005	1.67	1.75	1.43	1.54	1.94	1.98
2006	1.70	1.77	1.42	1.51	2.02	2.05
2007	1.72	1.78	1.40	1.49	2.11	2.12
2008	1.75	1.79	1.39	1.46	2.19	2.19
2009	1.78	1.81	1.38	1.44	2.28	2.27
2010	1.81	1.84	1.36	1.42	2.38	2.36
2011	1.83	1.86	1.35	1.41	2.47	2.45
2012	1.86	1.89	1.33	1.39	2.57	2.55
2013	1.89	1.92	1.32	1.38	2.68	2.66
2014	1.92	1.95	1.31	1.36	2.79	2.76
2015	1.94	1.98	1.29	1.35	2.90	2.88
2016	1.97	2.02	1.27	1.34	3.01	3.00
2017	1.99	2.05	1.26	1.33	3.12	3.13
2018	2.02	2.08	1.24	1.31	3.24	3.26
2019	2.04	2.12	1.23	1.30	3.37	3.40

8. Provide, on an annual and cumulative basis, the present worth revenue requirements associated with the proposed steam cycle addition, using the base case fuel price forecast contained in the *2001 AEO*. Break down by capital, operations and maintenance (O&M), and fuel costs.

A table showing the annual and cumulative PWRR associated with the proposed steam cycle addition using the requested fuel price forecast is attached. None of the 200 least cost plans produced by EGEAS included anything other than the Brandy Branch Combined Cycle Conversion as the 2004 unit addition. The PWRR associated with Plan #200 is $42.921 million higher than that associated with Plan #1. Thus the Brandy Branch Conversion is at least $42.921 million PWRR lower cost than the next least cost alternative.

As shown in the table attached to Interrogatory No. 9, the least cost plan based on this fuel price forecast still begins with the Brandy Branch Conversion in 2004. However, the least cost plan based on this fuel forecast differs in later years from the base case presented in the need application by including more solid fuel units (circulating fluidized bed and pulverized coal).

These results suggest that if natural gas prices were to remain for a long period of time at abnormally high levels, the least cost plan would include more coal-based units and fewer natural gas fired units beginning in 2006. Whether such a plan is ultimately selected as the most cost-effective alternative would depend on how robust the plan is under a variety of planning scenarios and on the consideration of strategic factors, such as fuel diversity and the risks involved in attempting to permit a coal-based unit.

Answer provided by: Mary Guyton-Baker and Randy Boswell

JEA Response to
Staff Interrogatory No. 8
Docket No. 001703-EM

JEA Need For Power Application
Interrogatory 8 - Basecase Using 2000 Fuel Forecast
Cumulative Present Worth Revenue Requirements
(Million $)

Discount Factor: 7.95%

		O&M					Present Worth	
Year	Fuel	Variable	Fixed	Capital	Total	Cumulative	Total	Cumulative
2000	282.26	0.97	96.35	0.00	379.57	379.57	379.57	379.57
2001	313.36	9.14	47.18	11.24	380.92	760.49	352.87	732.44
2002	238.84	11.28	43.65	11.24	305.01	1,065.50	261.74	994.18
2003	245.11	15.99	50.69	11.24	323.03	1,388.53	256.79	1,250.97
2004	252.38	13.10	35.56	25.43	326.47	1,715.01	240.41	1,491.38
2005	282.85	14.04	36.38	25.43	358.71	2,073.72	244.70	1,736.08
2006	248.42	18.63	45.86	64.09	377.00	2,450.72	238.24	1,974.31
2007	278.02	20.14	46.91	64.09	409.16	2,859.87	239.51	2,213.83
2008	266.66	25.56	57.03	104.55	453.80	3,313.68	246.09	2,459.91
2009	294.27	27.77	58.35	104.55	484.94	3,798.61	243.60	2,703.52
2010	320.16	43.08	69.15	146.90	579.28	4,377.89	269.56	2,973.08
2011	334.19	46.37	71.95	175.91	628.42	5,006.31	270.89	3,243.97
2012	369.31	50.83	73.61	175.91	669.66	5,675.96	267.41	3,511.38
2013	401.85	52.45	75.30	175.91	705.51	6,381.47	260.98	3,772.36
2014	386.58	58.88	86.23	221.38	753.07	7,134.54	258.06	4,030.42
2015	427.77	63.69	88.21	221.38	801.05	7,935.59	254.29	4,284.71
2016	408.93	66.50	99.87	268.97	844.26	8,779.85	248.26	4,532.97
2017	451.01	71.79	102.16	268.97	893.94	9,673.79	243.51	4,776.48
2018	489.91	76.29	105.20	282.61	954.01	10,627.80	240.74	5,017.22
2019	482.73	83.07	117.93	333.56	1,017.29	11,645.09	237.80	5,255.02

9. Compare the high, alternative and low fuel price forecasts contained in the *2001 AEO* to that in Table 14-1 of the need application. Discuss the impact of the *2001 AEO* fuel sensitivities on the cost-effectiveness of JEA's base case expansion plan.

As discussed in response to Interrogatory No. 7, the high and low fuel price forecasts used in the need application were developed by applying escalation rates derived from the *2000 AEO* to JEA's average fuel prices for 1999. Pursuant to a clarification from staff regarding the intent of this interrogatory, JEA updated this approach by one year and applied escalation rates derived from the *2001 AEO* to JEA's average fuel prices for 2000. The resulting comparisons for the base, high and low cases are all included in the tables attached in the response to Interrogatory No. 7.

JEA has not updated the "alternative" price forecast contained in the need application. That forecast was developed by applying the *2000 AEO* escalation rates to a September, 2000 fuel price number. The alternative forecast was designed simply to show how the forecast methodology would be affected by starting with recent, higher-priced actual 2000 fuel prices, rather than the average 1999 fuel prices. When the base, low and high cases are all updated to start with actual 2000 numbers, there is no longer a need to prepare an "alternative" forecast. JEA notes that the alternative forecast prepared in 1999 produces a natural gas price forecast which falls between the base case and high case forecasts developed using average 2000 fuel price data.

As shown in the attached table, the Brandy Branch Combined Cycle Conversion is selected as the 2004 addition in the base case, and each of the fuel price sensitivity cases, using either the 1999 or 2000 fuel forecasts. In the base case presented in the need application, the Brandy Branch Combined Cycle Conversion is $17.2 million (PWRR) lower cost than the next best alternative. Using the 2000 base case fuel forecast, the conversion is at least $42.9 million (PWRR) lower cost than the next best alternative.

Using the updated fuel forecast, the base case and sensitivities result in the addition of more solid fuel units, and fewer natural gas fired units, beginning in 2006 compared to the base case and fuel price sensitivities presented in the need application.

Answer provided by: Mary Guyton-Baker

JEA Response to
Staff Interrogatory No. 9
Docket No. 001703-EM

JEA Summary of Results

Need For Power Application

Interrogatory 9

	[redacted]				
Year	Plan #1	First Case w/out Conversion Plan # 145	High Fuel Price Forecast	Low Fuel Price Forecast	Alternate High Fuel Price Forecast
2000					
2001	3 - CTs	3 - CTs	3 - CTs	3 - CTs	3 - CTs
2002					
2003					
2004	BB CC Conv. 2x1	Greenfield 501G CC 1x1	BB CC Conv. 2x1	BB CC Conv. 2x1	BB CC Conv. 2x1
2005					
2006	Greenfield CC 1x1		Greenfield 501G CC 1x1	Greenfield CC 1x1	Greenfield 501G CC 1x1
2007		Greenfield 501G CC 1x1			
2008	Greenfield CT 7FA			Greenfield CT 7FA	
2009			Greenfield CT 7FA		Greenfield CFB
2010	Greenfield CC 2x1	Greenfield CC 2x1	Greenfield CC 2x1	Greenfield CC 2x1	Greenfield CFB
2011					
2012		BB CC Conv. 2x1			Greenfield CFB
2013	Greenfield CC 1x1	Greenfield 501G CC 1x1	Greenfield 501G CC 1x1	Greenfield CC 1x1	
2014					Greenfield CC 1x1
2015	Greenfield CFB	Greenfield CC 1x1		Greenfield 501G CC 1x1	
2016			Greenfield CC 1x1	Greenfield CC 1x1	Greenfield CC 1x1
2017	Greenfield CC 1x1	Greenfield CC 1x1			
2018			Greenfield CC 1x1	Greenfield 501G CC 1x1	Greenfield Coal
2019	Greenfield CT 7FA	Greenfield Coal			
Rundown	5 - CTs BB CC Conv. 2x1 3-Greenfield CC 1x1 1-Greenfield CC 2x1 1-Greenfield CFB	3 - CTs BB CC Conv. 2x1 3-Greenfield 501G 1x1 2-Greenfield CC 1x1 1-Greenfield CC 2x1 1-Greenfield Coal	4 - CTs BB CC Conv. 2x1 2-Greenfield 501G 1x1 2-Greenfield CC 1x1 1-Greenfield CC 2x1	4 - CTs BB CC Conv. 2x1 2-Greenfield 501G 1x1 3-Greenfield CC 1x1 1-Greenfield CC 2x1	3 - CTs BB CC Conv. 2x1 1-Greenfield 501G 1x1 2-Greenfield CC 1x1 3-Greenfield CFB 1-Greenfield Coal
Cumulative Present Worth (1000 $)	4,431,688	4,448,858	5,488,938	3,852,189	5,317,895
CPW Difference (1000 $)	[redacted]	17,170	1,057,250	(579,499)	886,207
Percent More Expensive Than Base Case		0.39%	23.86%	-13.08%	20.00%
Total Capacity Added (MW)	2,647	2,999	2,600	2,869	2,560

[redacted]			
Plan #1	Plan #200	High Fuel Price Forecast	Low Fuel Price Forecast
3 - CTs	3 - CTs	3 - CTs	3 - CTs
BB CC Conv. 2x1	BB CC Conv. 2x1	BB CC Conv. 2x1	BB CC Conv. 2x1
Greenfield CFB	Greenfield CFB	Greenfield CFB	Greenfield Coal
Greenfield CFB	Greenfield CFB	Greenfield CFB	Greenfield Coal
Greenfield CFB	Greenfield CFB	Greenfield CFB	Greenfield CC 2x1
Greenfield 501G CC 1x1	Greenfield 501G CC 1x1	Greenfield Coal	
		Greenfield Coal	Greenfield Coal
Greenfield Coal	Greenfield 501G CC 1x1		
		Greenfield Coal	Greenfield CT 7FA
Greenfield Coal	Greenfield CT 7FA		
		Greenfield CC 1x1	Greenfield Coal
Greenfield CT 7FA	Greenfield CC 1x1		
Greenfield Coal	2-Greenfield CT 7FA	Greenfield Coal	Greenfield CT 7FA
4 - CTs BB CC Conv. 2x1 1-Greenfield 501G 1x1 3-Greenfield CFB 3-Greenfield Coal	6 - CTs BB CC Conv. 2x1 2-Greenfield 501G 1x1 1-Greenfield CC 1x1 3-Greenfield CFB	3 - CTs BB CC Conv. 2x1 1-Greenfield CC 1x1 3-Greenfield CFB 4-Greenfield Coal	5 - CTs BB CC Conv. 2x1 1-Greenfield CC 2x1 4-Greenfield Coal
5,255,025	5,297,946	5,682,476	4,817,161
[redacted]	42,921	427,451	(437,864)
	0.82%	8.13%	-8.33%
2,696	2,888	2,717	2,590

21

JEA RESPONSE TO
STAFF'S FIRST REQUEST FOR PRODUCTION
DOCKET NO. 001703-EM

1. Provide copies of the transcript and/or vote records of JEA's Board approving the Brandy Branch combustion turbine units and the steam cycle addition.

    Although the JEA Board approves JEA's annual budget, which includes line items for generation projects, it has delegated the authority to approve equipment purchases, such as the purchase of the combustion turbine units, to JEA's Awards Committee. Attached are documents showing Awards Committee approval of the combustion turbine purchases, Board approval of JEA's budget including these projects, and other informational material provided to the JEA Board regarding JEA's generation expansion plans, which included the simple cycle combustion turbine additions and the Brandy Branch conversion.

2. Provide copies of the projected cost estimates reviewed by JEA's Board in approving the Brandy Branch combustion turbine units and the steam cycle addition.

    See response to Request for Production No. 1.

3. Provide copies of any memorandum of understanding, agreement, or order concerning potable water wells necessary at the project site for cooling purposes.

    There are no such documents.

4. Provide copies of any memorandum of understanding, agreement, or order concerning JEA's water usage for the Brandy Branch combustion turbine units and the steam cycle addition.

    A copy of the Consumptive Use Permit for the simple cycle combustion turbine units is attached.

JEA RESPONSE TO
STAFF'S FIRST REQUEST FOR PRODUCTION
DOCKET NO. 001703-EM

5. For each year during the period 1990-1999, provide the daily minimum temperature for the year's winter peak day.

   See attached table, which includes information from 1980-2000.

6. For each year during the period 1990-1999, provide the daily maximum temperature for the year's summer peak day.

   See attached table, which includes information from 1980-2000.

7. Provide the data used for the trend analysis used to forecast energy production and demand.

   See attached tables.

JEA PEAK DEMANDS / PEAK DAY TEMPERATURE EXTREMES

YEAR	Winter Peak	Peak Day Minimum Temp (F)		Summer Peak	Peak Day Maximum Temp (F)
1980	1,143	28		1,296	99
1981	1,260	13		1,306	102
1982	1,291	17		1,238	95
1983	1,159	26		1,389	96
1984	1,233	26		1,335	94
1985	1,586	7		1,478	100
1986	1,640	16		1,553	97
1987	1,439	29		1,628	98
1988	1,633	25		1,655	96
1989	1,657	27		1,714	97
1990	2,012	24		1,789	100
1991	1,725	25		1,756	95
1992	1,881	24		1,881	97
1993	1,791	27		1,998	99
1994	1,942	26		1,918	95
1995	2,190	20		2,067	96
1996	2,401	19		2,114	96
1997	2,084	25		2,130	93
1998	1,975	38		2,338	99
1999	2,403	22		2,427	101
2000	2,478	24		2,531	103

JEA Response to
Staff's Request for Production No. 7
Docket No. 001703-EM

Data JEA Used for the Trend Analysis Used to Forecast Energy Production
All Values in kWh

Year	Mo	Interchange Sales	Net Energy For System	Interchange Losses - 3%	NES Less Interchange Losses	Sales for Resale Energy Use
1979	10	3,780,000	456,917,196	113,400	456,803,796	#N/A
1979	11	2,632,000	425,399,434	78,960	425,320,474	#N/A
1979	12	10,506,000	473,163,620	315,180	472,848,440	#N/A
1980	1	6,096,000	486,446,438	182,880	486,263,558	#N/A
1980	2	7,593,000	483,758,990	227,790	483,531.200	#N/A
1980	3	31,786,000	433,065,822	953,580	432,112,242	#N/A
1980	4	7,213,000	397,420,626	216,390	397,204,236	#N/A
1980	5	145,000	466,546,214	4,350	466,541,864	#N/A
1980	6	2,949,000	540,334,480	88,470	540,246,010	#N/A
1980	7	12,926,000	642,631,186	387,780	642,243,406	#N/A
1980	8	13,483,000	639,178,070	404,490	638,773,580	#N/A
1980	9	9,891,000	591,144,692	296,730	590,847,962	#N/A
1980	10	12,786,000	443,039,252	383,580	442,655,672	#N/A
1980	11	5,055,000	421,175,968	151,650	421,024,318	#N/A
1980	12	5,078,000	505,898,454	152,340	505,746,114	#N/A
1981	1	6,325,000	569,392,240	189,750	569,202,490	#N/A
1981	2	8,741,000	433,025,696	262,230	432,763,466	#N/A
1981	3	8,100,000	428,123,176	243,000	427,880,176	#N/A
1981	4	11,241,000	420,951,818	337,230	420,614,588	#N/A
1981	5	7,879,000	460,797,262	236,370	460,560,892	#N/A
1981	6	61,492,000	608,150,952	1,844,760	606,306,192	#N/A
1981	7	19,148,000	643,940,382	574,440	643,365,942	#N/A
1981	8	19,561,000	601,135,942	586,830	600,549,112	#N/A
1981	9	7,192,000	519,420,172	215,760	519,204,412	#N/A
1981	10	24,366,108	456,560,152	730,983	455,829,169	#N/A
1981	11	24,588,814	438,019,116	737,664	437,281,452	#N/A
1981	12	3,643,029	509,094,822	109,291	508,985,531	#N/A
1982	1	14,825,199	514,514,706	444,756	514,069,950	#N/A
1982	2	13,057,827	400,340,526	391,735	399,948,791	#N/A
1982	3	20,224,234	454,411,166	606,727	453,804,439	#N/A
1982	4	52,339,486	432,441,524	1,570,185	430,871,339	#N/A
1982	5	26,725,023	492,527,170	801,751	491,725,419	#N/A
1982	6	21,417,855	593,711,510	642,536	593,068,974	#N/A
1982	7	12,377,897	621,082,060	371,337	620,710,723	#N/A
1982	8	7,637,155	628,138,450	229,115	627,909,335	#N/A
1982	9	324,380	541,929,780	9,731	541,920,049	#N/A
1982	10	168,283	481,947,650	5,048	481,942,602	#N/A
1982	11	744,160	436,650,880	22,325	436,628,555	#N/A
1982	12	764,094	478,666,378	22,923	478,643,455	#N/A
1983	1	354,051	552,189,962	10,622	552,179,340	#N/A

