ORIGINAL

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF DAVID E. CHRISTIANSON

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 David E. Christianson and my business address is 9400 Ward Parkway, Kansas City, Missouri, 64114.

I. QUALIFICATIONS

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

A. I am a Vice President with Burns & McDonnell Engineering Company, a full-service engineering and consulting firm, where I am responsible for managing the firm's Management Service Group.

Q. Please summarize your educational background.

A. I received a Bachelor of Science degree in Engineering Physics from South Dakota State University in 1972. Subsequently, I received a Master's in Business Administration from the University of Missouri in 1976.

Q. Please summarize your work experience with Burns & McDonnell.

A. I joined Burns & McDonnell in 1976 as a consultant in our company's Power Division. In this position, I was responsible for preparing economic studies for our electric utility clients. These included electric rate studies, load forecasts, financing studies, and feasibility studies. In 1984, I was promoted to Director of Human Resources of Burns & McDonnell where I was responsible for managing the firm's recruiting, compensation, benefits, and training programs. Subsequently in 1994, I was promoted to Vice President of Administration. On January 1, 1999 I was made Manager of the Management Services Group.

Q. What are your responsibilities as Vice President and Manager of the Management Services Group?

A. In this position I am responsible for managing a multi-discipline team of engineers, accountants, economists and other management professionals. I am responsible for developing personnel within the group, overall review of projects completed by the group, and quality control of the products produced by our consultants. In addition, I provide electric rates and human resources consultation services.

Q. Briefly describe your experience in the area of electric rate design.

A. In my nearly 25 years of experience with Burns & McDonnell, I have provided a variety of cost-of-service and rate design services to our consumer-owned electric utility clients. These assignments have included development of both wholesale and retail rates. At the retail level, my cooperative experience includes several studies for Southern Maryland Electric Cooperative. These ranged from tariff revisions as part of a make-whole rate proceeding to the development of alternative rate structures to satisfy the Public Utilities Regulatory Policy Act. On the wholesale level, my cooperative rate design experience includes assisting members of Sunflower Electric Cooperative evaluate wholesale rates from their generation and transmission cooperative. More recent cooperative rate experience includes providing oversight for the cost-of-service studies performed by Burns & McDonnell for the distribution and transmission members of the Associated Electric Cooperative system.

Q. Have you previously testified before regulatory commissions or governing boards?

A. Yes, I have testified before the Maryland Public Service Commission on several occasions in matters related to cost of service and rate design. I have provided testimony before the Texas Public Utility Commission in support of a certificate of convenience and necessity. In addition, I have presented the results of rate studies for approval before numerous boards of unregulated consumer-owned utilities.

II. PURPOSE OF TESTIMONY

Q. Who are you representing in this proceeding?

A. I have been retained by Seminole Electric Cooperative, Inc. to testify to the results and findings of assignments they have retained Burns & McDonnell to perform.

Q. Can you briefly describe what those assignments were?

A. Yes. Burns & McDonnell's first assignment was to perform an independent cost-of-service study and to recommend cost-based wholesale rates to Seminole's Board of Trustees. Second, after having completed this study Burns & McDonnell was retained by Seminole to evaluate its Rate Schedule SECI-7b. Finally, I have been asked to evaluate and comment on the rate structures being proposed by Lee County Electric Cooperative (LCEC).

Q. Briefly describe the points you wish to cover in your testimony.

A. First, I would like to summarize the Cost–of-Service Study and Wholesale Rate Design Report prepared by Burns & McDonnell in 1999. This report recommends that Seminole develop wholesale rates with demand charges that are based on the cost of adding peaking capacity. Second, I would like to comment on Seminole's Rate Schedule SECI-7b and how it compares with the recommendations contained in the Burns & McDonnell report. Third, I would like to comment on the wholesale rates being proposed by LCEC's witness, Mr. William Seelye. I would also like to respond to points in Mr. Seelye's testimony that relate to the Burns & McDonnell Report.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring the following exhibits which are attached to my testimony:

Exhibit ___ (DEC-1) – Burns & McDonnell's Cost-of-Service Study and Wholesale Rate Design Report for Seminole Electric Cooperative, December 1999.

Exhibit ____ (DEC-2) – Comparison of Revenue Collected with Energy, Demand and Consumer Charges, Burns & McDonnell Rates vs. SECI-7b.

Exhibit ____ (DEC-3) – Comparison of Expected Average Wholesale Power Costs in 2000, Burns & McDonnell Rates vs. SECI-7b.

Exhibit ____ (DEC-4) – Comparison of Expected Average Wholesale Power Costs in 2001, LCEC Alternative 2 vs. SECI-7b.

III. INDEPENDENT COST-OF-SERVICE STUDY AND WHOLESALE RATE DESIGN

Q. Please describe the initial assignment that Burns & McDonnell was requested to complete by Seminole.

A. Burns & McDonnell responded to a request from Seminole to provide a proposal to perform an independent wholesale cost-of-service and rate design study. After receiving this assignment, Burns & McDonnell was provided only limited direction from Seminole's staff. Burns & McDonnell was instructed to use Seminole's 2000 budget as a basis for developing revenue requirements. All of Seminole's ten member systems were to be included as one class. We were not provided and were instructed not to review the existing wholesale rate schedule at Seminole. We were not aware of Seminole's current or proposed rate schedules or of the LCEC rate structure complaint. We were not provided with any information related to Seminole's strategic plans or long-term goals. Staff from Seminole did provide cost and operating data. All face-to-face meetings between Burns & McDonnell and Seminole staff were also attended by Trustee representatives from the Seminole Rate Committee.

Q. Please describe the study performed by Burns & McDonnell.

A. The Cost-of-Service Study and Wholesale Rate Design Report is included as Exhibit ____ (DEC-1). Since Seminole had instructed us to use the budgeted cost and operating data for 2000 as a basis for the revenue requirements, Burns & McDonnell did not evaluate revenue requirements. Similarly, since all member systems were included in the same class, there was no need to develop allocation factors. This left the assignment of costs to the various utility functions as the key component of the study.

Q. How did Burns & McDonnell address the cost assignment issue in this study?

A. Burns & McDonnell elected to evaluate three methods of assigning the fixed costs of base-load generation to the energy and demand functions. In all other aspects, the cost assignments were the same. These methods included: (1) a traditional method where all fixed costs were assigned to the demand function, (2) an energy method where the fixed costs of base-load generation were assigned to the energy function, and (3) an equivalent peaker method where these same demand costs were assigned to both energy and demand functions.

Q. You referred to the first assignment method used by Burns & McDonnell as a traditional method. By this do you mean that it is the only method of assigning base-load fixed costs that conforms to generally accepted ratemaking principles?

