ORIGINAL

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF TRUDY S. NOVAK

ON BEHALF OF SEMINOLE ELECTRIC COOPERATIVE, INC.

DOCKET NO. 981827-EC

June 26, 2000

Q. Please state your name and business address.

A. My name is Trudy S. Novak and my business address is 16313 North Dale Mabry Highway, Tampa, Florida 33618.

I. QUALIFICATIONS

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

A. I am the Director of Pricing and Bulk Power Contracts at Seminole Electric Cooperative, Inc. ("Seminole").

Q. Please describe your background and experience.

A. I received a Bachelor of Science degree with honors in General Business and Management from the University of Maryland in 1978 and became a Certified Public Accountant in the State of Maryland in 1980. I came to Seminole in May 1982 as a Rate Analyst II. In February 1984, I was promoted to a Senior Rate Analyst. I have held several supervisory roles in the rates and power contracts area since June 1986, and I have been Director of Pricing and Bulk Power Contracts since January 2000.

Q. What are your current responsibilities?

A. The responsibilities of my present position include: coordination and direction of departmental activities in the areas of development, design and administration of Seminole's wholesale rates for sales of electricity; departmental responsibility for the negotiation and administration of Seminole's purchased power, transmission, and interconnection arrangements with other utilities; and evaluation of Federal Energy Regulatory Commission ("FERC") wholesale rate case filings by Seminole's power suppliers in the areas of cost-of-service and rate design and the provision of technical support during negotiations and/or hearings.

Q. Have you previously testified on behalf of Seminole before regulatory agencies?

A. Yes. I have provided written testimony and testified on behalf of Seminole in cases before the Federal Energy Regulatory Commission ("FERC").

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purposes of my testimony are as follows:

1. Describe the basic rate design structure for the Seminole wholesale rate schedule at issue in this case (i.e., Rate Schedule SECI-7b);
2. Describe the major differences between the rate structure of Rate Schedule SECI-7b and the rate structure of the rate schedule in effect

prior to 1999 (i.e., Rate Schedule SECI-6b);

3. Describe how Seminole's new rate schedule promotes efficient use of utility services;

4. Describe that the Production Fixed Energy Charge and its allocation to the Members based upon three-year rolling average historical energy usage are consistent with the fair cost-apportionment standard, as advocated by Dr. Blake;

5. Explain that Seminole does in fact prepare an annual cost-of-service study to analyze its rates; and

6. Describe and provide the specific revenue requirements calculation and cost-of-service study which were prepared to support the rates currently in effect under Rate Schedule SECI-7b.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I have prepared and attached to my testimony Exhibit __ (TSN-1) through Exhibit __ (TSN-8).

III. BASIC RATE DESIGN FOR SEMINOLE'S WHOLESALE RATE SCHEDULE AT ISSUE IN THIS CASE.

Q. Which rate schedule is at issue in this case?

A. Under the Wholesale Power Contract with its Member cooperatives, Seminole has three rate schedules available for the Member's full demand and energy requirements. The three rate schedules currently in effect are Rate Schedule

SECI-7b, Rate Schedule INT-1, and Rate Schedule INT-2. Rate Schedules INT-1 and INT-2 are available for the interruptible electric service from Seminole to its Members. Rate Schedule SECI-7b is applicable to serve the total firm demand and energy requirements at a Member cooperative delivery point less, if applicable, any sales made to the Member under the preexisting Southeastern Power Administration ("SEPA") contract. Mr. Woodbury in his testimony explains that although Lee County Electric Cooperative, Inc.'s ("LCEC") original complaint related to Seminole's Rate Schedule SECI-7, which was in effect during the period January 1, 1999 through December 31, 1999, the wholesale rate schedule currently in effect for Seminole's firm sales to its Members is Rate Schedule SECI-7b, which was approved by Seminole's Board of Trustees on November 3, 1999, and went into effect January 1, 2000. It is Rate Schedule SECI-7b that is at issue in this case (see Exhibit __ (TSN-1)).

Q. **Please describe the basic rate design structure reflected in Seminole's currently effective Rate Schedule SECI-7b.**

A. Seminole's Rate Schedule SECI-7b applies to each Seminole Member and all Member delivery points. Service for each delivery point under this rate schedule is the total demand and energy requirements of the delivery point, less, if applicable, the interruptible sales made to the Member under Seminole's separate interruptible rate schedules and/or the Member's purchases from SEPA. Under Rate Schedule SECI-7b, Seminole bills each Member monthly based upon the estimated billing determinants for the preceding month. The invoices are later trued up (with interest) to actual when the actual billing determinants become available. The monthly charges to the Members are equal to the sum of the Base Charges, Power Factor Penalties and Transmission Facilities Use Charges. The Power Factor Penalties, which are simply a pass through of power factor penalties from third party providers, and the Transmission Facilities Use Charges, which recover those transmission-related costs for facilities that are owned by Seminole and are provided for the exclusive use and benefit of a single Member, are not at issue in this case (see pages 2, 7, and 8 of Exhibit __ (TSN-1)).

Q. **Please describe the components of the monthly Base Charges that are at issue in this case.**

A. The monthly Base Charges under Rate Schedule SECI-7b are equal to the sum of the Fixed Charges, Non-Fuel Energy Charges, and Fuel Charges.

Q. **Describe the components of Seminole's Fixed Charges under SECI-7b.**

A. Seminole's fixed costs have been unbundled, resulting in separate charges for production and transmission related costs under Seminole's Rate Schedule SECI-7b. Based upon my review of the testimony filed by LCEC's witnesses, the fact that Seminole has unbundled its production and transmission related charges is not at issue in this case.

Q. **Please describe the Production Charges under Seminole's Rate Schedule SECI-7b.**

A. Seminole's production-related costs are recovered under a Production Demand Charge and a Production Fixed Energy Charge. The Production Demand Charge, which is \$8.50/kW/month, is applied to the aggregated Member demands at the time of Seminole's monthly system peak ("Seminole Monthly Coincident Demands") and is applicable during the eight peak months of the calendar year (i.e., January through March, June through September, and December). The Production Fixed Energy Charge is a flat (i.e., levelized) monthly payment and is based upon a formula-type recovery mechanism. The Production Fixed Energy Charge is designed to recover the remaining production fixed costs projected for a calendar year that are not recovered under the Production Demand Charge (see pages 1 and 4 of Exhibit __ (TSN-1)). The Production Fixed Energy Charge is allocated to each Member based upon a rolling three year historical average of kWh sales to the Member.

Q. What was the basis for Seminole's decision to recover the production fixed costs in two separate rate components under Rate Schedule SECI-7b?

A. The separation of production fixed costs into a Production Demand Charge and a Production Fixed Energy Charge was developed to meet one of the goals in Seminole's 1997 Strategic Plan to "establish a wholesale rate structure which provides an appropriate price signal that is more reflective of the incremental costs of new capacity." The \$8.50 per kW per month Production Demand Charge was originally developed as the first step in a three-year transition to meet this goal. Mr. Woodbury discusses in his testimony the details of the development of Seminole's 1997 Strategic Plan. I will discuss later in my testimony why the Production Demand Charge under Rate Schedule SECI-7b, reasonably reflects Seminole's incremental cost of capacity; and is therefore consistent with the rate structure goal of the 1997 Strategic Plan. In addition, later in my testimony (see Section VI, below), I will also discuss the reasons for Seminole collecting the remaining production fixed costs that are in excess of the revenues recovered under the Production Demand Charge through the Production Fixed Energy Charge. As I read LCEC's testimony, the only aspect of Seminole's rate structure that is at issue is the collection of less than all of the production fixed costs in the Production Demand Charge. Stated another way, LCEC protests the collection of production fixed costs through any rate component that is not based upon kW peak demands.

Q. Please describe the Transmission Charges under Seminole's Rate Schedule SECI-7b.

A. Seminole's transmission-related costs are recovered through Transmission Charges which are equal to the sum of the Transmission Demand Charge and a Distribution Demand Surcharge. Both the Transmission Demand Charge, which is currently $1.59/kW/month, and the Distribution Demand Surcharge, which is $1.27/kW/month, are applied to the Seminole Monthly Coincident Demands for each month of the year. The Distribution Demand Surcharge is applied only to those Member delivery points receiving service at less than 69 kV (see page 1 of Exhibit __ (TSN-1)). Based upon my review of LCEC's testimony, Seminole's Transmission Charges are not at issue in this case.

Q. Please describe the Non-Fuel Energy Charge and Fuel Charge under Seminole's Rate Schedule SECI-7b.

A. The Non-Fuel Energy Charge is designed to recover Seminole's non-fuel variable production costs which are budgeted for the calendar test year. The currently effective Non-Fuel Energy Charge under Rate Schedule SECI-7b is $0.00263/kWh (see page 2 of Exhibit __ (TSN-1)). Seminole's Fuel Charge has two components. The first is a base fuel rate based upon the projected total calendar year fuel costs associated with Seminole's owned and/or leased generation plus the fuel costs associated with purchased power. The currently effective base fuel rate is $0.01961/kWh (see page 9 of Exhibit __ (TSN-1)). In addition to the base fuel rate, Seminole maintains an accumulated balance of the differences between the base fuel rate and the actual fuel rate for each month for each Member system. This accumulated balance is maintained over a six-month period, with interest, and either paid back or charged to the Member over the last four months of the next six-month period (see pages 5 and 6 of Exhibit __ (TSN-1)). Based upon my review of LCEC's testimony, the Non-Fuel Energy Charge and Fuel Charge are not at issue in this case.

IV. BASIC RATE DESIGN FOR SEMINOLE'S WHOLESALE RATE SCHEDULE IN EFFECT PRIOR TO 1999

Q. What Seminole rate schedule was in effect under the Wholesale Power Contract prior to 1999?

A. The Seminole wholesale rate schedule in effect under the Wholesale Power

Contract prior to 1999 was Rate Schedule SECI-6b (see Exhibit __ (TSN-2)). This rate schedule was in effect from September 1, 1994, through December 31, 1998. It is important to note that although Rate Schedule SECI-6b went into effect on September 1, 1994, Rate Schedule SECI-6b contained the same charges as Rate Schedule SECI-6, which went into effect January 1, 1989.

Q. Please describe the major differences between Rate Schedule SECI-6b and Rate Schedule SECI-7b.

A. There are seven major differences between Rate Schedule SECI-6b and Rate Schedule SECI-7b. Under Rate Schedule SECI-7b, Seminole has 1) revised the voltage differentials, 2) unbundled production and transmission rates, 3) revised the timing of the billing demand, 4) developed separate non-fuel and fuel energy charges, 5) eliminated the Station Charge, 6) implemented a seasonal Production Demand Charge, and 7) reduced the monthly demand rates to reasonably reflect incremental costs and established a new rate component for collection of excess production fixed costs (i.e., the Production Fixed Energy Charge).

Q. Please describe the revisions to the voltage differentials under the new rate schedule.

A. Rate Schedule SECI-6b contained Demand Charges by voltage (i.e., below 69 kV, 69 kV, 115/138 kV and 230/240 kV) (see page 2 of Exhibit __ (TSN-2)), whereas Rate Schedule SECI-7b contains Transmission Demand Charges for only two voltages (i.e., below 69 kV and 69 kV and above). This revision to Seminole's rate schedule, which was made to reflect the actual costs incurred for delivery voltage differentials, is not at issue in this case.

Q. What does it mean to unbundle production and transmission rates.

A. Under Rate Schedule SECI-6b, the production and transmission related costs were combined and collected under the Demand Charges and Energy Charges (see page 2 of Exhibit __ (TSN-2)), whereas under Rate Schedule SECI-7b, Seminole has unbundled its production and transmission charges (see Section III of my testimony above). This revision to Seminole's rate schedule is not at issue in this case.

Q. Please describe the change made under Rate Schedule SECI-7b to the timing of the billing demand.

A. Under Rate Schedule SECI-6b, the demand charges were applied to the monthly kW demands by transmission supplier area ("Supplier Area Billing"). For those Member delivery points located in the Florida Power & Light Company ("FPL") control area, the monthly billing demand was equal to the kW demands at the time of the Member's aggregate peak load in the FPL area, which was also the time of Seminole's billing demand for its partial requirements purchases from FPL. For the remaining loads, the monthly billing demand was equal to the Member's kW demands at the time of Florida Power Corporation's ("FPC") system peak, which is also the time of Seminole's billing demand for its partial requirements purchases from FPC. LCEC's loads are located in the FPL control area, and therefore the monthly billing demands for LCEC under Rate Schedule SECI-6b were equal to LCEC's metered kW load at its delivery points at the time of the monthly aggregate peak demand for all Seminole Member delivery points in the FPL control area. The result of Supplier Area Billing was that the rate schedule provided each Member with the appropriate signal to control its peak demand when such control reduced Seminole's costs. As discussed in Section III of my testimony, under Rate Schedule SECI-7b, the timing of the billing demand was revised to Seminole Monthly Coincident Demands. This revision from Supplier Area Billing to Seminole Monthly Coincident Demands came about as a result of the termination of the partial requirements agreement with FPL effective January 1, 1999. With the termination of the FPL agreement, Seminole no longer had a cost justification to control the Members' load in the FPL area at the time of the FPL area aggregate peak. The elimination of Supplier Area Billing in Seminole's new rate schedule, which benefits LCEC, is not at issue in this case.

Q. **Please describe the changes made to the Energy Charges under the new rate schedule.**

A. Under Rate Schedule SECI-6b, Seminole's Energy Charge was equal to a non-fuel energy charge (which when the rates were designed in 1988, contained 15% of fixed costs and 100% of the non-fuel energy costs) plus a base fuel charge of $0.02443 per kWh. Rate Schedule SECI-6b also provided for a fuel adjustment mechanism to either pay back or charge the Members the differences between actual and estimated fuel costs every six months. As discussed in Section III, above, under Rate Schedule SECI-7b there is a separate Non-Fuel Energy Charge and Fuel Charge. Only variable related costs are included in the Non-

Fuel Energy Charge. The fuel adjustment mechanism in Rate Schedule SECI-6b and Rate Schedule SECI-7b are basically the same. LCEC does not quarrel with the Non-Fuel Energy Charge and the Fuel Charge under Rate Schedule SECI-7b.

Q. Please describe the elimination of the Station Charge under the new rate schedule.

A. Rate Schedule SECI-6b contained a Station Charge of $400 per delivery point per month primarily to recover metering costs. Effective in 1999, Seminole no longer separately compensates FPL for metering costs in the FPL area. Under Rate Schedule SECI-7b, the Station Charge was eliminated, and the metering costs that Seminole pays FPC are included in the fixed costs for rate design purposes. LCEC has not raised the elimination of the customer charge as an issue in this case.

Q. Please describe the seasonal feature of Rate Schedule SECI-7b.

A. Under Rate Schedule SECI-6b, Seminole collected a portion of its demand costs each month at a rate per kW per month. Under Rate Schedule SECI-7b, Seminole's Production Demand Charge is assessed only during the eight peak months (i.e., January through March, June through September, and December). In 1998 the average Demand Charge under Rate Schedule SECI-6b was $10.79 per kW per month during every month, whereas under Rate Schedule SECI-7b, with the seasonal Production Demand Charge, the average demand charge including transmission is budgeted to be $10.09 per kW per month during the eight peak months and $1.59 per kW per month during the off-peak months. The use of a seasonal demand rate was implemented to reflect that Seminole's needs for incremental capacity occur primarily during the winter and summer months. In addition, the elimination of the demand charge during the off-peak months met one of Seminole's goals in its rate structure strategic planning initiative to address the operational problems associated with the excessive Member load control required to chase the billing peak during an off-peak month. Based upon my reading of LCEC's testimony, the use of a seasonal rate is not an issue in this case.

Q. **Please describe the change in the manner in which Seminole collects fixed costs.**

A. Under Rate Schedule SECI-6b, all fixed costs were collected either in the Demand Charges or in the Energy Charges. The Demand and Energy Charges under Rate Schedule SECI-6b were identical to the charges contained in Rate Schedule SECI-6. When Rate Schedule SECI-6 was originally designed in 1988 for the 1989 test period, 85% of the budgeted fixed costs were included in the demand charge and 15% of the fixed costs were included in the Energy Charge. As discussed above in Section III of my testimony, Rate Schedule SECI-7b provides that all fixed production costs which are not collected in the Production Demand Charge of $8.50 per kW per month during the peak months, are recovered in a flat monthly payment (i.e., Production Fixed Energy Charge). Based upon the budgeted revenue requirement for 2000, which is the basis for Rate Schedule SECI-7b, it is projected that Seminole will recover approximately

81% of its total fixed costs in the Production Demand Charges and the Transmission Charges. It is the change in Seminole's methodology for collecting certain of the production fixed costs which is at issue in the case. I will discuss later in my testimony the specific reasons for Seminole's change in methodology for these costs.

Q. **Do you have a comparison of the average rates to each Member based upon revenues collected under Seminole's Rate Schedule SECI-6b and Rate Schedule SECI-7b?**

A. I do not have a comparison between Rate Schedules SECI-6b and SECI-7b; however, I do have a comparison, assuming a preliminary projected 1999 revenue requirement, between the rates which would have been developed based upon the rate structure underlying Rate Schedule SECI-6b (i.e., 85% of the fixed costs in the demand charges and the remaining fixed costs included in the energy charge) and the rate structure underlying Rate Schedule SECI-7 (i.e., $8.50 per kW per month Production Demand Charge and the remaining fixed costs collected through a Production Fixed Energy Charge). This comparison, a copy of which is provided in my Exhibit __ (TSN-3), was presented at the May 13, 1998 Rate Committee meeting. This was the meeting at which the Rate Committee approved the rate structure that was later reflected in Rate Schedule SECI-7. The rate design methodology (including the Production Demand Charge of $8.50 per kW per month) underlying Rate Schedules SECI-7 and SECI-7b is the same except that Rate Schedule SECI-7 was developed to recover a 1999 budgeted revenue requirement, and Rate Schedule SECI-7b was designed to recover a 2000 budgeted revenue requirement. As shown in Exhibit __ (TSN-3), moving from the rate structure incorporated in Rate Schedule SECI-6b to the current rate structure incorporated in Rate Schedule SECI-7b did not harm LCEC. In fact, LCEC was slightly benefitted by the new rate design, as average rates for 1999 were lower under Rate Schedule SECI-7 by 0.07 mills per kWh as compared to the average rates for LCEC under the rate structure underlying Rate Schedule SECI-6b. This represents a 0.15% reduction in the average rate for LCEC.

Q. Your Exhibit __ (TSN-3) shows that LCEC is actually benefitted by the *new rate structure. Do you wish to comment further?*

A. Yes. Seminole has made several changes in the rate design supporting Rate Schedule SECI-7b. As discussed in this section of my testimony, LCEC has not contested any of the revisions to the rate design with the exception of the allocation methodology for a portion of Seminole's fixed production costs. LCEC has chosen to simply cherry pick the one aspect of the rate design that it is unhappy with and then claim it to be a radical departure from previous rate structures.

V. SEMINOLE'S RATE SCHEDULE SECI-7B PROMOTES EFFICIENT USE OF UTILITY SERVICES

Q. Dr. Blake, on page 19 of his testimony, claims that Seminole's Rate Schedule SECI-7b is fundamentally flawed for three primary reasons: 1) it

is inconsistent with the fair cost-apportionment standard, 2) it fails to promote the efficient use of utility services, and 3) it is not supported by a valid cost-of-service analysis. Do you agree with Dr. Blake's claims relative to Seminole's rate structure?

A. No. In later sections of my testimony I will describe why I believe Dr. Blake is incorrect when he states that Seminole's rate structure is inconsistent with the fair cost-apportionment standard, and is not supported by a valid cost-of-service study. In this section, I will describe why Dr. Blake is incorrect when he states that Seminole fails to promote the efficient use of utility services.

Q. **Please describe why, in your opinion, Dr. Blake is incorrect when he states that Seminole fails to promote the efficient use of utility services.**

A. The basic reason that Dr. Blake is incorrect on this point is that Seminole has implemented its strategic planning initiative to provide a price signal in its rate schedule that reasonably reflects Seminole's incremental cost of new capacity. As I discuss further in my testimony, when the Production Demand Charge is reflective of the incremental cost of capacity, the Members are given the proper price signal regarding the costs and benefits associated with reductions or increases in the Member's monthly peak demands. Dr. Blake also claims that the new rate structure, which allocates a portion of Seminole's fixed production costs based upon energy, does not promote the efficient utilization of electric service by penalizing off-peak usage. In Section VI of my testimony, I will address this comment when I discuss the basis for Seminole's implementation of the Production Fixed Energy Charge.

Q. Please describe the basis for your claim that Seminole's current Production Demand Charge under Rate Schedule SECI-7b reasonably reflects the incremental cost of new capacity.

A. Seminole's current Production Demand Charge of $8.50 per kW per month over an eight month period is budgeted to collect on average $6.13 per kW per month during the calendar year 2000 (see Exhibit __ (TSN-4)). This rate is not only higher than the cost of new peaking generation, but is also basically the same as the first year's cost of Seminole's new combined cycle generating facility ("Payne Creek Generating Station"), which is expected to go into commercial operation in 2002.

Q. What is the incremental cost of Seminole's new capacity?

A. Seminole currently estimates the total fixed costs of the new Payne Creek facility in the first year of commercial operation will be $4.78 per kW per month of installed capacity expressed in 2000 dollars on a twelve month basis. Exhibit __ (TSN-5) shows how this rate is converted to a rate per kW per month based upon a 12-month and eight-month billing basis. As shown on Exhibit __ (TSN-5), the fixed costs of the new Payne Creek facility for the first year of commercial operation will be $6.13 per kW per month expressed in 2000 dollars on a 12-month billing basis and $8.49 per kW per month expressed on an eight-month billing basis. In addition, the current price of a new combustion turbine in the first year of operation is $3.53 per kW of installed capacity per month and $6.27 per kW per month expressed on an eight-month billing basis (see Exhibit __

(TSN-6). I note that the fixed costs per kW per month will be the highest in the first year of commercial operation. Each year thereafter the rate will decline as the interest expense associated with the capital investment declines each year in Seminole's revenue requirement.

Q. Do you have other information that supports Seminole's claim that the Production Demand Charge reasonably reflects the incremental cost of capacity to Seminole?

A. Yes. When Seminole's Members in the FPC control area reduce monthly peak demands, Seminole will incur an immediate reduction in purchased power costs for that month. Given the stratified pricing mechanism for partial requirements purchases from FPC, the incremental cost of capacity in the FPC area is the peaking demand rate of $4.94 per kW per month. In addition, the demand rates reflected in the purchased power agreements that were recently entered into for peaking capacity beginning in the 2002-2003 time frame, which total more than 900 MW of additional capacity by May 2003, are in the range of $4.00 per kW per month for year round capacity, or $7.10 per kW per month on an eight month billing basis.

Q. Now that you have shown that Seminole's Production Demand Charge reasonably reflects Seminole's incremental cost of new capacity, please describe why Dr. Blake incorrectly concludes that Seminole's use of the $8.50 per kW per month Production Demand Charge fails to promote the efficient use of utility services.

A. Dr. Blake claims that Seminole's reduced Production Demand Charge, among other things, reduces the value of LCEC's investment in load management equipment (pages 26-27), fails to promote the efficient investments in new load management equipment (pages 27-29), reduces the value of the Members' on-site generation (pages 30-32), and reinforces Seminole's need for new generation facilities (page 31). Dr. Blake is correct that when compared to Seminole's previous rate schedule, the incentive for LCEC to invest in load management or on-site generation has been reduced. The important question is not whether the incentive has been reduced from the previous levels, but rather whether the incentive under the new rate is based upon costs and therefore cost effective, consistent with the Florida Public Service Commission's Load Management Standard which Dr. Blake himself quotes:

> Load Management Standard - Each utility shall offer such load management tariffs <u>as the state regulatory authority has determined will be cost effective</u> and will likely to reduce the utility's peak kilowatt demand.
>
> (See page 32 of Dr. Blake's testimony, emphasis added).

Seminole's Production Demand Charge provides the correct current pricing signal to the Members when making <u>cost effective</u> decisions to invest in load management or on-site generators. If Seminole's previous demand rates were to stay in place, this would provide the Members incorrect price signals to invest in non-economical/non-cost effective programs. The previous production demand rates at an average of more than \$9.00 per kW per month (the \$10.89 bundled average demand rate minus the Transmission Demand Charge of \$1.59 per kW per month) are clearly higher than Seminole's incremental cost of peaking capacity, which is the capacity that would be avoided by load management. If Seminole can build new peaking capacity for an all in cost of $3.53 per kW per month in its first year of operation ($6.27 per kW per month on an eight-month billing basis), or enter into purchased power agreements for peaking capacity in the range of $4.00 per kW per month, why should the Members receive a $10.59 per kW per month price signal for load management reductions? (The $10.59 rate is the Production Demand Charge proposed by Mr. Seelye on an eight month basis based upon Seminole's 2001 preliminary revenue requirement.)

VI. THE PRODUCTION FIXED ENERGY CHARGE AND ITS ALLOCATION TO THE MEMBERS BASED UPON THREE YEAR ROLLING AVERAGE HISTORICAL ENERGY IS CONSISTENT WITH THE FAIR COST-APPORTIONMENT STANDARD

Q. Dr. Blake claims that Seminole's use of a Production Fixed Energy Charge is inconsistent with the fair cost-apportionment standard for rate design. Please provide the basis for the development of the Production Fixed Energy Charge.

A. Once the Production Demand Charge was developed to more closely reflect the incremental cost of capacity, it became necessary to develop a methodology for collecting Seminole's remaining fixed costs. The first decision that was made was to recommend to the Board of Trustees that the collection of these excess costs be collected as a flat monthly payment rather than through a charge applied to a billing determinant. Seminole considered these costs to be representative of the base load costs associated with its Palatka coal units, which are non-avoidable (sunk) costs. The fixed costs associated with Seminole's coal units are unaffected by increases or decreases in Seminole's kW or kWh billing determinants.

Q. What are the total dollars that Seminole will collect in 2000 under the Production Fixed Energy Charge?

A. As shown on Second Revised Sheet No. 7 of Rate Schedule SECI-7b (see page 9 of Exhibit __ TSN-1), Seminole will recover $4,521,507 per month under the Production Fixed Energy Charge. On a twelve month basis, Seminole will recover $54,258,084.

Q. What portion of Seminole's fixed costs are made up of the cost associated with Seminole's base load generation?

A. The fixed costs associated with Seminole's base load generation included in the 2000 budget are estimated to be $112,102,090 or 40% of Seminole's total fixed costs, including transmission.

Q. Once Seminole had determined that it was preferable to recover the base load costs in a monthly flat payment, why did Seminole propose that the monthly payment be allocated based upon energy rather than demand?

A. Seminole considered and rejected using any demand based allocation, as it would send an improper price signal and defeat the strategic goal of pricing demand based upon the incremental cost of capacity. Further we felt that an energy allocator was appropriate for the reasons described below.

Q. Please describe the reasons Seminole believed an energy allocator was appropriate for allocating a portion of its base load costs.

A. The variable cost of Seminole's coal fired units is the lowest of all of Seminole's power supply resources. Therefore, the Seminole coal units when available are always the first units to be dispatched. Seminole's decision to build the coal units was based on the energy requirements of its Member systems, while the peak demand requirements of the Members are currently supplied by peaking and intermediate purchases. Given that the coal units were built to serve the energy requirements of our Members rather than their peak demand requirements, it seemed reasonable to allocate at least some portion of these costs on an energy basis.

Q. Do you know whether this Commission has ever approved the allocation of a portion of fixed costs based upon energy rather than demand?

A. Yes. It is my understanding that this Commission has accepted the practice of allocating a portion of fixed costs on an energy basis for purposes of allocating costs among classes of retail customers. In fact, in the 1983 FPC retail case which Dr. Blake refers to on page 25 of his testimony, the Commission accepted FPC's position that the demand allocation methodology should be based upon a combination of average demand (which is the same as an energy allocator) and coincident peak demand. In addition, it is my understanding that the energy rates provided in FPC's current large demand general service retail rate schedule contain a significant portion, if not all, of the production fixed costs allocated to that class.

Q. **Do you have any other reasons to believe that the use of an energy allocation methodology for base load related costs is reasonable?**

A. Yes. The independent cost-of-service study prepared by Burns & McDonnell is consistent with the use of an energy allocator for Seminole's base load costs. Mr. Woodbury in his testimony discusses the details of why Seminole retained Burns & McDonnell to perform this study, and Dave Christianson, of Burns & McDonnell, describes in more detail why in his opinion Seminole's rate design structure is fair, just and reasonable.