JEA Response to
Staff's Request for Production No. 7
Docket No. 001703-EM

Year	Mo	Interchange Sales	Net Energy For System	Interchange Losses - 3%	NES Less Interchange Losses	Sales for Resale Energy Use
1983	2	(399,596)	463,835,580	(11,988)	463,847,568	#N/A
1983	3	(430,125)	468,659,000	(12,904)	468,671,904	#N/A
1983	4	(284,456)	425,852,000	(8,534)	425,860,534	#N/A
1983	5	119,600	492,000,000	3,588	491,996,412	#N/A
1983	6	6,742,226	554,984,000	202,267	554,781,733	#N/A
1983	7	6,465,852	679,321,000	193,976	679,127,024	#N/A
1983	8	3,454,028	689,788,000	103,621	689,684,379	#N/A
1983	9	6,407,698	565,205,000	192,231	565,012,769	#N/A
1983	10	2,824,000	480,631,000	84,720	480,546,280	#N/A
1983	11	214,000	438,368,000	6,420	438,361,580	#N/A
1983	12	1,028,000	537,186,000	30,840	537,155,160	#N/A
1984	1	2,383,000	575,370,542	71,490	575,299,052	#N/A
1984	2	21,000	479,691,432	630	479,690,802	#N/A
1984	3	550,000	466,830,310	16,500	466,813,810	#N/A
1984	4	141,000	441,071,767	4,230	441,067,537	#N/A
1984	5	20,000	536,572,381	600	536,571,781	#N/A
1984	6	-	589,530,841	-	589,530,841	#N/A
1984	7	300,000	637,368,370	9,000	637,359,370	#N/A
1984	8	-	658,916,580	-	658,916,580	#N/A
1984	9	34,000	551,982,809	1,020	551,981,789	#N/A
1984	10	25,000	529,801,429	750	529,800,679	#N/A
1984	11	107,000	496,443,653	3,210	496,440,443	#N/A
1984	12	11,000	489,543,510	330	489,543,180	#N/A
1985	1	841,000	627,238,991	25,230	627,213,761	#N/A
1985	2	698,000	504,200,927	20,940	504,179,987	#N/A
1985	3	34,000	488,085,980	1,020	488,084,960	#N/A
1985	4	1,831,000	476,062,493	54,930	476,007,563	#N/A
1985	5	4,304,000	571,030,286	129,120	570,901,166	#N/A
1985	6	2,702,000	668,617,765	81,060	668,536,705	#N/A
1985	7	3,043,000	685,081,127	91,290	684,989,837	#N/A
1985	8	32,595,000	681,912,222	977,850	680,934,372	#N/A
1985	9	18,140,000	599,999,353	544,200	599,455,153	#N/A
1985	10	10,807,000	592,811,249	324,210	592,487,039	#N/A
1985	11	3,020,000	503,304,810	90,600	503,214,210	#N/A
1985	12	2,123,000	598,010,412	63,690	597,946,722	#N/A
1986	1	1,374,000	609,985,376	41,220	609,944,156	#N/A
1986	2	103,000	477,351,310	3,090	477,348,220	#N/A
1986	3	1,500,000	528,222,023	45,000	528,177,023	#N/A
1986	4	422,000	489,646,779	12,660	489,634,119	#N/A
1986	5	1,216,000	587,835,468	36,480	587,798,988	#N/A
1986	6	4,059,000	697,518,007	121,770	697,396,237	#N/A
1986	7	2,699,000	793,615,879	80,970	793,534,909	#N/A
1986	8	5,458,000	739,110,216	163,740	738,946,476	#N/A

Year	Mo	Interchange Sales	Net Energy For System	Interchange Losses - 3%	NES Less Interchange Losses	Sales for Resale Energy Use
1986	9	3,307,000	701,254,373	99,210	701,155,163	#N/A
1986	10	6,175,843	611,843,039	185,275	611,657,764	#N/A
1986	11	2,836,157	534,869,480	85,085	534,784,395	#N/A
1986	12	3,946,000	565,681,130	118,380	565,562,750	#N/A
1987	1	1,921,000	643,643,364	57,630	643,585,734	#N/A
1987	2	1,535,000	545,890,237	46,050	545,844,187	#N/A
1987	3	25,117,000	550,799,486	753,510	550,045,976	#N/A
1987	4	25,949,000	536,376,797	778,470	535,598,327	#N/A
1987	5	21,060,000	618,127,303	631,800	617,495,503	#N/A
1987	6	18,357,000	733,037,247	550,710	732,486,537	#N/A
1987	7	15,115,000	806,763,028	453,450	806,309,578	#N/A
1987	8	21,723,000	844,624,771	651,690	843,973,081	#N/A
1987	9	8,297,000	720,289,211	248,910	720,040,301	#N/A
1987	10	16,576,000	558,038,684	497,280	557,541,404	#N/A
1987	11	13,785,000	561,668,975	413,550	561,255,425	#N/A
1987	12	3,807,000	609,656,582	114,210	609,542,372	#N/A
1988	1	159,000	721,114,128	4,770	721,109,358	13,564,838
1988	2	1,044,000	624,914,918	31,320	624,883,598	13,298,299
1988	3	2,618,000	584,408,022	78,540	584,329,482	9,861,285
1988	4	2,554,000	550,682,108	76,620	550,605,488	10,107,746
1988	5	27,995,000	620,123,558	839,850	619,283,708	8,464,816
1988	6	13,509,000	715,800,593	405,270	715,395,323	11,392,573
1988	7	41,659,000	798,376,312	1,249,770	797,126,542	14,325,076
1988	8	79,021,000	837,300,708	2,370,630	834,930,078	17,904,024
1988	9	92,292,000	761,382,533	2,768,760	758,613,773	14,023,539
1988	10	17,392,000	593,821,828	521,760	593,300,068	9,452,751
1988	11	16,652,000	573,502,440	499,560	573,002,880	30,427,374
1988	12	12,897,000	683,160,383	386,910	682,773,473	28,560,294
1989	1	48,515,000	604,318,117	1,455,450	602,862,667	19,944,988
1989	2	41,705,000	594,220,237	1,251,150	592,969,087	11,868,885
1989	3	35,825,000	624,974,402	1,074,750	623,899,652	13,331,202
1989	4	67,822,000	596,364,057	2,034,660	594,329,397	14,016,871
1989	5	46,188,000	693,570,165	1,385,640	692,184,525	14,679,488
1989	6	29,244,000	795,369,549	877,320	794,492,229	16,150,447
1989	7	41,286,000	851,822,887	1,238,580	850,584,307	19,909,954
1989	8	19,331,000	855,623,360	579,930	855,043,430	19,478,443
1989	9	22,080,000	758,243,877	662,400	757,581,477	13,818,648
1989	10	10,180,000	678,940,118	305,400	678,634,718	10,300,989
1989	11	6,861,000	593,920,328	205,830	593,714,498	7,975,491
1989	12	27,163,000	819,011,804	814,890	818,196,914	15,692,012
1990	1	9,372,000	640,014,179	281,160	639,733,019	11,263,781
1990	2	8,927,000	550,587,233	267,810	550,319,423	10,909,036
1990	3	30,926,000	596,883,529	927,780	595,955,749	9,745,741

Year	Mo	Interchange Sales	Net Energy For System	Interchange Losses - 3%	NES Less Interchange Losses	Sales for Resale Energy Use
1990	4	32,293,000	585,079,379	968,790	584,110,589	9,342,640
1990	5	34,601,000	760,657,446	1,038,030	759,619,416	15,939,087
1990	6	22,583,000	824,437,968	677,490	823,760,478	19,449,939
1990	7	53,446,000	906,183,087	1,603,380	904,579,707	21,104,478
1990	8	97,344,000	892,065,346	2,920,320	889,145,026	18,963,073
1990	9	27,404,000	801,164,845	822,120	800,342,725	17,869,593
1990	10	70,746,000	736,522,636	2,122,380	734,400,256	18,374,659
1990	11	24,370,000	596,518,986	731,100	595,787,886	10,720,403
1990	12	38,526,000	651,313,641	1,155,780	650,157,861	11,234,752
1991	1	12,053,000	690,552,828	361,590	690,191,238	14,355,330
1991	2	4,262,000	601,615,267	127,860	601,487,407	11,581,710
1991	3	35,770,000	632,673,747	1,073,100	631,600,647	11,449,747
1991	4	76,034,000	657,550,826	2,281,020	655,269,806	16,664,904
1991	5	59,712,000	818,084,456	1,791,360	816,293,096	18,234,592
1991	6	12,344,000	802,617,753	370,320	802,247,433	17,040,506
1991	7	23,750,000	892,009,652	712,500	891,297,152	23,549,626
1991	8	16,389,000	908,132,655	491,670	907,640,985	24,319,177
1991	9	14,039,000	800,997,435	421,170	800,576,265	22,922,123
1991	10	40,272,000	670,524,266	1,208,160	669,316,106	17,888,433
1991	11	18,904,000	661,276,826	567,120	660,709,706	19,042,132
1991	12	6,189,000	698,460,801	185,670	698,275,131	27,100,475
1992	1	18,025,000	765,533,649	540,750	764,992,899	25,314,555
1992	2	12,393,000	647,270,030	371,790	646,898,240	22,637,037
1992	3	9,946,000	645,633,668	298,380	645,335,288	22,109,703
1992	4	8,681,000	628,921,868	260,430	628,661,438	19,518,135
1992	5	23,906,000	712,865,381	717,180	712,148,201	23,759,916
1992	6	25,413,000	855,994,171	762,390	855,231,781	31,126,414
1992	7	25,684,000	981,402,728	770,520	980,632,208	34,040,930
1992	8	24,131,000	893,034,481	723,930	892,310,551	31,208,445
1992	9	15,122,000	817,737,404	453,660	817,283,744	28,310,976
1992	10	9,809,000	665,891,194	294,270	665,596,924	21,909,294
1992	11	7,259,000	680,573,426	217,770	680,355,656	24,023,375
1992	12	6,118,000	733,314,360	183,540	733,130,820	24,728,321
1993	1	5,276,000	708,822,911	158,280	708,664,631	25,764,084
1993	2	2,091,000	692,551,667	62,730	692,488,937	28,356,208
1993	3	26,324,000	717,765,326	789,720	716,975,606	28,211,012
1993	4	15,106,000	642,226,016	453,180	641,772,836	25,168,992
1993	5	9,078,000	769,505,630	272,340	769,233,290	28,952,242
1993	6	15,249,000	912,760,029	457,470	912,302,559	30,829,483
1993	7	29,215,000	1,016,290,976	876,450	1,015,414,526	33,492,467
1993	8	28,987,000	1,010,103,782	869,610	1,009,234,172	32,569,167
1993	9	40,456,000	901,878,098	1,213,680	900,664,418	26,841,874
1993	10	20,971,000	732,050,571	629,130	731,421,441	23,692,480

Year	Mo	Interchange Sales	Net Energy For System	Interchange Losses - 3%	NES Less Interchange Losses	Sales for Resale Energy Use
1993	11	23,624,000	692,091,007	708,720	691,382,287	27,895,858
1993	12	5,502,000	813,073,319	165,060	812,908,259	26,158,342
1994	1	8,975,000	843,671,727	269,250	843,402,477	28,739,240
1994	2	5,289,000	662,317,404	158,670	662,158,734	20,318,540
1994	3	7,088,000	690,523,523	212,640	690,310,883	19,232,924
1994	4	51,615,000	704,237,666	1,548,450	702,689,216	20,541,993
1994	5	25,999,000	812,814,276	779,970	812,034,306	25,731,177
1994	6	25,148,000	899,919,399	754,440	899,164,959	29,897,836
1994	7	13,037,000	954,284,392	391,110	953,893,282	27,244,915
1994	8	12,191,000	965,242,834	365,730	964,877,104	30,857,456
1994	9	8,781,000	849,191,526	263,430	848,928,096	27,231,295
1994	10	34,801,000	766,431,085	1,044,030	765,387,055	29,622,307
1994	11	42,276,000	697,744,191	1,268,280	696,475,911	22,456,802
1994	12	4,333,000	760,313,109	129,990	760,183,119	22,389,902
1995	1	1,031,000	832,895,772	30,930	832,864,842	27,222,794
1995	2	3,969,000	744,821,142	119,070	744,702,072	25,810,593
1995	3	14,597,000	725,809,630	437,910	725,371,720	29,578,698
1995	4	30,752,000	717,075,399	922,560	716,152,839	21,239,732
1995	5	21,499,000	925,841,968	644,970	925,196,998	30,962,972
1995	6	19,153,000	919,506,483	574,590	918,931,893	30,432,747
1995	7	34,597,000	1,036,095,499	1,037,910	1,035,057,589	35,294,886
1995	8	64,286,000	1,056,712,518	1,928,580	1,054,783,938	34,168,231
1995	9	25,420,000	906,867,505	762,600	906,104,905	30,507,033
1995	10	32,739,000	826,163,024	982,170	825,180,854	27,894,708
1995	11	25,021,000	761,561,235	750,630	760,810,605	19,897,781
1995	12	7,623,000	872,729,164	228,690	872,500,474	26,048,673
1996	1	13,608,000	886,830,317	408,240	886,422,077	31,475,396
1996	2	20,648,000	797,503,301	619,440	796,883,861	29,458,381
1996	3	18,313,000	815,308,064	549,390	814,758,674	25,334,565
1996	4	17,016,101	738,144,469	510,483	737,633,986	29,132,238
1996	5	26,186,899	922,632,429	785,607	921,846,822	30,713,578
1996	6	31,574,000	929,970,092	947,220	929,022,872	30,825,823
1996	7	27,254,000	1,098,486,435	817,620	1,097,668,815	38,327,777
1996	8	16,547,800	1,014,339,200	496,434	1,013,842,766	33,100,509
1996	9	18,693,000	937,109,585	560,790	936,548,795	34,802,764
1996	10	8,438,000	791,567,000	253,140	791,313,860	27,231,108
1996	11	6,472,000	750,761,202	194,160	750,567,042	23,296,054
1996	12	9,990,000	829,701,180	299,700	829,401,480	29,766,380
1997	1	8,630,000	844,224,737	258,900	843,965,837	31,411,481
1997	2	3,762,000	760,717,287	112,860	760,604,427	28,677,954
1997	3	13,624,000	776,222,468	408,720	775,813,748	28,037,800
1997	4	2,572,000	760,967,569	77,160	760,890,409	26,932,717
1997	5	8,205,000	869,252,798	246,150	869,006,648	29,500,591

JEA Response to
Staff's Request for Production No. 7
Docket No. 001703-EM

Year	Mo	Interchange Sales	Net Energy For System	Interchange Losses - 3%	NES Less Interchange Losses	Sales for Resale Energy Use
1997	6	21,582,000	936,503,078	647,460	935,855,618	34,398,859
1997	7	44,562,000	1,091,657,351	1,336,860	1,090,320,491	38,347,923
1997	8	38,364,000	1,084,075,434	1,150,920	1,082,924,514	36,697,237
1997	9	27,035,000	993,487,635	811,050	992,676,585	40,268,174
1997	10	38,296,000	882,789,167	1,148,880	881,640,287	32,011,084
1997	11	17,750,000	760,792,844	532,500	760,260,344	22,659,681
1997	12	5,998,000	904,809,505	179,940	904,629,565	34,053,522
1998	1	5,576,000	851,100,770	167,280	850,933,490	29,996,550
1998	2	11,209,000	736,777,709	336,270	736,441,439	28,532,100
1998	3	5,182,000	858,349,539	155,460	858,194,079	30,649,068
1998	4	14,514,000	792,776,007	435,420	792,340,587	26,646,793
1998	5	55,118,000	1,008,337,532	1,653,540	1,006,683,992	32,777,897
1998	6	44,336,000	1,241,198,729	1,330,080	1,239,868,649	47,845,122
1998	7	69,003,000	1,202,606,815	2,070,090	1,200,536,725	49,401,799

JEA Response to
Staff Request for Production No. 7
Docket No. 001703-EM

Data JEA Used for the Trend Analysis Used to Forecast Peak Demands

Year	System Winter Peak (MW) Actual Peak	System Winter Peak (MW) Normal Weather Peak	System Winter Peak (MW) Peak Day Minimum Temperature	System Summer Peak (MW) Actual Peak	System Summer Peak (MW) Normal Weather Peak	System Summer Peak (MW) Peak Day Maximum Temperature
1980	1,143	1,144	28°	1,296	1,317	99°
1981	1,260	1,134	13°	1,306	1,275	102°
1982	1,291	1,184	17°	1,238	1,294	95°
1983	1,159	1,196	26°	1,389	1,429	96°
1984	1,233	1,188	26°	1,335	1,443	94°
1985	1,586	1,344	7°	1,478	1,484	100°
1986	1,640	1,422	16°	1,553	1,556	97°
1987	1,439	1,594	29°	1,628	1,631	98°
1988	1,633	1,619	25°	1,655	1,654	96°
1989	1,657	1,675	27°	1,714	1,724	97°
1990	2,012	1,801	24°	1,789	1,780	100°
1991	1,725	1,723	25°	1,756	1,826	95°
1992	1,881	1,823	24°	1,881	1,898	97°
1993	1,791	1,875	27°	1,998	1,998	99°
1994	1,942	2,052	26°	1,918	2,024	95°
1995	2,190	2,113	20°	2,067	2,079	96°
1996	2,401	2,254	19°	2,114	2,160	96°
1997	2,084	2,175	25°	2,130	2,260	93°
1998	1,975	2,337	38°			

	Sales for Resale Peak Demands (MW)			
	Customer Peaks		Coincident Peaks	
Year	Winter	Summer	Winter	Summer
1984	42	40	#N/A	#N/A
1985	41	44	#N/A	#N/A
1986	49	51	#N/A	#N/A
1987	41	58	#N/A	#N/A
1988	41	55	#N/A	#N/A
1989	61	58	#N/A	#N/A
1990	70	63	69	38
1991	62	68	62	46
1992	68	64	65	#N/A
1993	65	72	65	57
1994	66	68	66	53
1995	78	76	78	65
1996	93	78	84	61
1997	78	83	72	70
1998	75		68	

	Non-Firm Customer Demands by Season First Participating					
	Max Billing Demands		Coincidence Factor		Est. Coincident Peak	
FY	Winter	Summer	Winter	Summer	Winter	Summer
1997	72	111	50%	72%	36	80
1998	130	147	50%	72%	65	106
1999	199	203	50%	72%	100	146