A. No. In fact, rates have been designed for many years with a portion of the fixed costs being recovered in non-demand charges. "Traditional" was used in the report because we wanted to identify the method with a term that would be understandable to the members of the Rate Committee, and we felt most of this audience would be more familiar with this basic assignment method. It could have been called the "demand" method just as easily. Although this method may be one of the more well known, all three methods are familiar to rate design professionals and have been used in the past. There are certainly other acceptable assignment or allocation methods. For example the average and excess method is a well known method that results in a portion of fixed costs being recovered through energy charges. This method is found in use more in retail rate design, yet produces results similar to the equivalent peaker method. As I will discuss later in my testimony, it is not uncommon to find wholesale rates that collect fixed costs in non-demand charges.

Q. The Burns & McDonnell Report states that the traditional method recognizes the cost causation relationship for a utility as it exists today. Does this mean that the traditional method sends appropriate pricing signals?

A. No. This method sends signals as to how the costs were booked for accounting purposes. It does not necessarily send the correct price signal based on forward-looking costs.

Q. Which of the three assignment methods did Burns & McDonnell use in designing its suggested wholesale rates for Seminole?

A. The equivalent peaker method was used. With this method, we recognized that base-load generation is installed both to produce capacity and to provide a source of lower cost energy. The share of base-load fixed costs that should be assigned to the demand function is assumed to equal the lowest cost of capacity available to the utility. Additional and more expensive capacity is only placed in service to provide a lower-cost source of energy, and therefore any remaining base-load fixed costs should be assigned to the energy function.

Q. Were purchased power costs assigned using the equivalent peaker method?

A. No. They were assigned to the demand and energy functions based on whether the purchases were billed as demand or energy rates from the supplier.

Q. Should they have been assigned using the equivalent peaker method?

A. Possibly. A more detailed review of Seminole's purchase power contracts would need to be completed to make this determination. To the extent that Seminole pays higher demand charges to obtain a lower cost energy source, the equivalent peaker method should be used to assign a portion of these demand charges to Seminole's energy function. To the extent that the Burns & McDonnell Report did not assign these types of costs to the energy function, it may be appropriate to transfer additional fixed costs to the energy function in future studies.

Q. What are the advantages of using the equivalent peaker method of assigning cost?

A. Using the equivalent peaker method results in wholesale rates that include a demand charge that reflects the cost of adding new peaking capacity. With this type of wholesale rate, the member systems can then design retail rates and develop load management programs that send a price signal that directs their consumers to make economically efficient decisions. In other words, if new peaking capacity can be installed by a utility for an annualized cost of $40 per kW per year and wholesale (and subsequently retail) rates are designed to reflect this price, then consumers will make decisions to limit their peak demand or find replacement power during periods of peak demand only if they can do so at a cost of less than $40 per kW per year. With a demand charge based on the equivalent peaker method, consumers would forgo opportunities to reduce load or purchase from another source when this same capacity can be provided by the utility at a lower price.

Q. By offering a rate with an equivalent peaker derived demand charge, is the utility committing to use only combustion turbines in its generation expansion plans?

A. Not necessarily. There may be other economic reasons to add capacity with higher fixed costs (i.e. base-load, steam generation) and the utility should certainly consider energy costs when developing generation expansion plans. However, one should recognize that capacity can be added for the cost of combustion turbines and that any additional cost of new capacity is incurred to reduce energy costs and should be assigned to the energy function.

Q. Were there other reasons that Burns & McDonnell recommended the equivalent peaker method?

A. Yes. As the utility industry moves from a regulated to a deregulated business, we anticipate there will be a shift from the traditional approach to the energy approach in developing rates. Using the equivalent peaker method will help prepare Seminole and its members for expected changes in the future while recognizing that many traditional techniques are still appropriate or must still be employed.

Q. Could you summarize the proposed rates developed as a result of the Cost of Service Study and Wholesale Rate Design Report?

A. Yes. The suggested rate consisted of an energy charge of 2.73 cents per kWh, a demand charge of $7.43 per kW per month, and a customer charge of $12,397 per member per month. These rates are summarized on page ES-10 of Exhibit ___ (DEC-1).

IV. REVIEW OF SEMINOLE RATE SCHEDULE SECI-7B

Q. Have you also reviewed Seminole's Rate Schedule SECI-7b?

A. Yes. This schedule is included with Ms. Novak's testimony, Exhibit ____ (TSN-1). As Ms. Novak has testified, this schedule includes:

- Levelized Fuel Energy Charge of $0.01961 per kWh
- Non-Fuel Energy Charge of $0.00263 per kWh
- Production Demand Charge of $8.50 per kW per month (for eight months)
- Transmission Demand Charge of $1.59 per kW per month
- Distribution Demand Charge of $1.27 per kW per month
- Production Fixed Energy Charge - a fixed monthly charge calculated annually for each member
- Monthly Fuel Adjustment

Q. Please compare Rate Schedule SECI-7b with the proposed rates in the Burns & McDonnell report.

A. While at first these rates may appear to have significantly different charges, a closer review of these rates reveals major similarities. These similarities stem from the fact that Seminole has chosen to collect a portion of its fixed costs in a charge other than a monthly production demand charge. As discussed above, the fact that Burns & McDonnell used the equivalent peaker method to assign costs also resulted in a portion of Seminole's fixed costs being recovered in non-demand charges. In both cases, demand charges are levied on the member system's peak coincident with Seminole; however, Seminole has elected to break this charge into two components, a Production Demand Charge and a Transmission Demand Charge. Also the Production Demand Charge is only levied in the four peak summer months and the four peak winter months. When comparing the summarized costs of service on page II-24 of Exhibit ___ (DEC-1) with the charges in Rate Schedule SECI-7b, the similarity becomes more apparent. The transmission cost of $1.59 per kW matches Seminole's transmission charge. The power supply-demand cost of $5.79 per kW is less than the $8.50 per kW charged by Seminole. However, it must be remembered that the Burns & McDonnell demand cost is expressed as a per kW per month charge for 12 months of the year, as opposed to eight months – the basis of Seminole's charge. If this cost had been applied to the eight peak months it would have been $8.02 per kW per month. In summary, had Burns & McDonnell chosen to structure its rates as Seminole has, our recommendation would have been to include a demand charge that was 48 cents per kW per month less than Seminole's Production Demand Charge and a transmission charge that was exactly the same as the Transmission Demand Charge.

Q. **In your opinion, are there significant reasons for Seminole to collect its Production Demand Charge over only eight months as opposed to the twelve months you recommended?**

A. Yes. Since completing the Cost-of-Service Study and Wholesale Rate Design Report, we have received additional information on Seminole that was not provided when we completed the original report. This information has given us added insight into Seminole's longer-term costs. Seminole's new power supply sources are being added to meet peak demand in the summer and winter months. There generally is surplus capacity available to meet demand in the spring and fall, and thus no reason to send a price signal to reduce demand at this time of year. Also a demand charge in these off-peak months would continue to send a false signal to Seminole's members as they attempt to control load when there would be no significant economic savings. To compound the problem, identifying monthly peaks in the spring and fall is extremely difficult if not impossible. With a demand charge in off-peak months, retail customers would likely see increased load management controls that would produce little or no savings for anyone. For the above reasons, limiting the Production Demand Charge to peak months was a sound decision.