Q. **Why did Seminole adopt the use of a three year historical period for the energy allocator for the Production Fixed Energy Charge?**

A. Using a three year historical period was intended to provide a more stable and predictable allocator. One year's energy usage pattern may fluctuate from year to year and cause swings in the allocation. In addition to providing a degree of stability, a rolling three-year period permits the use of actual rather than projected or normalized data. It also captures any long term trends in energy use as it updates each year to the most recent three year period. In order to utilize actual data, Seminole needed to skip one year in developing the three year average. For example, when Seminole developed the rates to go into effect in

2000, Seminole did not have the actual data for the 1999 calendar year. Therefore, the three year average could only include data through 1998.

Q. On page 22 of Dr. Blake's testimony, he claims that by allocating a portion of fixed costs based upon energy, Seminole is penalizing the off-peak users of the system. He goes on to say on page 23 that Seminole does not incur additional fixed production costs as a result of kWh sales made during off-peak periods. Do you agree with Dr. Blake's assertions on these points?

A. No, I do not. Dr. Blake is incorrect when he states that generating capacity is not constructed to serve off peak kWh. As I stated earlier, base load generation, such as the Seminole coal units, is built to serve the energy requirements of our Members over all time periods. These costs cannot be avoided by changes in Seminole's monthly peak demands. It is important to note that Dr. Blake's recommendation to allocate 100% of the production fixed costs based upon coincident peak demands, combined with the fact that LCEC agrees with the utilization of a seasonal Production Demand Charge, would result in no recovery of the fixed costs associated with the Seminole coal units from those Members purchasing electricity during the four off-peak months. Seminole submits that it is LCEC's approach, and not Seminole's, which would be unfair, would ignore cost incurrence, would result in inefficient utilization of utility resources, and would be unduly discriminatory.

VII. SEMINOLE PREPARES A COST-OF-SERVICE STUDY EACH YEAR

Q. The third reason that Dr. Blake believes that Seminole's rate design is flawed is that the rates are not supported by a valid cost-of-service study. In addition, Mr. Seelye claims to his knowledge Seminole failed to prepare a cost-of-service study prior to implementing SECI-7. Did Seminole prepare a cost-of-service study prior to implementing Rate Schedule SECI-7?

A. Yes. Seminole prepares a cost-of-service study every year prior to developing the recommended rates for the next year. Seminole's cost-of-service studies may not be in the same format as the studies developed by Burns & McDonnell or the cost-of-service study sponsored by Mr. Seelye; however, Seminole does prepare a cost-of-service study every year by first developing a total company cost-of-service, which is simply the budgeted revenue requirement, and then assigning costs to the cost categories. For purposes of the 1999 cost-of-service analysis, Seminole assigned the total revenue requirements to the following cost categories: fixed production, non-fuel variable production, fuel, transmission, and distribution. The revenue requirements allocated to the fixed production category represent the dollars to be collected in the Production Demand Charge and the Production Fixed Energy Payment. The costs assigned to the non-fuel variable production cost category represent the dollars to be collected in the Non-Fuel Energy Charge. The costs included in the fuel cost category represent the dollars to be collected in Seminole's projected Fuel Rate. The costs assigned to the transmission and distribution cost categories are the basis for Seminole's Transmission Charges.

Q. **Should LCEC's witnesses be aware of the procedure Seminole follows for developing its rates by preparing its revenue requirements and assigning costs to cost categories, which is no different from the cost-of-service studies performed by Mr. Seelye and by Burns & McDonnell?**

A. Yes. With regard to Mr. Seelye, I am very surprised that he would claim that Seminole had not prepared a cost-of-service study given that on July 19, 1999, I, along with two other Seminole representatives, met with Mr. Seelye to provide an explanation of the revenue requirement and rate design process followed by Seminole in developing the rates for 1999. In addition, on that same day, a copy of Seminole's 1999 detailed revenue requirements and rate design workpapers, which represent Seminole's cost-of-service study, were mailed to Mr. Seelye via overnight delivery along with several other documents supporting Rate Schedule SECI-7. Although Seminole does not routinely provide the detailed rate design workpapers to the Members (unless requested), Seminole does prepare summary overheads of the assignment of costs, which are presented to the Rate Committee at the time the rates are being approved. I have attached as Exhibit ___ (TSN-7), a copy of the summary of the assignment of costs that was presented to the Rate Committee on October 7, 1998, when Rate Schedule SECI-7 was approved by the Rate Committee. It is simply incorrect to claim that Seminole has not supported its rates with a cost-of-service study.

Q. **Do you believe that LCEC is in agreement with Seminole's methodology for assigning costs to the cost categories?**

A. Yes. Although Mr. Seelye has sponsored a cost-of-service study based upon

Seminole's total revenue requirements for 2000, he did not utilize the cost-of-service study for purposes of developing his recommended rate design alternatives. In fact, Mr. Seelye instead utilized Seminole's preliminary 2001 cost-of-service study. Mr. Seelye's recommended unit charges for Transmission, Distribution, Fuel and Non-Fuel Energy charges are identical to Seminole's preliminary unit charges for 2001, which were provided to each Member manager on April 5, 2000, and discussed at the ensuing April 7 Rate Committee meeting.

VIII. SEMINOLE'S REVENUE REQUIREMENTS AND COST-OF-SERVICE STUDY SUPPORTING RATE SCHEDULE SECI-7B

Q. Please describe and provide the specific cost-of-service study which was utilized by Seminole to develop the charges contained in the current rate SECI-7b.

A. The process of defining the various charges of SECI-7b begins with the annual budget. Annually, Seminole develops a budget for its expected operations for the upcoming year. The projected operating costs developed from this process provide the basis for developing the upcoming year's charges to Seminole's Members.

Q. What are the budgeted costs for the year 2000?

A. Seminole's total revenue requirement for the year 2000 was expected to be $553,794,942. Based on the 2000 budget, this is the amount of revenue that

Seminole must collect from its Members to recover the expected costs of its operations and provide a margin that meets its Rural Utilities Service ("RUS") obligation to achieve a 1.05 TIER (Times Interest Earned Ratio) ratio.

Q. Please provide the specific assignment of the 2000 revenue requirement to the cost categories previously described.

A. Exhibit __ (TSN-8) summarizes the results of assigning the 2000 revenue requirement to the various cost components. A worksheet similar to this was prepared during the budgeting process as the basis for developing the rates contained in Rate Schedule SECI-7b.

Q. What is the fuel charge per kWh for the year 2000 under SECI-7b?

A. The fuel charge under SECI-7b is calculated in accordance with the formula specified in the rate schedule's Appendix B and results from dividing the projected fuel costs for the year by the sum of the projected energy billing determinants for all Members for the year. For 2000, this results in a fuel rate of $.01961 per kWh.

Q. What is the non-fuel energy charge per kWh for the year 2000 under SECI-7b?

A. The non-fuel energy charge of $.00263 per kWh under SECI-7b results from dividing the non-fuel energy costs by the projected Member billing determinants.

Q. What are the total fixed costs that are included in the Revenue

Requirement for the year 2000?

A. After isolating the energy costs for fuel and non-fuel, the remaining costs of the revenue requirement are classified as fixed costs and recovered through transmission and production charges under SECI-7b. The total fixed costs for the year 2000 are projected to be $282,624,948 (see Exhibit __ (TSN-8) page 1, line 28).

Q. **What are the Transmission Demand Charges for year 2000 under SECI-7b and how are they determined?**

A. Transmission Demand Charges under SECI-7b for the year 2000 are $1.59 per kW-month. This charge results from dividing the total revenue requirement for transmission facilities by the sum of the 12 monthly coincident demands of the Members for the year 2000 (see Exhibit __ (TSN-8), page 1, line 31).

Q. **What are the distribution charges for year 2000 under SECI-7b and how are they determined?**

A. SECI-7b includes a Distribution Demand Surcharge of $1.27 per kW-month that applies to load at delivery points that take service below 69 kV. This surcharge is based on the additional costs charged by FPC and FPL to provide distribution level service and results from dividing those costs by the Member monthly coincident demands for those delivery points below 69 kV.

Q. **What is the next step in Seminole's development of SECI-7b charges?**

A. The fixed costs related to the production function are determined by deducting the transmission and distribution revenue requirements from the total fixed cost revenue requirement (see Exhibit __ (TSN-8), page 1, line 33). The next step is to determine the portion of production fixed costs recovered under the $8.50 per kW per month Production Demand Charge applied to the eight peak months. Of the $235,449,365 identified as the revenue requirement related to production fixed costs, $181,191,279 is collected through the Production Demand Charge. The remaining $54,258,086 is allocated to each Member based upon the three year average historical energy and collected monthly through the Production Fixed Energy Charge.

Q. **Does that complete your testimony?**

A. Yes.

Exhibit ___ (TSN-1)
Witness: Novak
Docket No. 981827-EC

SCHEDULE C
TO WHOLESALE POWER CONTRACT

Wholesale Service Rate to Members
Rate Schedule - SECI-7b

I. AVAILABILITY

Available for electric service from the Seller to its Members.

II. APPLICABILITY

Wholesale service to Members for use, redistribution, and resale in accordance with the terms and conditions of the Wholesale Power Contract. This Rate Schedule shall apply to each Member. The Member's delivery points under this Rate Schedule are listed in Schedule B of the Wholesale Power Contract. The electric service at any such delivery point will be either the total requirements of the Member's electric system served from the delivery points under this Rate Schedule, or if applicable, partial requirements service which complements the Member's purchases of Interruptible Wholesale Service pursuant to the Seller's Rate Schedule INT under Schedule C of the Wholesale Power Contract and/or the Member's purchases from the Southeastern Power Administration.

III. CHARACTER OF SERVICE

The electric capacity and energy hereunder will be three-phase alternating current at a nominal frequency of sixty hertz.

IV. MONTHLY RATES AND CHARGES

The monthly charges to the Members shall be equal to the sum of the Base Charges, Power Factor Penalties and Transmission Facilities Use Charges.

(A) BASE CHARGES - Base Charges shall be equal to the sum of the Fixed Charges, the Non-Fuel Energy Charge, and the Fuel Charge.

FIXED CHARGES - Fixed Charges shall be equal to the sum of Production Charges and Transmission Charges.

Production - Production Charges shall be equal to the sum of the Production Demand Charge and the Production Fixed Energy Charge.

(1) Production Demand Charge (Applicable only during the months of January, February, March, June, July, August, September, and December) - $8.50 per kW

(2) Production Fixed Energy Charge shall be allocated to Members on an energy basis and calculated in accordance with the formula specified in Seller's Production Fixed Energy Charge Recovery Clause which is incorporated as part of this Rate Schedule as Appendix A.

Transmission - Transmission Charges which shall be applicable during all months, shall be equal to the sum of the Transmission Demand Charge and the Distribution Demand Surcharge.

(1) Transmission Demand Charge (applicable to all delivery points) - $1.59 per kW

(2) Distribution Demand Surcharge (applicable to delivery points below 69 kV) - $1.27 per kW

Issued by: Richard J. Midulla
Executive Vice President
and General Manager

Effective: January 1, 2000

NON-FUEL ENERGY CHARGE - $.00263 per kWh

FUEL CHARGE

The Fuel Charge shall be calculated in accordance with the formula specified in Seller's Fuel Charge Recovery Clause which is incorporated as a part of this Rate Schedule as Appendix B.

BILLING DETERMINANTS

(1) Monthly Billing Demand Determinants:

The Monthly Billing Demand Determinants is the Member's Aggregate Hourly Demand at the time of the Seller's peak demand during the calendar billing month, expressed in kW and rounded to the nearest kW. The Aggregate Hourly Demand for each clock hour of the calendar billing month is determined by the summation of the 60-minute kW demands, corresponding to each such clock hour, metered at each of the Member's delivery points. The Aggregate Hourly Demand for each clock hour shall, where applicable, be reduced by the amount of Southeastern Power Administration capacity, and/or the amount of Interruptible Wholesale Service under the Seller's Rate Schedule INT delivered to certain specified delivery points in each such clock hour during the calendar billing month.

(2) Monthly Energy Determinants:

The Monthly Energy Determinants, expressed in kWh and rounded to the nearest kWh, is determined by the summation of the energy associated with each hour's Aggregate Hourly Demand for all hours during the calendar billing month.

(3) Estimated Billing Determinants:

To the extent that any of the metering information required to determine the Monthly Billing Demand and Monthly Energy supplied during the billing month is not available at the time of billing, bills will be rendered using estimates of said billing determinants with such estimates being based upon all known pertinent facts. Differences between billings based on actual and estimated billing determinants shall be subsequently trued up, with interest accrued at the Seller's short term investment or cost of funds rate, whichever is applicable.

(B) POWER FACTOR

Power factor penalties incurred by the Seller under its contracts with other utilities as a result of a Member delivery point's failing to maintain a power factor at or above the applicable contractually required level, shall be billed to the Member receiving service at the delivery point on a direct pass-through basis as part of the bill for electric service provided hereunder. Seller shall be obligated to keep the Members apprised of the applicable contractual requirements which could affect power factor billings hereunder.

(C) TRANSMISSION FACILITIES USE CHARGE

A Transmission Facilities Use Charge as provided for in Seller's Transmission Policy No. 303 and Seller's Rate Policy No. 304 shall, if applicable be billed to the Member each month. In accordance with the terms and conditions described in said policies the charge shall be calculated in the manner prescribed in Appendix C which is incorporated as part of this Rate Schedule.

V. METERED READINGS AND BILLINGS

(A) PAYMENT OF BILLS

Bills for electric power and energy and for transmission facilities use services furnished hereunder shall be paid for at the office of the Seller within fifteen (15) days after the bill therefore is mailed to the Member. Bills not paid within such fifteen-day period shall be deemed delinquent and shall accrue interest at the Seller's monthly line of credit rate. The Board of Trustees of the Seller may, from time to time, establish terms and conditions under which (1) either Seller or Member makes payments of amounts owed hereunder in advance of the performance date provided for herein or (2) Seller offers the Member a premium on any billing credits owed hereunder from the Seller to the Member in consideration of such credits being applied by the Seller to billings subsequent to those provided for above. Said terms and conditions shall be specified in writing and provided to each of the Members of the Seller.

(B) METER READING AND TESTING

The Seller shall read meters monthly, or cause meters to be read monthly. In cases whereby the meter installation is made at a voltage different from the delivery point voltage designated in Schedule B of the Wholesale Power Contract, compensating devices, which automatically adjust meter readings to account for losses, shall be installed. The Seller shall test and calibrate meters, or shall cause such meters to be tested and calibrated, by comparison with accurate standards at intervals of twelve (12) months. The Seller shall also make or cause to be made special meter tests at any time at the Member's request. The costs of all tests shall be borne by the Seller; provided, however, that if any special meter test made at the Member's request shall disclose that the meters are recording accurately, the Member shall reimburse the Seller for the cost of such test. Meters registering not more than two percent (2%) above or below normal shall be deemed to be accurate. The readings of any meter which shall have been disclosed by test to be inaccurate shall be corrected for the thirty (30) days previous to such test in accordance with the percentage of inaccuracy found by such test. If any meter shall fail to register for any period, the Member and the Seller shall agree as to the amount of power and energy furnished during such period and the Seller shall render a bill therefore.

VI. TERMS AND CONDITIONS

Service hereunder is subject to all of the provisions of the Wholesale Power Contract between Seller and its Members, including all schedules, amendments, and supplemental agreements thereto in effect from time to time.

VII. SPECIAL PROVISIONS

In the event that the Member purchases power from a cogenerator or a small power producer (Qualifying Facility), the Seller may reallocate to the Member any costs that have not been avoided as a result of the Member's purchases from the Qualifying Facility. The criteria that a small power producer or a cogenerator must meet to achieve the status of a Qualifying Facility is defined by Section 201 of the Public Utility Regulatory Policies Act of 1978 and regulations adopted thereunder.

RATE SCHEDULE C

APPENDIX A

Production Fixed Energy Charge Recovery Clause

The monthly Production Fixed Energy Charge shall be rounded to the nearest whole dollar and determined by use of the following formula:

PFE = ((PFC-PBR) X MEMALLOC) ÷ 12

where:

PFE = Member's monthly Production Fixed Energy Charge

PFC = Seller's production fixed costs projected for the applicable calendar year comprised of the following costs:

(i) Seller's total revenue requirements; less

(ii) Seller's transmission revenue requirements; less

(iii) Seller's Fuel costs; less

(iv) Seller's Non-fuel Energy costs.

PBR = Seller's Production Demand Charge revenues collected under this Rate Schedule projected for the applicable calendar year.

MEMALLOC = Portion of Production Fixed Energy Charge allocated to each Member based upon the Members' percentage share of actual Energy Determinants for the three calendar years ending with the year prior to the preceding calendar year. For example, for the year 1999 each Member's share of the total Production Fixed Energy Charge shall be based upon the total Energy Determinants for the years 1995 through 1997.

Appendix D, which is incorporated as part of this Rate Schedule, shall specify the Production Fixed Energy Charge in effect for the current calendar year.

RATE SCHEDULE C

APPENDIX B

Fuel Charge Recovery Clause

The Fuel Charge shall be equal to the Fuel Rate applied to the Monthly Energy Determinants (kWh), plus the Monthly Trueup, if applicable.

FUEL RATE The Fuel Rate shall be determined by the use of the following formula:

$$FR = \frac{F_m}{S_m}$$

where:

FR = Applicable Fuel Rate rounded to the nearest one thousandth of a cent.

F_m = Shall be comprised of the following costs projected for the applicable calendar year.

(i) Fossil and nuclear fuel consumed in Seller-owned plants and the Seller share of fossil and nuclear fuel consumed in jointly-owned or leased plants; plus

(ii) fossil and nuclear fuel costs associated with replacement power, reserve purchases and load following, exclusive of capacity or demand charges (irrespective of the designation assigned to such transactions); plus

(iii) the net energy cost of economy energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transactions); plus

(iv) allowable fuel and/or purchased economic power costs associated with Seller's purchases of full and partial requirements wholesale power; plus

(v) gains, losses, and associated costs related to fuel price hedging transactions; plus

(vi) the avoided energy payments to Qualifying Facilities; less

(vii) the cost of fossil and nuclear fuel recovered through inter-system sales.

S_m = Sum of the Projected Energy Determinants for all Members for the applicable calendar year.

Appendix D, which is incorporated as part of this Rate Schedule, shall specify the projected Fuel Rate in effect for the current calendar year.

MONTHLY TRUEUP In addition, each Member shall be charged or credited a Monthly Fuel Trueup during the last four months of each subsequent six-month period by a dollar amount equal to the sum of the following:

(A) The dollar amount equal to the difference between the Fuel Charges based on actual fuel costs during the preceding six-month period and the Fuel Charges collected based upon projected fuel costs during the same preceding six-month period.

(B) Interest compounded monthly on the amount computed each month pursuant to Item A above, up to the end of such six-month period, at the Seller's short term investment or cost of funds rate, whichever is applicable, and

(C) Interest compounded monthly for the two months following such six-month period on the total amount included in Items A and B above at the Seller's short term investment or cost of funds rate, whichever is applicable, for the month succeeding the end of the six-month period.

The distribution of the dollar amounts as determined by the sum of paragraphs A, B and C above shall be billed or credited in equal amounts on billings for the last four months of each six-month period.

Issued by: Richard J. Midulla
Executive Vice President
and General Manager

Effective: January 1, 2000

RATE SCHEDULE C

APPENDIX C

Components of
Transmission Facilities Use Charge

The Seller's Transmission Policy No. 303 and Rate Policy No. 304 specify that the costs for transmission facilities owned by the Seller and provided for the exclusive use and benefit of a single Member shall be borne by that Member. Costs of operation and maintenance are to be borne directly by the Member, whereas costs of ownership will be recovered by Seller from the benefiting Member through a Transmission Facilities Use Charge. Outlined below are those components of the Transmission Facilities Use Charge and how they are to be computed.

DEPRECIATION

For facilities constructed by Seller, depreciation will be calculated monthly based on original installed cost (including cost of capitalized renewals and replacements) of depreciable property relating to the transmission facilities used exclusively by a Member system and the depreciation rate prescribed in REA Bulletin 183-1, or revisions thereto. The date at which depreciation cost commences will be the date that the transmission facility is placed in service for its intended use by Seller for the benefiting Member, regardless of the date of closing of the construction work order.

For facilities purchased from a Member by Seller to be used exclusively by that Member, depreciation will commence as of the effective date of the transfer thereof and calculated according to the method previously described.

PROPERTY TAXES

For facilities constructed by Seller, for the exclusive use of a Member, property tax costs will be included in the Transmission Facilities Use Charge at such time that the facility qualifies as taxable property and becomes taxable to Seller. The cost will be based on the ratio of the net book value of taxable property comprising the transmission facility used exclusively by the benefiting Member to the total net book value of all taxable property owned by Seller in the county in which the facility is located, as of January 1 of each year. This ratio will be applied to the estimated tax bill for the county in which the facility is located as the basis for determining the estimated monthly charge. When the actual tax bill is received, appropriate adjustments will be made.

For facilities purchased from a Member by Seller for exclusive use by that Member, property taxes will be prorated as of the effective date of transfer. Taxes associated with the facility will be based on the ratio of the net book value of taxable property comprising the facility to the total net book value of taxable property owned by the Member in the county in which the facility is located. The taxes will be calculated by the method described for Seller-built facilities.

PROPERTY INSURANCE

Seller will carry property insurance for transmission facilities in accordance with its standard insurance purchasing practices. For built facilities, the cost will be based on the ratio of insured value of the facility to the total insured value of all property covered in the policy. This ratio will be applied to the total premium for the policy to determine the cost applicable to the facility; however, if the premium for the facility is specifically identified in the policy, this amount will be used in the Transmission Facilities Use Charge.

For facilities purchased by Seller from a Member system, Seller will obtain appropriate property insurance as of the effective date of the transfer thereof and include this amount in the Transmission Facilities Use Charge.

COST OF MONEY

For facilities constructed by Seller, the cost of money component will be included in the Transmission Facilities Use Charge as of the date of in-service of the facility. This cost will be determined by applying the cost of permanent financing or interim financing, if permanent not in place, for the facility to the net book value of the facilities used exclusively by the Member at the end of each month.

For facilities purchased by Seller from a Member system for exclusive use by the Member system, the cost of money component will be determined by the cost of debt assumed or Seller's cost of permanent financing or interim financing, if permanent not in place, used to finance the purchase of the facility.

Rate Schedule C

Appendix D

Monthly Production Fixed Energy Charge and Projected Fuel Rate

MONTHLY PRODUCTION FIXED ENERGY CHARGE

Pursuant to Appendix A of this Rate Schedule, the amounts provided below represent the Monthly Production Fixed Energy Charge for each member to become effective January 1, 2000 through December 31, 2000.

Member	Monthly Fixed Energy Charge
Central Florida Electric Cooperative, Inc.	$143,548
Clay Electric Cooperative, Inc.	$928,090
Glades Electric Cooperative, Inc.	$116,727
Lee County Electric Cooperative, Inc.	$1,044,149
Peace River Electric Cooperative, Inc.	$141,306
Sumter Electric Cooperative, Inc.	$590,459
Suwannee Valley Electric Cooperative, Inc.	$111,874
Talquin Electric Cooperative, Inc.	$309,768
Tri-County Electric Cooperative, Inc.	$69,876
Withlacoochee River Electric Cooperative, Inc.	$1,065,710
Total	$4,521,507

PROJECTED FUEL RATE

Pursuant to Appendix B of this Rate Schedule the projected Fuel Rate to become effective January 1, 2000 shall be $.01961 per kWh.

Exhibit ___ (TSN-2)
Witness: Novak
Docket No. 981827-EC

INTERIM BILLING ADJUSTMENT RIDER

For the cycle billing months of January through December, 1998, the non-fuel energy component of Rate Schedule SECI-6b shall decreased by $0.001 per kWh.

Issued by: Richard J. Midulla
Executive Vice President
And General Manager

Effective: January 1, 1998

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SCHEDULE C
TO WHOLESALE POWER CONTRACT

Wholesale Service Rate to Members'
Rate Schedule - SECI-6b

I. AVAILABILITY

Available for electric service from the Seller to its Members.

II. APPLICABILITY

Wholesale service to Members for use, redistribution, and resale in accordance with the terms and conditions of the Wholesale Power Contract. This schedule shall apply to each Member. The Member's delivery points under this schedule are listed in Schedule B of the Wholesale Power Contract.

III. CHARACTER OF SERVICE

The electric capacity and energy hereunder will be three-phase alternating current at a nominal frequency of sixty hertz.

IV. MONTHLY RATE

The rate to the Members shall be composed of the following charges:

(A) BASE RATE FOR SERVICE

	230/240 kV	115/138 kV	69 kV	Below 69
Station Charge ($/Delivery Point)	$400.00	$400.00	$400.00	$400.00
Demand Charges				
For each kW of Monthly Billing Demand at Applicable Voltage Level	$ 10.63	$ 10.76	$ 10.89	$ 12.02
Energy Charge ($/kWh)	.02919	.02919	.02919	.02919

FUEL ADJUSTMENT

The amount computed at the above monthly rate shall be adjusted in accordance with the formula specified in Seller's Fuel Adjustment Clause which is incorporated as a part of this rate as Appendix A.

MINIMUM MONTHLY CHARGE

The minimum monthly bill shall not be less than the sum of the station charge and the demand charge for the current effective Monthly Billing Demand.

BILLING DETERMINANTS

(1) Demand Determinants:

The Monthly Billing Demand shall be equal to the sum of the Members' Monthly Supplier Area Billing Demands, expressed in kW and rounded to the nearest kW. For Members' delivery points located in the Florida Power & Light (FPL) control area, the Monthly Supplier Area Billing Demand is the Aggregate Hourly Demand of such delivery points at the time of the aggregate peak load experienced during the FPL partial requirements billing cycle for those Member delivery points served through the partial requirements agreement between the Seller and FPL. For the remaining Members' delivery points, the Monthly Supplier Area Billing Demand is the Aggregate Hourly Demand for the remaining Member delivery points at the time of billing demand during the billing month under the partial requirements agreement between the Seller and Florida Power Corporation. The Aggregate Hourly Demand for each clock hour of the billing month is determined by the summation of the 60-minute kW demands, corresponding to each such clock hour, established at each of the Member's delivery points by Supplier Area. The Aggregate Hourly Demand for each clock hour shall, where applicable, be reduced by the amount of Southeastern

Power Administration capacity delivered to certain specified delivery points in each such clock hour during the billing month.

(2) Energy Determinants:

The Monthly energy, expressed in kWh and rounded to the nearest kWh, is determined by the summation of the energy associated with each hour's Aggregate Hourly Demand for all hours during the calendar billing month.

(3) Estimated Billing Determinants:

To the extent that any of the metering information required to determine the Monthly Billing Demand and energy supplied during the billing month is not available at the time of billing, bills will be rendered using estimates of said billing determinants with such estimates being based upon all known pertinent facts. Differences between billings based on actual and estimated billing determinants shall be subsequently trued up, with interest accrued at the Seller's short term investment or cost of funds rate, whichever is applicable.

POWER FACTOR

Power factor penalties incurred by the Seller under its contracts with other utilities as a result of a member delivery point's failing to maintain a power factor at/or above the applicable contractually required level, shall be billed to the member receiving service at said delivery point on a direct pass-through basis as part of the bill for electric service provided hereunder. Seller shall be obligated to keep the members apprised of the applicable contractual requirements which could affect power factor billings hereunder.

(B) TRANSMISSION FACILITIES USE CHARGE

A "facilities use charge" as described in Seller's Transmission Policy No. 303 shall, if applicable be billed in addition to the foregoing Monthly Base Rate. In accordance with the terms and conditions described in said policy, the charge shall be calculated in the manner prescribed in Appendix B which is incorporated as part of this rate schedule.