DATE	HOUR	PEAK	MAXTEMP	FY	MW3PM	MW5PM
08/15/1984	17	1,244	93	1984	1,199	1,244
08/16/1984	18	1,306	94	1984	1,264	1,305
08/17/1984	17	1,315	94	1984	1,266	1,315
08/22/1984	17	941	79	1984	894	941
08/23/1984	19	900	82	1984	779	826
08/24/1984	16	1,125	89	1984	1,078	1,107
08/27/1984	18	1,089	85	1984	1,023	1,086
08/28/1984	19	1,081	85	1984	1,018	1,047
08/29/1984	18	1,134	88	1984	1,014	1,126
08/30/1984	18	1,194	90	1984	1,108	1,154
08/31/1984	17	1,223	92	1984	1,143	1,223
09/03/1984	19	1,058	90	1984	983	1,034
09/05/1984	21	939	79	1984	894	915
09/10/1984	18	888	81	1984	832	872
09/11/1984	18	1,050	85	1984	986	1,039
09/12/1984	19	1,198	89	1984	1,093	1,154
09/13/1984	17	1,230	91	1984	1,151	1,230
09/14/1984	16	1,216	92	1984	1,173	1,193
09/17/1984	13	842	72	1984	809	839
09/18/1984	17	815	76	1984	797	815
09/20/1984	18	925	81	1984	875	904
09/21/1984	17	958	84	1984	923	958
09/24/1984	17	1,017	84	1984	991	1,017
09/25/1984	17	1,038	84	1984	969	1,038
09/26/1984	18	1,074	85	1984	1,011	1,057
06/03/1985	19	1,455	100	1985	1,416	1,452
06/04/1985	17	1,479	100	1985	1,402	1,479
06/06/1985	17	1,442	99	1985	1,330	1,442
06/07/1985	17	1,395	99	1985	1,336	1,395
06/11/1985	17	1,375	96	1985	1,331	1,375
06/17/1985	18	1,204	90	1985	1,083	1,178
06/18/1985	18	1,357	91	1985	1,255	1,335
06/19/1985	17	1,323	93	1985	1,267	1,323
06/21/1985	17	1,090	84	1985	1,048	1,090
06/24/1985	18	1,214	89	1985	1,149	1,209
06/26/1985	18	1,228	90	1985	1,161	1,210
07/01/1985	18	1,092	87	1985	1,035	1,085
07/02/1985	17	1,177	91	1985	1,158	1,177
07/03/1985	17	1,213	89	1985	1,194	1,213
07/04/1985	18	1,080	92	1985	970	1,048
07/08/1985	18	1,299	91	1985	1,236	1,290
07/09/1985	18	1,343	93	1985	1,265	1,333
07/10/1985	18	1,394	95	1985	1,321	1,348
07/16/1985	18	1,241	89	1985	1,167	1,220
07/18/1985	17	1,198	88	1985	1,138	1,198

JEA Response to
Staff Request for Production No. 7
Docket No. 001703-EM

DATE	HOUR	PEAK	MAXTEMP	FY	MW3PM	MW5PM
07/19/1985	16	1,182	89	1985	1,150	1,176
07/23/1985	18	1,273	89	1985	1,209	1,269
07/25/1985	18	1,117	85	1985	981	1,064
07/26/1985	19	1,110	87	1985	1,048	1,095
07/30/1985	18	1,222	92	1985	1,154	1,213
08/02/1985	17	1,192	89	1985	1,138	1,192
08/05/1985	18	1,193	90	1985	1,138	1,188
08/09/1985	18	1,144	88	1985	1,081	1,136
08/13/1985	18	1,240	91	1985	1,160	1,226
08/15/1985	18	1,208	90	1985	1,145	1,198
08/16/1985	18	1,278	93	1985	1,239	1,276
08/21/1985	17	1,223	90	1985	1,160	1,223
08/26/1985	18	1,355	93	1985	1,261	1,338
08/28/1985	18	1,232	89	1985	1,154	1,218
09/02/1985	21	1,024	89	1985	927	987
09/03/1985	17	1,279	90	1985	1,195	1,279
09/05/1985	17	1,170	90	1985	1,133	1,170
09/06/1985	16	1,132	90	1985	1,114	1,129
09/09/1985	17	1,351	93	1985	1,240	1,351
09/10/1985	19	1,319	93	1985	1,254	1,289
09/12/1985	17	1,078	89	1985	1,057	1,078
09/13/1985	17	1,023	85	1985	1,006	1,023
09/16/1985	20	860	77	1985	830	855
09/18/1985	17	937	86	1985	915	937
09/19/1985	18	1,007	86	1985	965	1,006
09/20/1985	17	932	84	1985	916	932
09/23/1985	18	1,144	86	1985	1,081	1,130
09/24/1985	18	1,225	92	1985	1,136	1,218
09/25/1985	18	1,206	89	1985	1,143	1,204
09/26/1985	18	1,139	86	1985	1,045	1,131
09/27/1985	17	1,135	84	1985	1,100	1,135
09/30/1985	17	953	85	1985	936	953
06/03/1986	17	1,230	89	1986	1,177	1,230
06/04/1986	18	1,174	86	1986	1,146	1,170
06/05/1986	17	1,229	87	1986	1,181	1,229
06/06/1986	18	1,223	90	1986	1,142	1,208
06/09/1986	18	1,429	97	1986	1,385	1,427
06/11/1986	17	1,332	92	1986	1,302	1,332
06/16/1986	17	1,302	92	1986	1,261	1,302
06/18/1986	17	1,257	91	1986	1,197	1,257
06/23/1986	18	1,277	88	1986	1,234	1,274
06/24/1986	18	1,361	93	1986	1,277	1,356
06/25/1986	18	1,444	97	1986	1,363	1,429
06/27/1986	17	1,405	94	1986	1,358	1,405
07/01/1986	18	1,229	91	1986	1,160	1,183

DATE	HOUR	PEAK	MAXTEMP	FY	MW3PM	MW5PM
07/04/1986	18	1,162	90	1986	1,113	1,158
07/07/1986	18	1,386	90	1986	1,322	1,374
07/08/1986	18	1,465	96	1986	1,372	1,446
07/09/1986	18	1,525	97	1986	1,427	1,516
07/10/1986	17	1,510	95	1986	1,457	1,510
07/14/1986	18	1,518	98	1986	1,445	1,510
07/16/1986	17	1,523	97	1986	1,466	1,523
07/17/1986	17	1,403	97	1986	1,342	1,403
07/18/1986	17	1,398	97	1986	1,370	1,398
07/21/1986	18	1,430	93	1986	1,374	1,419
07/28/1986	17	1,361	91	1986	1,309	1,361
07/29/1986	18	1,463	94	1986	1,357	1,462
07/30/1986	18	1,553	97	1986	1,474	1,545
07/31/1986	16	1,534	99	1986	1,514	1,530
08/07/1986	18	1,414	94	1986	1,330	1,409
08/14/1986	18	1,196	88	1986	1,152	1,193
08/18/1986	17	1,415	93	1986	1,350	1,415
08/19/1986	17	1,343	90	1986	1,304	1,343
08/21/1986	16	1,313	92	1986	1,273	1,311
08/22/1986	17	1,325	91	1986	1,301	1,325
08/25/1986	17	1,485	92	1986	1,428	1,485
08/26/1986	18	1,429	92	1986	1,391	1,426
08/27/1986	17	1,503	94	1986	1,409	1,503
09/01/1986	18	1,106	86	1986	1,053	1,096
09/02/1986	17	1,293	89	1986	1,255	1,293
09/03/1986	17	1,306	89	1986	1,244	1,306
09/04/1986	17	1,369	89	1986	1,312	1,369
09/08/1986	18	1,247	86	1986	1,201	1,218
09/10/1986	18	1,041	85	1986	997	1,021
09/11/1986	17	1,308	92	1986	1,225	1,308
09/15/1986	18	1,335	88	1986	1,259	1,331
09/16/1986	18	1,354	89	1986	1,286	1,349
09/17/1986	17	1,257	86	1986	1,229	1,257
09/18/1986	18	1,168	84	1986	1,120	1,165
09/19/1986	17	1,205	86	1986	1,160	1,205
09/23/1986	18	1,295	91	1986	1,227	1,289
09/24/1986	18	1,369	93	1986	1,290	1,361
09/25/1986	17	1,365	93	1986	1,307	1,365
09/26/1986	17	1,302	92	1986	1,230	1,302
09/29/1986	18	1,336	89	1986	1,284	1,316
06/01/1987	18	1,329	90	1987	1,234	1,312
06/02/1987	18	1,387	94	1987	1,301	1,346
06/03/1987	18	1,423	95	1987	1,343	1,417
06/05/1987	18	1,252	88	1987	1,176	1,240
06/08/1987	18	1,252	86	1987	1,185	1,248

JEA Response to
Staff Request for Production No. 7
Docket No. 001703-EM

DATE	HOUR	PEAK	MAXTEMP	FY	MW3PM	MW5PM
06/09/1987	18	1,300	89	1987	1,220	1,293
06/10/1987	17	1,376	95	1987	1,310	1,376
06/11/1987	17	1,345	94	1987	1,317	1,345
06/12/1987	17	1,406	95	1987	1,354	1,406
06/15/1987	18	1,389	94	1987	1,312	1,380
06/16/1987	17	1,414	93	1987	1,366	1,414
06/24/1987	17	1,414	93	1987	1,380	1,414
06/29/1987	17	1,397	91	1987	1,345	1,397
07/01/1987	17	1,449	90	1987	1,419	1,449
07/06/1987	17	1,456	95	1987	1,432	1,456
07/07/1987	17	1,503	95	1987	1,463	1,503
07/08/1987	17	1,491	95	1987	1,465	1,491
07/13/1987	18	1,605	99	1987	1,552	1,593
07/16/1987	17	1,432	93	1987	1,369	1,432
07/17/1987	17	1,385	89	1987	1,350	1,385
07/21/1987	18	1,483	90	1987	1,400	1,472
07/22/1987	18	1,462	93	1987	1,400	1,456
07/23/1987	17	1,555	99	1987	1,492	1,555
07/24/1987	17	1,513	92	1987	1,480	1,513
07/27/1987	18	1,543	95	1987	1,473	1,538
07/28/1987	18	1,585	96	1987	1,505	1,563
07/29/1987	16	1,523	94	1987	1,465	1,500
08/03/1987	17	1,504	94	1987	1,440	1,504
08/06/1987	17	1,591	98	1987	1,528	1,591
08/07/1987	17	1,628	98	1987	1,572	1,628
08/10/1987	17	1,615	99	1987	1,590	1,615
08/11/1987	17	1,583	96	1987	1,548	1,583
08/13/1987	13	1,186	86	1987	1,126	1,159
08/17/1987	18	1,531	94	1987	1,462	1,524
08/18/1987	18	1,588	95	1987	1,514	1,585
08/19/1987	17	1,588	95	1987	1,548	1,588
08/20/1987	18	1,462	95	1987	1,383	1,438
08/21/1987	18	1,430	90	1987	1,402	1,425
08/24/1987	17	1,596	99	1987	1,547	1,596
08/25/1987	18	1,580	95	1987	1,499	1,561
08/28/1987	17	1,552	96	1987	1,489	1,552
09/03/1987	21	1,093	82	1987	1,034	1,059
09/04/1987	17	1,117	82	1987	1,070	1,117
09/07/1987	18	1,268	91	1987	1,174	1,257
09/08/1987	18	1,424	92	1987	1,382	1,408
09/09/1987	18	1,498	92	1987	1,403	1,492
09/10/1987	18	1,504	94	1987	1,417	1,500
09/14/1987	18	1,489	93	1987	1,419	1,480
09/15/1987	17	1,421	91	1987	1,377	1,421
09/16/1987	17	1,405	92	1987	1,372	1,405

DATE	HOUR	PEAK	MAXTEMP	FY	MW3PM	MW5PM
09/17/1987	18	1,462	93	1987	1,410	1,459
09/18/1987	17	1,468	93	1987	1,414	1,468
09/21/1987	18	1,358	88	1987	1,280	1,340
09/22/1987	18	1,161	87	1987	1,082	1,145
09/23/1987	17	1,106	84	1987	1,057	1,106
09/24/1987	18	1,176	85	1987	1,095	1,169
09/25/1987	17	1,147	86	1987	1,075	1,147
09/28/1987	17	1,273	88	1987	1,219	1,273
09/29/1987	18	1,292	87	1987	1,229	1,267
09/30/1987	18	1,118	80	1987	1,049	1,097
06/01/1988	18	1,291	87	1988	1,204	1,274
06/02/1988	18	1,383	96	1988	1,275	1,373
06/03/1988	17	1,405	95	1988	1,343	1,405
06/08/1988	18	1,356	89	1988	1,258	1,340
06/09/1988	18	1,352	89	1988	1,229	1,335
06/13/1988	18	1,115	83	1988	1,071	1,104
06/14/1988	17	1,200	84	1988	1,164	1,200
06/15/1988	18	1,184	84	1988	1,128	1,175
06/16/1988	18	1,263	86	1988	1,189	1,249
06/17/1988	17	1,346	92	1988	1,289	1,346
06/20/1988	17	1,301	86	1988	1,266	1,301
06/21/1988	17	1,344	89	1988	1,302	1,344
06/22/1988	17	1,480	97	1988	1,401	1,480
06/23/1988	17	1,522	97	1988	1,470	1,522
06/24/1988	18	1,572	99	1988	1,518	1,558
06/27/1988	18	1,555	96	1988	1,482	1,551
06/28/1988	18	1,207	85	1988	1,170	1,187
06/29/1988	18	1,469	89	1988	1,400	1,465
06/30/1988	17	1,519	94	1988	1,485	1,519
07/04/1988	17	1,122	87	1988	1,106	1,122
07/06/1988	17	1,271	86	1988	1,218	1,271
07/07/1988	17	1,262	86	1988	1,246	1,262
07/08/1988	17	1,351	87	1988	1,295	1,351
07/12/1988	18	1,486	95	1988	1,446	1,472
07/15/1988	17	1,553	98	1988	1,536	1,553
07/19/1988	18	1,474	93	1988	1,383	1,473
07/20/1988	17	1,551	92	1988	1,514	1,551
07/25/1988	17	1,487	94	1988	1,381	1,487
07/26/1988	17	1,460	93	1988	1,381	1,460
07/27/1988	17	1,499	94	1988	1,447	1,499
07/28/1988	17	1,513	94	1988	1,474	1,513
07/29/1988	16	1,487	93	1988	1,452	1,474
08/01/1988	17	1,546	95	1988	1,451	1,546
08/02/1988	17	1,488	95	1988	1,396	1,488
08/09/1988	17	1,491	92	1988	1,369	1,491

DATE	HOUR	PEAK	MAXTEMP	FY	MW3PM	MW5PM
08/10/1988	17	1,510	93	1988	1,475	1,510
08/11/1988	17	1,466	90	1988	1,424	1,466
08/12/1988	17	1,453	91	1988	1,432	1,453
08/15/1988	18	1,390	90	1988	1,354	1,389
08/17/1988	17	1,523	92	1988	1,452	1,523
08/18/1988	16	1,554	94	1988	1,516	1,554
08/19/1988	16	1,589	96	1988	1,565	1,584
08/22/1988	18	1,655	96	1988	1,615	1,651
08/24/1988	17	1,627	94	1988	1,560	1,627
08/29/1988	17	1,533	92	1988	1,490	1,533
08/31/1988	17	1,469	90	1988	1,430	1,469
09/01/1988	20	1,221	88	1988	1,130	1,181
09/05/1988	20	1,046	82	1988	957	998
09/06/1988	19	1,144	79	1988	1,117	1,132
09/08/1988	20	1,031	75	1988	975	999
09/09/1988	17	1,406	91	1988	1,381	1,406
09/12/1988	17	1,479	89	1988	1,455	1,479
09/13/1988	17	1,420	86	1988	1,376	1,420
09/14/1988	17	1,491	89	1988	1,425	1,491
09/20/1988	17	1,500	94	1988	1,436	1,500
09/21/1988	17	1,544	94	1988	1,499	1,544
09/22/1988	17	1,510	93	1988	1,448	1,510
09/23/1988	16	1,426	92	1988	1,404	1,425
09/27/1988	17	1,245	82	1988	1,211	1,245
09/28/1988	17	1,292	86	1988	1,239	1,292
09/29/1988	17	1,356	86	1988	1,302	1,356
09/30/1988	16	1,252	85	1988	1,229	1,252
06/01/1989	18	1,510	94	1989	1,430	1,507
06/02/1989	17	1,602	97	1989	1,532	1,602
06/07/1989	17	1,384	90	1989	1,336	1,384
06/08/1989	17	1,152	80	1989	1,092	1,152
06/12/1989	18	1,615	95	1989	1,551	1,614
06/13/1989	17	1,595	95	1989	1,544	1,595
06/14/1989	18	1,645	96	1989	1,568	1,644
06/15/1989	17	1,627	96	1989	1,595	1,627
06/16/1989	16	1,550	94	1989	1,513	1,531
06/22/1989	17	1,429	89	1989	1,374	1,429
06/26/1989	17	1,512	91	1989	1,464	1,512
06/27/1989	17	1,560	92	1989	1,510	1,560
06/28/1989	17	1,605	95	1989	1,562	1,605
07/03/1989	17	1,491	94	1989	1,450	1,491
07/05/1989	17	1,567	93	1989	1,523	1,567
07/06/1989	17	1,536	92	1989	1,455	1,536
07/07/1989	18	1,537	93	1989	1,448	1,534
07/11/1989	17	1,687	96	1989	1,621	1,687

DATE	HOUR	PEAK	MAXTEMP	FY	MW3PM	MW5PM
07/12/1989	17	1,714	97	1989	1,671	1,714
07/18/1989	19	1,350	88	1989	1,237	1,288
07/19/1989	13	1,401	90	1989	1,307	1,350
07/24/1989	18	1,510	89	1989	1,448	1,498
07/25/1989	18	1,594	90	1989	1,527	1,593
07/26/1989	17	1,448	88	1989	1,429	1,448
07/27/1989	18	1,550	92	1989	1,481	1,548
07/28/1989	17	1,623	94	1989	1,545	1,623
08/01/1989	17	1,680	95	1989	1,621	1,680
08/03/1989	16	1,597	95	1989	1,565	1,596
08/04/1989	17	1,576	93	1989	1,526	1,576
08/10/1989	17	1,290	83	1989	1,254	1,290
08/11/1989	17	1,315	86	1989	1,269	1,315
08/15/1989	18	1,496	91	1989	1,404	1,488
08/16/1989	17	1,540	92	1989	1,483	1,540
08/17/1989	18	1,597	93	1989	1,533	1,590
08/21/1989	18	1,528	91	1989	1,505	1,526
08/23/1989	17	1,669	94	1989	1,584	1,669
08/24/1989	16	1,647	96	1989	1,605	1,643
08/28/1989	17	1,505	90	1989	1,456	1,505
08/29/1989	17	1,593	92	1989	1,512	1,593
08/30/1989	18	1,639	94	1989	1,556	1,637
09/01/1989	17	1,522	93	1989	1,479	1,522
09/05/1989	18	1,444	89	1989	1,343	1,435
09/06/1989	17	1,430	90	1989	1,379	1,430
09/08/1989	17	1,424	89	1989	1,394	1,424
09/11/1989	18	1,482	89	1989	1,403	1,479
09/12/1989	17	1,472	89	1989	1,402	1,472
09/13/1989	18	1,332	88	1989	1,264	1,325
09/15/1989	17	1,522	94	1989	1,466	1,522
09/19/1989	16	1,303	85	1989	1,267	1,301
09/20/1989	17	1,355	87	1989	1,282	1,355
09/21/1989	16	1,238	83	1989	1,220	1,238
09/25/1989	20	1,176	80	1989	1,111	1,155
09/26/1989	17	1,387	89	1989	1,290	1,387
09/28/1989	20	1,193	79	1989	1,112	1,170
09/29/1989	17	1,369	87	1989	1,319	1,369
06/01/1990	17	1,416	86	1990	1,369	1,416
06/05/1990	17	1,387	90	1990	1,326	1,387
06/06/1990	18	1,503	90	1990	1,456	1,487
06/08/1990	16	1,556	94	1990	1,514	1,550
06/12/1990	17	1,449	89	1990	1,389	1,449
06/13/1990	17	1,409	86	1990	1,360	1,409
06/14/1990	18	1,497	92	1990	1,393	1,481
06/15/1990	17	1,577	96	1990	1,523	1,577