Q. **Please comment on SECI-7b's Production Fixed Energy Charge.**

A. Here again is a charge that was not included in our recommended rates, but is consistent with the overall philosophy we proposed to Seminole in our independent Cost-of-Service and Wholesale Rate Design Report. Basically, Seminole is recovering its variable cost of fuel through its other energy and fuel charges. It is recovering its transmission cost through its Transmission Demand Charge and it is recovering the incremental cost of capacity through its Production Demand Charge. All of these charges provide price signals to Seminole's member systems. Certainly the energy and fuel charges send the signal to the member systems that if they conserve energy they will allow Seminole to avoid these variable costs and thus result in lower costs. The Production Demand Charge sends the price signal that consumption on peak should be reduced. However, the signal is that price should not be reduced at any cost. Surely, it would not make economic sense for Seminole's members to attempt to reduce peak through load management or generation at a cost greater than Seminole would need to expend to develop new capacity.

All of the charges discussed above do not provide sufficient revenue to meet Seminole's revenue requirements. Additional revenue of $54,000,000 must be collected to meet the fixed costs not recovered through Seminole's Production Demand Charge. These costs are sunk costs and no reduction in kilowatt-hour sales or peak demand will eliminate these costs. For the most part, these costs represent fixed costs associated with base-load generation. Since this base-load generation provides lower cost energy to Seminole and its member systems, it is appropriate that an energy-based charge be developed to recover these costs. Both the philosophical basis for developing Rate Schedule SECI-7b and the resulting effects on the member systems are similar to those proposed in Burns & McDonnell's Cost-of-Service Study and Wholesale Rate Design Report.

Q. Can you compare the rates recommended in the Burns & McDonnell Report with Rate Schedule SECI-7b?

A. Yes. To summarize the comparison, I have prepared Exhibit ___ (DEC-2) and Exhibit ___ (DEC-3). Exhibit ___ (DEC-2) contains pie charts that illustrate the relative amount of revenues collected through energy, demand, and consumer charges in both Rate Schedule SECI-7b and the rates suggested in the Burns & McDonnell Report. This chart shows graphically that both rates should collect approximately 60 percent of Seminole's revenue requirements in 2000 with the energy charges. Exhibit ___ (DEC-3) lists and graphs the expected average cost of power for each member system in 2000 under both rate schedules. Again it can be seen that the rates produce similar results. For one of the member systems the average rates are identical. For eight of the member systems the rate schedules produce average rates that differ from 0.1 mills per kWh to 0.6 mills per kWh. The largest difference can be seen at Glades where the Burns & McDonnell schedule would collect on average 1.5 mills per kWh more than Rate Schedule SECI-7b.

Q. Are there other reasons you feel that it is appropriate to collect fixed costs in an energy charge?

A. Yes. It is my opinion that as the electric utility industry moves towards deregulation we will see more commodity pricing of electricity. In a regulated industry, pricing in effect becomes a conduit where costs are passed along to the ultimate consumer to the maximum extent possible as they are incurred by the utility. This places the investment risk squarely on the shoulders of the ultimate consumer. The risks of over or under expansion are borne by the consumer. In a totally unregulated industry, products are sold based on commodity charges. Competitively-priced computers, automobiles, and widgets do not include a demand charge. General Motors does not charge customers directly for its investments in auto manufacturing plants. Rather, it rolls these costs into a per car charge along with the price of steel and labor. If General Motors can sell its product in a competitive market at a price that exceeds all of its costs (both fixed and variable), then it is profitable. If not, it loses money.

With deregulation coming to the electric utility industry, it is prudent for Seminole to begin charging more of its costs in an energy charge. This will provide a more gradual transition to what I feel will become a energy charge industry in the future, and will not result in a sudden change in rate structure for Seminole's member systems and their retail consumers.

Q. In your opinion was Rate Schedule SECI-7b developed using generally accepted ratemaking criteria?

A. Yes. As discussed by Ms. Novak, Seminole performed a full analysis of the cost of providing service and used the analysis as the basis for developing Rate Schedule SECI-7b. Also as I discussed above, Burns & McDonnell's independent cost-of-service study supports the general direction of the rates developed. In addition to considering the cost of service, Seminole went a step further and recognized the need to send appropriate pricing signals to its member systems. As discussed by Mr. Woodbury in his testimony, the rate design process followed by Seminole involved extensive input from its users and received support from the majority of those member systems. In summary, Seminole has done an exceptional job in following generally accepted ratemaking principles through a well thought out process that produced rates that are fair, just and reasonable.

Q. Are you familiar with other cases where a portion of the fixed costs are recovered through an energy charge?

A. Yes. I have completed an informal poll of other consumer-owned utilities and found several examples where fixed costs are intentionally recovered through an energy charge. Both East River Electric Power Cooperative and Kansas Electric Power Cooperative collect a major portion of their fixed costs through energy charges. The Indiana Municipal Power Agency attempts to collect most of its fixed costs through demand charge; however, it does recover both the fixed and variable portions of its purchased power cost for the summer months through an energy charge. TVA's rates to its wholesale customers result in the majority of TVA power being sold with energy charges and no demand charge. Finally, the rates charged by unregulated merchant plants are nearly all energy based. Certainly each utility has its own reasons for collecting fixed costs through energy charges. The fact remains that other wholesale rates do in fact collect fixed costs through energy charges.

V. REVIEW OF LCEC COST-OF-SERVICE STUDY AND PROPOSED RATES

Q. Have you had an opportunity to read the direct testimony of William Seelye?

A. Yes.

Q. What comments do you have about his testimony and the position he takes?

A. First, I find it interesting that Mr. Seelye has spent a significant portion of his testimony addressing Burns & McDonnell's Cost-of-Service Study and Wholesale Rate Design Report. This report was not the basis of the rate design implemented by Seminole, but rather an independent review requested by the Seminole Board of Trustees.

Q. Nevertheless, Mr. Seelye addresses what he feels are "seven serious flaws" in the cost allocation in the Burns & McDonnell study. Would you care to address these?

A. Gladly. Mr. Seelye refers to the costs used and our analysis as "hypothetical and fictional." As with Mr. Seelye's own cost-of-service analysis, we used budgeted costs for the year 2000. The equivalent peaker method was used to assign costs. As is pointed out in the study, this method is not intended to use historical data to assign costs, but rather to estimate the cost of future peaking capacity and use this information to assign costs. The approach we have chosen to use in assigning costs to the demand and energy functions for Seminole is a forward looking approach and not one that "looks in the rear view mirror." Looking forward requires an informed estimate of what future capacity costs will be. I would not characterize these as hypothetical and fictitious.

Second, Mr. Seelye is concerned that "...the higher operating cost of combustion turbine capacity has not been dealt with at all." The study does include the cost of all fuel for Seminole's system. Peaking capacity fuel is already included in the energy charge. In assigning costs to the demand and energy function, the fixed costs of a combustion turbine were assigned to the demand function. No adjustments were made to this assignment to consider the possible higher fuel costs from a combustion turbine. The cost to produce one additional kilowatt hour on peak can be viewed as the fixed cost of one kilowatt of capacity and the fuel cost of one kilowatt hour. The fuel cost of one kilowatt hour is insignificant when compared with the fixed cost of one kilowatt of capacity, and therefore was not included.