V. METERED READINGS AND BILLINGS

(A) PAYMENT OF BILLS

Bills for electric power and energy and for transmission facilities use services furnished hereunder shall be paid for at the office of the Seller within fifteen (15) days after the bill therefore is mailed to the Member. Bills not paid within such fifteen-day period shall be deemed delinquent and shall accrue interest at the Seller's monthly line of credit rate. The Board of Trustees of the Seller may, from time to time, establish terms and conditions under which (1) either Seller or Member makes payments of amounts owed hereunder in advance of the performance date provided for herein or (2) Seller offers the Member a premium on any billing credits owed hereunder from the Seller to the Member in consideration of such credits being applied by the Seller to billings subsequent to those provided for above. Said terms and conditions shall be specified in writing and provided to each of the Members of the Seller.

(B) METER READING AND TESTING

The Seller shall read meters monthly, or cause meters to be read monthly. In cases whereby the meter installation is made at a voltage different from the delivery point voltage designated in Schedule B of the Wholesale Power Contract, compensating devices, which automatically adjust meter readings to account for losses, shall be installed. The Seller shall test and calibrate meters, or shall cause such meters to be tested and calibrated, by comparison with accurate standards at intervals of twelve (12) months. The Seller shall also make or cause to be made special meter tests at any time at the Member's request. The costs of all tests shall be borne by the Seller; provided, however, that if any special meter test made at the Member's request shall disclose that the meters are recording accurately, the Member shall reimburse the Seller for the cost of such test. Meters registering not more than two perceht (2%) above or below normal shall be deemed to be accurate. The readings of any meter which shall have been disclosed by test to be inaccurate shall be corrected for the thirty (30) days previous

Issued by: William C. Walbridge
Executive Vice President
and General Manager

Effective: September 1, 1994

to such test in accordance with the percentage of inaccuracy found by such test. If any meter shall fail to register for any period, the Member and the Seller shall agree as to the amount of power and energy furnished during such period and the Seller shall render a bill therefore.

VI. TERMS AND CONDITIONS

Service hereunder is subject to all of the provisions of the Wholesale Power Contract between Seller and its Members, including all schedules, amendments, and supplemental agreements thereto in effect from time to time.

VII. SPECIAL PROVISIONS

In the event that the Member purchases power from a cogeneration or small power production Qualifying Facility, the Seller may reallocate to the Member any costs that have not been avoided as a result of the Member's purchases from the Qualifying Facility. The criteria that a small power producer or a cogenerator must meet to achieve the status of a Qualifying Facility is defined by Section 201 of the Public Utility Regulatory Policies Act of 1978 and regulations adopted thereunder.

RATE SCHEDULE C

APPENDIX A

Fuel Adjustment Clause

APPLICABILITY

To the Monthly Rate of all Board approved rate schedules as indicated with reference to this Appendix A.

CALCULATION

The monthly bill computed under the Base Rate for Service shall be increased or decreased, per kWh delivered, by an amount (FAC below), to the nearest one thousandth of a cent, determined by use of the formula:

$$FAC = \frac{F_m}{S_m} - 2.443¢$$

where:

FAC = Applicable fuel adjustment to be applied to each kWh of energy delivered in the current billing month.

F_m= Shall be comprised of the following costs projected for a 12-month test period:

(i) Fossil and nuclear fuel consumed in Seller-owned plants and the Seller share of fossil and nuclear fuel consumed in jointly-owned or leased plants; plus

(ii) fossil and nuclear fuel costs associated with replacement power, reserve purchases and load following, exclusive of capacity or demand charges (irrespective of the designation assigned to such transactions); plus

(iii) the net energy cost of economy energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transactions); plus

(iv) allowable fuel and/or purchased economic power costs associated with Seller's purchases of full and partial requirements wholesale power; plus

(v) the avoided energy payments to Qualifying Facilities; less

(vi) the cost of fossil and nuclear fuel recovered through inter-system sales.

S_m= Projected kWh sales to the Members for the 12-month test period.

In addition, each Member shall be charged or credited during the last four months of each subsequent six-month period by a dollar amount equal to the sum of the following:

(A) The dollar amount equal to the difference between the fuel adjustment charges based on actual fuel costs during the preceding six-month period and the fuel adjustment charges collected during the same preceding six-month period.

(B) Interest compounded monthly on the amount computed each month pursuant to Item A above, up to the end of such six-month period, at the Seller's short term investment or cost of funds rate, whichever is applicable and

(C) *Interest compounded monthly for the two months following such six-month period on the* total amount included in Items A and B above at the Seller's short term investment or cost of funds rate, whichever is applicable, for the month succeeding the end of the six-month period.

The distribution of the dollar amounts as determined by the sum of paragraphs A, B and C above shall be billed or credited in equal amounts on billings for the last four months of each six-month period.

Modifications to the applicable FAC factor during any six-month period will be made in accordance with Seminole Rate Policy No. 304.

RATE SCHEDULE C

APPENDIX B

Components of
Facilities Use Charge

Section 2 of the Transmission Policy No. 303 lists the costs that will be borne by a Member system that has exclusive use of facilities owned by Seller. Costs of operation and maintenance are to be borne directly by the Member, whereas costs of ownership will be recovered by Seller from the benefiting Member through a Facilities Use Charge. Outlined below are those components of the Facilities Use Charge and how they are to be computed.

DEPRECIATION

For facilities constructed by Seller, depreciation will be calculated monthly based on original installed cost (including cost of capitalized renewals and replacements) of depreciable property relating to the transmission facilities used exclusively by a Member system and the depreciation rate prescribed in REA Bulletin 183-1. or revisions thereto. The date at which depreciation cost commences will be the date that the transmission facility is placed in service for its intended use by Seller for the benefiting Member, regardless of the date of closing of the construction work order.

For facilities purchased from a Member by Seller to be used exclusively by that Member, depreciation will commence as of the effective date of the transfer thereof and calculated according to the method previously described.

PROPERTY TAXES

For facilities constructed by Seller, for the exclusive use of a Member, property tax costs will be included in the Facilities Use Charge at such time that the facility qualifies as taxable property and becomes taxable to Seller. The cost will be based on the ratio of the net book value of taxable property comprising the transmission facility used exclusively by the benefiting Member to the total net book value of all taxable property owned by Seller in the county in which the facility is located, as of January 1 of each year. This ratio will be applied to the estimated tax bill for the county in which the facility is located as the basis for determining the estimated monthly charge. When the actual tax bill is received, appropriate adjustments will be made.

For facilities purchased from a Member by Seller for exclusive use by that Member, property taxes will be prorated as of the effective date of transfer. Taxes associated with the facility will be based on the ratio of the net book value of taxable property comprising the facility to the total net book value of taxable property owned by the Member in the county in which the facility is located. The taxes will be calculated by the method described for Seller-built facilities.

PROPERTY INSURANCE

Seller will carry property insurance for transmission facilities in accordance with its standard insurance purchasing practices. For built facilities, the cost will be based on the ratio of insured value of the facility to the total insured value of all property covered in the policy. This ratio will be applied to the total premium for the policy to determine the cost applicable to the facility; however, if the premium for the facility is specifically identified in the policy, this amount will be used in the Facilities Use Charge.

For facilities purchased by Seller from a Member system, Seller will obtain appropriate property insurance as of the effective date of the transfer thereof and include this amount in the Facilities Use Charge.

COST OF MONEY

For facilities constructed by Seller, the cost of money component will be included in the Facilities Use Charge as of the date of in-service of the facility. This cost will be determined by applying the cost of permanent financing or interim financing, if permanent not in place, for the facility to the net book value of the facilities used exclusively by the Member at the end of each month.

For facilities purchased from a Member system Seller for exclusive use by the Member system, the cost of money component will be determined by the cost of debt assumed or Seller's cost of permanent financing or interim financing, if permanent not in place, used to finance the purchase of the facility.

COMPARISON OF MEMBER AVERAGE RATES

SECI-6B vs ALTERNATE 3(AT) SEASONAL RATE STRUCTURE

1999

MILLS PER KWH

Reflects $8.50 winter and $8.50 summer demand rates

with Voltage Discount Adjustment of $1.29 per kW-mo

Allocation of Fixed Charge Amount Based Upon

[illegible]-Year Rolling Average of KWH

	SEASONAL RATE STRUCTURE	SECI-6B	DIFFERENCE
Central Florida	46.30	46.80	-0.50
C[illegible]	46.07	45.86	0.21
[illegible]lades	46.18	46.11	0.07
Lee County	46.32	46.39	-0.07
Okefenoke	46.37	46.53	-0.16
Peace River	47.57	46.94	0.63
Sumter	48.91	48.85	0.06
Suwannee	46.37	46.04	0.33
Talquin	47.28	47.25	0.03
Tri-County	45.40	45.03	0.37
Withlacoochee	48.55	48.79	-0.24
Seminole	47.22	47.22	0.00

SEMINOLE ELECTRIC COOPERATIVE, INC.

RESULTING AVERAGE 12 MONTH RATE ASSOCIATED WITH PRODUCTION DEMAND CHARGES

BUDGETED 12 MONTHS ENDING DECEMBER 31, 2000

PRODUCTION DEMAND CHARGE REVENUES	$181,191,296
BILLING DEMANDS (KW-MONTHS)	29,536,582
AVERAGE PRODUCTION DEMAND RATE	$6.13 / KW / MO.

SOURCE: SEE PAGE 2

SEMINOLE ELECTRIC COOPERATIVE, INC
BUDGET 2000
MEMBER REVENUES with MONTHLY ACCRUED FUEL ADJUSTMENT

2000

Seminole

	Energy (KWH)	Billing Demands (KW) (a)	Production Demand Charge (b)	Production Fixed Energy Charge	Transmission Demand Charge (c)	Distribution Demand Surcharge (d)	Non-Fuel Energy Charge (e)	Levelized Fuel Energy Charge (f)	Monthly Fuel Adjustment	Total Revenues	Mills per Kwh
January	1,047,964,173	3,155,196	$26,819,168	$4,521,507	$5,016,762	$43,927	$2,756,146	$20,550,578	($125,755)	$59,582,333	56.86
February	954,285,204	3,037,822	25,821,491	4,521,507	4,830,137	41,374	2,509,770	18,713,533	(1,021,084)	55,416,728	58.07
March	923,183,609	2,446,570	20,795,847	4,521,507	3,890,045	32,429	2,427,973	18,103,632	(1,163,210)	48,608,223	52.65
April	837,346,862	1,796,265	0	4,521,507	2,856,061	19,788	2,202,222	16,420,371	(1,163,913)	24,856,036	29.68
May	1,011,519,641	2,204,362	0	4,521,507	3,504,936	24,608	2,660,296	19,835,900	(495,646)	30,051,601	29.71
June	1,114,557,665	2,453,008	20,850,571	4,521,507	3,900,283	25,709	2,931,287	21,856,475	735,609	54,821,441	49.19
July	1,192,949,763	2,506,916	21,308,788	4,521,507	3,985,996	26,277	3,137,458	23,393,745	1,359,964	57,733,735	48.40
August	1,205,433,901	2,559,083	21,752,207	4,521,507	4,068,940	26,931	3,170,291	23,638,558	1,567,063	58,745,497	48.73
September	1,092,153,930	2,368,043	20,128,368	4,521,507	3,765,189	25,228	2,872,366	21,417,139	1,081,231	53,811,028	49.27
October	928,087,410	2,035,466	0	4,521,507	3,236,391	22,155	2,440,869	18,199,795	491,886	28,912,603	31.15
November	888,265,283	2,183,868	0	4,521,507	3,472,350	24,204	2,336,137	17,418,882	(284,246)	27,488,834	30.95
December	998,396,040	2,789,983	23,714,856	4,521,507	4,436,075	35,532	2,625,782	19,578,546	(968,445)	53,943,853	54.03
Year	12,194,143,481	29,536,582	$181,191,296	$54,258,084	$46,963,165	$348,162	$32,070,597	$239,127,154	$13,454	$553,971,912	45.43

(a) Reflects Seminole coincident demands.
(b) $8.50/kW, excluding April, May, October and November
(c) $1.59/kW for 69 kV and above
(d) $1.27/kW for Below 69 kV
(e) $0.00263/kWh
(f) $0.01961/kWh

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Exhibit ___ (TSN-5)
Witness: Novak
Docket No. 981827-EC

SEMINOLE ELECTRIC COOPERATIVE, INC.

PAYNE CREEK FACILITY
FIXED COSTS FOR
FIRST YEAR OF COMMERCIAL OPERATION

1	Unit's ISO Rating - MW	538
2	Total Installed Cost to Build ($000)	$225,965
3	Cost per KW	$420
4	First Year Revenue Requirement (including O&M)	$32,200
5	Cost per KW-month of Installed Capacity (2002 $)	$4.99
6	Cost per KW-month of Installed Capacity (2000 $)	$4.78
7	Cost per KW-month on 12 month billing demands*	$6.13
8	Cost per KW-month on 8 month billing demands**	$8.49

* Based upon budgeted 2000 relationship between annual Seminole peak demand for 12 months and sum of 12 monthly demands of 1.28188 (see page 2).

** Based upon budgeted 2000 relationship between Seminole's sum of 12 monthly demands and sum of 8 production month demands of 1.38561 (see page 2).

CALCULATION OF ADJUSTMENTS TO
INSTALLED COST PER KW TO REFLECT
12 MONTH AND 8 MONTH BILLING

1	2000 SECI Peak Demand (kw)	3,155,196
2	Months	12
3	Annual Peak kw-months	37,862,352
4	2000 SECI Billing Demands, 12 months	29,536,582
5	Billing Demands / Annual Peak kw-months	1.28188
6	2000 SECI Production Billing Demands, 8 months	21,316,623
7	SECI Billing Demands, 12 months / SECI Production Demands, 8 months	1.38561

Exhibit ___ (TSN-6)
Witness: Novak
Docket No. 981827-EC

SEMINOLE ELECTRIC COOPERATIVE, INC.
ESTIMATED FIXED COSTS FOR
FIRST YEAR OF COMMERCIAL OPERATION
OF COMBUSTION TURBINE UNIT

1	*ISO Rating - mw*	170
		dated 6 /00, 2003$
2	Build Cost $000	$62,494
3	Owners Cost(stamps/spares)	<u>all-in-cost</u>
4		$62,494
5	Cost per KW	$368
6	Fixed Charge Rate	12.34%
7	Cost per KW-month of Installed Capacity (nominal $)	$3.78
8	Cost per KW-month of Installed Capacity (2000 $)	$3.53
9	*Cost per KW-month on 12 month billing demands**	$4.53
10	*Cost per KW-month on 8 month billing demands***	$6.27

* Based upon budgeted 2000 relationship between annual Seminole peak demand for 12 months and sum of 12 monthly billing demands of 1.28188 (see page 2 of Exhibit__TSN-5).

** Based upon budgeted 2000 relationship between Seminole's sum of 12 monthly billing demands and sum of 8 production month demands of 1.38561 (see page 2 of Exhibit__TSN-5).

RATE SCHEDULE SECI-7
1999 BUDGETED REVENUE REQUIREMENT

	Dollars	Billing Units	Rate
Total Revenue. Req	541,815,673	11,587,769 MWh	$.04676/kWh
Fuel:			
SECI Net Generation	177,082,376		
Purchased Power	62,158,208		
	239,240,584	11,587,769 MWh	$.02065/kWh
Non-Fuel Energy:			
Purchased Power	9,341,471		
SECI Variable O&M	20,233,481		
	29,574,952	11,587,769 MWh	$.00255/kWh
Production Demand	169,929,153	19,991,665 kW	$8.50/kW
Transmission Demand			
Transmission	50,995,054	27,819,402 kW	$1.83/kW
Distribution	384,389	306,128 kW	$1.26/kW
	51,379,443		
Prod. Fixed Energy	51,691,541		

Rate Committee
10/7/98

1999 BUDGET
TRANSMISSION RATE
(INCLUDES ALL TRANSMISSION ASSETS)
($ X 1,000)

TRANSMISSION RATE BASE	$114,644
COST OF DEBT	0.06990
TIER	1.05
TOTAL COST OF DEBT & ALLOWANCE FOR TIER	0.07340
TOTAL COST OF DEBT	$8,414
WHEELING (Including FPC Partial Reqmts Wheeling Component)	$34,560
SECI TRANSMISSION OPERATING EXPENSES	$9,026
REVENUE CREDITS (Consists of Wheeling Revenues & Member TFUC Revenue)	($1,005)
TOTAL TRANSMISSION REVENUE REQUIREMENT	$50,995
TOTAL COINCIDENT MEMBER DEMAND (MW-MONTHS)	27,819
TRANSMISSION RATE ($/MW-MONTH)	1.83

RATE COMMITTEE
10/07/98

SEMINOLE ELECTRIC COOPERATIVE, INC.

2000 BUDGET

Line #	2000 $8.50 / $1.59 / New Prod Fix En				Revenue Requirements	Calculated Rates ($/kwh) & Revenues	Exhibit __TSN 8 Page Reference
1	Total Revenue Requirement (From B&RA section of Corp Plg)				$553,794,942 A)	$0.04541	A) See page 47
	Less:						
2	Fuel :						
3	SECI Generation, net			$162,832,362			
4	Purchased Power			76,304,784			
5	Total Fuel Cost				$239,137,146 B)		B) See page 43
6	KWH & $/kwh	12,194,143,481 kwh		$0.0196108		$0.01961	
7	Fuel Revenue					$239,127,154	
	PR/FR Non-fuel Energy:						
8	FPC-FR		$1,512 C)				C) See page 56
9	-PR		248,452 D)				D) See page 55
10	GNVL		577,909 E)				E) See page 57
	Interchange Components:						
11	-Big Bend 4		1,861,125 F)				F) See page 33
12	-Hardee Power Station (CC / CT)		538,663 G)				G) See page 33
13	-Energy Imbalance (FPC/FPL)		2,823,410 H)				H) See page 32
14	-Non Firm Purchases		0				
15	-Emergency		0				
16	-JEA		193,142 I)				I) See page 35
17	-Hardee Delivery Point		170,487 J)				J) See page 35
18	-OUC		775,344 K)				K) See page 37
19	-LEE COUNTY		243,958 L)				L) See page 35
20	-FPC Intermediate Block		3,006,295 M)				M) See page 37
21	-FPC Peaking Block		96,849 N)				N) See page 37
22	Interchange Subtotal		$9,709,273				
23	subtotal		$10,537,146				
24	SECI Variable O&M (FERC classification)		$21,495,702 O)				
25	Total Non-Fuel Energy Cost				$32,032,848		O) See page 10
26	$ / kwh		$0.0026269			$0.00263	
27	Non-Fuel Energy Revenue					$32,070,597	
28	Total Fixed Costs				$282,624,948		
	Transmission Demand Revenues:	Annual Demands	Rate	$			
29	Transmission Voltage	29,262,440				$1.27	
30	Distribution Voltage	274,142		$348,226 P)		$348,160	P) See page 9
31	Total Transmission	29,536,582		46,827,357 Q)		$1.59	Q) See page 4
32	Total Transmission Demand Revenues				$47,175,583	$46,963,165	
33	Production Fixed Costs				$235,449,365		
34	Production Demand Revenues @ $8.50				@ $8.50		
35	Member Demand excluding April, May, October, November:		21,316,621 R)	$8.50	$181,191,279		R) See page 3
36	1999 Production Fixed Energy Charge Amount				54,258,086		
37	Demand Revenues (Trans & Prod. / Total Fixed Costs				80.9%		

00001

ALLOCATION OF PRODUCTION FIXED ENERGY CHARGE REVENUE REQUIREMENT
2000 BUDGET

2000

SECI-7b

Production Demand Revenues:

Member Demand excluding months April, May, *October, November:*

1	Central Florida	690,246	$8.50	$5,867,091
2	Clay	4,215,868	$8.50	35,834,878
3	Glades	443,263	$8.50	3,767,736
4	Lee	4,341,343	$8.50	36,901,416
5	Peace River	635,705	$8.50	5,403,493
6	Sumter	3,066,897	$8.50	26,068,625
7	Suwannee	535,843	$8.50	4,554,666
8	Talquin	1,547,582	$8.50	13,154,447
9	*Tri-County*	302,804	$8.50	2,573,834
10	Withlacoochee	5,537,070	$8.50	47,065,095
11	Total	21,316,621		$181,191,281

12 Production Fixed Energy Charge - Member Allocation based on 1996-1998 kwh ratios $54,258,086

		1996-1998 kwh	%'s		Allocated Production Fixed Charge	Monthly Production Fixed Charge	
13	Central Florida	1,027,694,935	3.17%	S)	$1,722,576	$143,548	*S) See page 2*
14	Clay	6,644,422,973	20.53%	S)	$11,137,080	$928,090	
15	Glades	835,675,535	2.58%	S)	$1,400,721	$116,727	
16	Lee	7,475,321,492	23.09%	S)	$12,529,794	$1,044,149	
17	Peace River	1,011,646,190	3.13%	S)	$1,695,675	$141,306	
18	Sumter	4,227,236,796	13.06%	S)	$7,085,502	$590,459	
19	Suwannee	800,930,629	2.47%	S)	$1,342,483	$111,874	
20	Talquin	2,217,707,004	6.85%	S)	$3,717,220	$309,768	
21	Tri-County	500,261,021	1.55%	S)	$838,515	$69,876	
22	Withlacoochee	7,629,676,814	23.57%	S)	$12,788,521	$1,065,710	
23		32,370,575,389	100.00%		$54,258,086	$4,521,507	

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2000 BUDGET
Member Demands

this folder is updated for 2000 budget

2000	J	F	M	A	M	J	J	A	S	O	N	D	Year	Total Excluding Apr, May, Oct, Nov
Central Florida	96,324	89,477	75,980	62,955	80,091	84,541	90,058	86,816	77,366	64,387	76,262	89,684	973,941	690,246
Clay	571,103	572,917	455,643	387,300	452,042	494,445	541,746	543,766	514,362	420,848	432,651	521,886	5,908,709	4,215,868
Glades	61,930	62,205	52,793	51,496	55,522	48,977	53,912	53,586	49,690	52,707	54,597	60,170	657,585	443,263
Lee County	696,022	594,005	489,577	375,486	457,521	508,700	516,841	527,099	469,471	434,388	358,136	539,628	5,966,874	4,341,343
Peace River	103,628	101,866	80,464	53,828	67,785	67,483	66,755	65,218	64,611	59,872	63,309	85,680	880,499	635,705
Sumter	444,000	455,389	348,338	277,448	287,836	356,526	347,544	363,304	357,212	325,225	347,235	394,584	4,304,641	3,066,897
Suwannee	70,129	63,957	55,527	42,214	45,893	70,147	74,856	72,572	62,467	45,250	54,765	66,188	723,965	535,843
Talquin	231,021	224,875	188,066	119,247	158,776	177,612	185,429	175,219	171,491	121,126	175,396	193,869	2,122,127	1,547,582
Tri-County	42,104	41,602	34,312	23,443	29,618	36,169	40,652	36,272	34,087	25,140	33,088	37,606	414,093	302,804
Withlacoochee	838,935	831,529	665,870	402,848	569,278	608,408	589,123	635,231	567,286	486,523	588,429	800,688	7,584,148	5,537,070
Total	3,155,196	3,037,822	2,446,570	1,796,265	2,204,362	2,453,008	2,506,916	2,559,083	2,368,043	2,035,466	2,183,868	2,789,983	29,536,582	21,316,621
2001														
Central Florida	100,259	93,359	79,311	65,671	83,561	87,260	91,141	88,788	80,515	67,107	79,596	93,371	1,009,939	714,004
Clay	611,291	592,530	471,754	401,416	468,074	513,606	549,693	570,854	530,629	435,147	447,563	539,262	6,131,819	4,379,619
Glades	71,279	64,671	54,697	53,462	57,557	57,963	56,293	59,077	50,594	54,537	56,486	62,013	698,629	476,587
Lee County	689,472	612,691	504,519	387,706	471,992	519,798	533,068	540,358	483,588	447,958	369,608	556,436	6,117,194	4,439,930
Peace River	107,717	105,911	83,651	55,942	70,346	69,550	66,568	75,739	66,880	62,002	65,695	89,003	919,004	665,019
Sumter	471,184	469,473	363,410	290,824	301,284	371,326	393,936	374,369	372,047	339,896	363,253	410,883	4,521,885	3,226,628
Suwannee	75,357	67,097	58,209	44,043	47,815	74,214	74,099	75,975	64,786	47,044	57,267	69,097	755,003	558,834
Talquin	247,718	234,944	196,754	124,350	165,227	189,373	184,106	181,743	177,930	125,833	182,843	201,833	2,212,654	1,614,401
Tri-County	46,925	43,388	35,735	24,187	30,436	37,452	39,178	38,172	34,884	25,773	34,221	38,885	429,236	314,619
Withlacoochee	855,836	859,234	688,534	417,915	590,647	618,234	602,630	646,318	584,647	504,117	610,445	828,226	7,806,783	5,683,659
Total	3,277,038	3,143,298	2,536,574	1,865,516	2,286,939	2,538,776	2,590,712	2,651,393	2,446,500	2,109,414	2,266,977	2,889,009	30,602,146	22,073,300

1 2000 BUDGET

2 **TRANSMISSION RATE**

3 (INCLUDES ALL TRANSMISSION ASSETS)

($)

		2000 Budget
7	Transmission Rate Base	$101,299,633
9	Cost of Debt	0.06690
11	TIER	1.05
13	Total Cost of Debt and Allowance for TIER (Line 9 * Line 11)	0.07025
15	Total Cost of Debt (Line 13 * Line 7)	$7,115,793
17	Wheeling (Including FPC Partial Reqmts Wheeling Component)	$33,610,695
17	Total Transmission Operating Expenses	$7,156,208
19	Revenue Credits (Wheeling Revenues & TFUC Revenue)	($1,055,339)
21	Total Transmission Revenue Requirement (Sum Lines 15..19)	$46,827,357
23	Total Coincident Member Demand (MW-months)	29,536,582
25	Transmission Rate ($/MW-month)	1.585

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2000 BUDGET
WHEELING CHARGES
(Excludes Distribution Charges)

	$		
WHEELING CHARGES, FPC	14,593,349		
ANCILLARY CHARGES	2,973,252		
WHEELING, FPC PR	3,851,635		
STRUCTURED SYSTEM CONTRACT	5,913,180		(5,460,000 kw *($1.016+$0.067))
FPL WHEELING CREDIT	(9,019,022)		(-1*5,460,000 kw *(1-0.0191)*$1.684)
SUB-TOTAL, FPC WHEELING		18,312,394	
NETWORK SERVICE, FPL	14,153,200		
REACTIVE SERVICE	894,444		
FERC ASSESSMENT	191,269		
WHEELING-RELATED FUEL	0		
SUB-TOTAL, FPL WHEELING		15,238,913	
WHEELING, HPS LOSSES		59,388	
TOTAL WHEELING AND TFUC CHARGES		33,610,695	

00005

DEVELOPMENT OF TRANSMISSION RATE BASE

($)

Line		SOURCES	ASSESSMENT BALANCE @ 12/31/99	BUDGET BALANCE @ 12/31/00	AVG BALANCE
7	**DEVELOPMENT OF GROSS PLANT BALANCES**				
9	Cedar Key Acq. Adjustment	SCH OF UTILITY PLANT - W DIXON	$18,575	$18,575	$18,575
11	SECI Transmission, less Gen Tran	SCH OF UTILITY PLANT - W DIXON	$123,634,436	$123,639,436	
12	Transmission Land	SCH OF UTILITY PLANT - W DIXON	$16,406,249	$16,406,249	
13	Total Transmission Plant		$140,040,685	$140,045,685	$140,043,185
15	General Plant	SCH OF UTILITY PLANT - W DIXON	$20,270,582	$23,587,200	
16	Land	SCH OF UTILITY PLANT - W DIXON	$798,157	$798,157	
17	Total		$21,068,739	$24,385,357	
18	Allocation Factor	Labor Ratio	5.73%	5.73%	
19	*Total General Plant Allocated to Transmission*		$1,207,239	$1,397,281	$1,302,260
21	TOTAL GROSS PLANT	(L9+L13+L19)	$141,266,499	$141,461,541	$141,364,020
23	**ACCUMULATED DEPRECIATION**				
25	Cedar Key Acq. Adjustment	FULLY DEPREC. PER A&F 3/2598	$18,575	$18,575	$18,575
27	SECI Transmission	ACCUM DEPREC ANALYSIS - W DIXON	$38,781,805	$42,182,377	$40,482,091
29	General Plant	ACCUM DEPREC ANALYSIS - W DIXON	$11,837,608	$12,791,254	
30	Allocation Factor	Labor Ratio	5.73%	5.73%	
31	Total General Plant Depreciation Allocated to Transmission		$678,295	$732,939	$705,617
33	TOTAL ACCUMULATED DEPRECIATION	SUM Line s 25, 27, 31	$39,478,675	$42,933,891	$41,206,283
35	TOTAL TRANSMISSION NET PLANT	(L21-L33)	$101,787,824	$98,527,650	$100,157,737
37	*Transmission Line Materials and Supplies*	*Assume avg balance, 1997/98 actual for 2000*	$1,139,198	$1,144,594	$1,141,896
39	TRANSMISSION RATE BASE	(L49+L51)	$102,927,022	$99,672,244	$101,299,633