JEA Response to
Staff Request for Production No. 7
Docket No. 001703-EM

DATE	HOUR	PEAK	MAXTEMP	FY	MW3PM	MW5PM
06/18/1990	17	1,556	91	1990	1,506	1,556
06/19/1990	17	1,693	99	1990	1,619	1,693
06/20/1990	17	1,789	100	1990	1,747	1,789
06/21/1990	17	1,768	99	1990	1,711	1,768
06/25/1990	17	1,536	94	1990	1,498	1,536
06/27/1990	17	1,473	90	1990	1,442	1,473
06/28/1990	18	1,528	92	1990	1,504	1,521
06/29/1990	17	1,605	97	1990	1,571	1,605
07/03/1990	18	1,261	84	1990	1,106	1,211
07/04/1990	18	1,414	94	1990	1,358	1,409
07/05/1990	18	1,677	95	1990	1,593	1,672
07/06/1990	17	1,695	97	1990	1,630	1,695
07/09/1990	17	1,734	96	1990	1,671	1,734
07/11/1990	18	1,749	97	1990	1,686	1,742
07/16/1990	17	1,571	92	1990	1,495	1,571
07/17/1990	18	1,574	89	1990	1,510	1,567
07/19/1990	17	1,638	91	1990	1,580	1,638
07/20/1990	17	1,451	89	1990	1,378	1,451
07/26/1990	17	1,523	89	1990	1,443	1,523
07/27/1990	17	1,551	91	1990	1,502	1,551
07/30/1990	18	1,680	94	1990	1,601	1,675
07/31/1990	17	1,728	98	1990	1,691	1,728
08/01/1990	17	1,775	97	1990	1,724	1,775
08/03/1990	17	1,594	90	1990	1,567	1,594
08/13/1990	17	1,577	92	1990	1,546	1,577
08/16/1990	17	1,652	96	1990	1,576	1,652
08/20/1990	17	1,710	91	1990	1,636	1,710
08/21/1990	17	1,737	96	1990	1,664	1,737
08/23/1990	18	1,571	92	1990	1,496	1,561
08/24/1990	17	1,593	94	1990	1,554	1,593
08/28/1990	18	1,677	95	1990	1,585	1,670
08/29/1990	17	1,760	99	1990	1,729	1,760
08/30/1990	17	1,665	97	1990	1,635	1,665
08/31/1990	17	1,533	92	1990	1,489	1,533
09/03/1990	17	1,419	94	1990	1,363	1,419
09/04/1990	17	1,516	91	1990	1,476	1,516
09/05/1990	18	1,407	89	1990	1,274	1,390
09/06/1990	18	1,483	89	1990	1,399	1,471
09/07/1990	17	1,579	95	1990	1,487	1,579
09/10/1990	18	1,645	94	1990	1,588	1,637
09/11/1990	17	1,628	93	1990	1,570	1,628
09/12/1990	17	1,609	91	1990	1,564	1,609
09/13/1990	17	1,624	92	1990	1,565	1,624
09/14/1990	18	1,566	95	1990	1,490	1,564
09/17/1990	17	1,579	93	1990	1,515	1,579

JEA Response to
Staff Request for Production No. 7
Docket No. 001703-EM

DATE	HOUR	PEAK	MAXTEMP	FY	MW3PM	MW5PM
09/18/1990	17	1,430	89	1990	1,405	1,430
09/19/1990	18	1,473	89	1990	1,387	1,463
09/20/1990	17	1,521	94	1990	1,431	1,521
09/21/1990	17	1,609	97	1990	1,519	1,609
09/24/1990	17	1,092	80	1990	1,047	1,092
09/25/1990	18	1,169	86	1990	1,094	1,168
09/26/1990	18	1,319	89	1990	1,229	1,312
09/27/1990	17	1,415	89	1990	1,339	1,415
06/03/1991	18	1,615	92	1991	1,505	1,599
06/04/1991	17	1,705	96	1991	1,646	1,705
06/06/1991	18	1,091	80	1991	1,061	1,086
06/10/1991	18	1,358	83	1991	1,284	1,349
06/11/1991	17	1,437	87	1991	1,366	1,437
06/12/1991	18	1,479	91	1991	1,400	1,471
06/13/1991	18	1,572	91	1991	1,492	1,565
06/20/1991	16	1,632	95	1991	1,580	1,626
06/21/1991	17	1,661	94	1991	1,604	1,661
06/26/1991	18	1,474	87	1991	1,380	1,458
06/27/1991	18	1,584	91	1991	1,549	1,580
07/01/1991	18	1,607	91	1991	1,558	1,603
07/02/1991	17	1,695	96	1991	1,625	1,695
07/03/1991	17	1,682	94	1991	1,660	1,682
07/04/1991	17	1,502	94	1991	1,464	1,502
07/08/1991	17	1,714	96	1991	1,653	1,714
07/10/1991	18	1,565	90	1991	1,378	1,558
07/11/1991	18	1,388	89	1991	1,171	1,344
07/12/1991	19	1,299	88	1991	1,148	1,234
07/15/1991	17	1,666	94	1991	1,613	1,666
07/16/1991	17	1,642	93	1991	1,581	1,642
07/22/1991	17	1,711	98	1991	1,660	1,711
07/24/1991	17	1,756	95	1991	1,685	1,756
07/25/1991	17	1,665	93	1991	1,644	1,665
07/29/1991	16	1,681	95	1991	1,639	1,665
08/01/199[illegible]	17	1,458	88	1991	1,415	1,458
08/02/[illegible]	17	1,582	92	1991	1,524	1,582
08/06/19[illegible]	17	1,697	95	1991	1,641	1,697
08/07/1[illegible]	18	1,735	95	1991	1,687	1,722
08/09/1991	17	1,677	96	1991	1,628	1,677
08/15/1991	18	1,534	91	1991	1,460	1,527
08/16/1991	17	1,519	89	1991	1,489	1,519
08/20/1991	17	1,630	93	1991	1,551	1,630
08/21/1991	18	1,645	92	1991	1,553	1,643
08/22/1991	17	1,553	89	1991	1,499	1,553
08/23/1991	17	1,539	89	1991	1,492	1,539
08/26/1991	17	1,659	93	1991	1,584	1,659

JEA Response to
Staff Request for Production No. 7
Docket No. 001703-EM

DATE	HOUR	PEAK	MAXTEMP	FY	MW3PM	MW5PM
08/27/1991	18	1,432	88	1991	1,350	1,424
08/28/1991	18	1,602	92	1991	1,539	1,594
08/29/1991	18	1,551	89	1991	1,431	1,530
09/02/1991	21	1,215	86	1991	1,131	1,182
09/03/1991	17	1,366	86	1991	1,331	1,366
09/04/1991	18	1,523	89	1991	1,462	1,515
09/05/1991	18	1,560	91	1991	1,495	1,550
09/06/1991	17	1,554	92	1991	1,524	1,554
09/09/1991	18	1,527	91	1991	1,459	1,524
09/10/1991	18	1,492	89	1991	1,396	1,486
09/11/1991	17	1,564	90	1991	1,498	1,564
09/12/1991	17	1,637	94	1991	1,573	1,637
09/13/1991	17	1,604	91	1991	1,573	1,604
09/16/1991	18	1,654	96	1991	1,589	1,649
09/17/1991	17	1,587	95	1991	1,505	1,587
09/18/1991	18	1,505	94	1991	1,342	1,484
09/19/1991	18	1,654	91	1991	1,597	1,643
09/23/1991	18	1,434	85	1991	1,353	1,432
09/24/1991	18	1,558	90	1991	1,466	1,551
09/25/1991	13	1,213	88	1991	1,144	1,197
09/26/1991	17	1,224	83	1991	1,157	1,224
09/27/1991	17	1,143	83	1991	1,121	1,143
09/30/1991	20	1,148	83	1991	1,115	1,141
06/02/1992	18	1,522	87	1992	1,437	1,516
06/04/1992	18	1,584	91	1992	1,473	1,582
06/05/1992	13	1,464	89	1992	1,370	1,405
06/10/1992	18	1,721	92	1992	1,588	1,706
06/11/1992	17	1,707	92	1992	1,672	1,707
06/16/1992	17	1,607	90	1992	1,576	1,607
06/17/1992	18	1,539	87	1992	1,507	1,534
06/18/1992	17	1,549	86	1992	1,490	1,549
06/25/1992	17	1,677	92	1992	1,566	1,677
06/26/1992	18	1,628	92	1992	1,530	1,620
07/01/1992	17	1,644	93	1992	1,618	1,644
07/02/1992	17	1,730	94	1992	1,658	1,730
07/03/1992	18	1,652	94	1992	1,569	1,645
07/06/1992	18	1,807	95	1992	1,727	1,794
07/07/1992	17	1,834	97	1992	1,802	1,834
07/09/1992	17	1,882	97	1992	1,844	1,882
07/10/1992	17	1,855	98	1992	1,786	1,855
07/13/1992	17	1,816	96	1992	1,734	1,816
07/14/1992	17	1,740	94	1992	1,693	1,740
07/20/1992	18	1,715	91	1992	1,633	1,714
07/21/1992	18	1,633	92	1992	1,571	1,602
07/22/1992	16	1,732	93	1992	1,687	1,715

DATE	HOUR	PEAK	MAXTEMP	FY	MW3PM	MW5PM
07/23/1992	17	1,791	94	1992	1,721	1,791
07/24/1992	17	1,712	94	1992	1,668	1,712
07/27/1992	17	1,848	96	1992	1,787	1,848
07/29/1992	17	1,805	95	1992	1,785	1,805
07/31/1992	17	1,704	95	1992	1,640	1,704
08/05/1992	17	1,717	93	1992	1,640	1,717
08/06/1992	18	1,600	92	1992	1,542	1,578
08/07/1992	17	1,692	93	1992	1,645	1,692
08/10/1992	17	1,769	97	1992	1,693	1,769
08/11/1992	18	1,741	94	1992	1,695	1,735
08/12/1992	16	1,696	94	1992	1,667	1,686
08/19/1992	17	1,648	91	1992	1,567	1,648
08/20/1992	18	1,658	91	1992	1,577	1,648
08/21/1992	17	1,649	92	1992	1,603	1,649
08/25/1992	18	1,638	90	1992	1,570	1,634
08/26/1992	18	1,685	91	1992	1,602	1,683
08/27/1992	18	1,729	92	1992	1,618	1,723
08/28/1992	18	1,418	86	1992	1,356	1,417
09/01/1992	17	1,652	90	1992	1,598	1,652
09/03/1992	17	1,578	90	1992	1,537	1,578
09/07/1992	17	1,467	91	1992	1,420	1,467
09/09/1992	18	1,415	86	1992	1,367	1,410
09/10/1992	21	1,178	79	1992	1,111	1,139
09/11/1992	17	1,486	89	1992	1,393	1,486
09/14/1992	18	1,344	85	1992	1,293	1,338
09/15/1992	21	1,258	82	1992	1,178	1,208
09/16/1992	17	1,528	87	1992	1,466	1,528
09/17/1992	17	1,578	88	1992	1,544	1,578
09/18/1992	17	1,565	90	1992	1,513	1,565
09/21/1992	17	1,653	94	1992	1,603	1,653
09/22/1992	17	1,705	94	1992	1,646	1,705
09/23/1992	17	1,695	92	1992	1,624	1,695
09/28/1992	20	1,328	85	1992	1,254	1,309
06/01/1993	17	1,570	89	1993	1,494	1,570
06/02/1993	17	1,599	91	1993	1,558	1,599
06/03/1993	18	1,702	93	1993	1,594	1,692
06/04/1993	18	1,686	92	1993	1,581	1,678
06/07/1993	18	1,859	100	1993	1,801	1,850
06/08/1993	17	1,885	99	1993	1,815	1,885
06/09/1993	17	1,871	96	1993	1,820	1,871
06/10/1993	17	1,893	99	1993	1,850	1,893
06/11/1993	17	1,879	99	1993	1,849	1,879
06/15/1993	17	1,647	88	1993	1,602	1,647
06/16/1993	17	1,690	87	1993	1,639	1,690
06/17/1993	17	1,641	87	1993	1,576	1,641

DATE	HOUR	PEAK	MAXTEMP	FY	MW3PM	MW5PM
06/18/1993	17	1,567	87	1993	1,526	1,567
06/21/1993	17	1,739	93	1993	1,677	1,739
06/23/1993	17	1,606	93	1993	1,476	1,606
06/25/1993	17	1,524	89	1993	1,473	1,524
06/30/1993	17	1,747	95	1993	1,694	1,747
07/05/1993	18	1,746	96	1993	1,656	1,726
07/07/1993	18	1,819	92	1993	1,758	1,811
07/09/1993	17	1,838	95	1993	1,813	1,838
07/12/1993	18	1,840	95	1993	1,737	1,834
07/13/1993	18	1,829	94	1993	1,774	1,818
07/15/1993	18	1,871	95	1993	1,780	1,868
07/16/1993	17	1,872	95	1993	1,825	1,872
07/19/1993	18	1,943	96	1993	1,870	1,938
07/20/1993	17	1,931	96	1993	1,850	1,931
07/21/1993	17	1,947	97	1993	1,878	1,947
07/27/1993	17	1,818	94	1993	1,746	1,818
07/28/1993	17	1,926	96	1993	1,865	1,926
07/29/1993	17	1,998	99	1993	1,942	1,998
07/30/1993	19	1,645	91	1993	1,383	1,594
08/02/1993	18	1,914	96	1993	1,854	1,911
08/04/1993	16	1,884	95	1993	1,818	1,870
08/05/1993	18	1,891	94	1993	1,824	1,888
08/06/1993	17	1,904	95	1993	1,840	1,904
08/09/1993	17	1,839	92	1993	1,792	1,839
08/10/1993	17	1,751	87	1993	1,697	1,751
08/11/1993	18	1,741	88	1993	1,655	1,731
08/12/1993	18	1,704	89	1993	1,655	1,691
08/13/1993	17	1,797	94	1993	1,724	1,797
08/16/1993	17	1,786	90	1993	1,730	1,786
08/17/1993	17	1,793	91	1993	1,731	1,793
08/18/1993	17	1,920	97	1993	1,853	1,920
08/20/1993	17	1,861	94	1993	1,813	1,861
08/23/1993	17	1,822	92	1993	1,789	1,822
08/24/1993	18	1,803	89	1993	1,744	1,795
08/25/1993	18	1,769	90	1993	1,722	1,766
08/27/1993	18	1,488	88	1993	1,377	1,462
08/30/1993	18	1,729	88	1993	1,655	1,728
08/31/1993	18	1,742	89	1993	1,673	1,735
09/03/1993	17	1,806	92	1993	1,768	1,806
09/06/1993	16	1,551	94	1993	1,525	1,546
09/07/1993	17	1,574	89	1993	1,453	1,574
09/08/1993	18	1,510	86	1993	1,379	1,475
09/10/1993	17	1,644	90	1993	1,624	1,644
09/13/1993	17	1,675	87	1993	1,630	1,675
09/14/1993	17	1,694	89	1993	1,674	1,694

JEA Response to
Staff Request for Production No. 7
Docket No. 001703-EM

DATE	HOUR	PEAK	MAXTEMP	FY	MW3PM	MW5PM
09/15/1993	18	1,734	91	1993	1,693	1,727
09/16/1993	18	1,724	92	1993	1,635	1,716
09/17/1993	16	1,745	90	1993	1,723	1,745
09/21/1993	17	1,759	92	1993	1,679	1,759
09/22/1993	17	1,729	92	1993	1,640	1,729
09/23/1993	17	1,657	91	1993	1,598	1,657
09/24/1993	17	1,663	92	1993	1,590	1,663
09/27/1993	17	1,543	89	1993	1,458	1,543
09/28/1993	17	1,395	82	1993	1,344	1,395
09/29/1993	18	1,254	83	1993	1,184	1,248
09/30/1993	18	1,159	79	1993	1,107	1,155
06/01/1994	18	1,688	90	1994	1,567	1,687
06/02/1994	17	1,570	90	1994	1,510	1,570
06/08/1994	16	1,581	91	1994	1,543	1,573
06/09/1994	18	1,770	93	1994	1,718	1,758
06/10/1994	17	1,715	92	1994	1,643	1,715
06/14/1994	17	1,773	95	1994	1,727	1,773
06/17/1994	18	1,416	84	1994	1,257	1,395
06/20/1994	17	1,731	89	1994	1,657	1,731
06/22/1994	17	1,813	92	1994	1,753	1,813
06/24/1994	17	1,770	92	1994	1,711	1,770
06/27/1994	18	1,808	91	1994	1,716	1,793
06/28/1994	17	1,885	94	1994	1,785	1,885
06/29/1994	17	1,895	94	1994	1,821	1,895
06/30/1994	17	1,826	92	1994	1,755	1,826
07/01/1994	17	1,686	92	1994	1,632	1,686
07/04/1994	16	1,419	89	1994	1,388	1,419
07/05/1994	17	1,732	92	1994	1,661	1,732
07/08/1994	17	1,753	90	1994	1,655	1,753
07/11/1994	17	1,849	95	1994	1,805	1,849
07/12/1994	17	1,852	94	1994	1,811	1,852
07/13/1994	17	1,848	93	1994	1,756	1,848
07/14/1994	18	1,815	94	1994	1,729	1,814
07/15/1994	17	1,843	93	1994	1,776	1,843
07/18/1994	17	1,918	95	1994	1,855	1,918
07/19/1994	16	1,883	95	1994	1,855	1,875
07/28/1994	13	1,436	87	1994	1,383	1,409
08/01/1994	17	1,815	93	1994	1,764	1,815
08/02/1994	17	1,871	92	1994	1,808	1,871
08/03/1994	17	1,860	90	1994	1,789	1,860
08/04/1994	16	1,838	91	1994	1,808	1,830
08/05/1994	17	1,857	93	1994	1,810	1,857
08/08/1994	17	1,556	86	1994	1,504	1,556
08/09/1994	18	1,569	85	1994	1,487	1,552
08/10/1994	17	1,725	89	1994	1,652	1,725