Third, Mr. Seelye feels the study "...ignores the historical fact that Seminole's system resources consist of a large amount of base-load capacity." Again this study does recognize all the costs of operating Seminole's system; however, as stated above this is a forward-looking view of costs and how appropriate price signals can be sent to Seminole's member systems. The study accomplishes this by recognizing that Seminole's base-load units are not just a source of capacity, but are also a source of lower cost energy.

Mr. Seelye's fourth criticism of the study is that transmission costs are recovered through the demand charge. Transmission costs were collected through a demand related charge to provide price signals to the members. Reducing a kilowatt of demand at peak will reduce Seminole's transmission costs. Mr. Seelye's argument should not be totally ignored, however. An argument can be made to include all transmission costs in an energy charge since the original purpose of most transmission systems was to bring low cost energy from remote generation sites to load centers. I doubt, however, that Mr. Seelye would argue that Seminole's transmission demand cost should be recovered through energy charges.

Mr. Seelye's fifth point is that the equivalent peaker method would not be allowed by the Federal Energy Regulatory Commission. Seminole is not regulated by the FERC, but rather governed by the Board of Trustees of Seminole. The equivalent peaker method was presented to the members of Seminole on December 8, 1999. This information was available to the Board before Rate Schedule SECI-7b was implemented.

In Mr. Seelye's sixth point he refers to the hypothetical cost of combustion turbines used in the study and suggests that the cost of Seminole's new combined cycle units represents the marginal cost of capacity As stated earlier, the cost of combustion turbines was used to assign costs to demand and energy because it was considered the lowest cost capacity addition available. The fact that Seminole is constructing new combined cycle units is irrelevant. The cost of combustion turbines is the marginal cost for new capacity. The addition of other types of capacity may be appropriate, but one should recognize that when more costly capacity is added, it is added to provide a lower cost energy source as well as capacity. (It is also interesting to note that Seminole, in addition to constructing new combined cycle units, is also buying peaking power at a cost of $4 per kW to meet its future power requirements. This may in fact be even more representative of Seminole's marginal cost of capacity.) Also, in preparing the Cost-of-Service Study and Wholesale Rate Design Report for Seminole we were instructed not to consider future plans or strategic objectives that may have been in place at the time, and did not evaluate Seminole's planned expansion.

Mr. Seelye's seventh and final point is that there are computational errors in the study. He cites incorrect numbers on Table ES-4 of the report. He is correct in that the coincident peaks for some of the cooperatives on this table are incorrect. This error was noted after the study was published and an errata sheet was provided to Seminole before the presentation to the Seminole Board. I apologize to Mr. Seelye for the inconvenience our typographical errors may have caused him in review of the study without the corrections.

Finally, I would like to again state the Burns & McDonnell study was not the basis for Rate Schedule SECI-7b, but rather it was an independent review that produced results which support the rate design concepts used by Seminole.

Q. Mr. Seelye states on page 5 of his testimony that "SECI-7b does not reflect fundamental cost of service principles...." Do you agree?

A. No. While Rate Schedule SECI-7b may not reflect Mr. Seelye's principles, it does reflect the cost of service. There is not necessarily one and only one correct way to complete a cost-of-service study. There are a variety of decisions and judgements that must be made in performing any such study. A test year must be chosen. Revenue requirements must be defined. Classes must be defined. Cost assignments must be made. Allocation factors must be developed. In all of these tasks one should consider the goals that the utility has established and not blindly make decisions based on what has happened in the past. Because both the analysis we performed and the analysis Seminole performed explicitly considered the future direction of the utility industry, I conclude that the results are more appropriate than those obtained from Mr. Seelye's "fundamental" cost-of-service study.

Q. Mr. Seelye states that wholesale rates consist of a demand charge, an energy charge, and a substation charge. Is that always the case?

A. Certainly not. While most wholesale rates contain one or more of these elements, it is an over simplification to imply that all rates except those of Seminole contain the three charges that recover costs exactly as Mr. Seelye has outlined in his testimony. (Even Mr. Seelye's proposed rates for LCEC do not contain the "typical" substation charge.) *In fact, inconsistency is probably the most consistent* aspect common to wholesale rates. The wide range of rate structures in wholesale rates (especially in member-owned generation and transmission cooperatives) reflects the unique goals and objectives of each utility. To state that rates in use today consist of three basic charges is a gross simplification.

Q. Are there other comments that you have about Mr. Seelye's testimony?

A. Yes, I find it interesting that Mr. Seelye has gone to great lengths to develop his own cost-of-service model, Exhibit ___ (WSS-2), yet he does not use the results of his model in developing his proposed rates. It would appear he relied heavily on the work of Seminole in developing his rates, and he seems to accept Seminole's assignment of energy and variable costs. It appears that his rate design was developed by applying different methods to collect the revenue now being recovered through the Fixed Production Energy Charge. Also, it is interesting that projected revenues by member system vary little between Mr. Seelye's Alternative 2 rate design and Seminole's Rate Schedule SECI-7b. Exhibit ___ (DEC-4) shows the average rate charged each of Seminole's member systems under the Lee County's Alternate 2 rates and Rate Schedule SECI-7b applied to estimated 2001 billing units and revenue requirements. The two schedules collect exactly the same average revenue. This is not surprising, since total revenue requirements have not been an issue in this case. What is surprising is how little the average rate varies with each method from member to member. Three member systems (Central, Clay, and Suwannee) pay nearly the same average rate under either rate schedule. All but one differ by less than 0.5 mills per kWh. Glade varies by only 0.6 mills per kWh. Assuming that purchase power cost represents seventy-five percent of the ultimate customer cost, the difference in rates would amount to less than 0.75 percent of Lee County's average retail customer's bill. Whether a difference of this magnitude should be debated in this forum and whether the resulting decision will add real value to the ultimate consumer is questionable.

Q. What are the differences in the rate schedules proposed by Mr. Seelye and Rate Schedule SECI-7b?

A. As discussed above, the revenue requirements that form the basis of all three of Mr. Seelye's proposed rate schedules are identical to those used by Seminole in Rate Schedule SECI-7b. Also, all three of his rate schedules include fuel and energy charges of 22.4 mills per kWh and distribution charges of $1.26 per kW per month. These charges are identical to the projected charges for 2001 under the Rate Schedule SECI-7b methodology. Two of Mr. Seelye's alternatives contain a transmission charge identical to Seminole's, the third includes this charge implicitly in the Demand Charge (Rate Alternative 1). The common (and only) difference between all of Mr. Seelye's rates and those in Rate Schedule SECI-7b is his treatment of fixed production costs. In two of his alternatives (Rate Alternatives 1 and 2) all production demand costs are collected in demand charges. Alternative 3 mirrors Rate Schedule SECI-7b with the exception that the Production Fixed Energy Charge is replaced with a Production Fixed Demand Charge. This charge collects fixed costs based on each member's demand. (From Mr. Seelye's testimony it is not clear whether this charge is calculated using current or historical demands.)