00006

DEVELOPMENT OF COST OF DEBT
(2000 BUDGET $)

Line	Description	SOURCE	ACCOUNTS	TYPE OF ACCOUNT	ACTUAL INTEREST & DEBT EXPENSE	AVG ANNUAL DAILY BALANCE (B)	COST OF DEBT WITH AVG BALANCE METHOD
8	NON-UNIT 2 INTEREST & DEBT EXPENSE						
10	RUS INSURED						
11	Interest	(A)	All 42710		$362,764		
12	Debt Expense	(A)	42810562	Debt Expense Amortization	$235	(F)	
13	TOTAL RUS INSURED INTEREST & DEBT				$362,999	$7,255,280	5.00%
15	RUS GUARANTEED						
16	Interest (A-8: CR3)	(A)	42720560		$320,076		
17	Interest (C-8: Palatka Plant)	(A)	42720563		$23,567,317		
18	Interest (G-8: HPS/JEA Transm)	(A)	42720554		$4,095,557		
19	Interest (K8/L8: Payne Creek)	(A)	42720579		$672,485		
20	SUBTOTAL RUS GUARANTEED INTEREST				$28,655,435		
21	Debt Expense	(A)	42810563	Debt Expense Amortization	$65,381		
22	Debt Expense	WO #99050	WRITEOFF	Debt Expense Amortization			
23	Debt Expense						
24	SUBTOTAL RUS GUARANTEED DEBT EXPENSE				$65,381	(F)	
25	TOTAL RUS GUARANTEED INTEREST & DEBT				$28,720,816	$498,545,712	5.76%
27	CFC GUARANTEED						
28	Interest (Series H & S Weeklys)	(A)	All 42722		$2,846,942		
29	Interest (Series H Semis)	(A)	All 42723		$2,446,032		
30	SUBTOTAL CFC GUARANTEED INTEREST				$5,292,974		
31	Debt Expense (Pollution Control Bonds)	(A)	42810539	Debt Expense Amortization	$208,260		
32	Debt Expense (Weeklys/FFB Svc'g Fees)	(A)	All 42822	Fees	$781,976		
33	Debt Expense (Semis)	(A)	All 42823	Fees	$187,568		
34	SUBTOTAL CFC GUARANTEED DEBT EXPENSES				$1,177,804	(F)	
35	SUBTOTAL CFC GUARANTEED INTEREST & DEBT				$6,470,778	$130,690,642	4.95%
36	DEBT SVC RESERVE INTEREST INCOME	(B)	41902101/119	Interest Income	($883,744)	($14,589,000)	(C)
37	SUB TERM CERTIFICATES 1984H/S PC BONI	(B)	4190110200	Interest Income	$0	$0	
38	TOTAL CFC GUARANTEED INTEREST & DEBT				$5,587,034	$116,101,642	4.81%
40	CFC OTHER						
41	Interest (F-6 Supplemental)	(A)	42720578		$71,003		
42	Interest (H-6 Supplemental)	(A)	42720568		$101,186	(F)	
43	TOTAL CFC OTHER INTEREST				$172,189	$2,375,021	7.25%
45	HEADQUARTERS						
46	Interest	(A)	42720566		$441,830		
47	Debt Expense	(A)	42810566	Fees	$1,354	(F)	
48	Hq Loan S.T.C.	(A)	41901101		($10,928)		
49	TOTAL HEADQUARTERS INTEREST & DEBT				$432,256	$5,729,924	7.54%
51	TOTAL NON-UNIT 2 INTEREST & DEBT	L13 + L24 + L37 + L42 + L47			$35,275,294	$630,007,579	5.60%
52	Refinancing Penalty	(C)			$8,281,240		
53	Amortization of BOLTS gain	AMORT SCHED FROM A&F (D)			($1,167,627)		
54	TOTAL WITH REFINANCING PENALTY	L49 + L50 +L51			$42,388,907	$630,007,579	6.73%
56	UNIT 2 INTEREST & DEBT EXPENSE						
58	Interest @ 6/15/00	LEASE AMORT FROM A&F (E)			$8,013,907		
59	Interest @ 12/15/00	LEASE AMORT FROM A&F (E)			$7,724,905		
60	SUBTOTAL UNIT 2 INTEREST				$15,738,812		
62	Debt Expense	(A)	50720531	Loan Participation Fees	$186,026		
63	Debt Expense	(A)		Amort of WO's 80027,40,42	$709,694		
64	Debt Expense	(A)	50720533	Amortization of Gain	($1,415,769)		
65	Debt Expense	(A)	50720535	Fees on 1984D bonds	$182,560		
66	TOTAL UNIT 2 DEBT EXPENSE				($337,489)		
67						Unit 2 Midpoint Of Debt (E)	
70		LEASE AMORT FROM A&F (E)				$242,224,354	Balance @ 12/15/99
71		LEASE AMORT FROM A&F (E)				$224,464,897	Balance @ 12/15/00
72	TOTAL UNIT 2 INTEREST & DEBT EXPENSE	L58 + L67			$15,401,323	$233,344,626	6.60%
74	TOTAL COST OF DEBT	L52 + L73			$57,790,230	$863,352,205	6.69%

00207

SEMINOLE ELECTRIC COOPERATIVE, INC.
TRANSMISSION OPERATING EXPENSES
($)

	SOURCE	BUDGET 2000
OPERATION & MAINTENANCE		
Transmission O&M Expenses:		
O&M Expenses, Incl. O/H, Property Tax Transfers In		$2,727,265
FPC TFUC Charges	RRSB014.WK4	$92,759
Total Transmission O&M Expenses		$2,820,024
A&G Expenses:		
Net A&G Expenses	GLSPB10, DTD 9/17/99	$15,374,654
Allocation Factor		0.0573
Total A&G allocated to Transmission		$880,968
TOTAL O&M/A&G ALLOCATED TO TRANSMISSION		$3,700,992
DEPRECIATION		
Fully Allocated Transmission Depreciation		$3,455,216
Total Transmission Operating Expenses	SUM Lines 19, 23	$\boxed{\$7,156,208}$

2000 BUDGET

28-Jul-99

DISTRIBUTION SURCHARGE RATE

2000

	$	kw	Incremental Rate
FPC PR	$13,643	18,896	$0.722
Wheeling:			
FPC	$62,219	86,181	$0.722
FPL	272,364	182,794	$1.49
Distribution Demand Surcharge $	$348,226		
Member Distribution kw at Meter	274,142		
Distribution Demand Surcharge Rate	$1.27024		

2001

	$	kw	Incremental Rate
FPC PR	11,497	15,923	$0.722
Wheeling:			
FPC	67,260	93,153	$0.722
FPL	281,273	188,775	$1.49
Distribution Demand Surcharge $	$360,030		
Member Distribution kw at Meter	286,156		
Distribution Demand Surcharge Rate	$1.25816		

SEMINOLE ELECTRIC COOPERATIVE, INC.
VARIABLE O&M (FERC CLASSIFICATION)
2000 BUDGET

PRIME ACCOUNT	DESCRIPTION	2000 BUDGET
510	Supervision & Engineering	$5,428,515
512	Boiler Plant	14,443,520
513	Electric Plant	1,105,936
528	Supervision & Engineering	428,717
530	Reactor Plant Equipment	74,996
531	Electric Plant	14,018
	Total	$21,495,702

RRSB002: PLANT STATISTICS	TOTAL YEAR	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE
GENERATION, MEMBER LOAD (MWh)	9,272,378	856,374	818,198	792,391	721,039	781,632	809,805
BROKER ENERGY AVAILABLE	751,930	71,066	49,408	60,239	87,476	129,768	72,195
SALES, AVAILABLE EXCESS GEN. (%)	31.50	31.50	31.50	31.50	31.50	31.50	31.50
GENERATION, BROKER SALES	236,858	22,386	15,564	18,975	27,555	40,877	22,741
PLANT NET GENERATION (MWh)	9,509,236	878,760	833,762	811,366	748,594	822,509	832,546
PLANT NET CAPACITY FACTOR (%) *							
MONTHLY	85.97	92.86	94.18	85.73	83.18	88.44	92.50
Y-T-D	85.97	92.86	93.50	90.85	88.97	88.86	89.45
PLANT AVAILABILITY (%)							
MONTHLY	90.64	98.00	98.00	90.10	8[illegible]3	98.00	98.00
Y-T-D	90.64	98.00	98.00	95.31	93.95	94.78	95.31
PLANNED MAINTENANCE DAYS	55	0	0	5	5	0	0
NET GENERATION, UNIT 1	4,978,860	455,888	430,564	385,286	431,479	438,364	438,248
NET CAPACITY FACTOR (%)							
MONTHLY	90.04	96.34	97.27	81.42	95.88	94.27	97.39
Y-T-D	90.04	96.34	96.79	91.55	92.61	92.95	93.68
UNIT AVAILABILITY (%)							
MONTHLY	91.04	98.00	98.00	82.19	98.00	98.00	98.00
Y-T-D	91.04	98.00	98.00	92.62	93.95	94.78	95.31
PLANNED MAINTENANCE DAYS	26	0	0	5	0	0	0
NET GENERATION, UNIT 2	4,530,376	422,872	403,198	426,080	317,115	384,145	394,298
NET CAPACITY FACTOR (%)							
MONTHLY	81.92	89.37	91.09	90.05	70.47	82.61	87.62
Y-T-D	81.92	89.37	90.20	90.15	85.33	84.78	85.24
UNIT AVAILABILITY (%)							
MONTHLY	90.23	98.00	98.00	98.00	81.67	98.00	98.00
Y-T-D	90.23	98.00	98.00	98.00	93.95	94.78	95.31
PLANNED MAINTENANCE DAYS	29	0	0	0	5	0	0

NET UNIT RATING AT THE GENERATOR: 636/625 MW (WIN/SUM) FORCED OUTAGE RATE:2.0%

Latest 9/15/99 20

00011

RRSB002: PLANT STATISTICS	TOTAL YEAR	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
GENERATION, MEMBER LOAD (MWh)	9,272,378	848,419	859,104	810,302	523,449	599,997	851,668
BROKER ENERGY AVAILABLE	751,930	62,981	52,296	71,698	5,735	13,296	75,772
SALES, AVAILABLE EXCESS GEN. (%)	31.50	31.50	31.50	31.50	31.51	31.50	31.50
GENERATION, BROKER SALES	236,858	19,839	16,473	22,585	1,807	4,188	23,868
PLANT NET GENERATION (MWh)	9,509,236	868,258	875,577	832,887	525,256	604,185	875,536
PLANT NET CAPACITY FACTOR (%) *							
MONTHLY	85.97	93.36	94.15	92.54	56.48	65.98	92.52
Y-T-D	85.97	90.01	90.53	90.75	87.29	85.36	85.97
PLANT AVAILABILITY (%)							
MONTHLY	90.64	98.00	98.00	98.00	56.90	66.97	98.00
Y-T-D	90.64	95.70	95.99	96.21	92.22	89.96	90.64
PLANNED MAINTENANCE DAYS	55	0	0	0	26	19	0
NET GENERATION, UNIT 1	4,978,860	453,859	454,439	438,553	147,011	447,917	457,252
NET CAPACITY FACTOR (%)							
MONTHLY	90.04	97.60	97.73	97.46	31.62	97.82	96.63
Y-T-D	90.04	94.25	94.69	94.99	88.58	89.42	90.04
UNIT AVAILABILITY (%)							
MONTHLY	91.04	98.00	98.00	98.00	31.61	98.00	98.00
Y-T-D	91.04	95.70	95.99	96.21	89.65	90.39	91.04
PLANNED MAINTENANCE DAYS	26	0	0	0	21	0	0
NET GENERATION, UNIT 2	4,530,376	414,399	421,138	394,334	378,245	156,268	418,284
NET CAPACITY FACTOR (%)							
MONTHLY	81.92	89.12	90.57	87.63	81.34	34.13	88.40
Y-T-D	81.92	85.80	86.40	86.53	86.01	81.31	81.92
UNIT AVAILABILITY (%)							
MONTHLY	90.23	98.00	98.00	98.00	82.19	35.93	98.00
Y-T-D	90.23	95.70	95.99	96.21	94.79	89.52	90.23
PLANNED MAINTENANCE DAYS	29	0	0	0	5	19	0

NET UNIT RATING AT THE GENERATOR: 636/625 MW (WIN/SUM) FORCED OUTAGE RATE:2.0%

FILE: 2000 BUDGET
RRSB004: PLANT IGNITION OIL EXPENSE

	TOTAL YEAR	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE
OIL PRICE ($ / GALLON)	0.52	0.59	0.57	0.55	0.54	0.53	0.51
TOTAL PLANT							
GALLONS BURNED	1,556,000	100,000	140,000	169,000	169,000	140,000	100,000
EXPENSE	$811,910	$59,000	$79,800	$92,950	$91,260	$74,200	$51,000
OIL MMBtu's *	214,728	13,800	19,320	23,322	23,322	19,320	13,800
UNIT 1							
GALLONS BURNED	782,000	50,000	70,000	99,000	70,000	70,000	50,000
EXPENSE	$408,080	$29,500	$39,900	$54,450	$37,800	$37,100	$25,500
OIL MMBtu's *	107,916	6,900	9,660	13,662	9,660	9,660	6,900
UNIT 2							
GALLONS BURNED	774,000	50,000	70,000	70,000	99,000	70,000	50,000
EXPENSE	$403,830	$29,500	$39,900	$38,500	$53,460	$37,100	$25,500
OIL MMBtu's *	106,812	6,900	9,660	9,660	13,662	9,660	6,900

HEAT CONTENT OF IGNITION OIL: 138,000 Btu/GAL

00013

FILE: 2000 BUDGET
RRSB004: PLANT IGNITION OIL EXPENSE

	TOTAL YEAR	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
OIL PRICE ($ / GALLON)	0.52	0.50	0.49	0.50	0.51	0.49	0.47
TOTAL PLANT							
GALLONS BURNED	1,556,000	100,000	100,000	140,000	124,000	134,000	140,000
EXPENSE	$811,910	$50,000	$49,000	$70,000	$63,240	$65,660	$65,800
OIL MMBtu's *	214,728	13,800	13,800	19,320	17,112	18,492	19,320
UNIT 1							
GALLONS BURNED	782,000	50,000	50,000	70,000	63,000	70,000	70,000
EXPENSE	$408,080	$25,000	$24,500	$35,000	$32,130	$34,300	$32,900
OIL MMBtu's *	107,916	6,900	6,900	9,660	8,694	9,660	9,660
UNIT 2							
GALLONS BURNED	774,000	50,000	50,000	70,000	61,000	64,000	70,000
EXPENSE	$403,830	$25,000	$24,500	$35,000	$31,110	$31,360	$32,900
OIL MMBtu's *	106,812	6,900	6,900	9,660	8,418	8,832	9,660

HEAT CONTENT OF IGNITION OIL: 138,000 Btu/GAL

000014

RRSB006: PLANT HEAT RATE, MMBtu's	TOTAL YEAR	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE
TOTAL PLANT							
NET GENERATION (MWh)	9,509,236	878,760	833,762	811,366	748,594	822,509	832,546
AVERAGE HEAT RATE (Btu/kWh)	9,850	9,850	9,850	9,850	9,850	9,850	9,850
TOTAL MMBtu's	93,665,971	8,655,786	8,212,555	7,991,955	7,373,651	8,101,713	8,200,578
OIL MMBtu's	214,728	13,800	19,320	23,322	23,322	19,320	13,800
COAL /PET MMBtu's	93,451,243	8,641,986	8,193,235	7,968,633	7,350,329	8,082,393	8,186,778
PETCOKE BURNED TONS	282,917	44,250	38,667	22,000	22,000	22,000	22,000
COAL BURNED TONS	3,423,445	296,474	284,732	294,281	269,549	298,832	303,007
TOTAL TONS BURNED	3,706,362	340,724	323,399	316,281	291,549	320,832	325,007
UNIT 1							
NET GENERATION (MWh)	4,978,860	455,888	430,564	385,286	431,479	438,364	438,248
AVERAGE HEAT RATE (Btu/kWh)	9,850	9,850	9,850	9,850	9,850	9,850	9,850
TOTAL MMBtu's	49,041,769	4,490,497	4,241,055	3,795,067	4,250,068	4,317,885	4,316,743
OIL MMBtu's	107,916	6,900	9,660	13,662	9,660	9,660	6,900
COAL MMBtu's	48,933,853	4,483,597	4,231,395	3,781,405	4,240,408	4,308,225	4,309,843
PETCOKE TONS	0	0	0	0	0	0	0
COAL BURNED (TONS) *	1,957,354	179,344	169,256	151,256	169,616	172,329	172,394
UNIT 2							
NET GENERATION (MWh)	4,530,376	422,872	403,198	426,080	317,115	384,145	394,298
AVERAGE HEAT RATE (Btu/kWh)	9,850	9,850	9,850	9,850	9,850	9,850	9,850
TOTAL MMBtu's	44,624,202	4,165,289	3,971,500	4,196,888	3,123,583	3,783,828	3,883,835
OIL MMBtu's	106,812	6,900	9,660	9,660	13,662	9,660	6,900
COAL MMBtu's	36,652,297	2,928,239	2,886,897	3,575,628	2,498,321	3,162,568	3,265,335
PETCOKE MMBtu's	7,865,093	1,230,150	1,074,943	611,600	611,600	611,600	611,600
PETCOKE TONS	282,917	44,250	38,667	22,000	22,000	22,000	22,000
COAL BURNED (TONS) *	1,466,091	117,130	115,476	143,025	99,933	126,503	130,613

HEAT CONTENT: COAL - 25.00 MMBtu/TON; PETCOKE - 27.80 MMBtu/TON

00015

RSB006: PLANT HEAT RATE, MMBtu's	TOTAL YEAR	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
TOTAL PLANT							
NET GENERATION (MWh)	9,509,236	868,258	875,577	832,887	525,256	604,185	875,536
AVERAGE HEAT RATE (Btu/kWh)	9,850	9,850	9,850	9,850	9,850	9,850	9,850
TOTAL MMBtu's	93,665,971	8,552,341	8,624,433	8,203,937	5,173,771	5,951,222	8,624,029
OIL MMBtu's	214,728	13,800	13,800	19,320	17,112	18,492	19,320
COAL /PET MMBtu's	93,451,243	8,538,541	8,610,633	8,184,617	5,156,659	5,932,730	8,604,709
PETCOKE BURNED TONS	282,917	22,000	22,000	22,000	2,000	22,000	22,000
COAL BURNED TONS	3,423,445	317,077	319,961	302,920	204,043	212,845	319,724
TOTAL TONS BURNED	3,706,362	339,077	341,961	324,920	206,043	234,845	341,724
UNIT 1							
NET GENERATION (MWh)	4,978,860	453,859	454,439	438,553	147,011	447,917	457,252
AVERAGE HEAT RATE (Btu/kWh)	9,850	9,850	9,850	9,850	9,850	9,850	9,850
TOTAL MMBtu's	49,041,769	4,470,511	4,476,224	4,319,747	1,448,058	4,411,982	4,503,932
OIL MMBtu's	107,916	6,900	6,900	9,660	8,694	9,660	9,660
COAL MMBtu's	48,933,853	4,463,611	4,469,324	4,310,087	1,439,364	4,402,322	4,494,272
PETCOKE TONS	0		0	0	0	0	0
COAL BURNED (TONS) *	1,957,354	178,544	178,773	172,403	57,575	176,093	179,771
UNIT 2							
NET GENERATION (MWh)	4,530,376	414,399	421,138	394,334	378,245	156,268	418,284
AVERAGE HEAT RATE (Btu/kWh)	9,850	9,850	9,850	9,850	9,850	9,850	9,850
TOTAL MMBtu's	44,624,202	4,081,830	4,148,209	3,884,190	3,725,713	1,539,240	4,120,097
OIL MMBtu's	106,812	6,900	6,900	9,660	8,418	8,832	9,660
COAL MMBtu's	36,652,297	3,463,330	3,529,709	3,262,930	3,661,695	918,808	3,498,837
PETCOKE MMBtu's	7,865,093	611,600	611,600	611,600	55,600	611,600	611,600
PETCOKE TONS	282,917	22,000	22,000	22,000	2,000	22,000	22,000
COAL BURNED (TONS) *	1,466,091	138,533	141,188	130,517	146,468	36,752	139,953

HEAT CONTENT: COAL - 25.00 MMBtu/TON; PETCOKE - 27.80 MMBtu/TON

00016

RRSB008: COAL EXPENSES

	TOTAL YEAR	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE
TOTAL PLANT							
DELIVERY PLAN:							
BEGINNING INVENTORY (TONS)	570,331	570,331	520,107	489,208	484,427	514,378	505,546
DELIVERIES	3,600,000	290,500	292,500	311,500	321,500	312,000	312,000
LESS COAL BURNED	3,706,362	340,724	323,399	316,281	291,549	320,832	325,007
ENDING INVENTORY	463,969	520,107	489,208	484,427	514,378	505,546	492,539
DELIVERED COST OF COAL ($/TON)	40.10	40.39	39.69	39.83	39.89	39.86	39.93
BEGINNING INVENTORY (DOLLARS)	$23,240,988	$23,240,988	$21,017,044	$19,738,455	$19,476,319	$20,682,361	$20,314,588
DELIVERIES & INVENTORY ADJ'S	144,331,785	11,733,295	11,609,260	12,406,615	12,825,095	12,435,640	12,456,600
COAL BURN EXPENSE	148,622,566	13,957,239	12,887,849	12,668,751	11,619,053	12,803,413	12,968,210
ENDING INVENTORY	$18,950,207	21,017,044	19,738,455	19,476,319	20,682,361	20,314,588	19,802,978
MEMBER BURN DAYS AT PALATKA	46.0	49.3	47.9	48.5	48.8	45.7	43.9
BURN RATE (TONS / DAY)	10,995	10,550	10,213	9,988	10,541	11,062	11,220
ENDING AVERAGE $/TON	40.84	40.41	40.35	40.20	40.21	40.18	40.21
COAL BURN PLAN:							
AVERAGE BURN COST*	40.10	40.75	40.41	40.35	40.20	40.21	40.18
TONS BURNED	3,706,362	340,724	323,399	316,281	291,549	320,832	325,007
COAL BURN EXPENSE	$148,622,566	$13,957,239	$12,887,849	$12,668,751	$11,619,053	$12,803,413	$12,968,210
FUEL HANDLING EXPENSE	1,964,373	180,584	171,401	167,629	154,521	170,041	172,254
TOTAL COAL EXPENSE	$150,586,939	$14,137,823	$13,059,250	$12,836,380	$11,773,574	$12,973,454	$13,140,464
COAL MMBtu's	93,451,243	8,641,986	8,193,235	7,968,633	7,350,329	8,082,393	8,186,778
UNIT 1							
COAL BURNED (TONS)	1,957,354	179,344	169,256	151,256	169,616	172,329	172,394
COAL EXPENSE (W/O HANDLING)	$80,306,908	$7,667,057	$6,994,708	$6,183,738	$6,909,644	$7,015,238	$7,014,948
COAL MMBtu's	48,933,853	4,483,597	4,231,395	3,781,405	4,240,408	4,308,225	4,309,843
UNIT 2							
COAL BURNED (TONS)	1,749,008	161,380	154,143	165,025	121,933	148,503	152,613
COAL EXPENSE (W/O HANDLING)	$68,315,658	$6,290,182	$5,893,141	$6,485,013	$4,709,409	$5,788,175	$5,953,262
COAL MMBtu's	44,517,390	4,158,389	3,961,840	4,187,228	3,109,921	3,774,168	3,876,935

BUDGETED COAL HANDLING RATE IS $0.53 PER TON BURNED

00017

RRSB008: COAL EXPENSES

	TOTAL YEAR	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
TOTAL PLANT							
DELIVERY PLAN:							
BEGINNING INVENTORY (TONS)	570,331	492,539	426,962	396,501	373,581	481,038	526,193
DELIVERIES	3,600,000	273,500	311,500	302,000	313,500	280,000	279,500
LESS COAL BURNED	3,706,362	339,077	341,961	324,920	206,043	234,845	341,724
ENDING INVENTORY	463,969	426,962	396,501	373,581	481,038	526,193	463,969
DELIVERED COST OF COAL ($/TON)	40.10	39.81	40.05	39.94	40.09	41.00	40.76
BEGINNING INVENTORY (DOLLARS)	$23,240,988	$19,802,978	$17,137,849	$15,939,821	$14,985,494	$19,169,086	$21,296,800
DELIVERIES & INVENTORY ADJ'S	144,331,785	10,887,725	12,476,755	12,060,960	12,567,420	11,480,000	11,392,420
COAL BURN EXPENSE	148,622,566	13,552,854	13,674,783	13,015,287	8,383,828	9,352,286	13,739,013
ENDING INVENTORY	$18,950,207	17,137,849	15,939,821	14,985,494	19,169,086	21,296,800	18,950,207
MEMBER BURN DAYS AT PALATKA	46.0	37.6	38.8	49.8	51.1	48.7	42.2
BURN RATE (TONS / DAY)	10,995	11,355	10,219	7,502	9,414	10,805	10,995
ENDING AVERAGE $/TON	40.84	40.14	40.20	40.11	39.85	40.47	40.84
COAL BURN PLAN:							
AVERAGE BURN COST*	40.10	40.21	40.14	40.20	40.11	39.85	40.47
TONS BURNED	3,706,362	339,077	341,961	324,920	206,043	234,845	341,724
COAL BURN EXPENSE	$148,622,566	$13,552,854	$13,674,783	$13,015,287	$8,383,828	$9,352,286	$13,739,013
FUEL HANDLING EXPENSE	1,964,373	179,711	181,239	172,208	109,203	124,468	181,114
TOTAL COAL EXPENSE	$150,586,939	$13,732,565	$13,856,022	$13,187,495	$8,493,031	$9 [illegible]76,754	$13,920,127
COAL MMBtu's	93,451,243	8,538,541	8,610,633	8,184,617	5,156,659	5,932,730	8,604,709
UNIT 1							
COAL BURNED (TONS)	1,957,354	178,544	178,773	172,403	57,575	176,093	179,771
COAL EXPENSE (W/O HANDLING)	$80,306,908	$7,271,651	$7,283,476	$7,043,747	$2,349,261	$7,208,132	$7,365,308
COAL MMBtu's	48,933,853	4,463,611	4,469,324	4,310,087	1,439,364	4,402,322	4,494,272
UNIT 2							
COAL BURNED (TONS)	1,749,008	160,533	163,188	152,517	148,468	58,752	161,953
COAL EXPENSE (W/O HANDLING)	$68,315,658	$6,281,203	$6,391,307	$5,971,540	$6,034,567	$2,144,154	$6,373,705
COAL MMBtu's	44,517,390	4,074,930	4,141,309	3,874,530	3,717,295	1,530,408	4,110,437