JEA Response to
Staff Request for Production No. 7
Docket No. 001703-EM

DATE	HOUR	PEAK	MAXTEMP	FY	MW3PM	MW5PM
08/12/1994	17	1,718	88	1994	1,666	1,718
08/19/1994	16	1,740	91	1994	1,722	1,737
08/23/1994	14	1,542	90	1994	1,499	1,525
08/24/1994	18	1,694	88	1994	1,621	1,686
08/25/1994	17	1,589	84	1994	1,537	1,589
08/26/1994	17	1,664	86	1994	1,602	1,664
08/29/1994	17	1,776	93	1994	1,695	1,776
08/30/1994	17	1,821	95	1994	1,758	1,821
08/31/1994	18	1,848	94	1994	1,777	1,846
09/01/1994	18	1,868	93	1994	1,775	1,850
09/02/1994	17	1,828	93	1994	1,798	1,828
09/05/1994	18	1,308	83	1994	1,255	1,303
09/06/1994	18	1,607	90	1994	1,500	1,603
09/07/1994	17	1,686	91	1994	1,621	1,686
09/12/1994	17	1,549	86	1994	1,494	1,549
09/13/1994	17	1,486	86	1994	1,450	1,486
09/14/1994	18	1,543	85	1994	1,468	1,520
09/15/1994	17	1,690	87	1994	1,611	1,690
09/19/1994	17	1,427	82	1994	1,399	1,427
09/21/1994	17	1,387	82	1994	1,350	1,387
09/22/1994	17	1,407	83	1994	1,326	1,407
09/23/1994	17	1,455	84	1994	1,419	1,455
09/26/1994	18	1,518	86	1994	1,387	1,502
09/27/1994	17	1,466	84	1994	1,410	1,466
09/28/1994	17	1,506	87	1994	1,453	1,506
09/29/1994	17	1,623	91	1994	1,541	1,623
09/30/1994	17	1,559	86	1994	1,512	1,559
06/01/1995	17	1,810	94	1995	1,759	1,810
06/05/1995	18	1,585	86	1995	1,513	1,581
06/06/1995	18	1,796	93	1995	1,673	1,780
06/07/1995	18	1,887	93	1995	1,789	1,877
06/08/1995	18	1,918	95	1995	1,838	1,910
06/09/1995	17	1,979	100	1995	1,940	1,979
06/13/1995	17	1,573	86	1995	1,510	1,573
06/14/1995	17	1,510	86	1995	1,456	1,510
06/15/1995	17	1,561	85	1995	1,450	1,561
06/19/1995	17	1,594	87	1995	1,493	1,594
06/20/1995	17	1,621	89	1995	1,529	1,621
06/21/1995	16	1,616	88	1995	1,588	1,615
06/22/1995	18	1,664	87	1995	1,568	1,653
06/23/1995	17	1,823	93	1995	1,760	1,823
06/28/1995	16	1,841	95	1995	1,801	1,817
07/04/1995	17	1,695	96	1995	1,626	1,695
07/05/1995	17	1,928	97	1995	1,862	1,928
07/06/1995	17	1,923	95	1995	1,860	1,923

DATE	HOUR	PEAK	MAXTEMP	FY	MW3PM	MW5PM
07/11/1995	17	1,873	96	1995	1,822	1,873
07/12/1995	18	1,877	92	1995	1,794	1,840
07/13/1995	17	1,886	92	1995	1,833	1,886
07/14/1995	17	1,858	94	1995	1,811	1,858
07/17/1995	18	1,480	85	1995	1,444	1,479
07/18/1995	18	1,760	88	1995	1,592	1,751
07/19/1995	17	1,901	93	1995	1,814	1,901
07/20/1995	17	1,978	98	1995	1,924	1,978
07/24/1995	17	2,034	96	1995	1,972	2,034
07/26/1995	17	1,893	93	1995	1,811	1,893
07/28/1995	18	1,728	89	1995	1,691	1,719
08/01/1995	17	1,790	88	1995	1,759	1,790
08/02/1995	17	1,586	84	1995	1,507	1,586
08/03/1995	18	1,668	88	1995	1,534	1,632
08/04/1995	17	1,856	89	1995	1,811	1,856
08/07/1995	17	1,989	94	1995	1,928	1,989
08/09/1995	17	1,747	86	1995	1,701	1,747
08/10/1995	18	1,739	88	1995	1,680	1,730
08/11/1995	16	1,847	92	1995	1,814	1,843
08/14/1995	18	2,067	96	1995	2,015	2,066
08/16/1995	17	2,001	93	1995	1,940	2,001
08/17/1995	17	2,038	94	1995	1,991	2,038
08/21/1995	18	1,689	86	1995	1,603	1,680
08/22/1995	18	1,659	87	1995	1,562	1,645
08/23/1995	17	1,783	87	1995	1,732	1,783
08/25/1995	18	1,460	84	1995	1,378	1,441
08/28/1995	17	1,937	90	1995	1,869	1,937
08/29/1995	17	1,543	83	1995	1,497	1,543
08/30/1995	17	1,735	86	1995	1,704	1,735
08/31/1995	18	1,752	86	1995	1,701	1,740
09/01/1995	17	1,631	86	1995	1,564	1,631
09/04/1995	21	1,381	84	1995	1,275	1,347
09/06/1995	17	1,436	82	1995	1,367	1,436
09/08/1995	17	1,610	85	1995	1,551	1,610
09/11/1995	17	1,715	87	1995	1,675	1,715
09/12/1995	18	1,674	86	1995	1,628	1,657
09/13/1995	16	1,805	91	1995	1,760	1,794
09/14/1995	17	1,864	91	1995	1,793	1,864
09/15/1995	17	1,680	86	1995	1,607	1,680
09/18/1995	17	1,812	88	1995	1,785	1,812
09/19/1995	17	1,671	84	1995	1,635	1,671
09/20/1995	18	1,565	83	1995	1,501	1,539
09/21/1995	18	1,693	86	1995	1,643	1,686
09/22/1995	17	1,810	90	1995	1,737	1,810
09/25/1995	20	1,418	81	1995	1,270	1,377

JEA Response to
Staff Request for Production No. 7
Docket No. 001703-EM

DATE	HOUR	PEAK	MAXTEMP	FY	MW3PM	MW5PM
09/26/1995	17	1,584	88	1995	1,557	1,584
09/28/1995	17	1,480	81	1995	1,450	1,480
06/03/1996	18	1,495	80	1996	1,440	1,466
06/04/1996	18	1,635	88	1996	1,568	1,624
06/05/1996	18	1,728	90	1996	1,672	1,725
06/06/1996	17	1,790	89	1996	1,734	1,790
06/12/1996	17	1,880	91	1996	1,762	1,880
06/17/1996	17	1,754	86	1996	1,694	1,754
06/18/1996	18	1,811	87	1996	1,720	1,805
06/21/1996	17	1,859	91	1996	1,786	1,859
06/25/1996	18	2,114	96	1996	2,041	2,108
06/27/1996	19	1,509	84	1996	1,413	1,487
06/28/1996	17	1,570	83	1996	1,526	1,570
07/01/1996	18	1,962	93	1996	1,875	1,954
07/02/1996	17	2,008	95	1996	1,959	2,008
07/03/1996	16	1,973	94	1996	1,944	1,962
07/08/1996	17	1,852	93	1996	1,797	1,852
07/09/1996	19	1,612	85	1996	1,445	1,557
07/10/1996	17	1,929	92	1996	1,876	1,929
07/11/1996	16	1,752	88	1996	1,711	1,750
07/15/1996	18	1,987	93	1996	1,941	1,973
07/16/1996	18	1,835	89	1996	1,741	1,819
07/17/1996	17	1,933	90	1996	1,862	1,933
07/18/1996	18	1,953	91	1996	1,869	1,946
07/19/1996	17	1,994	93	1996	1,931	1,994
07/22/1996	18	2,033	92	1996	1,953	2,020
07/23/1996	17	2,063	94	1996	2,024	2,063
07/25/1996	16	1,987	94	1996	1,948	1,970
07/26/1996	17	1,932	89	1996	1,864	1,932
07/29/1996	17	2,023	94	1996	1,939	2,023
07/30/1996	17	2,014	92	1996	1,954	2,014
07/31/1996	17	2,016	92	1996	1,952	2,016
08/02/1996	17	1,628	85	1996	1,564	1,628
08/05/1996	17	1,948	91	1996	1,882	1,948
08/08/1996	18	1,803	87	1996	1,764	1,800
08/09/1996	17	1,861	89	1996	1,797	1,861
08/15/1996	17	1,724	90	1996	1,638	1,724
08/16/1996	17	1,767	87	1996	1,727	1,767
08/19/1996	17	1,884	88	1996	1,847	1,884
08/20/1996	17	1,808	88	1996	1,752	1,808
08/21/1996	18	1,734	87	1996	1,694	1,723
08/22/1996	17	1,838	87	1996	1,766	1,838
08/23/1996	17	1,810	87	1996	1,743	1,810
08/26/1996	17	1,643	86	1996	1,548	1,643
08/27/1996	18	1,886	90	1996	1,777	1,869

DATE	HOUR	PEAK	MAXTEMP	FY	MW3PM	MW5PM
08/28/1996	17	1,945	90	1996	1,846	1,945
08/29/1996	17	1,820	86	1996	1,738	1,820
09/03/1996	18	1,835	90	1996	1,746	1,825
09/04/1996	17	1,798	89	1996	1,718	1,798
09/05/1996	18	1,788	88	1996	1,611	1,761
09/06/1996	16	1,888	90	1996	1,851	1,884
09/11/1996	17	1,642	87	1996	1,578	1,642
09/12/1996	18	1,763	88	1996	1,682	1,762
09/13/1996	17	1,781	90	1996	1,757	1,781
09/17/1996	18	1,687	88	1996	1,547	1,643
09/18/1996	17	1,800	87	1996	1,735	1,800
09/20/1996	17	1,507	82	1996	1,461	1,507
09/23/1996	18	1,580	87	1996	1,447	1,566
09/24/1996	18	1,632	87	1996	1,508	1,627
09/25/1996	18	1,644	86	1996	1,555	1,642
09/26/1996	17	1,698	86	1996	1,617	1,698
09/27/1996	17	1,678	87	1996	1,651	1,678
09/30/1996	17	1,593	84	1996	1,568	1,593
06/02/1997	17	1,620	84	1997	1,556	1,620
06/03/1997	18	1,616	84	1997	1,557	1,614
06/10/1997	18	1,456	79	1997	1,397	1,442
06/11/1997	17	1,553	83	1997	1,526	1,553
06/16/1997	18	1,854	88	1997	1,780	1,844
06/18/1997	14	1,809	91	1997	1,715	1,798
06/19/1997	17	1,886	89	1997	1,817	1,886
06/20/1997	18	1,730	87	1997	1,651	1,712
06/23/1997	17	1,891	90	1997	1,863	1,891
06/25/1997	18	1,970	89	1997	1,886	1,968
06/27/1997	17	1,966	91	1997	1,896	1,966
07/01/1997	18	1,986	91	1997	1,863	1,962
07/02/1997	18	2,030	94	1997	1,934	2,021
07/03/1997	17	2,077	97	1997	2,025	2,077
07/08/1997	18	1,961	90	1997	1,872	1,948
07/09/1997	17	1,991	90	1997	1,927	1,991
07/10/1997	18	2,006	92	1997	1,919	1,993
07/14/1997	17	1,894	89	1997	1,817	1,894
07/15/1997	17	1,996	91	1997	1,919	1,996
07/17/1997	17	1,989	92	1997	1,950	1,989
07/21/1997	17	2,009	92	1997	1,947	2,009
07/22/1997	18	2,061	92	1997	1,992	2,059
07/23/1997	18	2,092	93	1997	2,030	2,079
07/24/1997	17	2,091	94	1997	2,033	2,091
07/28/1997	18	2,131	93	1997	1,938	2,022
07/29/1997	17	2,048	92	1997	2,026	2,048
08/01/1997	17	1,444	78	1997	1,415	1,444

DATE	HOUR	PEAK	MAXTEMP	FY	MW3PM	MW5PM
08/04/1997	18	1,960	89	1997	1,808	1,937
08/05/1997	17	2,034	92	1997	1,963	2,034
08/06/1997	17	1,978	92	1997	1,942	1,978
08/08/1997	17	1,805	86	1997	1,777	1,805
08/11/1997	18	1,627	86	1997	1,564	1,594
08/12/1997	16	1,915	89	1997	1,882	1,899
08/14/1997	17	2,096	94	1997	2,032	2,096
08/18/1997	17	2,127	94	1997	2,051	2,127
08/20/1997	17	2,098	95	1997	2,018	2,098
08/22/1997	17	1,890	88	1997	1,827	1,890
08/25/1997	18	1,691	85	1997	1,641	1,685
08/26/1997	18	1,759	85	1997	1,671	1,748
08/27/1997	18	1,657	84	1997	1,592	1,636
08/28/1997	18	1,947	92	1997	1,828	1,936
08/29/1997	17	2,007	93	1997	1,952	2,007
09/01/1997	18	1,692	89	1997	1,648	1,680
09/02/1997	17	1,814	89	1997	1,751	1,814
09/03/1997	18	1,934	91	1997	1,814	1,911
09/05/1997	17	1,610	81	1997	1,566	1,610
09/08/1997	17	1,764	86	1997	1,674	1,764
09/09/1997	18	1,816	89	1997	1,718	1,815
09/11/1997	18	1,864	91	1997	1,832	1,858
09/12/1997	17	1,886	90	1997	1,834	1,886
09/15/1997	18	1,905	88	1997	1,831	1,902
09/16/1997	17	1,921	90	1997	1,866	1,921
09/17/1997	17	1,931	88	1997	1,857	1,931
09/18/1997	17	1,911	90	1997	1,852	1,911
09/19/1997	17	1,917	90	1997	1,872	1,917
09/22/1997	18	1,840	87	1997	1,746	1,833
09/23/1997	18	1,831	87	1997	1,733	1,827
09/24/1997	17	1,959	91	1997	1,866	1,959
09/29/1997	18	1,758	87	1997	1,668	1,750
09/30/1997	18	1,750	88	1997	1,656	1,748

JEA Response to
Staff Request for Production No. 7
Docket No. 001703-EM

Data JEA Used for the Trend Analysis Used to Forecast Summer Peak Demand
Daily Peak Demands and Temperature Extremes - Summer Non-Holiday Weekdays PM Peak

DATE	HOUR	PEAK	MAXTEMP	FY	MW3PM	MW5PM
06/02/1980	18	907	88	1980	837	897
06/03/1980	17	993	92	1980	883	993
06/04/1980	18	1,121	96	1980	1,012	1,050
06/09/1980	17	893	84	1980	829	893
06/11/1980	16	1,013	91	1980	895	933
06/13/1980	17	901	85	1980	842	901
06/16/1980	19	1,129	94	1980	986	1,089
06/17/1980	18	1,147	95	1980	1,078	1,112
06/18/1980	18	1,115	95	1980	1,073	1,093
06/24/1980	17	1,052	91	1980	944	1,052
06/25/1980	18	854	89	1980	799	838
06/27/1980	18	978	91	1980	942	963
06/30/1980	17	1,104	93	1980	1,065	1,104
07/01/1980	19	1,186	93	1980	1,044	1,107
07/04/1980	18	1,044	94	1980	892	947
07/07/1980	18	1,163	94	1980	1,038	1,151
07/09/1980	17	1,208	95	1980	1,162	1,208
07/10/1980	17	1,277	99	1980	1,189	1,277
07/11/1980	18	1,260	100	1980	1,230	1,250
07/16/1980	17	1,200	92	1980	1,175	1,200
07/17/1980	17	1,142	92	1980	1,100	1,142
07/21/1980	18	1,243	91	1980	1,116	1,170
07/22/1980	18	1,131	91	1980	1,043	1,091
07/23/1980	17	1,171	94	1980	1,077	1,171
07/28/1980	17	1,213	95	1980	1,115	1,213
07/30/1980	17	1,167	95	1980	1,100	1,167
07/31/1980	18	1,243	96	1980	1,135	1,156
08/01/1980	18	1,226	97	1980	1,138	1,195
08/04/1980	18	1,242	96	1980	1,153	1,221
08/05/1980	18	1,273	94	1980	1,182	1,202
08/06/1980	16	1,224	92	1980	1,171	1,194
08/07/1980	18	1,195	92	1980	1,143	1,189
08/08/1980	17	1,232	93	1980	1,141	1,232
08/11/1980	18	1,215	94	1980	1,113	1,149
08/12/1980	18	1,200	94	1980	1,126	1,163
08/14/1980	21	952	89	1980	903	935
08/15/1980	19	1,152	94	1980	1,122	1,140
08/19/1980	18	1,183	92	1980	1,142	1,165
08/20/1980	17	1,292	99	1980	1,220	1,292
08/21/1980	17	1,261	97	1980	1,152	1,261
08/25/1980	17	991	88	1980	951	991
08/27/1980	19	1,059	88	1980	1,023	1,054