Q. What are your major concerns with Mr. Seelye's rate structure alternatives?

A. Although Mr. Seelye's rate alternatives produce similar results to Rate Schedule SECI-7b in 2001, they send different price signals. In Alternative 1 Mr. Seelye is sending a signal to reduce peak each month of the year if the cost of saving a kilowatt is less than $9.13. As I have discussed previously, Seminole sees little or no savings by reducing peak in its four off-peak months. For the remaining months, Seminole's cost of additional power at peak periods is significantly lower than the demand charge Mr. Seelye is proposing. (See Ms. Novak's testimony.) Sending incorrect price signals can cause Seminole's members to make incorrect decisions. For example, a member, through load management, may curtail 100 kilowatts of load during a non-peak month and reduce its power bill by $913. Unfortunately, Seminole's costs would most likely remain the same and Seminole could experience a $913 shortfall. As a member-owned utility, Seminole would eventually need to recover this lost revenue with a rate increase. Alternative 2, while correctly pricing demand in the off-peak months, sends the even more erroneous signal that $10.59 per kW can be saved during peak months. It is not clear how Mr. Seelye would apply Alternative 3. Depending on how he applied his Fixed Production Demand Charge, he may be sending a delayed price signal. However, with a charge based on demand, he would be sending a price signal to curtail demand when there would not be associated cost savings to the members of Seminole.

Q. Are there areas of Mr. Seelye's or Dr. Blake's testimony that you feel support Rate Schedule SECI-7b?

A. Indirectly, yes. Both Mr. Seelye and Dr. Blake testify that rates should be easily understood. I agree. I feel that Rate Schedule SECI-7b is easy to understand and easy to explain. Although both of these witnesses state an opposing opinion, both are able to explain this new rate schedule quite clearly in their own testimony. Mr. Seelye is able to distill a rate schedule that he feels contains "unnecessary complexity" into two pages of double spaced testimony and still has room to add his editorial comments.

Q. In your opinion, do the rate schedules proposed by Mr. Seelye meet the ratemaking standards advocated in Dr. Blake's testimony?

A. No. As I have previously indicated, the resulting average power rates to Seminole's members differ little between Rate Schedule SECI-7b and the rate schedule Mr. Seelye proposes. It is hard to imagine how such similar rates would not both fail the same criteria. The most obvious example can be found in Dr. Blake's criticism that Rate Schedule SECI-7b does not encourage conservation. If Seminole's energy charge of 22.4 mills per kWh does not encourage conservation, how will Mr. Seelye's charge of 2.24 cents per kWh meet this objective?

Q. Does this conclude your testimony?

A Yes it does.

Exhibit _____ (DEC-1)
Witness David E. Christianson
Docket # 981827-EC

Cost of Service Study and Wholesale Rate Design

December 1999

Prepared for

Seminole Electric
COOPERATIVE, INC.
IN PARTNERSHIP WITH THOSE WE SERVE

Burns & McDonnell
SINCE 1898

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Board of Directors
Seminole Electric Cooperative
1613 N Dale Mabry Highway
Tampa, FL 33618

Seminole Electric Cooperative, Inc.
Report on Cost-of-Service Analysis
And Wholesale Rate Design
Project: 99-727-4

Dear Board Members,

Burns & McDonnell is pleased to present this report on the Cost-of-Service Study and Wholesale Rate Design performed on the behalf of Seminole Electric Cooperative Inc. This report provides an explanation of the analysis preformed to develop a cost-based wholesale rate for Seminole's member distribution systems. It describes the data, assumptions, and methodologies used in our study. It also presents the results of the analysis and Burns & McDonnell's recommendations to Seminole for proceeding with wholesale rate design.

In completing the study Burns & McDonnell relied only on cost information. Wholesale rates were not adjusted to account for other factor such as existing rates, long-term goals, etc. All member systems were considered as one class. The year 2000 budget was used as the basis of this study so as to develop rates reflecting the cost that can be expected for the period in which the rates are applied. Also, input from your staff was limited to providing data so that this report would result in an independent, cost-based recommendation for wholesale rates.

The recommended rates are based on an equivalent peaker method for assigning base load generation costs. The recommended cost-based rates are:

- 2.73 cents per kilowatt-hour
- $7.43 per kilowatt per month (coincident with Seminole's peak)
- $12,397 per member system

Rates were also calculated using other assignment methodologies and are discussed in more detail in this report.

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We appreciate having had the opportunity to provide services to Seminole and its member systems. We look forward to discussing this report with you on December 8.

Sincerely,

David E. Christianson P.E.
Vice-President
Management Services Group

Michelle Z. Simmons P.E.
Project Manager

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EXECUTIVE SUMMARY

INTRODUCTION

Seminole Electric Cooperative, Inc. (Seminole) has entered into an agreement with Burns & McDonnell to prepare a cost-of-service study and to recommend an appropriate rate structure for Seminole. As part of this agreement, dated September 21, 1999, Burns & McDonnell has completed an electric cost-of-service analysis and wholesale rate design for Seminole, a generation and transmission cooperative located in Tampa, Florida.

At Seminole's request, this is an independent, cost-based study in which Seminole staff has limited their involvement. Seminole or its member systems' strategic plans and long- and short-term objectives were not considered in the study. To further ensure an independent analysis, Seminole staff did not provide guidance or direction during the study, and they did not provide existing or prior wholesale rate schedules.

The primary objectives of this study are to perform an independent cost-of-service study for the Seminole system, where individual member cooperatives are considered as one customer class, and to recommend an appropriate wholesale rate structure for Seminole. This report contains a description of the results of the electric cost-of-service analysis and proposed wholesale rate for application to all Seminole members.

As the electric utility industry deregulates across the nation, Seminole should begin preparing itself for a more competitive business environment. While the effects that competition will have on the state of Florida are still not known, Seminole and its members systems should move to position themselves for an uncertain and competitive future.

COST-OF-SERVICE ANALYSIS

This analysis consisted of two primary steps: 1) development of the revenue requirement consistent with Seminole's year 2000 budget and 2) assignment of the various costs which make up the revenue requirement to unbundled functions.

Revenue Requirements

A cost-of-service study analyzes and identifies the revenue requirement for the fiscal year in which any revised rates would be implemented. The first step is to select a test year to be used in the development of revenue requirements. Since operating revenues and expenses of a utility generally vary on a seasonal basis, a 12-month period was used to capture the seasonal impacts on Seminole's financial results. Seminole has requested that Burns & McDonnell develop rates based on its budget for the year 2000. Given the advantages of using a future test year and the relationship of trust and accountability one would expect in a cooperative organization, this approach seems reasonable. Therefore, Seminole's budget for 2000 was used as the basis for identifying costs for this cost-of-service study.