BUDGETED COAL HANDLING RATE IS $0.53 PER TON BURNED

00018

RRSB008A: COAL EXPENSES

	TOTAL YEAR	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE
TOTAL PLANT							
DELIVERY PLAN:							
BEGINNING INVENTORY (TONS)	487,414	487,414	481,440	467,208	462,427	492,378	483,546
DELIVERIES	3,400,000	290,500	270,500	289,500	299,500	290,000	290,000
LESS COAL BURNED	3,423,445	296,474	284,732	294,281	269,549	298,832	303,007
ENDING INVENTORY	463,969	481,440	467,208	462,427	492,378	483,546	470,539
DELIVERED COST OF COAL ($/TON)	40.74	40.39	40.56	40.65	40.69	40.68	40.75
BEGINNING INVENTORY (DOLLARS)	$20,837,224	$20,837,224	$19,896,088	$19,100,675	$18,837,879	$20,043,921	$19,676,148
DELIVERIES & INVENTORY ADJ'S	138,523,705	11,733,295	10,971,480	11,768,175	12,186,655	11,797,200	11,817,500
COAL BURN EXPENSE	140,410,722	12,674,431	11,766,893	12,030,971	10,980,613	12,164,973	12,329,770
ENDING INVENTORY	$18,950,207	$19,896,088	$19,100,675	$18,837,879	$20,043,921	$19,676,148	$19,163,878
MEMBER BURN DAYS AT PALATKA	45.0	48.3	46.9	47.5	47.8	44.7	42.9
BURN RATE (TONS / DAY)	11,261	9,968	9,962	9,735	10,301	10,818	10,968
ENDING AVERAGE $/TON	40.84	41.33	40.88	40.74	40.71	40.69	40.73
COAL BURN PLAN:							
AVERAGE BURN COST*	41.01	42.75	41.33	40.88	40.74	40.71	40.69
TONS BURNED	3,423,445	296,474	284,732	294,281	269,549	298,832	303,007
COAL BURN EXPENSE	$140,410,722	$12,674,431	$11,766,893	$12,030,971	$10,980,613	$12,164,973	$12,329,770
FUEL HANDLING EXPENSE	1,814,427	157,131	150,908	155,969	142,861	158,381	160,594
TOTAL COAL EXPENSE	$142,225,149	$12,831,562	$11,917,801	$12,186,940	$11,123,474	$12,323,354	$12,490,364
COAL MMBtu's	85,586,150	7,411,836	7,118,292	7,357,033	6,738,729	7,470,793	7,575,178
UNIT 1							
COAL BURNED (TONS)	1,957,354	179,344	169,256	151,256	169,616	172,329	172,394
COAL EXPENSE (W/O HANDLING)	$80,306,908	$7,667,057	$6,994,708	$6,183,738	$6,909,644	$7,015,238	$7,014,948
COAL MMBtu's	48,933,853	4,483,597	4,231,395	3,781,405	4,240,408	4,308,225	4,309,843
UNIT 2							
COAL BURNED (TONS)	1,466,091	117,130	115,476	143,025	99,933	126,503	130,613
COAL EXPENSE (W/O HANDLING)	$60,103,814	$5,007,374	$4,772,185	$5,847,233	$4,070,969	$5,149,735	$5,314,822
COAL MMBtu's	36,652,297	2,928,239	2,886,897	3,575,628	2,498,321	3,162,568	3,265,335

BUDGETED COAL HANDLING RATE IS $0.53 PER TON BURNED

000019

RRSB008A: COAL EXPENSES

	TOTAL YEAR	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
TOTAL PLANT							
DELIVERY PLAN:							
BEGINNING INVENTORY (TONS)	487,414	470,539	404,962	374,501	351,581	437,038	504,193
DELIVERIES	3,400,000	251,500	289,500	280,000	289,500	280,000	279,500
LESS COAL BURNED	3,423,445	317,077	319,961	302,920	204,043	212,845	319,724
ENDING INVENTORY	463,969	404,962	374,501	351,581	437,038	504,193	463,969
DELIVERED COST OF COAL ($/TON)	40.74	40.75	40.89	40.79	41.00	41.00	40.76
BEGINNING INVENTORY (DOLLARS)	$20,837,224	$19,163,878	$16,498,749	$15,300,721	$14,345,734	$17,889,566	$20,657,040
DELIVERIES & INVENTORY ADJ'S	138,523,705	10,248,625	11,837,655	11,421,200	11,869,500	11,480,000	11,392,420
COAL BURN EXPENSE	140,410,722	12,913,754	13,035,683	12,376,187	8,325,668	8,712,526	13,099,253
ENDING INVENTORY	$18,950,207	$16,498,749	$15,300,721	$14,345,734	$17,889,566	$20,657,040	$18,950,207
MEMBER BURN DAYS AT PALATKA	45.0	36.6	37.8	48.9	50.1	47.7	41.2
BURN RATE (TONS / DAY)	11,261	11,065	9,907	7,190	8,723	10,570	11,261
ENDING AVERAGE $/TON	40.84	40.74	40.86	40.80	40.93	40.97	40.84
COAL BURN PLAN:							
AVERAGE BURN COST*	41.01	40.73	40.74	40.86	40.80	40.93	40.97
TONS BURNED	3,423,445	317,077	319,961	302,920	204,043	212,845	319,724
COAL BURN EXPENSE	$140,410,722	$12,913,754	$13,035,683	$12,376,187	$8,325,668	$8,712,526	$13,099,253
FUEL HANDLING EXPENSE	1,814,427	168,051	169,579	160,548	108,143	112,808	169,454
TOTAL COAL EXPENSE	$142,225,149	$13,081,805	$13,205,262	$12,536,735	$8,433,811	$8,825,334	$13,268,707
COAL MMBtu's	85,586,150	7,926,941	7,999,033	7,573,017	5,101,059	5,321,130	7,993,109
UNIT 1							
COAL BURNED (TONS)	1,957,354	178,544	178,773	172,403	57,575	176,093	179,771
COAL EXPENSE (W/O HANDLING)	$80,306,908	$7,271,651	$7,283,476	$7,043,747	$2,349,261	$7,208,132	$7,365,308
COAL MMBtu's	48,933,853	4,463,611	4,469,324	4,310,087	1,439,364	4,402,322	4,494,272
UNIT 2							
COAL BURNED (TONS)	1,466,091	138,533	141,188	130,517	146,468	36,752	139,953
COAL EXPENSE (W/O HANDLING)	$60,103,814	$5,642,103	$5,752,207	$5,332,440	$5,976,407	$1,504,394	$5,733,945
COAL MMBtu's	36,652,297	3,463,330	3,529,709	3,262,930	3,661,695	918,808	3,498,837

BUDGETED COAL HANDLING RATE IS $0.53 PER TON BURNED

RRSB008B: PETCOKE EXPENSES

	TOTAL YEAR	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE
TOTAL PLANT							
DELIVERY PLAN:							
BEGINNING INVENTORY (TONS)	82,917	82,917	38,667	22,000	22,000	22,000	22,000
DELIVERIES	200,000	0	22,000	22,000	22,000	22,000	22,000
LESS COAL BURNED	282,917	44,250	38,667	22,000	22,000	22,000	22,000
ENDING INVENTORY	0	38,667	22,000	22,000	22,000	22,000	22,000
DELIVERED COST OF COAL ($/TON)	29.04	N/A	28.99	29.02	29.02	29.02	29.05
BEGINNING INVENTORY (DOLLARS)	$2,403,764	$2,403,764	$1,120,956	$637,780	$638,440	$638,440	$638,440
DELIVERIES & INVENTORY ADJ'S	5,808,080	0	637,780	638,440	638,440	638,440	639,100
COAL BURN EXPENSE	8,211,844	1,282,808	1,120,956	637,780	638,440	638,440	638,440
ENDING INVENTORY	($0)	$1,120,956	$637,780	$638,440	$638,440	$638,440	$639,100
MEMBER BURN DAYS AT PALATKA	0.9	1.0	1.0	1.0	1.0	1.0	1.0
BURN RATE (TONS / DAY)	0	38,667	22,000	22,000	22,000	22,000	22,000
ENDING AVERAGE $/TON	ERR	28.99	28.99	29.02	29.02	29.02	29.05
PETCOKE BURN PLAN:							
AVERAGE BURN COST*	29.03	28.99	28.99	28.99	29.02	29.02	29.02
TONS BURNED	282,917	44,250	38,667	22,000	22,000	22,000	22,000
PETCOKE BURN EXPENSE	$8,211,844	$1,282,808	$1,120,956	$637,780	$638,440	$638,440	$638,440
FUEL HANDLING EXPENSE	149,947	23,453	20,494	11,660	11,660	11,660	11,660
TOTAL PETCOKE EXPENSE	$8,361,791	$1,306,261	$1,141,450	$649,440	$650,100	$650,100	$650,100
COAL MMBtu's	7,865,093	1,230,150	1,074,943	611,600	611,600	611,600	611,600
UNIT 1							
PETCOKE BURNED (TONS)	0	0	0	0	0	0	0
PETCOKE EXPENSE (W/O HANDLING)	$0	$0	$0	N/A	N/A	N/A	N/A
COAL MMBtu's	0	0	0	0	0	0	0
UNIT 2							
PETCOKE BURNED (TONS)	282,917	44,250	38,667	22,000	22,000	22,000	22,000
PETCOKE EXPENSE (W/O HANDLING)	$8,211,844	$1,282,808	$1,120,956	$637,780	$638,440	$638,440	$638,440
COAL MMBtu's	7,865,093	1,230,150	1,074,943	611,600	611,600	611,600	611,600

BUDGETED COAL HANDLING RATE IS $0.53 PER TON BURNED

00021

RRSB008B: PETCOKE EXPENSES

	TOTAL YEAR	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
TOTAL PLANT							
DELIVERY PLAN:							
BEGINNING INVENTORY (TONS)	82,917	22,000	22,000	22,000	22,000	44,000	22,000
DELIVERIES	200,000	22,000	22,000	22,000	24,000	0	0
LESS COAL BURNED	282,917	22,000	22,000	22,000	2,000	22,000	22,000
ENDING INVENTORY	0	22,000	22,000	22,000	44,000	22,000	0
DELIVERED COST OF COAL ($/TON)	29.04	29.05	29.05	29.08	29.08	0.00	0.00
BEGINNING INVENTORY (DOLLARS)	$2,403,764	$639,100	$639,100	$639,100	$639,760	$1,279,520	$639,760
DELIVERIES & INVENTORY ADJ'S	5,808,080	639,100	639,100	639,760	697,920	0	0
COAL BURN EXPENSE	8,211,844	639,100	639,100	639,100	58,160	639,760	639,760
ENDING INVENTORY	($0)	$639,100	$639,100	$639,760	$1,279,520	$639,760	($0)
MEMBER BURN DAYS AT PALATKA	0.9	1.0	1.0	1.0	1.0	1.0	0.1
BURN RATE (TONS / DAY)	0	22,000	22,000	22,000	44,000	22,000	0
ENDING AVERAGE $/TON	ERR	29.05	29.05	29.08	29.08	29.08	N/A
PETCOKE BURN PLAN:							
AVERAGE BURN COST*	29.03	29.05	29.05	29.05	29.08	29.08	29.08
TONS BURNED	282,917	22,000	22,000	22,000	2,000	22,000	22,000
PETCOKE BURN EXPENSE	$8,211,844	$639,100	$639,100	$639,100	$58,160	$639,760	$639,760
FUEL HANDLING EXPENSE	149,947	11,660	11,660	11,660	1,060	11,660	11,660
TOTAL PETCOKE EXPENSE	$8,361,791	$650,760	$650,760	$650,760	$59,220	$651,420	$651,420
COAL MMBtu's	7,865,093	611,600	611,600	611,600	55,600	611,600	611,600
UNIT 1							
PETCOKE BURNED (TONS)	0	0	0	0	0	0	0
PETCOKE EXPENSE (W/O HANDLING)	$0	N/A	N/A	N/A	N/A	N/A	N/A
COAL MMBtu's	0	0	0	0	0	0	0
UNIT 2							
PETCOKE BURNED (TONS)	282,917	22,000	22,000	22,000	2,000	22,000	22,000
PETCOKE EXPENSE (W/O HANDLING)	$8,211,844	$639,100	$639,100	$639,100	$58,160	$639,760	$639,760
COAL MMBtu's	7,865,093	611,600	611,600	611,600	55,600	611,600	611,600

BUDGETED COAL HANDLING RATE IS $0.53 PER TON BURNED

00022

RRSD010: PRODUCTION O & M EXPENSES

	TOTAL YEAR	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE
NET GENERATION (MWh)	9,509,236	878,760	833,762	811,366	748,594	822,509	832,546
FUEL EXPENSES							
TOTAL COAL (INCL. HANDLING)	$150,586,939	$14,137,823	$13,059,250	$12,836,380	$11,773,574	$12,973,454	$13,140,464
OIL	811,910	59,000	79,800	92,950	91,260	74,200	51,000
SUBTOTAL FUEL EXPENSE	$151,398,849	$14,196,823	$13,139,050	$12,929,330	$11,864,834	$13,047,654	$13,191,464
FUEL ADJUSTMENTS	0	0	0	0	0	0	0
INBAND FUEL	0	0	0	0	0	0	0
INVENTORY ADJUSTMENTS	10,785,513	991,507	941,091	920,378	848,408	933,621	945,770
TOTAL FUEL EXPENSE	$162,184,362	$15,188,330	$14,080,141	$13,849,708	$12,713,242	$13,981,275	$14,137,234
PLANT O & M EXPENSES (NON-FUEL)	$49,537,119	$0	$0	$0	$0	$0	$0
TOTAL PRODUCTION O & M EXPENSES	$211,721,481	$15,188,330	$14,080,141	$13,849,708	$12,713,242	$13,981,275	$14,137,234

000023

RRSB010: PRODUCTION O & M EXPENSES

	TOTAL YEAR	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
NET GENERATION (MWh)	9,509,236	868,258	875,577	832,887	525,256	604,185	875,536
FUEL EXPENSES							
TOTAL COAL (INCL. HANDLING)	$150,586,939	$13,732,565	$13,856,022	$13,187,495	$8,493,031	$9,476,754	$13,920,127
OIL	811,910	50,000	49,000	70,000	63,240	65,660	65,800
SUBTOTAL FUEL EXPENSE	$151,398,849	$13,782,565	$13,905,022	$13,257,495	$8,556,271	$9,542,414	$13,985,927
FUEL ADJUSTMENTS	0	0	0	0	0	0	0
INBAND FUEL	0	0	0	0	0	0	0
INVENTORY ADJUSTMENTS	10,785,513	986,714	995,107	945,517	599,585	683,399	994,417
TOTAL FUEL EXPENSE	$162,184,362	$14,769,279	$14,900,129	$14,203,012	$9,155,856	$10,225,813	$14,980,344
PLANT O & M EXPENSES (NON-FUEL)	$49,537,119	$0	$0	$0	$0	$0	$49,537,119
TOTAL PRODUCTION O & M EXPENSES	$211,721,481	$14,769,279	$14,900,129	$14,203,012	$9,155,856	$10,225,813	$64,517,463

00024

RRSB012: PLANT AVERAGE FUEL RATES

	TOTAL YEAR	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE
NET GENERATION (MWh)	9,509,236	878,760	833,762	811,366	748,594	822,509	832,546
TOTAL FUEL EXPENSE (W/O ADJ'S):							
COAL:							
COST ($/TON)	40.10	40.75	40.41	40.35	40.20	40.21	40.18
HANDLING	0.53	0.53	0.53	0.53	0.53	0.53	0.53
TOTAL BURN COST ($/TON)	40.63	41.28	40.94	40.88	40.73	40.74	40.71
TOTAL COAL EXPENSE	$150,586,939	$14,137,823	$13,059,250	$12,836,380	$11,773,574	$12,973,454	$13,140,464
TONS BURNED	3,706,362	340,724	323,399	316,281	291,549	320,832	325,007
COAL MMBtu's	93,451,243	8,641,986	8,193,235	7,968,633	7,350,329	8,082,393	8,186,778
RATES - AVG. MILLS/KWh	15.84	16.09	15.66	15.82	15.73	15.77	15.78
AVG. $/MMBtu	1.61	1.64	1.59	1.61	1.60	1.61	1.61
IGNITION OIL:							
COST ($/GALLON)	0.52	0.59	0.57	0.55	0.54	0.53	0.51
OIL EXPENSE	$811,910	$59,000	$79,800	$92,950	$91,260	$74,200	$51,000
GALLONS CONSUMED	1,556,000	100,000	140,000	169,000	169,000	140,000	100,000
OIL MMBtu's	214,728	13,800	19,320	23,322	23,322	19,320	13,800
RATES - AVG. MILLS/KWh	0.09	0.07	0.10	0.11	0.12	0.09	0.06
AVG. $/MMBtu	3.78	4.28	4.13	3.99	3.91	3.84	3.70
TOTAL PLANT FUEL EXPENSE	$151,398,849	$14,196,823	$13,139,050	$12,929,330	$11,864,834	$13,047,654	$13,191,464
INBAND AND ADJUSTMENTS	10,785,513	991,507	941,091	920,378	848,408	933,621	945,770
TOTAL PLANT FUEL EXPENSE	$162,184,362	$15,188,330	$14,080,141	$13,849,708	$12,713,242	$13,981,275	$14,137,234
TOTAL MONTHLY RATES:							
- AVG. FUEL (MILLS/KWh)	17.06	17.28	16.89	17.07	16.98	17.00	16.98
- AVG. $/MMBtu	1.73	1.75	1.71	1.73	1.72	1.73	1.72
YEAR-TO-DATE RATES							
- AVG. FUEL (MILLS/KWh)	17.06	17.28	17.09	17.08	17.06	17.05	17.04
- AVG. $/MMBtu	1.73	1.75	1.74	1.73	1.73	1.73	1.73

00025

RRSB012: PLANT AVERAGE FUEL RATES

	TOTAL YEAR	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
NET GENERATION (MWh)	9,509,236	868,258	875,577	832,887	525,256	604,185	875,536
TOTAL FUEL EXPENSE (W/O ADJ'S):							
COAL:							
COST ($/TON)	40.10	40.21	40.14	40.20	40.11	39.85	40.47
HANDLING	0.53	0.53	0.53	0.53	0.53	0.53	0.53
TOTAL BURN COST ($/TON)	40.63	40.74	40.67	40.73	40.64	40.38	41.00
TOTAL COAL EXPENSE	$150,586,939	$13,732,565	$13,856,022	$13,187,495	$8,493,031	$9,476,754	$13,920,127
TONS BURNED	3,706,362	339,077	341,961	324,920	206,043	234,845	341,724
COAL MMBtu's	93,451,243	8,538,541	8,610,633	8,184,617	5,156,659	5,932,730	8,604,709
RATES - AVG. MILLS/KWh	15.84	15.82	15.83	15.83	16.17	15.69	15.90
AVG. $/MMBtu	1.61	1.61	1.61	1.61	1.65	1.60	1.62
IGNITION OIL:							
COST ($/GALLON)	0.52	0.50	0.49	0.50	0.51	0.49	0.47
OIL EXPENSE	$811,910	$50,000	$49,000	$70,000	$63,240	$65,660	$65,800
GALLONS CONSUMED	1,556,000	100,000	100,000	140,000	124,000	134,000	140,000
OIL MMBtu's	214,728	13,800	13,800	19,320	17,112	18,492	19,320
RATES - AVG. MILLS/KWh	0.09	0.06	0.06	0.08	0.12	0.11	0.08
AVG. $/MMBtu	3.78	3.62	3.55	3.62	3.70	3.55	3.41
TOTAL PLANT FUEL EXPENSE	$151,398,849	$13,782,565	$13,905,022	$13,257,495	$8,556,271	$9,542,414	$13,985,927
INBAND AND ADJUSTMENTS	10,785,513	986,714	995,107	945,517	599,585	683,399	994,417
TOTAL PLANT FUEL EXPENSE	$162,184,362	$14,769,279	$14,900,129	$14,203,012	$9,155,856	$10,225,813	$14,980,344
TOTAL MONTHLY RATES:							
- AVG. FUEL (MILLS/KWh)	17.06	17.01	17.02	17.05	17.43	16.92	17.11
- AVG. $/MMBtu	1.73	1.73	1.73	1.73	1.77	1.72	1.74
YEAR-TO-DATE RATES							
- AVG. FUEL (MILLS/KWh)	17.06	17.03	17.03	17.03	17.06	17.05	17.06
- AVG. $/MMBtu	1.73	1.73	1.73	1.73	1.73	1.73	1.73

00026

RRSB014: WHEELING CHARGES

	TOTAL YEAR	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE
FPC - SECI GEN (MW)	17,563	1934	1917	1313	1222	1265	1423
TOTAL FPC WHEELING	$21,553,484	$2,373,363	$2,352,153	$1,611,768	$1,498,978	$1,552,952	$1,746,450
WEIGHTED RATE ($/MW)	1,227	1,227	1,227	1,228	1,227	1,228	1,227
FPC STRUC. SYS. CONTRACT DEMAND (M	5,460	455	455	455	455	455	455
NETWORK CONTRACT WHEELING	$5,913,180	$492,765	$492,765	$492,765	$492,765	$492,765	$492,765
WEIGHTED RATE ($/MW)	1,083	1,083	1,083	1,083	1,083	1,083	1,083
WHEELING CREDIT	($9,019,022)	($751,585)	($751,585)	($751,585)	($751,585)	($751,585)	($751,585)
WEIGHTED RATE ($/MW)	(1,652)	(1,652)	(1,652)	(1,652)	(1,652)	(1,652)	(1,652)
FPL - SECI GEN (MW)	8,873	926	905	712	565	687	751
TOTAL FPL WHEELING	$15,511,274	$1,302,402	$1,300,773	$1,278,376	$1,260,427	$1,281,584	$1,294,230
FUEL FPL WHEELING	$0	$0	$0	$0	$0	$0	$0
WEIGHTED RATE ($/MW)	1,748	1,406	1,437	1,796	2,232	1,866	1,723
WHEELING CHARGES	$0	$0	$0	$0	$0	$0	$0
TOTAL WHEELING CHARGES	$33,958,916	$3,416,945	$3,394,106	$2,631,324	$2,500,585	$2,575,716	$2,781,860
TFUC CHARGES:							
FPC	$92,759	$7,158	$7,158	$7,158	$7,158	$7,158	$7,158
FPL	0	0	0	0	0	0	0
O & M	0	0	0	0	0	0	0
TOTAL TFUC CHARGES	$92,759	$7,158	$7,158	$7,158	$7,158	$7,158	$7,158
TOTAL WHEELING & TFUC CHARGES	$34,051,675	$3,424,103	$3,401,264	$2,638,482	$2,507,743	$2,582,874	$2,789,018

000027

RRSB014: WHEELING CHARGES

	TOTAL YEAR	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
FPC - SECI GEN (MW)	17,563	1450	1470	1339	1168	1371	1691
TOTAL FPC WHEELING	$21,553,484	$1,778,932	$1,803,667	$1,642,700	$1,433,939	$1,682,943	$2,075,639
WEIGHTED RATE ($/MW)	1,227	1,227	1,227	1,227	1,228	1,228	1,227
FPC STRUC. SYS. CONTRACT DEMAND (M	5,460	455	455	455	455	455	455
NETWORK CONTRACT WHEELING	$5,913,180	$492,765	$492,765	$492,765	$492,765	$492,765	$492,765
WEIGHTED RATE ($/MW)	1,083	1,083	1,083	1,083	1,083	1,083	1,083
WHEELING CREDIT	($9,019,022)	($751,585)	($751,585)	($751,585)	($751,585)	($751,585)	($751,585)
WEIGHTED RATE ($/MW)	(1,652)	(1,652)	(1,652)	(1,652)	(1,652)	(1,652)	(1,652)
FPL - SECI GEN (MW)	8,873	791	789	714	654	635	745
TOTAL FPL WHEELING	$15,511,274	$1,303,562	$1,306,385	$1,297,220	$1,290,221	$1,288,906	$1,307,188
FUEL FPL WHEELING	$0	$0	$0	$0	$0	$0	$0
WEIGHTED RATE ($/MW)	1,748	1,648	1,656	1,817	1,971	2,031	1,754
WHEELING CHARGES	$0	$0	$0	$0	$0	$0	$0
TOTAL WHEELING CHARGES	$33,958,916	$2,823,674	$2,851,232	$2,681,100	$2,465,340	$2,713,029	$3,124,007
TFUC CHARGES:							
FPC	$92,759	$7,158	$7,158	$7,158	$7,158	$7,158	$14,021
FPL	0	0	0	0	0	0	0
O & M	0	0	0	0	0	0	0
TOTAL TFUC CHARGES	$92,759	$7,158	$7,158	$7,158	$7,158	$7,158	$14,021
TOTAL WHEELING & TFUC CHARGES	$34,051,675	$2,830,832	$2,858,390	$2,688,258	$2,472,498	$2,720,187	$3,138,028

000028

RRSB018: PURCHASED POWER - PR/FR

	TOTAL YEAR	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE
PARTIAL REQUIREMENTS:							
FPC SUPPLEMENTAL							
DEMAND PURCHASES (MW)	3,149	712	695	289	0	43	201
ENERGY PURCHASES (MWh)	92,690	18,261	6,486	1,276	0	1,811	11,246
TOTAL CHARGES	$21,281,066	$4,432,830	$3,828,347	$1,693,550	$62,436	$479,010	$1,622,906
WHEELING COMPONENT	$0	$0	$0	$0	$0	$0	$0
* FUEL COMPONENT	$3,318,614	$748,354	$254,310	$47,598	$0	$46,815	$365,611
* PR FUEL PURCHASED FROM FPC ONLY							
FPL ABPRSA							
DEMAND PURCHASES (MW)	0	0	0	0	0	0	0
ENERGY PURCHASES (MWh)	0	0	0	0	0	0	0
TOTAL CHARGES	$0	$0	$0	$0	$0	$0	$0
FUEL COMPONENT	$0	$0	$0	$0	$0	$0	$0
FULL REQUIREMENTS:							
FPL							
DEMAND PURCHASES (MW)	0	0.0	0.0	0.0	0.0	0.0	0.0
ENERGY PURCHASES (MWh)	0	0	0	0	0	0	0
TOTAL CHARGES	$0	$0	$0	$0	$0	$0	$0
FUEL COMPONENT	$0	$0	$0	$0	$0	$0	$0
GAINESVILLE							
DEMAND PURCHASES (MW)	129	11.7	13.0	9.8	8.0	10.6	11.8
ENERGY PURCHASES (MWh)	49,017	4,334	3,899	3,750	3,371	3,934	4,549
TOTAL CHARGES	$2,490,800	$220,716	$212,549	$189,156	$173,655	$200,223	$229,154
FUEL COMPONENT	$1,176,406	$104,019	$93,584	$90,003	$80,899	$94,404	$109,177
JACKSONVILLE							
DEMAND PURCHASES (MW)	0	0.0	0.0	0.0	0.0	0.0	0.0
ENERGY PURCHASES (MWh)	0	0	0	0	0	0	0
TOTAL CHARGES	$0	$0	$0	$0	$0	$0	$0
FUEL COMPONENT	$0	$0	$0	$0	$0	$0	$0
FPC							
DEMAND PURCHASES (MW)	0.324	0.027	0.027	0.027	0.027	0.027	0.027
ENERGY PURCHASES (MWh)	363	23.0	27.0	23.0	23.0	24.0	30.0
TOTAL CHARGES	$14,531	$1,063	$1,145	$1,063	$1,063	$1,083	$1,205
FUEL COMPONENT	$6,719	$426	$500	$426	$426	$444	$555
TOTAL PURCHASED POWER - PR/FR:							
DEMAND PURCHASES (MW)	3,278	724	708	299	8	54	213
ENERGY PURCHASES (MWh)	142,070	22,618	10,412	5,049	3,394	5,769	15,825
TOTAL CHARGES	$23,786,397	$4,654,609	$4,042,041	$1,883,769	$237,154	$680,316	$1,853,265
FUEL COMPONENT	$4,501,739	$852,799	$348,394	$138,027	$81,325	$141,663	$475,343