JEA Response to
Staff Request for Production No. 7
Docket No. 001703-EM

DATE	HOUR	PEAK	MAXTEMP	FY	MW3PM	MW5PM
08/28/1980	17	1,120	90	1980	1,021	1,120
08/29/1980	18	1,068	90	1980	1,025	1,063
09/01/1980	21	930	91	1980	881	898
09/02/1980	16	1,085	92	1980	1,030	1,073
09/05/1980	17	1,119	90	1980	1,098	1,119
09/09/1980	18	1,133	90	1980	1,059	1,078
09/10/1980	19	1,101	90	1980	1,009	1,031
09/11/1980	18	1,085	89	1980	1,058	1,081
09/12/1980	17	1,055	89	1980	912	1,055
09/15/1980	19	1,198	96	1980	1,040	1,141
09/16/1980	17	1,165	95	1980	1,112	1,165
09/18/1980	16	1,101	90	1980	989	1,013
09/19/1980	16	1,133	92	1980	1,044	1,087
09/22/1980	18	1,188	91	1980	1,140	1,164
09/23/1980	18	1,203	92	1980	1,055	1,114
09/24/1980	17	1,162	91	1980	1,091	1,162
09/25/1980	17	1,131	92	1980	1,059	1,131
09/26/1980	19	1,145	93	1980	1,086	1,133
09/29/1980	16	996	88	1980	975	992
09/30/1980	17	1,083	90	1980	979	1,083
06/01/1981	17	1,078	96	1981	1,029	1,078
06/02/1981	17	1,092	92	1981	1,058	1,092
06/09/1981	19	1,181	98	1981	1,128	1,155
06/10/1981	17	1,114	94	1981	1,077	1,114
06/16/1981	19	1,259	102	1981	1,220	1,244
06/17/1981	17	1,263	99	1981	1,167	1,263
06/18/1981	17	1,256	99	1981	1,183	1,256
06/19/1981	17	1,201	95	1981	1,114	1,201
06/22/1981	18	1,213	97	1981	1,082	1,171
06/24/1981	17	1,235	95	1981	1,155	1,235
06/29/1981	18	988	89	1981	912	962
06/30/1981	18	1,013	90	1981	932	1,007
07/01/1981	18	840	84	1981	810	830
07/02/1981	18	978	90	1981	918	970
07/03/1981	18	990	94	1981	918	977
07/07/1981	19	1,225	100	1981	1,157	1,208
07/09/1981	18	1,134	95	1981	1,083	1,121
07/10/1981	18	1,153	96	1981	1,105	1,137
07/13/1981	16	1,218	101	1981	1,180	1,210
07/14/1981	19	1,285	102	1981	1,240	1,281
07/15/1981	18	1,306	102	1981	1,247	1,275
07/23/1981	17	1,150	95	1981	1,120	1,150
07/24/1981	18	1,149	95	1981	1,105	1,140
07/27/1981	17	1,217	95	1981	1,167	1,217
07/28/1981	17	1,173	96	1981	1,153	1,173

DATE	HOUR	PEAK	MAXTEMP	FY	MW3PM	MW5PM
07/29/1981	17	1,236	95	1981	1,205	1,236
07/31/1981	18	1,102	89	1981	1,052	1,095
08/03/1981	18	1,115	92	1981	1,055	1,107
08/04/1981	19	1,027	90	1981	988	1,019
08/05/1981	18	1,144	94	1981	1,099	1,129
08/06/1981	18	1,228	95	1981	1,142	1,205
08/10/1981	18	1,198	94	1981	1,152	1,195
08/11/1981	17	1,120	92	1981	1,100	1,120
08/14/1981	17	1,081	89	1981	1,061	1,081
08/17/1981	18	1,169	92	1981	1,130	1,163
08/19/1981	17	1,031	87	1981	884	1,031
08/21/1981	17	876	82	1981	846	876
08/24/1981	18	941	83	1981	851	930
08/25/1981	17	1,020	87	1981	969	1,020
08/26/1981	18	1,004	87	1981	953	999
08/31/1981	19	973	85	1981	942	970
09/01/1981	18	1,077	89	1981	1,027	1,070
09/02/1981	17	1,079	89	1981	1,043	1,079
09/03/1981	18	1,089	89	1981	1,003	1,077
09/04/1981	18	970	88	1981	942	969
09/07/1981	21	828	87	1981	725	759
09/08/1981	21	989	93	1981	909	929
09/09/1981	18	1,073	92	1981	977	1,067
09/11/1981	16	1,027	89	1981	992	1,027
09/14/1981	18	1,066	93	1981	996	1,046
09/15/1981	17	1,144	93	1981	1,048	1,144
09/16/1981	19	934	86	1981	832	909
09/18/1981	17	762	82	1981	735	762
09/22/1981	19	774	87	1981	589	624
09/23/1981	18	969	92	1981	897	957
09/25/1981	17	805	84	1981	790	805
09/28/1981	17	933	90	1981	908	933
09/29/1981	18	960	89	1981	910	945
09/30/1981	17	960	89	1981	926	960
06/01/1982	18	924	88	1982	869	889
06/02/1982	17	1,087	91	1982	1,035	1,087
06/07/1982	18	1,134	91	1982	1,044	1,100
06/08/1982	18	1,190	95	1982	1,078	1,128
06/09/1982	19	1,228	99	1982	1,160	1,177
06/10/1982	17	1,237	97	1982	1,209	1,237
06/14/1982	18	1,111	93	1982	1,047	1,087
06/15/1982	17	1,186	94	1982	1,103	1,186
06/16/1982	17	1,192	95	1982	1,159	1,192
06/18/1982	19	837	83	1982	809	829
06/21/1982	18	1,225	95	1982	1,113	1,171

DATE	HOUR	PEAK	MAXTEMP	FY	MW3PM	MW5PM
06/29/1982	18	1,189	96	1982	1,095	1,182
07/01/1982	18	1,217	97	1982	1,156	1,209
07/02/1982	16	1,183	91	1982	1,139	1,165
07/05/1982	18	1,130	97	1982	1,019	1,061
07/06/1982	18	1,114	90	1982	1,077	1,095
07/09/1982	17	1,124	92	1982	1,069	1,124
07/12/1982	17	1,136	93	1982	1,102	1,136
07/13/1982	17	1,191	93	1982	1,105	1,191
07/14/1982	18	1,160	92	1982	1,117	1,137
07/15/1982	17	1,180	91	1982	1,163	1,180
07/16/1982	17	1,029	88	1982	989	1,029
07/20/1982	13	969	89	1982	890	908
07/21/1982	18	1,166	92	1982	1,079	1,121
07/28/1982	18	1,212	91	1982	1,090	1,157
07/29/1982	18	1,155	91	1982	1,104	1,150
07/30/1982	17	1,179	95	1982	1,119	1,179
08/02/1982	18	1,037	91	1982	997	1,027
08/03/1982	19	1,157	92	1982	1,079	1,098
08/04/1982	18	1,160	91	1982	1,068	1,115
08/05/1982	17	1,160	91	1982	1,098	1,160
08/10/1982	17	1,137	92	1982	1,088	1,137
08/11/1982	18	1,196	92	1982	1,092	1,120
08/12/1982	18	1,230	95	1982	1,128	1,186
08/17/1982	17	1,116	89	1982	1,011	1,116
08/19/1982	17	970	84	1982	948	970
08/20/1982	16	1,084	91	1982	1,038	1,068
08/24/1982	20	1,215	95	1982	1,138	1,188
08/25/1982	17	1,238	95	1982	1,219	1,238
08/27/1982	16	1,216	93	1982	1,152	1,179
08/30/1982	18	1,131	89	1982	1,036	1,083
08/31/1982	17	1,121	88	1982	1,018	1,121
09/01/1982	18	1,115	90	1982	1,034	1,102
09/02/1982	18	1,121	92	1982	1,061	1,101
09/03/1982	17	1,176	96	1982	1,124	1,176
09/06/1982	17	842	87	1982	822	842
09/07/1982	16	1,001	88	1982	981	1,001
09/13/1982	17	1,114	90	1982	1,061	1,114
09/14/1982	18	1,092	89	1982	1,051	1,071
09/15/1982	17	1,025	90	1982	993	1,025
09/16/1982	17	1,127	91	1982	1,068	1,127
09/20/1982	18	1,135	92	1982	1,073	1,121
09/22/1982	16	851	83	1982	817	851
09/28/1982	18	1,032	85	1982	994	1,031
09/29/1982	17	1,034	84	1982	984	1,034
09/30/1982	17	1,024	78	1982	998	1,024

JEA Response to
Staff Request for Production No. 7
Docket No. 001703-EM

DATE	HOUR	PEAK	MAXTEMP	FY	MW3PM	MW5PM
06/01/1983	17	1,018	88	1983	962	1,018
06/02/1983	17	987	82	1983	932	987
06/03/1983	18	1,046	87	1983	991	1,038
06/08/1983	18	816	74	1983	788	803
06/09/1983	17	953	83	1983	886	953
06/14/1983	17	1,003	83	1983	956	1,003
06/15/1983	19	968	87	1983	883	942
06/16/1983	18	1,045	85	1983	985	1,038
06/17/1983	18	1,059	86	1983	988	1,034
06/20/1983	18	1,056	86	1983	1,006	1,040
06/21/1983	13	900	79	1983	857	881
06/24/1983	18	983	85	1983	936	961
06/28/1983	17	1,153	89	1983	1,106	1,153
06/29/1983	17	1,148	91	1983	1,100	1,148
07/05/1983	19	1,196	92	1983	1,155	1,190
07/06/1983	18	1,209	89	1983	1,046	1,144
07/07/1983	17	1,197	91	1983	1,180	1,197
07/11/1983	18	1,246	92	1983	1,146	1,230
07/12/1983	18	1,227	92	1983	1,154	1,225
07/13/1983	18	1,263	93	1983	1,162	1,238
07/14/1983	17	1,285	94	1983	1,227	1,285
07/15/1983	17	1,119	95	1983	1,085	1,119
07/18/1983	18	1,381	96	1983	1,327	1,376
07/19/1983	17	1,311	98	1983	1,254	1,311
07/20/1983	18	1,350	96	1983	1,291	1,317
07/21/1983	19	1,375	95	1983	1,259	1,300
07/22/1983	18	1,334	98	1983	1,294	1,331
07/29/1983	17	1,174	88	1983	1,155	1,174
08/01/1983	18	1,273	90	1983	1,184	1,241
08/03/1983	17	1,219	90	1983	1,177	1,219
08/04/1983	14	1,147	88	1983	1,044	1,061
08/05/1983	18	1,195	89	1983	1,164	1,193
08/09/1983	17	1,278	94	1983	1,232	1,278
08/10/1983	18	1,291	93	1983	1,246	1,278
08/15/1983	18	1,100	87	1983	1,050	1,094
08/16/1983	17	1,125	87	1983	1,090	1,125
08/17/1983	17	1,198	89	1983	1,114	1,198
08/18/1983	17	1,227	91	1983	1,187	1,227
08/19/1983	18	1,300	94	1983	1,195	1,263
08/23/1983	17	1,361	95	1983	1,284	1,361
08/24/1983	18	1,343	94	1983	1,286	1,342
08/25/1983	17	1,257	90	1983	1,233	1,257
08/26/1983	17	1,255	91	1983	1,219	1,255
08/31/1983	18	1,292	93	1983	1,237	1,280
09/05/1983	18	1,166	93	1983	1,089	1,157

JEA Response to
Staff Request for Production No. 7
Docket No. 001703-EM

DATE	HOUR	PEAK	MAXTEMP	FY	MW3PM	MW5PM
09/06/1983	17	1,340	93	1983	1,257	1,340
09/07/1983	18	1,323	93	1983	1,213	1,290
09/09/1983	17	1,271	92	1983	1,226	1,271
09/14/1983	18	1,003	83	1983	933	992
09/15/1983	18	976	82	1983	907	953
09/22/1983	18	819	77	1983	758	794
06/01/1984	17	774	80	1984	749	774
06/04/1984	18	1,201	94	1984	1,057	1,144
06/05/1984	19	1,203	92	1984	1,114	1,165
06/06/1984	17	1,189	88	1984	1,092	1,189
06/07/1984	18	1,100	85	1984	1,023	1,081
06/08/1984	16	1,098	86	1984	1,003	1,061
06/11/1984	18	1,038	85	1984	955	1,027
06/12/1984	18	1,121	86	1984	1,024	1,069
06/14/1984	19	1,031	87	1984	993	1,019
06/15/1984	16	1,105	87	1984	1,053	1,090
06/18/1984	19	1,197	90	1984	1,127	1,154
06/19/1984	18	1,234	93	1984	1,203	1,224
06/22/1984	19	1,110	85	1984	1,012	1,068
06/25/1984	17	1,173	91	1984	1,087	1,173
06/26/1984	17	1,182	88	1984	1,143	1,182
06/28/1984	19	1,109	88	1984	1,064	1,091
07/03/1984	16	1,104	88	1984	1,019	1,064
07/04/1984	18	1,022	89	1984	890	967
07/05/1984	17	1,204	90	1984	1,136	1,204
07/06/1984	17	1,184	90	1984	1,130	1,184
07/09/1984	17	1,226	91	1984	1,206	1,226
07/10/1984	16	1,229	90	1984	1,188	1,210
07/11/1984	17	1,261	92	1984	1,209	1,261
07/12/1984	18	1,293	93	1984	1,228	1,290
07/16/1984	18	1,257	92	1984	1,181	1,228
07/17/1984	17	1,282	91	1984	1,205	1,282
07/20/1984	16	952	82	1984	929	948
07/23/1984	19	1,151	86	1984	1,066	1,103
07/24/1984	19	1,231	88	1984	1,090	1,142
07/25/1984	17	1,252	89	1984	1,117	1,252
07/26/1984	18	1,177	91	1984	1,146	1,161
07/27/1984	16	1,249	90	1984	1,107	1,183
08/01/1984	19	1,231	89	1984	1,088	1,126
08/03/1984	17	1,184	89	1984	1,142	1,184
08/07/1984	17	1,299	93	1984	1,223	1,299
08/08/1984	18	1,335	94	1984	1,252	1,321
08/09/1984	18	1,295	92	1984	1,236	1,293
08/10/1984	16	1,320	93	1984	1,254	1,286
08/14/1984	16	1,315	93	1984	1,243	1,301

Data JEA Used for the Trend Analysis Used to Forecast Winter Peak Demand
Daily Peak Demands and Temperature Extremes - Winter Non-Holiday Weekdays with AM Peak

DATE	HOUR	PEAK	MINTEMP	FY
11/16/1979	8	830	35	1980
11/30/1979	8	950	28	1980
12/04/1979	9	963	34	1980
12/05/1979	9	898	34	1980
12/18/1979	8	976	33	1980
12/19/1979	8	955	32	1980
12/20/1979	9	922	34	1980
12/27/1979	10	813	34	1980
12/28/1979	10	839	38	1980
01/02/1980	9	955	34	1980
01/03/1980	8	988	30	1980
01/07/1980	8	998	29	1980
01/08/1980	8	848	44	1980
01/14/1980	9	922	46	1980
01/15/1980	8	839	42	1980
01/16/1980	8	819	42	1980
01/17/1980	8	785	48	1980
01/21/1980	8	822	38	1980
01/24/1980	8	952	31	1980
01/25/1980	9	848	41	1980
01/29/1980	8	869	37	1980
01/30/1980	8	817	39	1980
02/04/1980	7	1,085	25	1980
02/06/1980	8	942	33	1980
02/07/1980	7	1,019	31	1980
02/08/1980	8	1,012	31	1980
02/11/1980	8	918	35	1980
02/12/1980	8	941	35	1980
02/14/1980	7	805	45	1980
02/15/1980	8	782	47	1980
02/19/1980	8	824	43	1980
02/20/1980	8	815	41	1980
02/27/1980	8	1,018	29	1980
02/28/1980	8	848	38	1980
03/03/1980	8	1,143	23	1980
03/04/1980	7	1,110	24	1980
03/05/1980	9	778	42	1980
11/07/1980	8	783	41	1981
12/01/1980	8	845	36	1981
12/04/1980	8	834	43	1981
12/05/1980	8	737	45	1981
12/08/1980	8	798	42	1981

JEA Response to
Staff's Request for Production No. 7
Docket No. 001703-EM

DATE	HOUR	PEAK	MINTEMP	FY
12/12/1980	8	877	36	1981
12/15/1980	9	837	38	1981
12/17/1980	8	901	39	1981
12/18/1980	9	949	31	1981
12/19/1980	9	931	33	1981
12/29/1980	10	954	45	1981
12/30/1980	9	868	40	1981
12/31/1980	9	865	40	1981
01/02/1981	10	1,051	32	1981
01/06/1981	9	1,076	30	1981
01/08/1981	9	1,062	26	1981
01/09/1981	9	1,043	30	1981
01/13/1981	8	1,260	13	1981
01/14/1981	8	1,174	28	1981
01/15/1981	8	894	41	1981
01/16/1981	10	928	35	1981
01/19/1981	8	1,068	25	1981
01/23/1981	8	990	39	1981
01/26/1981	8	939	30	1981
01/27/1981	9	899	37	1981
01/29/1981	8	957	30	1981
01/30/1981	8	1,006	28	1981
02/04/1981	8	1,089	23	1981
02/05/1981	8	1,051	27	1981
02/06/1981	11	972	33	1981
02/09/1981	9	867	31	1981
02/10/1981	7	777	39	1981
02/25/1981	9	810	35	1981
02/26/1981	9	709	47	1981
03/13/1981	7	763	39	1981
03/17/1981	8	792	32	1981
03/18/1981	8	731	48	1981
03/20/1981	9	797	37	1981
03/24/1981	8	825	40	1981
03/25/1981	8	777	42	1981
03/26/1981	8	776	41	1981
03/27/1981	9	691	45	1981
11/16/1981	8	786	42	1982
11/18/1981	8	809	37	1982
11/19/1981	8	798	39	1982
11/23/1981	8	923	32	1982
11/24/1981	8	822	38	1982
11/25/1981	9	815	33	1982
11/26/1981	10	712	38	1982
12/04/1981	8	859	39	1982

DATE	HOUR	PEAK	MINTEMP	FY
12/07/1981	8	886	34	1982
12/08/1981	8	870	41	1982
12/11/1981	8	1,135	23	1982
12/16/1981	8	940	35	1982
12/17/1981	8	1,040	30	1982
12/21/1981	9	1,109	22	1982
12/22/1981	9	864	40	1982
01/05/1982	9	923	36	1982
01/06/1982	8	935	36	1982
01/12/1982	8	1,291	17	1982
01/13/1982	7	931	41	1982
01/15/1982	8	1,189	27	1982
01/18/1982	8	1,004	30	1982
01/19/1982	8	868	43	1982
01/25/1982	8	976	32	1982
01/27/1982	8	1,167	30	1982
01/28/1982	8	1,037	34	1982
01/29/1982	8	886	40	1982
02/23/1982	7	863	35	1982
02/24/1982	8	785	43	1982
03/02/1982	8	913	38	1982
03/03/1982	8	824	39	1982
03/08/1982	7	922	34	1982
03/09/1982	8	916	36	1982
03/10/1982	8	766	46	1982
03/11/1982	9	778	47	1982
03/26/1982	11	690	45	1982
12/14/1982	8	985	35	1983
12/20/1982	10	925	33	1983
12/21/1982	9	915	33	1983
12/22/1982	9	984	28	1983
12/23/1982	9	879	35	1983
01/07/1983	10	931	33	1983
01/13/1983	8	1,159	26	1983
01/14/1983	9	1,150	26	1983
01/17/19[illegible]	8	1,150	25	1983
01/20/19[illegible]	10	887	44	1983
01/24/1983	8	997	34	1983
01/25/1983	8	1,009	35	1983
01/26/1983	8	1,058	32	1983
01/28/1983	9	938	39	1983
01/31/1983	9	807	45	1983
02/01/1983	8	797	46	1983
02/04/1983	8	1,049	31	1983
02/08/1983	8	1,075	27	1983