Seminole provided budget information for the year that is summarized as Table ES-1. From this budget it can be seen that Utility Member Service Revenues are expected to be $553,789,741. This amount represents the revenue requirements that must be recovered from the proposed wholesale rates and thus the cost of service for the member distribution cooperatives. Revenues from other sources result in a total Operating Revenue and Patronage Capital of $568,221,117.

Rate Base

In addition to identifying all the costs for the test year, it is also necessary to define the rate base. The rate base represents the total investment required by Seminole to provide service to its member systems. It includes utility net of depreciation and an additional amount to recognize Seminole's investment in working capital to operate the system. The rate base is not truly a cost and is not added to the cost of service. Rather, it represents the investment needed to provide service and is used later to assign capital-related costs included in the year 2000 budget.

Cost Assignments

Having identified the costs to be included in the analysis, Burns & McDonnell turned to the next phase of the cost-of-service study, assigning costs to the appropriate utility functions. This phase is also known as the unbundling phase, in that total utility costs are broken out or unbundled by function. In this phase costs are assigned to the various functions or service that the utility provides. Breaking costs down into functions allows them to be used in rate design. Rates can then be designed to reflect how each customer or customer class uses the various functions or unbundled services of the utility. The unbundled costs for Seminole were summarized into the following major areas: 1) power supply – demand; 2) power supply – energy; 3) transmission; 4) consumer services; and 5) general.

The generation investment costs, i.e. depreciation, interest, patronage capital, etc., are a significant portion of the cost of service. How these costs are assigned can significantly impact the rate design process. Three different approaches were considered in the assignment of investment costs.

Table ES-1

YEAR 2000 BUDGET
Seminole Electric Cooperative, Inc.

Item	Year 2000 Budget
Utility Member Service Revenues	$ 553,789,741
Non-member Sales	8,006,085
Interruptible Sales	5,137,708
Martel Sales	62,806
Other Operating Revenues	1,224,777
Total Operating Revenue and Patronage Capital	**$ 568,221,117**
Production Expense	$243,299,011
Cost of Purchased Power	218,516,713
Transmission Expense - Operation	35,526,936
Transmission Expense - Maintenance	1,200,514
Administrative and General Expense	15,336,534
Total Operation & Maintenance Expense	**$513,879,708**
Depreciation and Amortization Expense	$25,581,072
Taxes	164,817
Interest on Long-Term Debt	30,145,557
Other Deductions	3,818,880
Total Expenses	**$573,590,034**
Patronage Capital or Operating Margins	**($5,368,917)**
Non Operating Margins - Interest	$7,010,135
Gain on Disposition of Clean Air Allowances	100,000
Non Operating Margins - Other	493,662
Other Capital Credits and Patronage Dividends	100,000
Patronage Capital or Margins	**$2,334,880**

Using a "Traditional" approach, the investment cost (and fixed O&M cost) of a plant are recovered through the demand charge and the commodity cost of fuel and variable O&M are recovered through an energy charge. This type of assignment recognizes the cost-causation relationship for the utility as it exists today.

An alternative approach to assigning power production costs, the "Energy" method, is to assign all baseload generation investment cost to power supply - energy. The reasoning behind this assignment method is that baseload units are developed to produce kilowatt-hours. Therefore the investment costs as well as the fuel and variable O&M cost should be recovered through an energy charge (investment costs of peaking units under this methodology are normally assigned to the power supply - demand function).

The recommended approach, the "Equivalent Peaker" method of assigning investment costs, is based on the type of generation resource and not whether the costs are fixed or variable. Peaking units are installed to provide capacity and the investment costs associated with this type of generation are assigned to the power supply - demand function. On the other hand, a baseload resource is installed to provide capacity, but also low-cost energy. Therefore, the investment cost for these units should be assigned to both the power supply - energy and power supply - demand function. Only that portion of the investment cost that would have been incurred with the peaking unit is assigned to the power supply - demand function, thus the term equivalent peaker method. The remaining investment costs are more appropriately assigned to the power supply - energy function.

The budget costs identified in Table ES-1 were assigned to the utility functions and sub-functions. Results of all three methods are compared on Table ES-2. In addition to the rate base assignments discussed above, several assignment methodologies were used for other costs. These included the use of a cost-of-service ratio, payroll ratio and total utility plant ratio. These ratios were developed by adding the costs assigned to each of the functional categories and then dividing by the total cost. In other cases, costs were directly assigned to specific functions.

Unbundling the costs of providing electricity to the distribution cooperatives will give Seminole a clearer picture of the source of their costs. It is important for Seminole to remain aware of the opportunities and consequences of deregulation in other states and in Florida as they relate to its electric system. Examining and understanding the detailed costs of delivering power through its transmission system will aid Seminole in its management of competition. With the nationwide movement toward deregulation, and the challenges undertaken by Seminole to be the future provider of choice, it will be important for

Table ES-2

COMPARISON OF YEAR 2000 BUDGET ASSIGNMENT
Seminole Electric Cooperative, Inc.

Assignment Method	Year 2000 Budget	kW	KWH	ACC	T-KW	CONS	GENL
TRADITIONAL	$553,789,741	$211,041,972	$290,308,500	$33,596,446	$13,330,013	$1,476,741	$4,036,067
EQUIVALENT PEAKER	**$553,789,741**	**$171,056,692**	**$330,293,781**	**$33,596,446**	**$13,330,013**	**$1,476,741**	**$4,036,067**
ENERGY	$553,789,741	$136,967,004	$364,383,468	$33,596,446	$13,330,013	$1,476,741	$4,036,067

Seminole to know the unbundled cost of service in order to realize its efficiency in each separate unbundled category. In preparation for changes in the industry, the proprietary cost-of-service model developed by Burns & McDonnell was designed to support the development of unbundled service rates.

Cost Allocation

Generally, the next step in a cost-of-service study is to allocate the unbundled costs to the appropriate customer classes. In this part of a study, costs are allocated based on various classes use of different services, i.e., kWh, kW, meters, etc. For this study, Seminole requested that all member distribution systems be considered as one class. To the extent that all member cooperatives receive the same level of service, this is an appropriate approach. Actual allocation between the various member systems then becomes covered in the actual rate design.

The unbundled costs listed on Table ES-2 (for the "Equivalent Peaker" method) were subsequently summarized into the following major areas:

- **Power supply - energy** – Power supply energy costs are expected to vary directly with the production or purchase of energy measured in kilowatt-hours (kWh). The power supply energy portion of Seminole's budgeted costs totaled $330,293,781. Power supply energy costs included Seminole's expenditures associated with electricity generation and purchases. Power supply - energy costs were defined as the costs incurred to meet the energy needs of the consumers and consisted primarily of fuel costs and variable generation operation and maintenance (O&M) costs.