000294

RRSB018: PURCHASED POWER - PR/FR

	TOTAL YEAR	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
PARTIAL REQUIREMENTS:							
FPC SUPPLEMENTAL							
DEMAND PURCHASES (MW)	3,149	227	248	116	0	149	469
ENERGY PURCHASES (MWh)	92,690	16,740	19,701	8,414	0	1,622	7,133
TOTAL CHARGES	$21,281,066	$1,966,841	$2,194,359	$1,114,439	$62,909	$1,041,902	$2,781,537
WHEELING COMPONENT	$0	$0	$0	$0	$0	$0	$0
* FUEL COMPONENT	$3,318,614	$570,662	$696,038	$264,102	$0	$56,101	$269,023
* PR FUEL PURCHASED FROM FPC ONLY							
FPL ABPRSA							
DEMAND PURCHASES (MW)	0	0	0	0	0	0	0
ENERGY PURCHASES (MWh)	0	0	0	0	0	0	0
TOTAL CHARGES	$0	$0	$0	$0	$0	$0	$0
FUEL COMPONENT	$0	$0	$0	$0	$0	$0	$0
FULL REQUIREMENTS:							
FPL							
DEMAND PURCHASES (MW)	0	0.0	0.0	0.0	0.0	0.0	0.0
ENERGY PURCHASES (MWh)	0	0	0	0	0	0	0
TOTAL CHARGES	$0	$0	$0	$0	$0	$0	$0
FUEL COMPONENT	$0	$0	$0	$0	$0	$0	$0
GAINESVILLE							
DEMAND PURCHASES (MW)	129	11.4	13.1	10.9	9.0	9.0	10.8
ENERGY PURCHASES (MWh)	49,017	4,874	4,923	4,516	3,594	3,348	3,925
TOTAL CHARGES	$2,490,800	$238,361	$250,154	$223,262	$180,438	$171,613	$201,519
FUEL COMPONENT	$1,176,406	$116,969	$118,158	$108,382	$86,264	$80,346	$94,201
JACKSONVILLE							
DEMAND PURCHASES (MW)	0	0.0	0.0	0.0	0.0	0.0	0.0
ENERGY PURCHASES (MWh)	0	0	0	0	0	0	0
TOTAL CHARGES	$0	$0	$0	$0	$0	$0	$0
FUEL COMPONENT	$0	$0	$0	$0	$0	$0	$0
FPC							
DEMAND PURCHASES (MW)	0.324	0.027	0.027	0.027	0.027	0.027	0.027
ENERGY PURCHASES (MWh)	363	40.0	43.0	41.0	34.0	30.0	25.0
TOTAL CHARGES	$14,531	$1,410	$1,472	$1,431	$1,287	$1,205	$1,104
FUEL COMPONENT	$6,719	$740	$796	$759	$629	$555	$463
TOTAL PURCHASED POWER - PR/FR:							
DEMAND PURCHASES (MW)	3,278	238	261	127	9	158	480
ENERGY PURCHASES (MWh)	142,070	21,654	24,667	12,971	3,628	5,000	11,083
TOTAL CHARGES	$23,786,397	$2,206,612	$2,445,985	$1,339,132	$244,634	$1,214,720	$2,984,160
FUEL COMPONENT	$4,501,739	$688,371	$814,992	$373,243	$86,893	$137,002	$363,687

000030

RRSB020: PURCHASED POWER, OTHER THAN FR/PR

	TOTAL YEAR	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE
INTERCHANGE/OTHER PURCHASES:							
ENERGY PURCHASES (MWh)	3,067,184	195,500	141,875	146,234	132,404	254,187	320,939
TOTAL INTERCHANGE EXPENSE	$182,307,779	$13,765,213	$12,395,274	$11,398,602	$10,846,464	$14,677,267	$17,372,247
FUEL CHARGES (INCLUDED)	$77,787,728	$4,897,384	$3,482,336	$3,373,726	$3,058,548	$6,188,465	$8,587,290
Average Fuel Rate ($/MWh)	25.36	25.05	24.55	23.07	23.10	24.35	26.76
RESERVES (SCHEDULE H):							
ENERGY PURCHASES (MWh)	0	0	0	0	0	0	0
TOTAL RESERVES	$259,000	$21,937	$20,522	$21,937	$21,230	$21,937	$21,230
FUEL CHARGES (INCLUDED)	$0	$0	$0	$0	$0	$0	$0
ENERGY IMBALANCE & REG		20/34					
ENERGY PURCHASES (MWh)	34,000	2,881	2,694	2,881	2,787	2,881	2,787
TOTAL ENERGY IMB. & REG.	$5,211,788	$484,262	$463,078	$426,535	$401,285	$421,562	$427,583
FUEL CHARGES (INCLUDED)	$576,590	$48,307	$42,731	$47,463	$52,412	$53,054	$48,434
INTERRUPTIBLE PURCHASES:							
ENERGY PURCHASES (MWh)	151,596	12,633	12,633	12,633	12,633	12,633	12,633
TOTAL, INTERRUPTIBLE POWER	$5,122,708	$427,445	$426,122	$426,563	$426,298	$425,872	$425,960
TRANSM LOSSES, MARTEL DELIVERY PT:	$62,806	$6,526	$6,191	$4,811	$4,027	$4,562	$5,368
TOTAL PURCHASED POWER, OTHER THAN FR/PR/WHLG							
ENERGY PURCHASES (MWh)	3,252,780	211,014	157,202	161,748	147,824	269,701	336,359
TOTAL EXPENSES	**$192,964,081**	**$14,705,383**	**$13,311,187**	**$12,278,448**	**$11,699,304**	**$15,551,200**	**$18,252,388**
FUEL CHARGES (INCLUDED)	**$78,364,318**	**$4,945,691**	**$3,525,067**	**$3,421,189**	**$3,110,960**	**$6,241,519**	**$8,635,724**

✓ 2823410 Non-fuel Imbal.

FPC Imbal 1660829

2823410 * 20/34 =

RRSB020: PURCHASED POWER, OTHER THAN FR/PR

	TOTAL YEAR	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
INTERCHANGE/OTHER PURCHASES:							
ENERGY PURCHASES (MWh)	3,067,184	357,258	357,042	289,988	414,956	296,773	160,028
TOTAL INTERCHANGE EXPENSE	$182,307,779	$18,710,619	$18,818,436	$17,102,402	$18,431,387	$15,552,323	$13,237,545
FUEL CHARGES (INCLUDED)	$77,787,728	$9,844,630	$9,986,039	$8,324,826	$9,430,556	$6,795,527	$3,818,401
Average Fuel Rate ($/MWh)	25.36	27.56	27.97	28.71	22.73	22.90	23.86
RESERVES (SCHEDULE H):							
ENERGY PURCHASES (MWh)	0	0	0	0	0	0	0
TOTAL RESERVES	$259,000	$21,937	$21,937	$21,230	$21,937	$21,230	$21,937
FUEL CHARGES (INCLUDED)	$0	$0	$0	$0	$0	$0	$0
ENERGY IMBALANCE & REG							
ENERGY PURCHASES (MWh)	34,000	2,880	2,880	2,787	2,879	2,785	2,878
TOTAL ENERGY IMB. & REG.	$5,211,788	$441,319	$442,607	$419,200	$412,630	$416,343	$455,384
FUEL CHARGES (INCLUDED)	$576,590	$52,603	$46,868	$44,478	$48,584	$47,548	$44,108
INTERRUPTIBLE PURCHASES:							
ENERGY PURCHASES (MWh)	151,596	12,633	12,633	12,633	12,633	12,633	12,633
TOTAL, INTERRUPTIBLE POWER	$5,122,708	$426,651	$426,783	$427,548	$427,283	$426,754	$429,429
TRANSM LOSSES, MARTEL DELIVERY PT:	$62,806	$5,492	$5,546	$5,303	$4,481	$4,483	$6,016
TOTAL PURCHASED POWER, OTHER THAN FR/PR/WHLG							
ENERGY PURCHASES (MWh)	3,252,780	372,771	372,555	305,408	430,468	312,191	175,539
TOTAL EXPENSES	**$192,964,081**	**$19,606,018**	**$19,715,309**	**$17,975,683**	**$19,297,718**	**$16,421,133**	**$14,150,311**
FUEL CHARGES (INCLUDED)	**$78,364,318**	**$9,897,233**	**$10,032,907**	**$8,369,304**	**$9,479,140**	**$6,843,075**	**$3,862,509**

Detail of Interchange Purchases...

1. COSTS RELATED TO BIG BEND 4 / HPS:		TOTAL	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE
BIG BEND 4 (145 MW):								
Total Entitlement (MWh):	470,000 Backup/RPR:	293,814	22,479	14,899	7,966	889	1,768	42,029
Available Excess Generation:	176,186							
Percent Avail. Excess Sold:	5.0% Broker:	8,808	0	0	0	0	0	2,202
Total Energy Purchased:		302,622	22,479	14,899	7,966	889	1,768	44,231
Monthly Capacity Charge		**$15,221,004**	**$1,268,417**	**$1,268,417**	**$1,268,417**	**$1,268,417**	**$1,268,417**	**$1,268,417**
Variable O & M @	$3.84 /MWh F	1,162,068	86,319	57,212	30,589	3,414	6,789	169,847
Variable A & G @	$2.31 /MWh F	699,057	51,926	34,417	18,401	2,054	4,084	102,174
Avg. Fuel @	$22.63 /MWh	6,849,234	493,639	320,924	171,269	18,918	37,499	975,736
TOTAL BIG BEND 4:	**$28.78 /MWh**	**$23,931,363**	**$1,900,301**	**$1,680,970**	**$1,488,676**	**$1,292,803**	**$1,316,789**	**$2,516,174**
Big Bend 4 Fuel Cost ($/MWh)		22.63	21.96	21.54	21.50	21.28	21.21	22.06
HPS: COMBINED CYCLE (220 MW): CT1A, CT1B, ST								
MWh		205,967	954	542	15,709	15,008	1,392	2,744
Fixed O & M:		$1,089,704	$64,142	$224,142	$64,142	$64,142	$224,142	$64,142
Variable O & M:	G	531,395	2,461	1,398	40,529	38,721	3,591	7,080
Fixed, Replace Prop		5,688	474	474	474	474	474	474
Admin & General:		98,424	8,202	8,202	8,202	8,202	8,202	8,202
Fuel:		5,084,294	29,864	16,221	406,643	363,974	36,273	71,032
TOTAL COMBINED CYCLE EXPENSES		**$6,809,505**	**$105,143**	**$250,437**	**$519,990**	**$475,513**	**$272,682**	**$150,930**
CC Fuel ($/MWh), incl. 'sunk' stand-by & adder charg		24.68	31.30	29.93	25.89	24.25	26.06	25.89
COMBUSTION TURBINE (75 MW): CT2A								
MWh		6,989	198	164	47	78	378	858
Fixed O & M:		$536,572	$21,381	$21,381	$21,381	$21,381	$21,381	$21,381
Variable O & M:	G	7,268	206	171	49	81	393	892
Fixed, Replace Prop		6,096	508	508	508	508	508	508
Admin & General:		42,672	3,556	3,556	3,556	3,556	3,556	3,556
Fuel:		271,847	9,369	7,419	1,839	2,859	14,890	33,574
TOTAL COMBUSTION TURBINE EXPENSES		**$864,455**	**$35,020**	**$33,035**	**$27,333**	**$28,385**	**$40,728**	**$59,911**
CT Fuel ($/MWh), incl. 'sunk' stand-by & adder charg		38.90	47.32	45.24	39.13	36.65	39.39	39.13
HPS Monthly Capacity Charge		**$18,883,200**	**$1,573,600**	**$1,573,600**	**$1,573,600**	**$1,573,600**	**$1,573,600**	**$1,573,600**
Hardee County Tax Abatement		**($252,180)**	**($21,015)**	**($21,015)**	**($21,015)**	**($21,015)**	**($21,015)**	**($21,015)**
HPS Broker Profit (Offset to Purchased Power Invoice)		**($144,000)**	**$0**	**$0**	**$0**	**$0**	**$0**	**($36,000)**
TOTAL BIG BEND 4 / HARDEE POWER STATION:								
MWh		**515,578**	**23,631**	**15,605**	**23,722**	**15,975**	**3,538**	**47,833**
Non-fuel Expenses		**$37,886,968**	**$3,060,177**	**$3,172,463**	**$3,008,833**	**$2,963,535**	**$3,094,122**	**$3,163,258**
Fuel expenses		**12,205,375**	**532,872**	**344,564**	**579,751**	**385,751**	**88,662**	**1,080,342**
TOTAL EXPENSES, BIG BEND 4 / HPS		**$50,092,343**	**$3,593,049**	**$3,517,027**	**$3,588,584**	**$3,349,286**	**$3,182,784**	**$4,243,600**
Average Fuel Cost ($/MWh)		**23.67**	**22.55**	**22.08**	**24.44**	**24.15**	**25.06**	**22.59**

Detail of Interchange Purchases...

1. COSTS RELATED TO BIG BEND 4 / HPS:				TOTAL	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
BIG BEND 4 (145 MW):										
Total Entitlement (MWh):	470,000	Backup/RPR:		293,814	47,915	44,856	42,075	48,938	4,799	15,201
Available Excess Generation:	176,186									
Percent Avail. Excess Sold:	5.0%	Broker:		8,808	2,202	2,202	2,202	0	0	0
Total Energy Purchased:				302,622	50,117	47,058	44,277	48,938	4,799	15,201
Monthly Capacity Charge				**$15,221,004**	**$1,268,417**	**$1,268,417**	**$1,268,417**	**$1,268,417**	**$1,268,417**	**$1,268,417**
Variable O & M @	$3.84	/MWh		1,162,068	192,449	180,703	170,024	187,922	18,428	58,372
Variable A & G @	$2.31	/MWh		699,057	115,770	108,704	102,280	113,047	11,086	35,114
Avg. Fuel @	$22.63	/MWh		6,849,234	1,132,644	1,079,981	1,023,684	1,133,404	111,001	350,535
TOTAL BIG BEND 4:	**$28.78**	**/MWh**		**$23,931,363**	**$2,709,280**	**$2,637,805**	**$2,564,405**	**$2,702,790**	**$1,408,932**	**$1,712,438**
Big Bend 4 Fuel Cost ($/MWh)				22.63	22.60	22.95	23.12	23.16	23.13	23.06
HPS: COMBINED CYCLE (220 MW): CT1A, CT1B, ST										
	MWh			205,967	3,205	2,959	2,544	94,729	65,691	490
Fixed O & M:				$1,089,704	$64,142	$64,142	$64,142	$64,142	$64,142	$64,142
Variable O & M:				531,395	8,269	7,634	6,564	244,401	169,483	1,264
Fixed, Replace Prop				5,688	474	474	474	474	474	474
Admin & General:				98,424	8,202	8,202	8,202	8,202	8,202	8,202
Fuel:				5,084,294	82,965	76,851	66,291	2,264,781	1,655,282	14,117
TOTAL COMBINED CYCLE EXPENSES				**$6,809,505**	**$164,052**	**$157,303**	**$145,673**	**$2,582,000**	**$1,897,583**	**$88,199**
CC Fuel ($/MWh), incl. 'sunk' stand-by & adder charg				24.68	25.89	25.97	26.06	23.91	25.20	28.81
COMBUSTION TURBINE (75 MW): CT2A										
	MWh			6,989	995	932	759	1,221	1,252	107
Fixed O & M:				$536,572	$21,381	$21,381	$21,381	$21,381	$21,381	$301,381
Variable O & M:				7,268	1,035	969	789	1,270	1,302	111
Fixed, Replace Prop				6,096	508	508	508	508	508	508
Admin & General:				42,672	3,556	3,556	3,556	3,556	3,556	3,556
Fuel:				271,847	38,934	36,590	29,897	44,127	47,689	4,660
TOTAL COMBUSTION TURBINE EXPENSES				**$864,455**	**$65,414**	**$63,004**	**$56,131**	**$70,842**	**$74,436**	**$310,216**
CT Fuel ($/MWh), incl. 'sunk' stand-by & adder charg				38.90	39.13	39.26	39.39	36.14	38.09	43.55
HPS Monthly Capacity Charge				**$18,883,200**	**$1,573,600**	**$1,573,600**	**$1,573,600**	**$1,573,600**	**$1,573,600**	**$1,573,600**
Hardee County Tax Abatement				**($252,180)**	**($21,015)**	**($21,015)**	**($21,015)**	**($21,015)**	**($21,015)**	**($21,015)**
HPS Broker Profit (Offset to Purchased Power Invoice)				**($144,000)**	**($36,000)**	**($36,000)**	**($36,000)**	**$0**	**$0**	**$0**
TOTAL BIG BEND 4 / HARDEE POWER STATION:										
MWh				515,578	54,317	50,949	47,580	144,888	71,742	15,798
Non-fuel Expenses				$37,886,968	$3,200,788	$3,181,275	$3,162,922	$3,465,905	$3,119,564	$3,294,126
Fuel expenses				12,205,375	1,254,543	1,193,422	1,119,872	3,442,312	1,813,972	369,312
TOTAL EXPENSES, BIG BEND 4 / HPS				$50,092,343	$4,455,331	$4,374,697	$4,282,794	$6,908,217	$4,933,536	$3,663,438
Average Fuel Cost ($/MWh)				23.67	23.10	23.42	23.54	23.76	25.28	23.38

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Detail of Interchange Purchases...	TOTAL	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE
2. NON-FIRM INTERCHANGE PURCHASES:							
ENERGY PURCHASES (MWh)	430,033	33,097	16,099	5,293	8,941	41,170	34,183
PEAKING RPR ENERGY PURCHASES (MWh)	12,167	2,237	849	201	0	46	1,370
INTERMEDIATE RPR ENERGY PURCHASES (M	0	0	0	0	0	0	0
TOTAL ENERGY PURCHASES (MWh)	442,200	35,334	16,948	5,494	8,941	41,216	35,553
TOTAL 'OTHER' INTERCHANGE EXPENSE ✓ Ø	**$14,602,566**	**$841,351**	**$409,395**	**$140,952**	**$230,963**	**$1,077,386**	**$1,612,797**
FUEL CHARGES (INCLUDED)	$14,602,566	$841,351	$409,395	$140,952	$230,963	$1,077,386	$1,612,797
RATES ($/MWh)		***(ECONIGHT INTERCHANGE UNIT PRICED AT $18.89/MWH - 61,733 MWH)***					
TOTAL RATE	33.02	26.14	26.14	26.14	26.14	26.14	45.85
NON-FUEL COMPONENT	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FUEL COMPONENT	33.02	26.14	26.14	26.14	26.14	26.14	45.85
3. EMERGENCY PURCHASES:							
ENERGY PURCHASES (MWh)	20,000	1,300	600	200	400	2,600	3,000
TOTAL EMERGENCY EXPENSE ✓ Ø	**$1,753,500**	**$97,500**	**$45,000**	**$15,000**	**$30,000**	**$234,000**	**$270,000**
FUEL CHARGES (INCLUDED)	$1,753,500	$97,500	$45,000	$15,000	$30,000	$234,000	$270,000
RATES ($/MWh)							
TOTAL RATE	87.68	75.00	75.00	75.00	75.00	90.00	90.00
NON-FUEL COMPONENT	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FUEL COMPONENT	87.68	75.00	75.00	75.00	75.00	90.00	90.00
4. OTHER PURCHASES:							
A. JACKSONVILLE:							
CAPACITY (MW)	628.8	52.4	52.4	52.4	52.4	52.4	52.4
ENERGY PURCHASES (MWh)	13,422	2,762	1,206	1,253	555	1,557	1,271
TOTAL EXPENSE	**$3,563,001**	**$405,815**	**$302,714**	**$305,829**	**$259,579**	**$325,972**	**$307,022**
CAPACITY CHARGES (INCLUDED):	$2,673,660	$222,805	$222,805	$222,805	$222,805	$222,805	$222,805
OTHER NON-FUEL CHARGES (INCLUDED)	✓$193,142	$39,745	$17,354	$18,031	$7,986	$22,405	$18,290
FUEL CHARGES (INCLUDED)	$696,199	$143,265	$62,555	$64,993	$28,788	$80,762	$65,927
B. HARDEE POWER STATION DELIVERY POINT:							
ENERGY PURCHASES (MWh)	8,119	601	554	729	616	875	791
TOTAL EXPENSE ✓ 170487	**$292,096**	**$21,962**	**$20,254**	**$23,850**	**$22,750**	**$30,634**	**$28,082**
FUEL CHARGES (INCLUDED)	$121,609	$8,999	$8,299	$10,916	$9,225	$13,115	$11,850
C. LEE COUNTY							
CAPACITY (MW)	400	35	35	35	35	35	30
ENERGY PURCHASES (MWh)	139,901	10,486	9,655	8,641	4,782	9,691	12,844
TOTAL EXPENSE	**$4,621,978**	**$384,720**	**$368,100**	**$406,492**	**$198,110**	**$263,820**	**$406,880**
CAPACITY CHARGES (INCLUDED):	$1,580,000	$175,000	$175,000	$175,000	$70,000	$70,000	$150,000
OTHER NON-FUEL CHARGES (INCLUDED)	✓$243,958	$0	$0	$58,672	$32,470	$0	$0
FUEL CHARGES (INCLUDED)	$2,798,020	$209,720	$193,100	$172,820	$95,640	$193,820	$256,880

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Detail of Interchange Purchases...	TOTAL	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
2. NON-FIRM INTERCHANGE PURCHASES:							
ENERGY PURCHASES (MWh)	430,033	47,032	51,722	41,075	87,837	41,288	22,296
PEAKING RPR ENERGY PURCHASES (MWh)	12,167	2,408	2,971	893	0	250	942
INTERMEDIATE RPR ENERGY PURCHASES (M	0	0	0	0	0	0	0
TOTAL ENERGY PURCHASES (MWh)	442,200	49,440	54,693	41,968	87,837	41,538	23,238
TOTAL 'OTHER' INTERCHANGE EXPENSE	**$14,602,566**	**$2,227,489**	**$2,469,256**	**$1,897,030**	**$2,138,067**	**$1,025,222**	**$532,658**
FUEL CHARGES (INCLUDED)	$14,602,566	$2,227,489	$2,469,256	$1,897,030	$2,138,067	$1,025,222	$532,658
RATES ($/MWh)							
TOTAL RATE	33.02	45.85	45.85	45.85	26.14	26.14	26.14
NON-FUEL COMPONENT	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FUEL COMPONENT	33.02	45.85	45.85	45.85	26.14	26.14	26.14
3. EMERGENCY PURCHASES:							
ENERGY PURCHASES (MWh)	20,000	3,900	4,100	3,300	100	200	300
TOTAL EMERGENCY EXPENSE	**$1,753,500**	**$351,000**	**$369,000**	**$297,000**	**$7,500**	**$15,000**	**$22,500**
FUEL CHARGES (INCLUDED)	$1,753,500	$351,000	$369,000	$297,000	$7,500	$15,000	$22,500
RATES ($/MWh)							
TOTAL RATE	87.68	90.00	90.00	90.00	75.00	75.00	75.00
NON-FUEL COMPONENT	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FUEL COMPONENT	87.68	90.00	90.00	90.00	75.00	75.00	75.00
4. OTHER PURCHASES:							
A. JACKSONVILLE:							
CAPACITY (MW)	628.8	52.4	52.4	52.4	52.4	52.4	52.4
ENERGY PURCHASES (MWh)	13,422	949	330	127	2,114	414	884
TOTAL EXPENSE	**$3,563,001**	**$285,686**	**$244,671**	**$231,220**	**$362,878**	**$250,236**	**$281,379**
CAPACITY CHARGES (INCLUDED):	$2,673,660	$222,805	$222,805	$222,805	$222,805	$222,805	$222,805
OTHER NON-FUEL CHARGES (INCLUDED)	$193,142	$13,656	$4,749	$1,828	$30,420	$5,957	$12,721
FUEL CHARGES (INCLUDED)	$696,199	$49,225	$17,117	$6,587	$109,653	$21,474	$45,853
B. HARDEE POWER STATION DELIVERY POINT:							
ENERGY PURCHASES (MWh)	8,119	437	612	609	841	803	651
TOTAL EXPENSE	**$292,096**	**$17,484**	**$22,719**	**$22,582**	**$29,617**	**$28,487**	**$23,675**
FUEL CHARGES (INCLUDED)	$121,609	$6,543	$9,164	$9,118	$12,598	$12,033	$9,749
C. LEE COUNTY							
CAPACITY (MW)	400	30	30	30	35	35	35
ENERGY PURCHASES (MWh)	139,901	13,792	13,548	12,296	12,309	22,506	9,351
TOTAL EXPENSE	**$4,621,978**	**$425,840**	**$420,960**	**$395,920**	**$316,180**	**$672,936**	**$362,020**
CAPACITY CHARGES (INCLUDED):	$1,580,000	$150,000	$150,000	$150,000	$70,000	$70,000	$175,000
OTHER NON-FUEL CHARGES (INCLUDED)	$243,958	$0	$0	$0	$0	$152,816	$0
FUEL CHARGES (INCLUDED)	$2,798,020	$275,840	$270,960	$245,920	$246,180	$450,120	$187,020

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4. OTHER PURCHASES CONTINUED:	TOTAL	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE
D. ORLANDO UTILITIES COMMISSION:							
CAPACITY (MW)	1,500	125	125	125	125	125	125
ENERGY PURCHASES (MWh)	114,189	5,450	3,006	2,012	2,419	7,864	19,847
TOTAL EXPENSE	**$12,506,624**	**$852,593**	**$738,604**	**$692,243**	**$711,226**	**$965,181**	**$1,524,068**
CAPACITY CHARGES (INCLUDED):	$7,180,848	$598,404	$598,404	$598,404	$598,404	$598,404	$598,404
OTHER NON-FUEL CHARGES (INCLUDED)	$775,344	$37,006	$20,411	$13,661	$16,425	$53,397	$134,761
FUEL CHARGES (INCLUDED)	$4,550,432	$217,183	$119,789	$80,178	$96,397	$313,380	$790,903
E. FLORIDA POWER CORPORATION:							
STRUCTURED SYSTEM:							
CAPACITY (MW)	3,600	300	300	300	300	300	300
ENERGY PURCHASES (MWh)	1,149,663	72,255	64,401	74,704	69,681	124,948	128,064
AVAILABLE EXCESS FOR RESALE (MWh)	142,900	14,900	0	12,500	14,700	27,700	19,400
PERCENT AVAIL. EXCESS SOLD: 50%	71,450	7,450	0	6,250	7,350	13,850	9,700
TOTAL ENERGY PURCHASED (MWh)	1,221,113	79,705	64,401	80,954	77,031	138,798	137,764
TOTAL EXPENSE	**$52,582,388**	**$4,016,529**	**$3,673,252**	**$3,906,859**	**$3,772,970**	**$5,138,097**	**$5,111,253**
CAPACITY CHARGES (INCLUDED):	$21,600,000	$1,800,000	$1,800,000	$1,800,000	$1,800,000	$1,800,000	$1,800,000
OTHER NON-FUEL CHARGES (INCLUDED)	$3,600,000	$300,000	$300,000	$300,000	$300,000	$300,000	$300,000
FUEL CHARGES (INCLUDED)	$27,382,388	$1,916,529	$1,573,252	$1,806,859	$1,672,970	$3,038,097	$3,011,253
INTERMEDIATE BLOCK:							
CAPACITY (MW)	1,800	150	150	150	150	150	150
ENERGY PURCHASES (MWh)	534,928	30,820	26,202	21,846	18,903	42,067	54,057
TOTAL EXPENSE	**$25,062,855**	**$1,736,108**	**$1,617,795**	**$1,506,195**	**$1,430,795**	**$2,024,257**	**$2,331,440**
CAPACITY CHARGES (INCLUDED):	$11,358,000	$946,500	$946,500	$946,500	$946,500	$946,500	$946,500
OTHER NON-FUEL CHARGES (INCLUDED)	$3,006,295	$173,208	$147,255	$122,775	$106,235	$236,417	$303,800
FUEL CHARGES (INCLUDED)	$10,698,560	$616,400	$524,040	$436,920	$378,060	$841,340	$1,081,140
PEAKING BLOCK:							
CAPACITY (MW)	3,660	305	305	305	305	305	305
ENERGY PURCHASES (MWh)	49,162	3,310	2,686	1,376	2,782	5,169	7,034
TOTAL EXPENSE	**$10,862,063**	**$866,641**	**$836,083**	**$771,933**	**$840,785**	**$957,676**	**$1,049,005**
CAPACITY CHARGES (INCLUDED):	$8,454,600	$704,550	$704,550	$704,550	$704,550	$704,550	$704,550
OTHER NON-FUEL CHARGES (INCLUDED)	$96,849	$6,521	$5,291	$2,711	$5,481	$10,183	$13,857
FUEL CHARGES (INCLUDED)	$2,310,614	$155,570	$126,242	$64,672	$130,754	$242,943	$330,598