JEA Response to
Staff's Request for Production No. 7
Docket No. 001703-EM

DATE	HOUR	PEAK	MINTEMP	FY
02/09/1983	8	1,107	28	1983
02/10/1983	8	919	37	1983
02/14/1983	10	1,038	37	1983
02/15/1983	8	1,017	34	1983
02/17/1983	8	807	47	1983
02/18/1983	8	891	40	1983
02/24/1983	8	796	43	1983
02/25/1983	9	742	46	1983
03/02/1983	8	829	43	1983
03/11/1983	8	999	35	1983
03/14/1983	8	872	37	1983
03/22/1983	8	861	36	1983
03/23/1983	8	907	34	1983
03/25/1983	8	909	36	1983
03/29/1983	8	803	38	1983
03/30/1983	8	833	38	1983
11/14/1983	9	821	40	1984
11/17/1983	8	901	33	1984
11/18/1983	8	948	32	1984
11/22/1983	8	785	43	1984
11/30/1983	9	836	36	1984
12/01/1983	8	862	40	1984
12/02/1983	8	795	46	1984
12/08/1983	8	957	32	1984
12/09/1983	8	989	33	1984
12/14/1983	8	833	47	1984
12/16/1983	8	947	38	1984
12/22/1983	9	867	43	1984
12/26/1983	10	1,205	13	1984
12/27/1983	9	1,072	24	1984
01/02/1984	10	977	33	1984
01/03/1984	8	1,047	30	1984
01/04/1984	8	1,110	30	1984
01/05/1984	7	1,012	33	1984
01/06/1984	8	1,036	34	1984
01/09/1984	8	1,005	34	1984
01/23/1984	9	979	45	1984
01/30/1984	8	935	37	1984
02/01/1984	8	1,123	30	1984
02/02/1984	8	1,063	31	1984
02/03/1984	8	861	45	1984
02/06/1984	9	1,039	31	1984
02/07/1984	7	1,233	26	1984
02/08/1984	8	1,154	25	1984
02/09/1984	8	1,069	33	1984

JEA Response to
Staff's Request for Production No. 7
Docket No. 001703-EM

DATE	HOUR	PEAK	MINTEMP	FY
02/10/1984	8	909	38	1984
02/15/1984	8	829	42	1984
02/16/1984	8	816	46	1984
02/17/1984	8	828	46	1984
02/29/1984	7	1,115	34	1984
03/01/1984	7	1,149	29	1984
03/02/1984	8	1,136	31	1984
03/08/1984	8	952	37	1984
03/09/1984	8	883	40	1984
03/12/1984	8	833	40	1984
03/22/1984	8	756	43	1984
03/30/1984	9	765	41	1984
11/09/1984	8	845	46	1985
11/13/1984	8	977	34	1985
11/14/1984	8	1,033	31	1985
11/15/1984	8	929	39	1985
11/16/1984	8	830	46	1985
11/23/1984	10	954	40	1985
11/29/1984	8	976	35	1985
11/30/1984	8	1,066	31	1985
12/07/1984	8	1,226	26	1985
12/10/1984	8	1,004	36	1985
12/13/1984	8	868	47	1985
01/07/1985	8	1,102	31	1985
01/08/1985	8	974	36	1985
01/09/1985	8	1,063	30	1985
01/10/1985	8	887	40	1985
01/11/1985	8	851	44	1985
01/14/1985	8	1,079	34	1985
01/15/1985	8	1,111	31	1985
01/16/1985	8	1,201	27	1985
01/17/1985	8	880	42	1985
01/21/1985	8	1,586	7	1985
01/22/1985	8	1,558	16	1985
01/23/1985	8	1,346	26	1985
01/24/1985	8	1,286	25	1985
01/25/1985	8	978	43	1985
01/28/1985	8	1,004	38	1985
01/30/1985	8	1,092	31	1985
02/05/1985	8	913	47	1985
02/08/1985	8	1,098	29	1985
02/11/1985	8	965	41	1985
02/13/1985	8	1,258	31	1985
02/14/1985	8	1,226	30	1985
02/15/1985	8	1,042	31	1985

DATE	HOUR	PEAK	MINTEMP	FY
02/18/1985	8	951	35	1985
02/19/1985	8	956	43	1985
02/21/1985	8	886	49	1985
02/22/1985	8	860	47	1985
03/18/1985	8	910	37	1985
03/19/1985	7	1,061	32	1985
03/20/1985	8	937	38	1985
11/06/1985	7	896	44	1986
11/07/1985	8	848	46	1986
12/04/1985	8	947	42	1986
12/09/1985	8	890	44	1986
12/16/1985	8	1,205	30	1986
12/17/1985	8	1,162	32	1986
12/18/1985	8	1,121	36	1986
12/20/1985	8	1,143	34	1986
12/23/1985	9	1,133	34	1986
12/26/1985	10	1,411	20	1986
12/27/1985	9	1,298	27	1986
12/30/1985	9	1,097	32	1986
12/31/1985	9	1,156	29	1986
01/06/1986	8	1,204	30	1986
01/13/1986	8	1,097	35	1986
01/14/1986	8	1,253	29	1986
01/15/1986	8	1,125	36	1986
01/16/1986	8	1,027	42	1986
01/17/1986	8	910	47	1986
01/20/1986	9	971	40	1986
01/21/1986	8	1,080	37	1986
01/22/1986	8	1,056	38	1986
01/23/1986	8	900	48	1986
01/28/1986	8	1,640	16	1986
01/29/1986	8	1,367	29	1986
01/31/1986	8	1,175	32	1986
02/03/1986	8	943	44	1986
02/04/1986	8	875	49	1986
02/12/1986	8	1,054	34	1986
02/13/1986	8	1,166	32	1986
02/14/1986	8	1,261	30	1986
02/24/1986	8	837	46	1986
02/26/1986	8	1,045	34	1986
03/03/1986	8	1,035	40	1986
03/05/1986	8	1,010	38	1986
03/06/1986	8	1,086	38	1986
03/07/1986	8	1,040	37	1986
03/24/1986	8	990	36	1986

JEA Response to
Staff's Request for Production No. 7
Docket No. 001703-EM

DATE	HOUR	PEAK	MINTEMP	FY
12/04/1986	8	1,040	40	1987
12/05/1986	8	1,041	44	1987
12/19/1986	8	931	47	1987
12/22/1986	11	1,015	44	1987
12/30/1986	11	1,033	44	1987
12/31/1986	10	985	43	1987
01/02/1987	10	1,101	34	1987
01/05/1987	8	1,132	41	1987
01/06/1987	8	1,145	38	1987
01/07/1987	8	1,107	40	1987
01/08/1987	8	1,004	43	1987
01/09/1987	8	1,022	41	1987
01/12/1987	8	1,367	31	1987
01/13/1987	8	1,216	38	1987
01/14/1987	8	1,197	34	1987
01/23/1987	8	1,371	29	1987
01/27/1987	8	1,439	29	1987
01/28/1987	8	1,430	29	1987
01/29/1987	8	1,260	32	1987
02/02/1987	8	913	49	1987
02/03/1987	8	985	47	1987
02/09/1987	8	1,197	32	1987
02/10/1987	8	1,368	29	1987
02/11/1987	8	1,333	30	1987
02/12/1987	8	1,153	40	1987
02/13/1987	8	981	43	1987
02/18/1987	8	1,032	47	1987
02/19/1987	8	1,084	41	1987
02/24/1987	8	1,035	45	1987
02/27/1987	8	963	49	1987
03/03/1987	8	1,042	40	1987
03/04/1987	8	938	40	1987
03/05/1987	8	1,046	37	1987
03/06/1987	8	1,000	47	1987
03/13/1987	8	1,156	35	1987
03/16/1987	8	932	46	1987
11/12/1987	8	1,121	33	1988
11/13/1987	8	1,249	31	1988
11/23/1987	8	1,011	45	1988
12/01/1987	8	1,065	39	1988
12/02/1987	8	1,162	34	1988
12/03/1987	8	1,222	33	1988
12/07/1987	8	1,007	49	1988
12/17/1987	8	1,370	29	1988
12/18/1987	8	1,387	28	1988

DATE	HOUR	PEAK	MINTEMP	FY
12/23/1987	9	969	43	1988
12/30/1987	9	1,229	31	1988
12/31/1987	9	1,051	38	1988
01/05/1988	8	1,345	30	1988
01/06/1988	8	1,400	31	1988
01/08/1988	8	1,308	35	1988
01/11/1988	8	1,324	33	1988
01/12/1988	8	1,482	29	1988
01/13/1988	8	1,264	37	1988
01/15/1988	8	1,373	32	1988
01/22/1988	8	1,154	39	1988
01/26/1988	7	1,391	31	1988
01/27/1988	7	1,504	26	1988
01/28/1988	8	1,633	25	1988
01/29/1988	7	1,473	28	1988
02/08/1988	7	1,178	40	1988
02/09/1988	7	1,224	39	1988
02/10/1988	7	1,205	38	1988
02/16/1988	7	1,299	36	1988
02/17/1988	8	1,389	30	1988
02/22/1988	7	1,336	33	1988
02/23/1988	7	1,153	40	1988
02/24/1988	7	999	44	1988
02/25/1988	7	1,214	33	1988
02/26/1988	7	1,259	34	1988
02/29/1988	7	1,212	34	1988
03/02/1988	7	1,028	40	1988
03/07/1988	7	974	46	1988
03/08/1988	8	966	47	1988
03/11/1988	8	1,030	41	1988
03/15/1988	8	1,223	34	1988
03/16/1988	8	1,302	30	1988
03/17/1988	8	1,290	32	1988
03/18/1988	8	1,068	40	1988
03/21/1988	8	1,071	42	1988
11/08/1988	7	1,000	41	1989
11/24/1988	11	871	49	1989
11/29/1988	8	1,205	35	1989
12/02/1988	7	1,304	34	1989
12/05/1988	7	1,131	38	1989
12/06/1988	7	1,235	33	1989
12/08/1988	8	1,060	45	1989
12/13/1988	7	1,526	27	1989
12/14/1988	7	1,488	31	1989
12/15/1988	7	1,221	37	1989

JEA Response to
Staff's Request for Production No. 7
Docket No. 001703-EM

DATE	HOUR	PEAK	MINTEMP	FY
12/19/1988	8	1,542	24	1989
12/20/1988	8	1,344	31	1989
12/21/1988	8	1,033	48	1989
12/22/1988	8	976	48	1989
01/05/1989	8	1,340	32	1989
01/17/1989	8	1,041	40	1989
01/18/1989	8	1,106	40	1989
01/19/1989	8	1,124	37	1989
01/20/1989	8	974	49	1989
01/23/1989	8	1,198	44	1989
01/24/1989	8	1,167	40	1989
01/25/1989	8	1,191	36	1989
01/26/1989	8	1,055	45	1989
02/09/1989	8	1,170	35	1989
02/10/1989	8	1,404	29	1989
02/13/1989	8	1,155	37	1989
02/24/1989	7	1,657	27	1989
03/10/1989	8	1,421	35	1989
11/17/1989	8	1,214	37	1990
11/20/1989	8	1,204	38	1990
11/22/1989	8	990	47	1990
11/24/1989	9	1,036	37	1990
11/30/1989	8	1,201	35	1990
12/01/1989	8	1,278	35	1990
12/04/1989	8	1,536	27	1990
12/05/1989	8	1,430	33	1990
12/06/1989	8	1,218	38	1990
12/07/1989	8	1,089	47	1990
12/11/1989	8	1,419	33	1990
12/12/1989	8	1,289	38	1990
12/14/1989	8	1,543	29	1990
12/15/1989	8	1,553	30	1990
12/21/1989	10	1,308	38	1990
12/26/1989	9	1,628	29	1990
12/27/1989	9	1,567	29	1990
12/28/1989	9	1,242	38	1990
12/29/1989	9	1,342	35	1990
01/02/1990	8	1,319	35	1990
01/04/1990	8	1,072	47	1990
01/10/1990	8	1,147	46	1990
01/11/1990	8	1,217	40	1990
01/12/1990	8	1,049	43	1990
01/15/1990	9	1,186	37	1990
01/16/1990	8	1,114	45	1990
01/17/1990	8	1,056	45	1990

DATE	HOUR	PEAK	MINTEMP	FY
01/19/1990	8	952	49	1990
01/23/1990	8	1,288	34	1990
01/24/1990	8	1,126	43	1990
01/29/1990	8	1,027	48	1990
02/06/1990	8	1,102	42	1990
02/12/1990	8	1,108	43	1990
02/13/1990	8	1,151	40	1990
02/26/1990	8	1,204	37	1990
02/27/1990	8	1,125	43	1990
02/28/1990	8	1,011	49	1990
03/01/1990	8	1,007	47	1990
03/05/1990	8	1,023	44	1990
03/09/1990	8	970	49	1990
03/21/1990	8	1,167	36	1990
03/22/1990	8	1,122	38	1990
03/23/1990	8	955	46	1990
11/19/1990	8	1,171	36	1991
11/20/1990	8	1,187	38	1991
11/21/1990	8	1,123	42	1991
11/30/1990	8	1,157	40	1991
12/05/1990	8	1,400	29	1991
12/06/1990	8	1,365	33	1991
12/07/1990	8	1,142	44	1991
12/10/1990	8	1,473	32	1991
12/11/1990	8	1,352	35	1991
12/12/1990	8	1,302	41	1991
12/13/1990	8	1,197	42	1991
12/14/1990	8	1,093	47	1991
12/26/1990	10	1,065	43	1991
01/10/1991	8	1,141	48	1991
01/14/1991	8	1,482	31	1991
01/15/1991	8	1,157	44	1991
01/17/1991	8	1,163	41	1991
01/18/1991	8	1,329	36	1991
01/21/1991	9	1,172	43	1991
01/22/1991	8	1,403	32	1991
01/23/1991	8	1,530	31	1991
02/01/1991	8	1,175	45	1991
02/11/1991	8	1,182	42	1991
02/12/1991	8	1,261	37	1991
02/18/1991	8	1,145	43	1991
02/27/1991	8	1,250	36	1991
02/28/1991	8	1,110	46	1991
03/05/1991	8	1,284	40	1991
03/11/1991	8	1,344	35	1991

DATE	HOUR	PEAK	MINTEMP	FY
03/12/1991	8	1,264	39	1991
03/20/1991	8	1,058	43	1991
11/05/1991	8	1,279	39	1992
11/06/1991	8	1,134	46	1992
11/07/1991	8	1,068	43	1992
11/08/1991	8	1,218	39	1992
11/11/1991	8	1,261	39	1992
11/12/1991	8	1,355	36	1992
11/13/1991	8	1,276	38	1992
11/14/1991	8	1,206	40	1992
11/25/1991	8	1,438	30	1992
11/26/1991	8	1,525	29	1992
11/27/1991	8	1,226	43	1992
11/28/1991	11	934	43	1992
12/05/1991	8	1,497	30	1992
12/06/1991	8	1,292	40	1992
12/16/1991	8	1,439	31	1992
12/17/1991	8	1,563	29	1992
12/18/1991	8	1,462	33	1992
12/20/1991	9	1,262	40	1992
12/23/1991	9	1,117	44	1992
12/31/1991	8	1,223	40	1992
01/06/1992	8	1,165	46	1992
01/07/1992	8	1,369	34	1992
01/08/1992	8	1,327	37	1992
01/15/1992	8	1,513	33	1992
01/16/1992	8	1,589	28	1992
01/17/1992	8	1,883	24	1992
01/20/1992	9	1,560	33	1992
01/21/1992	8	1,710	29	1992
01/22/1992	8	1,560	32	1992
01/24/1992	8	1,219	36	1992
01/27/1992	8	1,223	32	1992
02/03/1992	8	1,407	38	1992
02/04/1992	8	1,423	36	1992
02/07/1992	8	1,358	43	1992
02/11/1992	8	1,273	48	1992
02/12/1992	8	1,268	42	1992
02/13/1992	8	1,113	48	1992
02/14/1992	8	1,159	47	1992
02/21/1992	8	1,179	45	1992
02/28/1992	8	1,248	42	1992
03/02/1992	8	1,077	46	1992
03/12/1992	8	1,288	41	1992
03/13/1992	8	1,194	46	1992

DATE	HOUR	PEAK	MINTEMP	FY
03/17/1992	8	1,441	31	1992
03/24/1992	8	1,084	45	1992
03/26/1992	8	1,043	49	1992
03/27/1992	8	1,030	47	1992
11/17/1992	8	1,251	40	1993
11/30/1992	8	1,520	33	1993
12/02/1992	8	1,442	34	1993
12/03/1992	8	1,444	35	1993
12/04/1992	8	1,451	36	1993
12/07/1992	8	1,180	47	1993
12/09/1992	8	1,426	36	1993
12/11/1992	8	1,306	44	1993
12/14/1992	8	1,428	38	1993
12/15/1992	8	1,261	45	1993
01/15/1993	8	1,214	45	1993
01/18/1993	9	1,247	42	1993
01/19/1993	8	1,265	44	1993
01/27/1993	8	1,626	37	1993
01/28/1993	8	1,672	32	1993
01/29/1993	8	1,349	40	1993
02/01/1993	8	1,361	45	1993
02/03/1993	8	1,556	32	1993
02/04/1993	8	1,324	42	1993
02/09/1993	8	1,333	41	1993
02/15/1993	8	1,317	38	1993
02/18/1993	8	1,406	37	1993
02/19/1993	8	1,768	26	1993
02/23/1993	8	1,399	40	1993
02/24/1993	8	1,466	36	1993
02/25/1993	8	1,379	38	1993
02/26/1993	8	1,099	46	1993
03/01/1993	8	1,475	36	1993
03/02/1993	8	1,388	38	1993
03/05/1993	8	1,190	46	1993
03/08/1993	8	1,178	47	1993
03/12/1993	8	1,040	48	1993
03/15/1993	8	1,791	27	1993
03/16/1993	8	1,382	38	1993
11/01/1993	8	1,537	33	1994
11/02/1993	7	1,425	35	1994
11/08/1993	8	1,237	45	1994
11/11/1993	8	1,234	42	1994
11/12/1993	8	1,157	48	1994
11/29/1993	8	1,363	38	1994
11/30/1993	8	1,453	36	1994