- **Power supply - demand** – Power supply - demand costs are expected to vary directly with the capacity installed or purchased to meet the demand requirements of Seminole's system measured in kilowatts (kW). The power supply - demand portion of Seminole's budgeted costs totaled $171,056,692. Power supply - demand costs were defined as the costs incurred to meet the peak demand needs of the customers and included Seminole's expenditures associated with electricity generation and purchases. These costs consisted primarily of the equivalent peaker portion of investment costs for Seminole's generation resources, fixed generation O&M costs, and demand-related purchased power costs.

- **Transmission** – Transmission costs are expected to vary directly with the transmission capacity installed or purchased to meet the transmission demand requirements of Seminole's system measured in kilowatts (kW). The transmission demand portion of Seminole's budgeted costs totaled $46,926,459. Transmission demand costs were defined as the costs incurred to transmit the peak demands of Seminole's customers and consisted primarily of transmission facilities and operating expenses.

- **Consumer** – Consumer costs for the Seminole system totaled $1,476,741. Consumer service costs included expenditures that are directly related to providing member services to Seminole's ten distribution cooperatives.

- ***General*** – General costs totaled $4,036,067. These general costs are necessary to support all of the above functions of the utility. For this reason, the general costs wre broken down into sub-functions in proportion of the subtotal of the costs for power supply – energy, power supply – demand, transmission, and consumer costs.

RATE DESIGN

Burns & McDonnell used the cost-of-service study results that were based on the equivalent peaker method of assigning costs to design the proposed wholesale rates. The costs were combined into three major categories: *commodity, capacity,* and *customer* costs. These costs are summarized on Table ES-3. Commodity costs included the power supply – energy costs. Capacity costs included the power supply – demand and transmission costs. Customer costs included the consumer costs. General costs were included in each category based on the sub-function breakdown. The three major categories of costs provided the basis for developing three separate charges to recover revenues from the member distribution cooperatives on a cost basis.

Having determined the costs to be collected, the next task in designing wholesale rates was to identify the billing units that would be applied to the resulting rates. Table ES-4 summarizes the billing units that were selected for recovering each of the three cost categories.

Proposed Rates

Having defined the costs and the billing units, developing the proposed rates basically became a matter of dividing costs by billing units. The proposed cost-based rates for Seminole's member systems are summarized in Table ES-5. The commodity charge of 2.73 cents per kilowatt-hour is applied to all energy sales. The capacity charge is applied to the members' contribution to Seminole's monthly peak. The actual rate was developed by dividing the sum of monthly capacity costs by the sum of Seminole's

Table ES-3

COST TO BE RECOVERED
THROUGH WHOLESALE RATES
Seminole Electric Cooperative, Inc.

Equivalent Peaker Method

Category	Cost
Commodity	$332,718,663
Capacity	219,583,495
Customer	1,487,583
Total Cost of Service	$553,789,741

Table ES-4

BILLING UNITS
Seminole Electric Cooperative, Inc.

Units	Central Florida	Clay	Glades	Lee County	Peace River	Sumter
kWh Purchased	401,047,636	2,522,169,887	325,643,638	2,671,165,760	387,811,955	1,658,790,641
Sum of Monthly Coincident Peaks (kW)	973,941	5,908,709	657,585	5,966,874	880,499	4,304,641
Customer	1	1	1	1	1	1

Units	**Suwannee**	**Talquin**	**Tri-County**	**Withlacoochee**	**Total**
kWh Purchased	302,701,398	856,509,058	185,508,871	2,882,794,637	**12,194,143,481**
Sum of Monthly Coincident Peaks (kW)	723,965	2,122,127	414,093	7,584,148	**29,536,582**
Customer	1	1	1	1	**10**

Corrected

Table ES-5

PROPOSED WHOLESALE RATES
Seminole Electric Cooperative, Inc.

Equivalent Peaker Method

Commodity	2.73	cents per kWh
Capacity	$7.43	kW per month Monthly member contribution to SECI peak.
Customer Charge	$12,397	per member

monthly peak demand and then dividing this result by 12. Since the billing units used to determine this rate were the sum of the 12 months' demands, no ratchet is included in this rate. Finally, the customer charge is a monthly charge assessed to each member system.

Rates Under Alternate Assignment Methodologies

To provide an indication of how assigning the investment costs of baseload generation would affect the rates, rates were also calculated using the traditional and energy methods. Table ES-6 was included to compare the effect of using different assignment methods on each of the member systems. The average cost of service, expressed in cents per kilowatt-hour, was calculated for each member cooperative using each of the three assignment methods.

CONCLUSIONS AND RECOMMENDATIONS

This study was based on information provided by Seminole, including the 2000 budget numbers, and other sources. The information was also used by Burns & McDonnell to make certain assumptions with respect to conditions that may exist in the future. These assumptions provided the basis for this cost-of-service and rate design study.

Important assumptions made in performing the cost-of-service study and rate design are that:

1. energy and demand will be as forecast for Seminole and its members;
2. costs will be as budgeted by Seminole; and
3. all member cooperatives will be considered as one customer class.

Conclusions

Based on the cost-of-service study and rate design, Burns & McDonnell concludes that:

1. Seminole will need to meet a load of 37,907 MW and produce 12,194,143,000 kWh for its members in 2000.

2. The total cost of service for Seminole to provide service to its ten member distribution systems in the year 2000, will be $553,789,741;

Table ES-6

COMPARISON OF COST TO MEMBER SYSTEMS WITH DIFFERENT ASSIGNMENT METHODS

Seminole Electric Cooperative, Inc.

(cents/kWh)

Units	Central Florida	Clay	Glades	Lee County	Peace River	Sumter
TRADITIONAL	4.57	4.47	4.22	4.37	4.43	4.69
EQUIVALENT PEAKER	4.57	4.48	4.28	4.39	4.45	4.67
ENERGY	4.57	4.49	4.32	4.42	4.47	4.65

Units	Suwannee	Talquin	Tri-County	Withlacoochee	Average
TRADITIONAL	4.55	4.60	4.44	4.72	**$4.54**
EQUIVALENT PEAKER	4.56	4.59	4.47	4.69	**$4.54**
ENERGY	4.56	4.58	4.49	4.67	**$4.54**

3. This total cost of service can be assigned to the major utility functions using the equivalent peaker method to:
   - Commodity costs - $332,718.663;
   - Capacity costs - $219,583,495; and
   - Consumer cost - $1,487,583.

4. Using the traditional method of assigning costs transfers $40,278,836 from power supply – energy to power supply – demand. The total cost of service can be assigned to the major utility functions using the traditional method to:
   - Commodity costs - $292,439,827;
   - Capacity costs - $259,862,331; and
   - Consumer cost - $1,487,583.

5. Using the energy method of assigning costs transfers $34,339,960 from power supply – demand to power supply – energy. The total cost of service for Seminole in the year 2000 using the energy method consists of:
   - Commodity costs - $367,058,623;
   - Capacity costs - $185,243,535; and
   - Consumer cost - $1,487,583.