4. OTHER PURCHASES CONTINUED:	TOTAL	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
D. ORLANDO UTILITIES COMMISSION:							
CAPACITY (MW)	1,500	125	125	125	125	125	125
ENERGY PURCHASES (MWh)	114,189	23,495	23,668	21,379	1,028	1,296	2,725
TOTAL EXPENSE	**$12,506,624**	**$1,694,211**	**$1,702,280**	**$1,595,520**	**$646,350**	**$658,850**	**$725,498**
CAPACITY CHARGES (INCLUDED):	$7,180,848	$598,404	$598,404	$598,404	$598,404	$598,404	$598,404
OTHER NON-FUEL CHARGES (INCLUDED)	$775,344	$159,531	$160,706	$145,163	$6,980	$8,800	$18,503
FUEL CHARGES (INCLUDED)	$4,550,432	$936,276	$943,170	$851,953	$40,966	$51,646	$108,591
E. FLORIDA POWER CORPORATION:							
STRUCTURED SYSTEM:							
CAPACITY (MW)	3,600	300	300	300	300	300	300
ENERGY PURCHASES (MWh)	1,149,663	133,663	133,397	100,455	89,855	86,556	71,684
AVAILABLE EXCESS FOR RESALE (MWh)	142,900	18,900	19,200	0	0	0	15,600
PERCENT AVAIL. EXCESS SOLD: 50%	71,450	9,450	9,600	0	0	0	7,800
TOTAL ENERGY PURCHASED (MWh)	1,221,113	143,113	142,997	100,455	89,855	86,556	79,484
TOTAL EXPENSE	**$52,582,388**	**$5,210,445**	**$5,218,368**	**$4,509,061**	**$4,003,928**	**$4,036,834**	**$3,984,792**
CAPACITY CHARGES (INCLUDED):	$21,600,000	$1,800,000	$1,800,000	$1,800,000	$1,800,000	$1,800,000	$1,800,000
OTHER NON-FUEL CHARGES (INCLUDED)	$3,600,000	$300,000	$300,000	$300,000	$300,000	$300,000	$300,000
FUEL CHARGES (INCLUDED)	$27,382,388	$3,110,445	$3,118,368	$2,409,061	$1,903,928	$1,936,834	$1,884,792
INTERMEDIATE BLOCK:							
CAPACITY (MW)	1,800	150	150	150	150	150	150
ENERGY PURCHASES (MWh)	534,928	58,850	57,263	54,402	75,638	70,478	24,402
TOTAL EXPENSE	**$25,062,855**	**$2,454,237**	**$2,413,578**	**$2,340,279**	**$2,884,346**	**$2,752,146**	**$1,571,679**
CAPACITY CHARGES (INCLUDED):	$11,358,000	$946,500	$946,500	$946,500	$946,500	$946,500	$946,500
OTHER NON-FUEL CHARGES (INCLUDED)	$3,006,295	$330,737	$321,818	$305,739	$425,086	$396,086	$137,139
FUEL CHARGES (INCLUDED)	$10,698,560	$1,177,000	$1,145,260	$1,088,040	$1,512,760	$1,409,560	$488,040
PEAKING BLOCK:							
CAPACITY (MW)	3,660	305	305	305	305	305	305
ENERGY PURCHASES (MWh)	49,162	7,907	7,886	6,955	336	1,198	2,523
TOTAL EXPENSE	**$10,862,063**	**$1,091,756**	**$1,090,727**	**$1,045,136**	**$721,004**	**$763,216**	**$828,101**
CAPACITY CHARGES (INCLUDED):	$8,454,600	$704,550	$704,550	$704,550	$704,550	$704,550	$704,550
OTHER NON-FUEL CHARGES (INCLUDED)	$96,849	$15,577	$15,535	$13,701	$662	$2,360	$4,970
FUEL CHARGES (INCLUDED)	$2,310,614	$371,629	$370,642	$326,885	$15,792	$56,306	$118,581

	TOTAL	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE
F. SEASONAL PURCHASES							
CAPACITY (MW)	1,056	148	148	10	0	75	75
ENERGY PURCHASES (MWh)	8,572	2,101	1,012	7	0	812	945
TOTAL EXPENSE	**$6,368,365**	**$948,945**	**$867,050**	**$40,665**	**$0**	**$477,460**	**$488,100**
DEMAND CHARGES (INCLUDED)	$5,699,900	$790,950	$790,950	$40,000	$0	$412,500	$412,500
FUEL CHARGES (INCLUDED)	$668,465	$157,995	$76,100	$665	$0	$64,960	$75,600
G. OTHER NON-FIRM CAPACITY							
CAPACITY (MW)	0	0	0	0	0	0	0
ENERGY PURCHASES (MWh)	0	0	0	0	0	0	0
TOTAL EXPENSE	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
DEMAND CHARGES (INCLUDED)	$0	$0	$0	$0	$0	$0	$0
FUEL CHARGES (INCLUDED)	$0	$0	$0	$0	$0	$0	$0
(1 + 2 + 3 + 4) INTERCHANGE/OTHER PURCHASES:							
ENERGY PURCHASES (MWh)	**3,067,184**	**195,500**	**141,875**	**146,234**	**132,404**	**254,187**	**320,939**
TOTAL INTERCHANGE/OTHER EXPENSE	$182,307,779	$13,765,213	$12,395,274	$11,398,602	$10,846,464	$14,677,267	$17,372,247
FUEL CHARGES (INCLUDED)	$77,787,728	$4,897,384	$3,482,336	$3,373,726	$3,058,548	$6,188,465	$8,587,290

	TOTAL	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
F. SEASONAL PURCHASES							
CAPACITY (MW)	1,056	75	75	75	75	75	225
ENERGY PURCHASES (MWh)	8,572	1,058	996	917	10	42	672
TOTAL EXPENSE	**$6,368,365**	**$497,140**	**$492,180**	**$485,860**	**$413,300**	**$415,860**	**$1,241,805**
DEMAND CHARGES (INCLUDED)	$5,699,900	$412,500	$412,500	$412,500	$412,500	$412,500	$1,190,500
FUEL CHARGES (INCLUDED)	$668,465	$84,640	$79,680	$73,360	$800	$3,360	$51,305
G. OTHER NON-FIRM CAPACITY							
CAPACITY (MW)	0	0	0	0	0	0	0
ENERGY PURCHASES (MWh)	0	0	0	0	0	0	0
TOTAL EXPENSE	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
DEMAND CHARGES (INCLUDED)	$0	$0	$0	$0	$0	$0	$0
FUEL CHARGES (INCLUDED)	$0	$0	$0	$0	$0	$0	$0
(1 + 2 + 3 + 4) INTERCHANGE/OTHER PURCHASES:							
ENERGY PURCHASES (MWh)	**3,067,184**	**357,258**	**357,042**	**289,988**	**414,956**	**296,773**	**160,028**
TOTAL INTERCHANGE/OTHER EXPENSE	$182,307,779	$18,710,619	$18,818,436	$17,102,402	$18,431,387	$15,552,323	$13,237,545
FUEL CHARGES (INCLUDED)	$77,787,728	$9,844,630	$9,986,039	$8,324,826	$9,430,556	$6,795,527	$3,818,401

RRSB021: NON-MEMBER SALES

	TOTAL YEAR	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE
TOTAL BROKER SALES							
ENERGY SALES (MWh)	317,116	29,836	15,564	25,225	34,905	54,727	34,643
REVENUE:							
RATE (MILLS/kWh)	22.68	22.84	20.90	22.41	22.33	22.63	23.19
TOTAL BROKER SALES REVENUE	$7,192,704	$681,352	$325,350	$565,192	$779,484	$1,238,416	$803,343
EXPENSES:							
FUEL	$5,960,913	$567,793	$271,125	$470,993	$649,570	$1,032,013	$661,087
NON-FUEL	54,168	0	0	0	0	0	13,542
TOTAL BROKER EXPENSES	$6,015,081	$567,793	$271,125	$470,993	$649,570	$1,032,013	$674,629
MARGIN CONTRIBUTION, BROKER	**$1,177,623**	**$113,559**	**$54,225**	**$94,199**	**$129,914**	**$206,403**	**$128,714**
LOAD FOLLOWING SALES:							
TOTAL SALES (MWh)	34,000	2,890	2,608	2,890	2,795	2,890	2,795
REVENUE	$582,820	$49,540	$44,706	$49,540	$47,911	$49,540	$47,911
VARIABLE EXPENSE (FUEL)	$600,360	$50,170	$45,431	$50,488	$49,695	$51,529	$49,220
MARGIN CONTRIBUTION, LOAD FOLL.	**($17,540)**	**($630)**	**($725)**	**($948)**	**($1,784)**	**($1,989)**	**($1,309)**
TOTAL NON-MEMBER SALES:							
TOTAL NON-MEMBER ENERGY SALES	351,116	32,726	18,172	28,115	37,700	57,617	37,438
NON-MEMBER REVENUE	**$7,775,524**	**$730,892**	**$370,056**	**$614,732**	**$827,395**	**$1,287,956**	**$851,254**
AVERAGE RATE (MILLS/kWh)	22.15	22.33	20.36	21.86	21.95	22.35	22.74
NON-MEMBER FUEL	**$6,561,273**	**$617,963**	**$316,556**	**$521,481**	**$699,265**	**$1,083,542**	**$710,307**
AVERAGE COST (MILLS/kWh)	18.69	18.88	17.42	18.55	18.55	18.81	18.97
INCREMENTAL NON-FUEL	**$54,168**	**$0**	**$0**	**$0**	**$0**	**$0**	**$13,542**
AVERAGE COST (MILLS/kWh)	0.15	0.00	0.00	0.00	0.00	0.00	0.36
NON-MEM. MARGIN CONTRIBUTION	**$1,160,083**	**$112,929**	**$53,500**	**$93,251**	**$[illegible]28,130**	**$204,414**	**$127,405**
AVERAGE RATE (MILLS/kWh)	3.30	3.45	2.94	3.32	3.40	3.55	3.40

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RRSB021: NON-MEMBER SALES

	TOTAL YEAR	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
TOTAL BROKER SALES							
ENERGY SALES (MWh)	317,116	31,491	28,275	24,787	1,807	4,188	31,668
REVENUE:							
RATE (MILLS/kWh)	22.68	23.30	23.63	22.11	22.09	21.54	22.71
TOTAL BROKER SALES REVENUE	$7,192,704	$733,866	$668,263	$548,164	$39,920	$90,210	$719,144
EXPENSES:							
FUEL	$5,960,913	$603,288	$548,684	$448,632	$33,267	$75,175	$599,286
NON-FUEL	54,168	13,542	13,542	13,542	0	0	0
TOTAL BROKER EXPENSES	$6,015,081	$616,830	$562,226	$462,174	$33,267	$75,175	$599,286
MARGIN CONTRIBUTION, BROKER	**$1,177,623**	**$117,036**	**$106,037**	**$85,990**	**$6,653**	**$15,035**	**$119,858**
LOAD FOLLOWING SALES:							
TOTAL SALES (MWh)	34,000	2,886	2,886	2,793	2,886	2,794	2,887
REVENUE	$582,820	$49,471	$49,471	$47,877	$49,471	$47,894	$49,488
VARIABLE EXPENSE (FUEL)	$600,360	$50,649	$50,592	$49,185	$53,131	$50,152	$50,118
MARGIN CONTRIBUTION, LOAD FOLL.	**($17,540)**	**($1,178)**	**($1,121)**	**($1,308)**	**($3,660)**	**($2,258)**	**($630)**
TOTAL NON-MEMBER SALES:							
TOTAL NON-MEMBER ENERGY SALES	351,116	34,377	31,161	27,580	4,693	6,982	34,555
NON-MEMBER REVENUE	**$7,775,524**	**$783,337**	**$717,734**	**$596,041**	**$89,391**	**$138,104**	**$768,632**
AVERAGE RATE (MILLS/kWh)	22.15	22.79	23.03	21.61	19.05	19.78	22.24
NON-MEMBER FUEL	**$6,561,273**	**$653,937**	**$599,276**	**$497,817**	**$86,398**	**$125,327**	**$649,404**
AVERAGE COST (MILLS/kWh)	18.69	19.02	19.23	18.05	18.41	17.95	18.79
INCREMENTAL NON-FUEL	**$54,168**	**$13,542**	**$13,542**	**$13,542**	**$0**	**$0**	**$0**
AVERAGE COST (MILLS/kWh)	0.15	0.39	0.43	0.49	0.00	0.00	0.00
NON-MEM. MARGIN CONTRIBUTION	**$1,160,083**	**$115,858**	**$104,916**	**$84,682**	**$2,993**	**$12,777**	**$119,228**
AVERAGE RATE (MILLS/kWh)	3.30	3.37	3.37	3.07	0.64	1.83	3.45

00042

RRSB022: MEMBER FUEL

	TOTAL YEAR	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE
MEMBER FUEL FROM GENERATION:							
SECI	$162,184,362	$15,188,330	$14,080,141	$13,849,708	$12,713,242	$13,981,275	$14,137,234
CR3	648,000	54,839	51,482	54,839	53,161	54,839	53,161
TOTAL GENERATED MEMBER FUEL	$162,832,362	$15,243,169	$14,131,623	$13,904,547	$12,766,403	$14,036,114	$14,190,395
PURCHASED POWER FUEL EXPENSE:							
FPC SUPPLEMENTAL	$3,318,614	$748,354	$254,310	$47,598	$0	$46,815	$365,611
FPL ABPRSA	0	0	0	0	0	0	0
FPL WHEELING	0	0	0	0	0	0	0
SUB-TOTAL PR FUEL	$3,318,614	$748,354	$254,310	$47,598	$0	$46,815	$365,611
FPL FR	$0	$0	$0	$0	$0	$0	$0
GAINESVILLE FR	1,176,406	104,019	93,584	90,003	80,899	94,404	109,177
JACKSONVILLE FR	0	0	0	0	0	0	0
FPC FR	6,719	426	500	426	426	444	555
SUB-TOTAL FR FUEL	$1,183,125	$104,445	$94,084	$90,429	$81,325	$94,848	$109,732
INTERCHANGE	$77,787,728	$4,897,384	$3,482,336	$3,373,726	$3,058,548	$6,188,465	$8,587,290
RESERVES	0	0	0	0	0	0	0
LOAD FOLLOWING	576,590	48,307	42,731	47,463	52,412	53,054	48,434
SUB-TOTAL INTER / OTHER	$78,364,318	$4,945,691	$3,525,067	$3,421,189	$3,110,960	$6,241,519	$8,635,724
TOTAL PURCHASED POWER, FUEL	$82,866,057	$5,798,490	$3,873,461	$3,559,216	$3,192,285	$6,383,182	$9,111,067
(NONMEMBER FUEL OFFSET)	(6,561,273)	(617,963)	(316,556)	(521,481)	(699,265)	(1,083,542)	(710,307)
TOTAL MEMBER FUEL	$239,137,146	$20,423,696	$17,688,528	$16,942,282	$15,259,423	$19,335,754	$22,591,155
MEMBER SALES (MWh) @ METER	12,194,143	1,047,964	954,285	923,184	837,347	1,011,520	1,114,557
SALES RATE (MILLS/kWh)	19.61	19.49	18.54	18.35	18.22	19.12	20.27
FUEL FACTOR:							
BASE FUEL RATE, MILLS/kWh	19.61	19.61	19.61	19.61	19.61	19.61	19.61
FUEL ADJ. FACTOR	0.00	-0.12	-1.07	-1.26	-1.39	-0.49	0.66

00043

RRSB022: MEMBER FUEL

	TOTAL YEAR	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
MEMBER FUEL FROM GENERATION:							
SECI	$162,184,362	$14,769,279	$14,900,129	$14,203,012	$9,155,856	$10,225,813	$14,980,344
CR3	648,000	54,839	54,839	53,161	54,839	53,161	54,840
TOTAL GENERATED MEMBER FUEL	$162,832,362	$14,824,118	$14,954,968	$14,256,173	$9,210,695	$10,278,974	$15,035,184
PURCHASED POWER FUEL EXPENSE:							
FPC SUPPLEMENTAL	$3,318,614	$570,662	$696,038	$264,102	$0	$56,101	$269,023
FPL ABPRSA	0	0	0	0	0	0	0
FPL WHEELING	0	0	0	0	0	0	0
SUB-TOTAL PR FUEL	$3,318,614	$570,662	$696,038	$264,102	$0	$56,101	$269,023
FPL FR	$0	$0	$0	$0	$0	$0	$0
GAINESVILLE FR	1,176,406	116,969	118,158	108,382	86,264	80,346	94,201
JACKSONVILLE FR	0	0	0	0	0	0	0
FPC FR	6,719	740	796	759	629	555	463
SUB-TOTAL FR FUEL	$1,183,125	$117,709	$118,954	$109,141	$86,893	$80,901	$94,664
INTERCHANGE	$77,787,728	$9,844,630	$9,986,039	$8,324,826	$9,430,556	$6,795,527	$3,818,401
RESERVES	0	0	0	0	0	0	0
LOAD FOLLOWING	576,590	52,603	46,868	44,478	48,584	47,548	44,108
SUB-TOTAL INTER / OTHER	$78,364,318	$9,897,233	$10,032,907	$8,369,304	$9,479,140	$6,843,075	$3,862,509
TOTAL PURCHASED POWER, FUEL	$82,866,057	$10,585,604	$10,847,899	$8,742,547	$9,566,033	$6,980,077	$4,226,196
(NONMEMBER FUEL OFFSET)	(6,561,273)	(653,937)	(599,276)	(497,817)	(86,398)	(125,327)	(649,404)
TOTAL MEMBER FUEL	$239,137,146	$24,755,785	$25,203,591	$22,500,903	$18,690,330	$17,133,724	$18,611,976
MEMBER SALES (MWh) @ METER	12,194,143	1,192,949	1,205,434	1,092,154	928,088	888,265	998,396
SALES RATE (MILLS/kWh)	19.61	20.75	20.91	20.60	20.14	19.29	18.64
FUEL FACTOR:							
BASE FUEL RATE, MILLS/kWh	19.61	19.61	19.61	19.61	19.61	19.61	19.61
FUEL ADJ. FACTOR	0.00	1.14	1.30	0.99	0.53	-0.32	-0.97

00044

RRSB024: ENERGY BALANCE SUMMARY (MWh)

	TOTAL YEAR	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE
RESOURCES:							
SECI GENERATION, MEMBER LOAD	9,272,378	856,374	818,198	792,391	721,039	781,632	809,805
" " " " " " " " " BROKER SALES	236,858	22,386	15,564	18,975	27,555	40,877	22,741
SEMINOLE PLANT NET GENERATION	9,509,236	878,760	833,762	811,366	748,594	822,509	832,546
CRYSTAL RIVER 3	115,596	9,791	9,159	9,791	9,475	9,791	9,475
SEPA GENERATION	0	0	0	0	0	0	0
PURCHASED POWER:							
FPC SUPPLEMENTAL	92,690	18,261	6,486	1,276	0	1,811	11,246
FPL ABPRSA	0	0	0	0	0	0	0
FPL FR	0	0	0	0	0	0	0
GAINESVILLE FR	49,017	4,334	3,899	3,750	3,371	3,934	4,549
JACKSONVILLE FR	0	0	0	0	0	0	0
FPC FR	363	23	27	23	23	24	30
INTERCHANGE PURCHASES	3,067,184	195,500	141,875	146,234	132,404	254,187	320,939
RESERVES	0	0	0	0	0	0	0
LOAD FOLLOWING	34,000	2,881	2,694	2,881	2,787	2,881	2,787
PRECO-1 PURCHASES	151,596	12,633	12,633	12,633	12,633	12,633	12,633
TOTAL PURCHASED POWER	3,394,850	233,632	167,614	166,797	151,218	275,470	352,184
TOTAL RESOURCES	13,019,682	1,122,183	1,010,535	987,954	909,287	1,107,770	1,194,205
USES:							
MEMBER SALES	12,194,143	1,047,964	954,285	923,184	837,347	1,011,520	1,114,557
PRECO-1 SALES	151,596	12,633	12,633	12,633	12,633	12,633	12,633
BROKER SALES	245,666	22,386	15,564	18,975	27,555	40,877	24,943
LOAD FOLLOWING SALES	34,000	2,890	2,608	2,890	2,795	2,890	2,795
SEPA MEMBER SALES	0	0	0	0	0	0	0
TOTAL USES	12,625,405	1,085,873	985,090	957,682	880,330	1,067,920	1,154,928
DIFFERENCE (RESOURCES - USES)	394,277	36,310	25,445	30,272	28,957	39,850	39,277
% DIFFERENCE..ATTRIBUTED TO LOSSES	3.03%	3.24%	2.52%	3.06%	3.18%	3.60%	3.29%

00045

RRSB024: ENERGY BALANCE SUMMARY (MWh)

	TOTAL YEAR	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
RESOURCES:							
SECI GENERATION, MEMBER LOAD	9,272,378	848,419	859,104	810,302	523,449	599,997	851,668
" " " " " " " " " BROKER SALES	236,858	19,839	16,473	22,585	1,807	4,188	23,868
SEMINOLE PLANT NET GENERATION	9,509,236	868,258	875,577	832,887	525,256	604,185	875,536
CRYSTAL RIVER 3	115,596	9,791	9,791	9,475	9,791	9,475	9,791
SEPA GENERATION	0	0	0	0	0	0	0
PURCHASED POWER:							
FPC SUPPLEMENTAL	92,690	16,740	19,701	8,414	0	1,622	7,133
FPL ABPRSA	0	0	0	0	0	0	0
FPL FR	0	0	0	0	0	0	0
GAINESVILLE FR	49,017	4,874	4,923	4,516	3,594	3,348	3,925
JACKSONVILLE FR	0	0	0	0	0	0	0
FPC FR	363	40	43	41	34	30	25
INTERCHANGE PURCHASES	3,067,184	357,258	357,042	289,988	414,956	296,773	160,028
RESERVES	0	0	0	0	0	0	0
LOAD FOLLOWING	34,000	2,880	2,880	2,787	2,879	2,785	2,878
PRECO-1 PURCHASES	151,596	12,633	12,633	12,633	12,633	12,633	12,633
TOTAL PURCHASED POWER	3,394,850	394,425	397,222	318,379	434,096	317,191	186,622
TOTAL RESOURCES	13,019,682	1,272,474	1,282,590	1,160,741	969,143	930,851	1,071,949
USES:							
MEMBER SALES	12,194,143	1,192,949	1,205,434	1,092,154	928,088	888,265	998,396
PRECO-1 SALES	151,596	12,633	12,633	12,633	12,633	12,633	12,633
BROKER SALES	245,666	22,041	18,675	24,787	1,807	4,188	23,868
LOAD FOLLOWING SALES	34,000	2,886	2,886	2,793	2,886	2,794	2,887
SEPA MEMBER SALES	0	0	0	0	0	0	0
TOTAL USES	12,625,405	1,230,509	1,239,628	1,132,367	945,414	907,880	1,037,784
DIFFERENCE (RESOURCES - USES)	394,277	41,965	42,962	28,374	23,729	22,971	34,165
% DIFFERENCE..ATTRIBUTED TO LOSSES	3.03%	3.30%	3.35%	2.44%	2.45%	2.47%	3.19%

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09/23/1999 0[illegible]:37 PM 2000 REVENUE REQUIREMENT, SEMINOLE ELECTRIC COOPERATIVE, INC.

	RRSB026: 2000 REVENUE REQUIREMENT	TOTAL YEAR	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE
1.	OPERATION AND MAINTENANCE:							
2.	PRODUCTION EXPENSE:							
3.	FUEL -SECI	$162,184,362	$15,188,330	$14,080,141	$13,849,708	$12,713,242	$13,981,275	$14,137,234
4.	-CRYSTAL RIVER 3	648,000	54,839	51,482	54,839	53,161	54,839	53,161
5.	TOTAL SECI FUEL	$162,832,362	$15,243,169	$14,131,623	$13,904,547	$12,766,403	$14,036,114	$14,190,395
6.	PURCH POWER: FR/PR	23,786,397	4,654,609	4,042,041	1,883,769	237,154	680,316	1,853,265
7.	OTHER	192,964,081	14,705,383	13,311,187	12,278,448	11,699,304	15,551,200	18,252,388
8.	TOTAL PURCHASED POWER	$216,750,478	$19,359,992	$17,353,228	$14,162,217	$11,936,458	$16,231,516	$20,105,653
9.	OTHER (NON-FUEL):							
10.	SECI O&M	49,537,119	0	0	0	0	0	0
11.	CR3 O&M	2,336,334	0	0	0	0	0	0
12.	TOTAL OTHER NON-FUEL	$51,873,453	$0	$0	$0	$0	$0	$0
13.	TOTAL PRODUCTION EXPENSE	$431,456,293	$34,603,161	$31,484,851	$28,066,764	$24,702,860	$30,267,630	$34,296,048
14.	TRANSMISSION EXPENSE:							
15.	WHEELING	33,958,916	3,416,945	3,394,106	2,631,324	2,500,585	2,575,716	2,781,860
16.	T F U C	92,759	7,158	7,158	7,158	7,158	7,158	7,158
17.	O&M	4,393,549	0	0	0	0	0	0
18.	TOTAL TRANSMISSION EXPENSE	$38,445,224	$3,424,103	$3,401,264	$2,638,482	$2,507,743	$2,582,874	$2,789,018
19.	ADMINISTRATIVE & GENERAL	$15,374,654	$0	$0	$0	$0	$0	$0
20.	FIXED CHARGES:							
21.	DEPRECIATION / AMORTIZATIO	25,581,144	0	0	0	0	0	0
22.	INTEREST, NET	33,926,245	0	0	0	0	0	0
23.	LEASE	28,641,657	0	0	0	0	0	0
24.	TAXES:							
25.	PROPERTY	8,675,679	0	0	0	0	0	0
26.	PAYROLL	1,771,097	0	0	0	0	0	0
27.	ALTERNATIVE MINIMUM	0	0	0	0	0	0	0
28.	TOTAL TAXES	10,446,776	0	0	0	0	0	0
29.	TAX TRANSFERS	(10,281,959)	0	0	0	0	0	0
30.	NET TAXES	164,817	0	0	0	0	0	0
31.	TOTAL FIXED CHARGES	$88,313,863	$0	$0	$0	$0	$0	$0
32.	OTHER DEDUCTIONS	0	0	0	0	0	0	0
33.	TOTAL OPERATION & MAINTENANCE	$573,590,034	$38,027,264	$34,886,115	$30,705,246	$27,210,603	$32,850,504	$37,085,066
34.	OTHER REVENUE:							
35.	BROKER / LOAD FOLLOWING / WHEELI	$8,006,085	$750,420	$388,325	$634,260	$846,294	$1,307,484	$870,153
36.	INTERRUPTIBLE REVENUE / MARTEL	5,200,514	435,221	433,563	432,624	431,575	431,684	432,578
37.	TFUC / BYPRODUCT REVENUE	1,224,777	0	0	0	0	0	0
38.	OTHER MARGINS	7,703,797	0	0	0	0	0	0
39.	LINE ITEM NOT IN USE	0						
40.	JAN-FEB MEM. FUEL TRUE-UP INTERES	(5,201)	(2,595)	(2,606)	0	0	0	0
41.	TOTAL OTHER REVENUE / MARGINS	$22,129,972	$1,183,046	$819,282	$1,066,884	$1,277,869	$1,739,168	$1,302,731
42.	TOTAL NET MARGIN	$2,334,880	$0	$0	$0	$0	$0	$0
43.	MEMBER REVENUE REQUIREMENT	$553,794,942	$36,844,218	$34,066,833	$29,638,362	$25,932,734	$31,111,336	$35,782,335
44.	MEMBER SALES (MWh)	12,194,143	1,047,964	954,285	923,184	837,347	1,011,520	1,114,557
45.	MEMBER SALES (MW-MOS)	29,536	3,155	3,038	2,447	1,796	2,204	2,453
46.	MEMBER RATE (AVG MILLS/kWh)	45.41	35.18	35.72	32.13	31.00	30.78	32.12