JEA Response to
Staff's Request for Production No. 7
Docket No. 001703-EM

DATE	HOUR	PEAK	MINTEMP	FY
12/06/1993	8	1,217	44	1994
12/07/1993	8	1,292	40	1994
12/08/1993	8	1,270	39	1994
12/09/1993	8	1,362	41	1994
12/10/1993	8	1,166	48	1994
12/13/1993	8	1,611	31	1994
12/14/1993	8	1,206	43	1994
12/16/1993	8	1,461	40	1994
12/17/1993	8	1,467	37	1994
12/20/1993	8	1,391	39	1994
12/22/1993	10	1,456	35	1994
12/23/1993	11	1,497	38	1994
12/27/1993	9	1,685	31	1994
12/28/1993	8	1,447	37	1994
12/29/1993	9	1,239	44	1994
12/31/1993	9	1,530	33	1994
01/05/1994	8	1,678	32	1994
01/06/1994	8	1,799	30	1994
01/07/1994	8	1,376	42	1994
01/10/1994	8	1,479	37	1994
01/11/1994	8	1,343	48	1994
01/14/1994	8	1,458	43	1994
01/17/1994	9	1,359	41	1994
01/19/1994	8	1,911	26	1994
01/20/1994	8	1,805	33	1994
01/21/1994	8	1,788	30	1994
01/24/1994	8	1,496	40	1994
01/25/1994	8	1,391	40	1994
01/26/1994	8	1,237	47	1994
02/01/1994	8	1,547	36	1994
02/02/1994	8	1,570	31	1994
02/03/1994	8	1,942	26	1994
02/04/1994	8	1,678	32	1994
02/08/1994	8	1,144	48	1994
02/15/1994	8	1,360	39	1994
02/25/1994	8	1,304	39	1994
03/03/1994	8	1,324	46	1994
03/04/1994	8	1,418	39	1994
03/11/1994	8	1,400	37	1994
03/15/1994	8	1,133	46	1994
03/17/1994	8	1,269	33	1994
03/18/1994	8	1,249	41	1994
11/24/1994	10	1,175	37	1995
11/25/1994	9	1,002	45	1995
12/14/1994	8	1,327	47	1995

JEA Response to
Staff's Request for Production No. 7
Docket No. 001703-EM

DATE	HOUR	PEAK	MINTEMP	FY
12/19/1994	9	1,444	38	1995
12/20/1994	8	1,353	41	1995
12/27/1994	9	1,290	43	1995
12/28/1994	9	1,332	41	1995
12/29/1994	9	1,333	41	1995
01/05/1995	8	1,709	34	1995
01/06/1995	8	1,576	37	1995
01/09/1995	8	1,696	35	1995
01/10/1995	8	1,413	43	1995
01/11/1995	8	1,383	43	1995
01/12/1995	8	1,282	47	1995
01/17/1995	8	1,455	42	1995
01/18/1995	8	1,431	42	1995
01/20/1995	8	1,438	39	1995
01/23/1995	8	1,438	38	1995
01/24/1995	8	1,755	33	1995
01/25/1995	8	1,814	29	1995
01/26/1995	8	1,635	35	1995
01/27/1995	8	1,544	37	1995
01/31/1995	8	1,761	32	1995
02/01/1995	8	1,755	30	1995
02/02/1995	8	1,511	40	1995
02/06/1995	8	1,784	30	1995
02/07/1995	8	1,727	32	1995
02/09/1995	8	2,190	20	1995
02/10/1995	8	1,614	39	1995
02/13/1995	8	1,379	45	1995
02/14/1995	8	1,329	46	1995
02/21/1995	8	1,367	39	1995
02/22/1995	8	1,544	34	1995
02/23/1995	8	1,585	34	1995
02/24/1995	8	1,240	49	1995
03/03/1995	8	1,332	44	1995
03/09/1995	8	1,333	40	1995
03/10/1995	8	1,438	35	1995
11/09/1995	8	1,347	36	1996
11/10/1995	8	1,192	44	1996
11/13/1995	8	1,421	39	1996
11/15/1995	8	1,584	33	1996
11/16/1995	8	1,620	33	1996
11/17/1995	8	1,301	43	1996
11/20/1995	8	1,240	45	1996
11/22/1995	8	1,429	36	1996
11/23/1995	9	1,369	33	1996
11/24/1995	9	1,096	43	1996

DATE	HOUR	PEAK	MINTEMP	FY
11/27/1995	8	1,356	42	1996
12/01/1995	8	1,348	43	1996
12/08/1995	8	1,208	49	1996
12/11/1995	8	1,984	27	1996
12/12/1995	8	1,912	30	1996
12/13/1995	8	1,541	36	1996
12/21/1995	8	1,763	31	1996
12/22/1995	9	1,627	38	1996
12/26/1995	9	1,724	30	1996
12/27/1995	9	1,859	28	1996
12/28/1995	10	1,777	33	1996
12/29/1995	9	1,675	34	1996
01/04/1996	8	1,811	32	1996
01/05/1996	8	1,803	32	1996
01/08/1996	8	2,278	27	1996
01/09/1996	8	2,276	23	1996
01/10/1996	8	1,733	36	1996
01/11/1996	8	1,944	30	1996
01/15/1996	9	1,480	38	1996
01/16/1996	8	1,414	41	1996
01/22/1996	8	1,617	33	1996
01/23/1996	8	1,370	46	1996
01/24/1996	8	1,201	48	1996
01/25/1996	8	1,650	36	1996
01/26/1996	8	1,432	38	1996
01/29/1996	8	1,455	42	1996
01/30/1996	8	1,327	46	1996
02/05/1996	8	2,401	19	1996
02/06/1996	8	2,153	25	1996
02/07/1996	8	2,025	27	1996
02/08/1996	8	1,675	35	1996
02/13/1996	8	1,773	29	1996
02/14/1996	8	1,668	36	1996
02/19/1996	8	1,491	37	1996
03/04/1996	8	1,428	38	1996
03/05/1996	8	1,242	45	1996
03/11/1996	8	1,816	37	1996
03/12/1996	8	1,697	34	1996
03/13/1996	8	1,739	32	1996
03/14/1996	8	1,515	38	1996
03/15/1996	8	1,298	43	1996
03/20/1996	8	1,445	40	1996
03/21/1996	8	1,669	37	1996
03/22/1996	8	1,552	35	1996
11/08/1996	11	1,278	47	1997

JEA Response to
Staff's Request for Production No. 7
Docket No. 001703-EM

DATE	HOUR	PEAK	MINTEMP	FY
11/11/1996	9	1,354	37	1997
11/12/1996	8	1,522	36	1997
11/13/1996	8	1,319	44	1997
11/14/1996	8	1,258	47	1997
11/27/1996	8	1,407	40	1997
11/28/1996	10	1,209	41	1997
12/03/1996	8	1,377	37	1997
12/04/1996	8	1,381	38	1997
12/09/1996	8	1,484	34	1997
12/10/1996	8	1,686	30	1997
12/11/1996	8	1,429	39	1997
12/12/1996	8	1,274	48	1997
12/16/1996	8	1,427	37	1997
12/20/1996	9	2,084	25	1997
12/23/1996	8	1,388	41	1997
01/10/1997	8	1,524	37	1997
01/13/1997	8	1,722	34	1997
01/14/1997	8	1,528	42	1997
01/15/1997	8	1,406	42	1997
01/17/1997	8	1,928	28	1997
01/20/1997	8	1,779	30	1997
01/21/1997	8	1,784	33	1997
01/22/1997	8	1,431	43	1997
01/23/1997	8	1,314	46	1997
01/27/1997	8	1,408	43	1997
01/31/1997	8	1,512	42	1997
02/03/1997	8	1,274	49	1997
02/07/1997	8	1,242	49	1997
02/11/1997	8	1,439	38	1997
02/12/1997	8	1,716	33	1997
02/13/1997	8	1,319	48	1997
02/17/1997	8	1,479	37	1997
02/18/1997	8	1,318	44	1997
02/19/1997	8	1,291	45	1997
03/07/1997	8	1,279	38	1997
11/05/1997	8	1,314	44	1998
11/10/1997	8	1,363	44	1998
11/17/1997	8	1,726	32	1998
11/18/1997	7	1,506	40	1998
11/20/1997	8	1,415	42	1998
11/25/1997	8	1,454	42	1998
11/26/1997	8	1,358	43	1998
11/27/1997	11	1,136	47	1998
12/02/1997	8	1,333	46	1998
12/08/1997	8	1,840	32	1998

JEA Response to
Staff's Request for Production No. 7
Docket No. 001703-EM

DATE	HOUR	PEAK	MINTEMP	FY
12/16/1997	8	1,791	42	1998
12/17/1997	8	1,672	39	1998
12/18/1997	8	1,694	39	1998
12/19/1997	8	1,629	38	1998
12/30/1997	9	1,748	36	1998
12/31/1997	8	1,556	36	1998
01/02/1998	8	1,617	35	1998
01/12/1998	8	1,596	39	1998
01/20/1998	8	1,689	34	1998
01/21/1998	8	1,445	42	1998
01/26/1998	8	1,609	40	1998
01/28/1998	8	1,541	44	1998
01/29/1998	8	1,617	38	1998
01/30/1998	8	1,524	41	1998
02/05/1998	8	1,733	40	1998
02/06/1998	8	1,741	37	1998
02/09/1998	8	1,588	40	1998
02/10/1998	8	1,685	36	1998
02/11/1998	8	1,425	45	1998
02/12/1998	8	1,287	46	1998
02/13/1998	8	1,479	40	1998
02/19/1998	8	1,297	46	1998
02/24/1998	8	1,494	47	1998
02/25/1998	8	1,403	44	1998
02/26/1998	8	1,352	47	1998
03/03/1998	8	1,505	39	1998
03/04/1998	8	1,726	34	1998
03/05/1998	8	1,511	41	1998
03/10/1998	8	1,554	39	1998
03/11/1998	8	1,820	32	1998
03/12/1998	8	1,868	33	1998
03/13/1998	7	1,938	32	1998
03/16/1998	8	1,311	45	1998
03/23/1998	8	1,424	41	1998
03/24/1998	8	1,392	43	1998
03/25/1998	8	1,229	46	1998

EXHIBIT ______

THE FLORIDA TIMES-UNION
Jacksonville, Fl
Affidavit of Publication

00 DEC 20 AM 8:52

FLORIDA PUBLIC SERVICE COMM. DIV. OF ADMINISTRATION
OUT IF CHECKED

Florida Times-Union

PUBLIC SERVICE COMM.
2540 SHUMARD OAK BLVD
TALLAHASSEE FL 32399

001703-EM

REFERENCE: 0464849 001703-EM
R50985 Before the Florida

00 DEC 20 AM 8:20
MAIL ROOM

State of Florida
County of Duval

Before the undersigned authority personally appeared Wendy Reynolds who on oath says she is a Legal Advertising Representative of The Florida Times-Union, a daily newspaper published in Jacksonville in Duval County, Florida; that the attached copy of advertisement is a legal ad published in The Florida Times-Union. Affiant further says that The Florida Times-Union is a newspaper published in Jacksonville, in Duval County, Florida, and that the newspaper has heretofore been continuously published in Duval County, Florida each day, has been entered as second class mail matter at the post office in Jacksonville, in Duval County, Florida for a period of one year preceeding the first publication of the attached copy of advertisement; and affiant further says that he/she has neither paid nor promised any person, firm or corporation any discount, rebate, commission, or refund for the purpose of securing this advertisement for publication in said newspaper.

PUBLISHED ON: 12/10

APP ___
CAF ___
CMP ___
COM ___
CTR ___
ECR ___
LEG ___
OPC ___
PAI ___
RGO ___
SEC 1
SER ___
OTH SKG

FILED ON: 12/12/00 Wendy Reynolds

Name: Wendy Reynolds Title: Legal Advertising Representative

In testimony whereof, I have hereunto set my hand and affixed my official seal, the day and year aforesaid.

NOTARY: Sally W. Rhodes

Sally W. Rhodes
MY COMMISSION # CC684407 EXPIRES
January 30, 2002
BONDED THRU TROY FAIN INSURANCE, INC.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 001703-EM EXHIBIT NO. 4
COMPANY/WITNESS: FPSC Staff
DATE: 2-8-01

DOCUMENT NUMBER-DATE
16302 DEC 20 8
FPSC-RECORDS/REPORTING

ORE THE FLORIDA PUBLIC SERVICE COMMISSION

EED DETERMINATION HEARING AND PREHEARING CONFERENCE ON PROPOSED ELECTRICAL POWER PLANT

TO

JEA

DEPARTMENT OF COMMUNITY AFFAIRS

DEPARTMENT OF ENVIRONMENTAL PROTECTION

ELECTRIC AND GAS UTILITIES

AND

ALL INTERESTED PERSONS

IN RE: DOCKET NO. 001703-EM - PETITION FOR DETERMINATION OF NEED FOR POWER PLANT IN DUVAL COUNTY BY JEA

ISSUED: <u>December 10, 2000</u>

NOTICE is hereby given that the Florida Public Service Commission will hold a public hearing in the above docket. The time and location of the hearing are listed below. All persons who wish to be heard are urged to be present at the beginning of the hearing on Thursday, February 8, 2001.

February 8 and 9, 2001, 9:30 a.m.
Commission Hearing Room 148
Betty Easley Conference Center
4075 Esplanade Way
Tallahassee, Florida

The starting time for the second day will be determined at the end of the first day of hearing. Notice is given that the Commission reserves the right to enter a bench decision at the end of the hearing.

Any person requiring some accommodation at the hearing or prehearing conference because of a physical impairment should call the Division of Records and Reporting at (850) 413-6770 at least 48 hours prior to the hearing or prehearing conference. Any person who is hearing or speech impaired should contact the Florida Public Service Commission by using the Florida Relay Service, which can be reached at 1-800-955-8771 (TDD).

<u>PURPOSE AND PROCEDURE</u>

The purpose of this hearing will be for the Commission to take final action to determine the need, pursuant to Sections 403.501-519, Florida Statutes, for the construction of a power plant and related facilities in Duval County, Florida. This proceeding shall: 1) allow JEA to present evidence and testimony in support of their petition for a determination of need for their proposed plant and related facilities in Duval County, Florida; 2) allow any intervenors to present testimony and exhibits concerning this matter; 3) allow members of the public who are not parties to the need determination proceeding the opportunity to present testimony concerning this matter; and, 4) allow for such other purposes as the Commission may deem appropriate. All witnesses shall be subject to cross-examination at the conclusion of their testimony.

The proceedings will be governed by the provisions of Chapter 120, Florida Statutes, Section 403.519, Florida Statutes, Chapter 25-22, Florida Administrative Code, and Chapter 28-106, Florida Administrative Code.

Under Section 403.519, Florida Statutes, the Commission is the sole forum for the determination of need for the electrical power plant and associated facilities. In making its determination, the Commission must take into account the need for electric system reliability and integrity, the need for adequate electricity at a reasonable cost, and whether the proposed plant is the most cost-effective alternative available. The Commission must also expressly consider the conservation measures taken by or reasonably available to the petitioners which might mitigate the need for the proposed plant, and other matters within its jurisdiction which it deems relevant. The Commission's determination of need for the Duval County facility shall create a presumption of public need and necessity and shall serve as the Commission's report as required by Section 403.507 (2) (a) (2), Florida Statutes. An order entered by the Commission pursuant to this hearing shall constitute final agency action.

Only issues relating to the need for the power plant and its associated facilities will be heard at the February 8 and 9, 2001, hearing. Separate public hearings will be held before the Division of Administrative Hearings to consider environmental and other impacts of the proposed plant and associated facilities.

Members of the public who are not parties to the need determination proceeding will have an opportunity to present testimony regarding the need for the proposed plant and associated facilities. All members of the public who wish to offer testimony should be present at the beginning of the hearing. All witnesses will be sworn and will be subject to cross-examination at the conclusion of their testimony.

Written comments regarding the need for the proposed plant and associated facilities may be sent to the Commission at the following address:

Blanca S. Bayo, Director
Division of Records and Reporting
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0870
Re: Docket No. 001703-EM

Anyone wishing to become a party to the need determination proceeding should file an appropriate petition pursuant to Rule 25-22.039, Florida Administrative Code, with the Director of the Commission's Division of Records and Reporting at the address listed above. Copies of the petition should be sent by mail to all parties. Those wishing to intervene in these proceedings, unless appearing on their own behalf, must be represented by an attorney or other person who can be determined to be a qualified representative pursuant to Chapter 120, Florida Statutes, and Rule 28-106.106, Florida Administrative Code. Petitions for leave to intervene must be filed at least five (5) days before the final hearing, must conform with Rule 28-106.201 (2), Florida Administrative Code, and must include allegations sufficient to demonstrate that the intervenor is entitled to participate in the proceeding as a matter of constitutional or statutory right or pursuant to Commission rule, or that the substantial interests of the intervenor are subject to determination or will be affected through the hearing.

<u>GENERAL LOCATION AND PROJECT DESCRIPTION</u>

The proposed plant will be located at JEA's Brandy Branch Generating Station near the city of Baldwin in Duval County, Florida. JEA is proposing to convert two of the 173 MW Brandy Branch simple cycle units currently under construction into a combined cycle unit. This conversion will be accomplished by adding two heat recovery steam generators (HRSGs) and one steam turbine generator to be shared by the two HRSGs. The total capacity of the Brandy Branch Generating Station after the proposed conversion will be 692 MW.

<u>PREHEARING CONFERENCE</u>

A prehearing conference will be held at the following time and place:

January 22, 2001, 9:30 a.m.
Commission Hearing Room 152
Betty Easley Conference Center
4075 Esplanade Way
Tallahassee, Florida

The purpose of the prehearing conference will be to consider: (1) the simplification of the issues; (2) the identification of the positions of the parties on the issues; (3) the possibility of obtaining admissions of fact and of documents which will avoid unnecessary proof; (4) the identification of exhibits; (5) the establishment of an order of witnesses; and (6) such other matters as may aid in the disposition of the action.

<u>JURISDICTION</u>

Jurisdiction over this determination of need is vested in the Commission by Chapter 366 and Section 403.519, Florida Statutes. This proceeding will be governed by the provisions of Chapter 120, Florida Statutes, as well as Chapter 25-22 and Chapter 28-106, Florida Administrative Code.

<u>APPLICATION</u>

A copy of the Petition for Determination of Need and supporting exhibits is available for public inspection during normal business hours at the following location:

Florida Public Service Commission
Division of Records and Reporting
Room 110, Betty Easley Conference Center
4075 Esplanade Way
Tallahassee, Florida

By Direction of the Florida Public Service Commission this <u>10th day</u> of <u>December, 2000</u>.

BLANCA S. BAYO, Director
Division of Records and Reporting

GREAT SEAL OF THE STATE OF FLORIDA
IN GOD WE TRUST