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	RRSB026: 2000 REVENUE REQUIREMENT	TOTAL YEAR	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
1.	OPERATION AND MAINTENANCE:							
2.	PRODUCTION EXPENSE:							
3.	FUEL -SECI	$162,184,362	$14,769,279	$14,900,129	$14,203,012	$9,155,856	$10,225,813	$14,980,344
4.	-CRYSTAL RIVER 3	648,000	54,839	54,839	53,161	54,839	53,161	54,840
5.	TOTAL SECI FUEL	$162,832,362	$14,824,118	$14,954,968	$14,256,173	$9,210,695	$10,278,974	$15,035,184
6.	PURCH POWER: FR/PR	23,786,397	2,206,612	2,445,985	1,339,132	244,634	1,214,720	2,984,160
7.	OTHER	192,964,081	19,606,018	19,715,309	17,975,683	19,297,718	16,421,133	14,150,311
8.	TOTAL PURCHASED POWER	$216,750,478	$21,812,630	$22,161,294	$19,314,815	$19,542,352	$17,635,853	$17,134,471
9.	OTHER (NON-FUEL):							
10.	SECI O&M	49,537,119	0	0	0	0	0	49,537,119
11.	CR3 O&M	2,336,334	0	0	0	0	0	2,336,334
12.	TOTAL OTHER NON-FUEL	$51,873,453	$0	$0	$0	$0	$0	$51,873,453
13.	TOTAL PRODUCTION EXPENSE	$431,456,293	$36,636,748	$37,116,262	$33,570,988	$28,753,047	$27,914,826	$84,043,108
14.	TRANSMISSION EXPENSE:							
15.	WHEELING	33,958,916	2,823,674	2,851,232	2,681,100	2,465,340	2,713,029	3,124,007
16.	T F U C	92,759	7,158	7,158	7,158	7,158	7,158	14,021
17.	O&M	4,393,549	0	0	0	0	0	4,393,549
18.	TOTAL TRANSMISSION EXPENSE	$38,445,224	$2,830,832	$2,858,390	$2,688,258	$2,472,498	$2,720,187	$7,531,577
19.	ADMINISTRATIVE & GENERAL	$15,374,654	$0	$0	$0	$0	$0	$15,374,654
20.	FIXED CHARGES:							
21.	DEPRECIATION / AMORTIZATIO	25,581,144	0	0	0	0	0	25,581,144
22.	INTEREST, NET	33,926,245	0	0	0	0	0	33,926,245
23.	LEASE	28,641,657	0	0	0	0	0	28,641,657
24.	TAXES:							
25.	PROPERTY	8,675,679	0	0	0	0	0	8,675,679
26.	PAYROLL	1,771,097	0	0	0	0	0	1,771,097
27.	ALTERNATIVE MINIMUM	0	0	0	0	0	0	0
28.	TOTAL TAXES	10,446,776	0	0	0	0	0	10,446,776
29.	TAX TRANSFERS	(10,281,959)	0	0	0	0	0	(10,281,959)
30.	NET TAXES	164,817	0	0	0	0	0	164,817
31.	TOTAL FIXED CHARGES	$88,313,863	$0	$0	$0	$0	$0	$88,313,863
32.	OTHER DEDUCTIONS	0	0	0	0	0	0	0
33.	TOTAL OPERATION & MAINTENANCE	$573,590,034	$39,467,580	$39,974,651	$36,259,246	$31,225,545	$30,635,013	$195,263,202
34.	OTHER REVENUE:							
35.	BROKER / LOAD FOLLOWING / WHEELI	$8,006,085	$802,865	$737,262	$614,940	$108,919	$157,003	$788,160
36.	INTERRUPTIBLE REVENUE / MARTEL	5,200,514	433,393	433,579	434,101	433,014	432,487	436,695
37.	TFUC / BYPRODUCT REVENUE	1,224,777	0	0	0	0	0	1,224,777
38.	OTHER MARGINS	7,703,797	0	0	0	0	0	7,703,797
39.	LINE ITEM NOT IN USE	0						
40.	JAN-FEB MEM. FUEL TRUE-UP INTERES	(5,201)	0	0	0	0	0	0
41.	TOTAL OTHER REVENUE / MARGINS	$22,129,972	$1,236,258	$1,170,841	$1,049,041	$541,933	$589,490	$10,153,429
42.	TOTAL NET MARGIN	$2,334,880	$0	$0	$0	$0	$0	$2,334,880
43.	MEMBER REVENUE REQUIREMENT	$553,794,942	$38,231,322	$38,803,810	$35,210,205	$30,683,612	$30,045,523	$187,444,653
44.	MEMBER SALES (MWh)	12,194,143	1,192,949	1,205,434	1,092,154	928,088	888,265	998,396
45.	MEMBER SALES (MW-MOS)	29,536	2,507	2,559	2,368	2,035	2,184	2,790
46.	MEMBER RATE (AVG MILLS/kWh)	45.41	32.07	32.21	32.26	33.08	33.85	187.77

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RRSB027: MONTHLY SECI INCOME STATEMENT

			TOTAL YEAR	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE
1.	OPERATING REVENUE								
2.	ENERGY SALES:	MEMBERS, SECI-7	$553,789,741	$36,841,623	$34,064,227	$29,638,362	$25,932,734	$31,111,336	$35,782,335
		INTERRUPT. SALE	5,137,708	428,695	427,372	427,813	427,548	427,122	427,210
		MARTEL	62,806	6,526	6,191	4,811	4,027	4,562	5,368
	SUB_TOTAL MEMBERS		$558,990,255	$37,276,844	$34,497,790	$30,070,986	$26,364,309	$31,543,020	$36,214,913
3.	NON-MEMBER REVENUE		8,006,085	750,420	388,325	634,260	846,294	1,307,484	870,153
4.	OTHER UTILITY REVENUE		1,224,777	0	0	0	0	0	0
5.	TOTAL OPERATING REVENUE		$568,221,117	$38,027,264	$34,886,115	$30,705,246	$27,210,603	$32,850,504	$37,085,066
6.	OPERATING EXPENSES								
7.	PURCHASED POWER: TOTAL		$250,802,153	$22,784,095	$20,754,492	$16,800,699	$14,444,200	$18,814,390	$22,894,670
8.	GENERATION & TRANSMISSION								
9.	SEMINOLE PLANT								
10.	FUEL		$162,184,362	$15,188,330	$14,080,141	$13,849,708	$12,713,242	$13,981,275	$14,137,234
11.	OPERATION & MAINTENANCE		49,537,119	0	0	0	0	0	0
12.	TOTAL PLANT		$211,721,481	$15,188,330	$14,080,141	$13,849,708	$12,713,242	$13,981,275	$14,137,234
13.	TRANSMISSION / LOAD CONTROL		4,393,549	0	0	0	0	0	0
14.	TOTAL SEMINOLE		$216,115,030	$15,188,330	$14,080,141	$13,849,708	$12,713,242	$13,981,275	$14,137,234
15.	CRYSTAL RIVER 3		2,984,334	54,839	51,482	54,839	53,161	54,839	53,161
16.	TOTAL GENERATION & TRANSMISSION		$219,099,364	$15,243,169	$14,131,623	$13,904,547	$12,766,403	$14,036,114	$14,190,395
17.	ADMIN & GENERAL (NET)		$15,374,654	$0	$0	$0	$0	$0	$0
18.	FIXED CHARGES (NET)								
19.	DEPRECIATION / AMORTIZATION		$25,581,144	$0	$0	$0	$0	$0	$0
20.	TAXES		164,817	0	0	0	0	0	0
21.	INTEREST/LEASE		62,567,902	0	0	0	0	0	0
22.	TOTAL NET FIXED CHARGES		$88,313,863	$0	$0	$0	$0	$0	$0
23.	TOTAL OPERATING EXPENSES		$573,590,034	$38,027,264	$34,886,115	$30,705,246	$27,210,603	$32,850,504	$37,085,066
24.	OPERATING MARGIN		($5,368,917)	$0	$0	$0	$0	$0	$0
25.	OTHER MARGINS		$7,703,797	$0	$0	$0	$0	$0	$0
26.	NET MARGIN		$2,334,880	$0	$0	$0	$0	$0	$0

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RRSB027: MONTHLY SECI INCOME STATEMENT

			TOTAL YEAR	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
1.	OPERATING REVENUE								
2.	ENERGY SALES:	MEMBERS, SECI-7	$553,789,741	$38,231,322	$38,803,810	$35,210,205	$30,683,612	$30,045,523	$187,444,653
		INTERRUPT. SALE	5,137,708	427,901	428,033	428,798	428,533	428,004	430,679
		MARTEL	62,806	5,492	5,546	5,303	4,481	4,483	6,016
	SUB_TOTAL MEMBERS		$558,990,255	$38,664,715	$39,237,389	$35,644,306	$31,116,626	$30,478,010	$187,881,348
3.	NON-MEMBER REVENUE		8,006,085	802,865	737,262	614,940	108,919	157,003	788,160
4.	OTHER UTILITY REVENUE		1,224,777	0	0	0	0	0	1,224,777
5.	TOTAL OPERATING REVENUE		$568,221,117	$39,467,580	$39,974,651	$36,259,246	$31,225,545	$30,635,013	$189,894,285
6.	OPERATING EXPENSES								
7.	PURCHASED POWER: TOTAL		$250,802,153	$24,643,462	$25,019,684	$22,003,072	$22,014,850	$20,356,039	$20,272,499
8.	GENERATION & TRANSMISSION								
9.	SEMINOLE PLANT								
10.	FUEL		$162,184,362	$14,769,279	$14,900,129	$14,203,012	$9,155,856	$10,225,813	$14,980,344
11.	OPERATION & MAINTENANCE		49,537,119	0	0	0	0	0	49,537,119
12.	TOTAL PLANT		$211,721,481	$14,769,279	$14,900,129	$14,203,012	$9,155,856	$10,225,813	$64,517,463
13.	TRANSMISSION / LOAD CONTROL		4,393,549	0	0	0	0	0	4,393,549
14.	TOTAL SEMINOLE		$216,115,030	$14,769,279	$14,900,129	$14,203,012	$9,155,856	$10,225,813	$68,911,012
15.	CRYSTAL RIVER 3		2,984,334	54,839	54,839	53,161	54,839	53,161	2,391,174
16.	TOTAL GENERATION & TRANSMISSION		$219,099,364	$14,824,118	$14,954,968	$14,256,173	$9,210,695	$10,278,974	$71,302,186
17.	ADMIN & GENERAL (NET)		$15,374,654	$0	$0	$0	$0	$0	$15,374,654
18.	FIXED CHARGES (NET)								
19.	DEPRECIATION / AMORTIZATION		$25,581,144	$0	$0	$0	$0	$0	$25,581,144
20.	TAXES		164,817	0	0	0	0	0	164,817
21.	INTEREST/LEASE		62,567,902	0	0	0	0	0	62,567,902
22.	TOTAL NET FIXED CHARGES		$88,313,863	$0	$0	$0	$0	$0	$88,313,863
23.	TOTAL OPERATING EXPENSES		$573,590,034	$39,467,580	$39,974,651	$36,259,246	$31,225,545	$30,635,013	$195,263,202
24.	OPERATING MARGIN		($5,368,917)	$0	$0	$0	$0	$0	($5,368,917)
25.	OTHER MARGINS		$7,703,797	$0	$0	$0	$0	$0	$7,703,797
26.	NET MARGIN		$2,334,880	$0	$0	$0	$0	$0	$2,334,880

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RRSB029A: FUEL & NON-FUEL MEMBER REVENUE

	TOTAL YEAR	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE
1. FUEL COMPONENT:							
* SEMINOLE PLANT & CR3 FUEL	$162,832,362	$15,243,169	$14,131,623	$13,904,547	$12,766,403	$14,036,114	$14,190,395
(LESS NON-MEMBER FUEL)	(6,561,273)	(617,963)	(316,556)	(521,481)	(699,265)	(1,083,542)	(710,307)
* PURCHASED POWER FUEL	82,866,057	5,798,490	3,873,461	3,559,216	3,192,285	6,383,182	9,111,067
TOTAL MEMBER FUEL REVENUE	$239,137,146	$20,423,696	$17,688,528	$16,942,282	$15,259,423	$19,335,754	$22,591,155
2. NON-FUEL COMPONENT:							
* BROKER / LD FOLL MARGIN CONTR.	($1,160,083)	($112,929)	($53,500)	($93,251)	($128,130)	($204,414)	($127,405)
* PURCHASED POWER:							
WHEELING / TFUC	34,051,675	3,424,103	3,401,264	2,638,482	2,507,743	2,582,874	2,789,018
PR / FR	19,284,658	3,801,810	3,693,647	1,745,742	155,829	538,653	1,377,922
BACKUP / RESERVES / LD FOLL.	114,545,595	9,759,692	9,786,120	8,857,259	8,588,344	9,309,681	9,603,122
SUB-TOT PURCH'D POWER	$167,881,928	$16,985,605	$16,881,031	$13,241,483	$11,251,915	$12,431,208	$13,770,061
* O&M / CR3	56,267,002	0	0	0	0	0	0
* ADMIN & GENERAL	15,374,654	0	0	0	0	0	0
* FIXED CHARGES:							
DEPRECIATION / AMORTIZATION	25,581,144	0	0	0	0	0	0
INTEREST / LEASE, NET	62,567,902	0	0	0	0	0	0
TAXES, NET	164,817	0	0	0	0	0	0
SUB-TOTAL FIXED CHARGES	$88,313,863	$0	$0	$0	$0	$0	$0
* OTHER MARGINS	(7,703,797)	0	0	0	0	0	0
* TFUC,By-Prod,Interr,Martel,Whl'g	(6,655,852)	(454,749)	(451,832)	(452,152)	(450,474)	(451,212)	(451,477)
* MEM. FUEL TRUE-UP INTEREST	5,201	2,595	2,606	0	0	0	0
* NET MARGIN	$2,334,880	$0	$0	$0	$0	$0	$0
TOTAL NON-FUEL MEM REVENUE	$314,657,796	$16,420,522	$16,378,305	$12,696,080	$10,673,311	$11,775,582	$13,191,179
TOTAL MEMBER REVENUE REQUIREMENT	$553,794,942	$36,844,218	$34,066,833	$29,638,362	$25,932,734	$31,111,336	$35,782,335
MEMBER SALES (MWh)	12,194,143	1,047,964	954,285	923,184	837,347	1,011,520	1,114,557
AVERAGE SALES RATE (MILLS/kWh)	45.41	35.16	35.70	32.10	30.97	30.76	32.10

RRSB029A: FUEL & NON-FUEL MEMBER REVENUE

	TOTAL YEAR	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
1. FUEL COMPONENT:							
• SEMINOLE PLANT & CR3 FUEL	$162,832,362	$14,824,118	$14,954,968	$14,256,173	$9,210,695	$10,278,974	$15,035,184
(LESS NON-MEMBER FUEL)	(6,561,273)	(653,937)	(599,276)	(497,817)	(86,398)	(125,327)	(649,404)
• PURCHASED POWER FUEL	82,866,057	10,585,604	10,847,899	8,742,547	9,566,033	6,980,077	4,226,196
TOTAL MEMBER FUEL REVENUE	$239,137,146	$24,755,785	$25,203,591	$22,500,903	$18,690,330	$17,133,724	$18,611,976
2. NON-FUEL COMPONENT:							
• BROKER / LD FOLL MARGIN CONTR.	($1,160,083)	($115,858)	($104,916)	($84,682)	($2,993)	($12,777)	($119,228)
• PURCHASED POWER:							
WHEELING / TFUC	34,051,675	2,830,832	2,858,390	2,688,258	2,472,498	2,720,187	3,138,028
PR / FR	19,284,658	1,518,241	1,630,993	965,889	157,741	1,077,718	2,620,473
BACKUP / RESERVES / LD FOLL.	114,545,595	9,695,243	9,668,860	9,592,837	9,818,578	9,578,058	10,287,802
SUB-TOT PURCH'D POWER	$167,881,928	$14,044,316	$14,158,243	$13,246,983	$12,448,817	$13,375,962	$16,046,303
• O&M / CR3	56,267,002	0	0	0	0	0	56,267,002
• ADMIN & GENERAL	15,374,654	0	0	0	0	0	15,374,654
• FIXED CHARGES:							
DEPRECIATION / AMORTIZATION	25,581,144	0	0	0	0	0	25,581,144
INTEREST / LEASE, NET	62,567,902	0	0	0	0	0	62,567,902
TAXES, NET	164,817	0	0	0	0	0	164,817
SUB-TOTAL FIXED CHARGES	$88,313,863	$0	$0	$0	$0	$0	$88,313,863
• OTHER MARGINS	(7,703,797)	0	0	0	0	0	(7,703,797)
• TFUC,By-Prod,Interr,Martel,Whl'g	(6,655,852)	(452,921)	(453,107)	(453,000)	(452,542)	(451,386)	(1,681,000)
• MEM. FUEL TRUE-UP INTEREST	5,201	0	0	0	0	0	0
• NET MARGIN	$2,334,880	$0	$0	$0	$0	$0	$2,334,880
TOTAL NON-FUEL MEM REVENUE	$314,657,796	$13,475,537	$13,600,220	$12,709,301	$11,993,282	$12,911,799	$168,832,677
TOTAL MEMBER REVENUE REQUIREMENT	$553,794,942	$38,231,322	$38,803,810	$35,210,205	$30,683,612	$30,045,523	$187,444,653
MEMBER SALES (MWh)	12,194,143	1,192,949	1,205,434	1,092,154	928,088	888,265	998,396
AVERAGE SALES RATE (MILLS/kWh)	45.41	32.05	32.19	32.24	33.06	33.82	187.75

RRSB029B: FUEL & NON-FUEL MEMBER REVENUE
(MILLS / kWh, MEMBER SALES)

	TOTAL YEAR	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE
1. FUEL COMPONENT:							
• SEMINOLE PLANT & CR3 FUEL	13.35	14.55	14.81	15.06	15.25	13.88	12.73
(LESS NON-MEMBER FUEL)	-0.54	-0.59	-0.33	-0.56	-0.84	-1.07	-0.64
• PURCHASED POWER FUEL	6.80	5.53	4.06	3.86	3.81	6.31	8.17
TOTAL MEMBER FUEL REVENUE	19.61	19.49	18.54	18.35	18.22	19.12	20.27
2. NON-FUEL COMPONENT:							
• BROKER / LD FOLL MARGIN CONTR.	-0.10	-0.11	-0.06	-0.10	-0.15	-0.20	-0.11
• PURCHASED POWER:							
WHEELING / TFUC	2.79	3.27	3.56	2.86	2.99	2.55	2.50
PR / FR	1.58	3.63	3.87	1.89	0.19	0.53	1.24
BACKUP / RESERVES / LD FOLL.	9.39	9.31	10.25	9.59	10.26	9.20	8.62
SUB-TOT PURCH'D POWER	13.77	16.21	17.69	14.34	13.44	12.29	12.35
• O&M / CR3	4.61	0.00	0.00	0.00	0.00	0.00	0.00
• ADMIN & GENERAL	1.26	0.00	0.00	0.00	0.00	0.00	0.00
• FIXED CHARGES:							
DEPRECIATION / AMORTIZATION	2.10	0.00	0.00	0.00	0.00	0.00	0.00
INTEREST / LEASE, NET	5.13	0.00	0.00	0.00	0.00	0.00	0.00
TAXES, NET	0.01	0.00	0.00	0.00	0.00	0.00	0.00
SUB-TOTAL FIXED CHARGES	7.24	0.00	0.00	0.00	0.00	0.00	0.00
• OTHER MARGINS	-0.63	0.00	0.00	0.00	0.00	0.00	0.00
• TFUC,By-Prod,Interr,Martel,Whl'g	-0.55	-0.43	-0.47	-0.49	-0.54	-0.45	-0.41
• MEM. FUEL TRUE-UP INTEREST	0.00	0.00	0.00	0.00	0.00	0.00	0.00
• NET MARGIN	0.19	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL NON-FUEL MEM REVENUE	25.80	15.67	17.16	13.75	12.75	11.64	11.84
TOTAL MEMBER REVENUE REQUIREMENT	45.41	35.16	35.70	32.10	30.97	30.76	32.11
MEMBER SALES (MWh)	12,194,143	1,047,964	954,285	923,184	837,347	1,011,520	1,114,557

00053

RRSB029B: FUEL & NON-FUEL MEMBER REVENUE
(MILLS / kWh, MEMBER SALES)

	TOTAL YEAR	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
1. FUEL COMPONENT:							
• SEMINOLE PLANT & CR3 FUEL	13.35	12.43	12.41	13.05	9.92	11.57	15.06
(LESS NON-MEMBER FUEL)	-0.54	-0.55	-0.50	-0.46	-0.09	-0.14	-0.65
• PURCHASED POWER FUEL	6.80	8.87	9.00	8.00	10.31	7.86	4.23
TOTAL MEMBER FUEL REVENUE	19.61	20.75	20.91	20.60	20.14	19.29	18.64
2. NON-FUEL COMPONENT:							
• BROKER / LD FOLL MARGIN CONTR.	-0.10	-0.10	-0.09	-0.08	-0.00	-0.01	-0.12
• PURCHASED POWER:							
WHEELING / TFUC	2.79	2.37	2.37	2.46	2.66	3.06	3.14
PR / FR	1.58	1.27	1.35	0.88	0.17	1.21	2.62
BACKUP / RESERVES / LD FOLL.	9.39	8.13	8.02	8.78	10.58	10.78	10.30
SUB-TOT PURCH'D POWER	13.77	11.77	11.75	12.13	13.41	15.06	16.07
• O&M / CR3	4.61	0.00	0.00	0.00	0.00	0.00	56.36
• ADMIN & GENERAL	1.26	0.00	0.00	0.00	0.00	0.00	15.40
• FIXED CHARGES:							
DEPRECIATION / AMORTIZATION	2.10	0.00	0.00	0.00	0.00	0.00	25.62
INTEREST / LEASE, NET	5.13	0.00	0.00	0.00	0.00	0.00	62.67
TAXES, NET	0.01	0.00	0.00	0.00	0.00	0.00	0.17
SUB-TOTAL FIXED CHARGES	7.24	0.00	0.00	0.00	0.00	0.00	88.46
• OTHER MARGINS	-0.63	0.00	0.00	0.00	0.00	0.00	-7.72
• TFUC,By-Prod,Interr,Martel,Whl'g	-0.55	-0.38	-0.38	-0.41	-0.49	-0.51	-1.68
• MEM. FUEL TRUE-UP INTEREST	0.00	0.00	0.00	0.00	0.00	0.00	0.00
• NET MARGIN	0.19	0.00	0.00	0.00	0.00	0.00	2.34
TOTAL NON-FUEL MEM REVENUE	25.80	11.30	11.28	11.64	12.92	14.54	169.10
TOTAL MEMBER REVENUE REQUIREMENT	45.41	32.05	32.19	32.24	33.06	33.83	187.74
MEMBER SALES (MWh)	12,194,143	1,192,949	1,205,434	1,092,154	928,088	888,265	998,396

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SEMINOLE ELECTRIC COOPERATIVE, INC.
BUDGET 2000 - MONTHLY PURCHASED POWER COSTS
SUPPLEMENTAL PURCHASES FOR FLORIDA POWER CORPORATION
FOR THE YEAR 2000
DELAY CASE

MONTH	PR KWH	PR KW	INTD FUEL ENERGY	PEAK FUEL ENERGY	STATION COST(1)	DEMAND COST(2)	ENERGY COST(3)	FUEL ADJUSTMENT COST(4)	SUPPLEMENTAL TRANSMISSION COST(5)	TOTAL PURCHASED COST
JANUARY	18,261,535	711,726	4,290,173	11,734,362	$61,490	$3,577,189	$45,797	$748,354	$0	$4,432,830
FEBRUARY	6,485,603	694,444	1,796,902	3,839,701	$61,963	$3,495,497	$16,577	$254,310	$0	$3,828,347
MARCH	1,275,737	289,269	371,354	703,383	$62,436	$1,580,235	$3,281	$47,598	$0	$1,693,550
APRIL	0	0	0	0	$62,436	$0	$0	$0	$0	$62,436
MAY	1,811,329	43,275	1,621,900	143,429	$62,909	$363,380	$5,906	$46,815	$0	$479,010
JUNE	11,245,882	200,932	5,727,810	4,148,072	$62,909	$1,162,666	$31,720	$365,611	$0	$1,622,906
JULY	16,739,888	227,398	7,019,092	7,312,796	$62,909	$1,287,770	$45,500	$570,662	$0	$1,966,841
AUGUST	19,701,404	247,552	7,230,153	9,500,251	$62,909	$1,383,038	$52,374	$696,038	$0	$2,194,359
SEPTEMBER	8,413,690	116,400	4,823,740	2,696,950	$62,909	$763,083	$24,345	$264,102	$0	$1,114,439
OCTOBER	0	0	0	0	$62,909	$0	$0	$0	$0	$62,909
NOVEMBER	1,621,576	149,189	623,720	747,856	$63,382	$918,076	$4,343	$56,101	$0	$1,041,902
DECEMBER	7,133,448	469,148	2,306,692	3,884,756	$63,382	$2,430,523	$18,609	$269,023	$0	$2,781,537
	92,690,092	3,149,333	35,811,536	44,711,556	$752,543	$16961457	$248,452	$3,318,614	$0	$21,281,066

ACCOUNT NUMBER

	PRIME/SUB	AAC	LOCATOR CODE
(1)	55512	000	00
(2)	55512	000	00
(3)	55512	000	00
(4)	55512	784	00
(5)	55512	000	00

SEMINOLE ELECTRIC COOPERATIVE, INC.
BUDGET 2000 MONTHLY PURCHASED POWER COST
UNDER FLORIDA POWER CORPORATION
FULL REQUIREMENTS CONTRACT FOR THE YEAR 2000
BASE CASE

YEAR=2000

MONTH	KWH	ACTUAL KW	STATION COST(1)	DEMAND/AMORT COST(2)	ENERGY COST(3)	FUEL ADJUSTMENT COST(4)	TOTAL PURCHASED COST
JANUARY	23,000	27	$264	$261	$112	$426	$1,063
FEBRUARY	27,000	27	$264	$261	$120	$500	$1,145
MARCH	23,000	27	$264	$261	$112	$426	$1,063
APRIL	23,000	27	$264	$261	$112	$426	$1,063
MAY	24,000	27	$264	$261	$114	$444	$1,083
JUNE	30,000	27	$264	$261	$125	$555	$1,205
JULY	40,000	27	$264	$261	$145	$740	$1,410
AUGUST	43,000	27	$264	$261	$151	$796	$1,472
SEPTEMBER	41,000	27	$264	$261	$147	$759	$1,431
OCTOBER	34,000	27	$264	$261	$133	$629	$1,287
NOVEMBER	30,000	27	$264	$261	$125	$555	$1,205
DECEMBER	25,000	27	$264	$261	$116	$463	$1,104
YEAR	363,000	324	$3,168	$3,132	$1,512	$6,719	$14,531
	363,000	324	$3,168	$3,132	$1,512	$6,719	$14,531

ACCOUNT NUMBER

	PRIME/SUB	AAC	LOCATOR CODE
(1)	55511	000	00
(2)	55511	000	00
(3)	55511	000	00
(4)	55511	784	00

00056

SEMINOLE ELECTRIC COOPERATIVE, INC.
BUDGET 2000 PURCHASED POWER COST FROM CITY OF GAINESVILLE
FOR THE YEAR 2000
BASE CASE

YEAR=2000

MONTH	TOTAL KWH	ACTUAL KW	BILLED KW	STATION COST(1)	DEMAND COST(2)	ENERGY COST(3)	FUEL ADJUSTMENT COST(4)	TOTAL PURCHASED COST
JANUARY	4,334,128	11,673	11,673	$112	$65,486	$51,099	$104,019	$220,716
FEBRUARY	3,899,325	12,991	12,991	$112	$72,880	$45,973	$93,584	$212,549
MARCH	3,750,137	9,773	9,773	$112	$54,827	$44,214	$90,003	$189,156
APRIL	3,370,798	8,044	9,430	$112	$52,902	$39,742	$80,899	$173,655
MAY	3,933,499	10,576	10,576	$112	$59,331	$46,376	$94,404	$200,223
JUNE	4,549,044	11,806	11,806	$112	$66,232	$53,633	$109,177	$229,154
JULY	4,873,723	11,376	11,376	$112	$63,819	$57,461	$116,969	$238,361
AUGUST	4,923,257	13,162	13,162	$112	$73,839	$58,045	$118,158	$250,154
SEPTEMBER	4,515,909	10,967	10,967	$112	$61,525	$53,243	$108,382	$223,262
OCTOBER	3,594,337	8,776	9,213	$112	$51,685	$42,377	$86,264	$180,438
NOVEMBER	3,347,750	9,074	9,213	$112	$51,685	$39,470	$80,346	$171,613
DECEMBER	3,925,032	10,861	10,861	$112	$60,930	$46,276	$94,201	$201,519
YEAR	49,016,939	129,079	131,041	$1,344	$735,141	$577,909	$1,176,406	$2,490,800
	49,016,939	129,079	131,041	$1,344	$735,141	$577,909	$1,176,406	$2,490,800

ACCOUNT NUMBER

	PRIME/SUB	AAC	LOCATOR CODE
(1)	55511	000	00
(2)	55511	000	00
(3)	55511	000	00
(4)	55511	784	00

000057