6. The following rates (based on the equivalent peaker method of assigning costs) are cost-based and can provide the basis for designing wholesale rates for Seminole's ten members systems:
   - Commodity 2.73 cents per kWh
   - Capacity $7.43 kW per month.
   - Customer $12,397 per member

Recommendations

Based on conclusions as stated above, it is recommended that:

1. The equivalent peaker method be used for the assignment of costs;
2. Assignments based on the equivalent peaker method be the basis for developing final rates:
3. Seminole compare the cost-based rates with Seminole's existing rates to consider rate stability;
4. Seminole compare the cost-based rates with its strategic plans and other long- and short-term goals:
5. Seminole modify the rates, if necessary, after making comparisons with existing rates and Seminole and member goals;
6. Seminole implement the rate among its member systems;
7. Seminole's cost of service be re-evaluated regularly to ensure full cost recovery;
8. Seminole continue to review the effectiveness of its rates, especially if changes in member status or the electric utility occur;
9. Seminole continue to position itself to be prepared as changes occur through the deregulation of the electric utility industry; and
10. Seminole continue to position itself to be prepared as changes occur through the deregulation of the electric utility industry and consider investigating the appropriateness of rate concepts in the future including time-of-use rates, performance-based rates and accelerated recovery of investments.

PART I - INTRODUCTION

PART I
INTRODUCTION

Seminole Electric Cooperative, Inc. (Seminole) has entered into an agreement with Burns & McDonnell to prepare a wholesale cost-of-service study for the Seminole system and to develop a wholesale rate for application to all Seminole members. As part of this agreement, dated September 21, 1999, Burns & McDonnell has completed an electric cost-of-service analysis and wholesale rate design for Seminole Electric Cooperative, Inc., a generation and transmission cooperative located in Tampa, Florida.

At Seminole's request, this is an independent, cost-based study in which Seminole staff has limited their involvement. Seminole's or its members' strategic plans and long- and short-term objectives were not considered in this study. To further ensure an independent analysis, Seminole staff did not provide guidance or direction to Burns & McDonnell, nor did they provide existing or prior wholesale rate schedules.

This report contains a description of the results of the electric cost-of-service analysis and rate design performed for Seminole. The primary objectives of this study were:

- to determine the revenue required to meet all operating and capital costs consistent with Seminole's 2000 budget;
- to perform a cost-of-service study for the Seminole system where individual member systems are considered one customer class; and
- to develop a wholesale rate for application to all Seminole members.

The electric utility industry has undergone substantial changes in moving toward a more competitive business environment. The potential impacts of the impending deregulation of the electric industry are becoming clearer. While the effects that competition will have on Seminole are still not completely known, Seminole and its members should move to position itself for an uncertain and competitive future.

As the electric utility industry deregulates, utilities and suppliers must have competitive rates. In response to this changing environment, Seminole should have a clear understanding of its current cost structure. This cost-of-service analysis will provide Seminole with information to continue addressing this changing environment. The knowledge gained from the cost-of-service analysis will result in a rate design that will allow Seminole to effectively recover its costs based on the assumptions made. including the projections in Seminole's 2000 budget.

SEMINOLE ELECTRIC COOPERATIVE, INC.

Seminole is a generation and transmission cooperative system with headquarters located in Tampa. Florida. Seminole provides wholesale electric service to ten member distribution cooperatives:

- Central Florida Electric Cooperative
- Clay Electric Cooperative
- Glades Electric Cooperative
- Lee County Electric Cooperative
- Peace River Electric Cooperative
- Sumter Electric Cooperative
- Suwannee Valley Electric Cooperative
- Talquin Electric Cooperative
- Tri-County Electric Cooperative
- Withlacoochee River Electric Cooperative

Seminole's primary generating facility, the Palatka generating station, is located on the St. Johns River in Putman County and consists of two 625 megawatt coal-fired units. Seminole also owns 14.4 megawatts of Florida Power Corporation's Crystal River 3 nuclear plant and approximately 345 miles of transmission line. While Seminole's primary source of electric power purchases is provided through a long-term agreement with an independent power producer, Seminole also has contracts with other Florida utilities.

METHOD OF ANALYSIS

The cost-of-service analysis performed by Burns & McDonnell first consisted of the determination of Seminole's revenue requirement for the year 2000. This determination was made by use of Burns & McDonnell's "Unbundle" model using data from Seminole's 2000 operating budget. Then the various costs that make up the revenue requirement were assigned to electric utility functions (i.e., power production, transmission, and consumer). The functionalized costs were classified as being either demand-related, energy-related, transmission-related, consumer-related or some combination of these four. The ten member cooperatives in the Seminole system were treated as one customer class for the purposes of this study. The resulting cost of service provided the basis for the design of the proposed wholesale rate that resulted in a cost-based wholesale rate for all members.

Seminole's financial and accounting data, provided as input for the analysis, closely followed the Federal Energy Regulatory Commission's (FERC) Uniform System of Accounts for electric utilities. The FERC USOA captures expense data on a functional cost basis as unique accounts are categorized as production, transmission, or administration expenses. This organization of accounting data is important in a cost-of-service analysis for functionalizing costs, as well as assigning these costs to power supply - demand, power supply - energy, transmission or consumer services.

Part II of this report discusses the cost-of-service study including the determination of the revenue required from the distribution cooperatives. Results are shown at various stages in the analysis and are explained in detail in this section. The assignment of costs in the cost-of-service study performed for Seminole is based on an "equivalent peaker" methodology. Results are also shown for two other methods so that the reader can compare the equivalent peaker method to other alternative methodologies.

Part III discusses the rate design for Seminole developed with their member systems treated as one customer class. Results for two other methodologies are also shown here for comparison to alternative methodologies.

Part IV summarizes this report and provides conclusions and recommendations regarding the cost of service and recommended rate structure.

SOURCES OF DATA

Seminole's staff and management provided data for the cost-of-service study. This data included computer-generated reports, financial and statistical information, financial reports, and other documents such as power bills, debt service schedules, trial balances, and RUS Form 12 data. The data for the year 2000 provided by Seminole reflected the projected levels of expenses, sales, and revenues from the 2000 operating budget.

Burns & McDonnell used the information provided by Seminole and other sources to make certain assumptions with respect to conditions that may exist in the future. While we believe the assumptions made are reasonable for the purposes of this report, we make no representation that the conditions assumed will, in fact, occur. In addition, while we have no reason to believe that the information provided to us by Seminole and other parties is inaccurate in any material respect, we have not independently verified such information and cannot guarantee its accuracy or completeness. To the extent that actual future conditions differ from those assumed herein or from the information provided to us, the actual results will vary from those projected.

PART II – COST-OF-SERVICE STUDY

PART II
COST-OF-SERVICE ANALYSIS

OVERVIEW

This part of the report describes the data, methodology, and results of the wholesale cost-of-service analysis performed by Burns & McDonnell for Seminole Electric Cooperative Inc. Seminole has requested that Burns & McDonnell develop rates that were based solely on the cost of service. To complete this assignment, a cost-of-service study needed to be completed. In an electric utility there are many costs that are shared or common to more than one consumer. For this reason, a detailed study is necessary to determine the cost of providing service to each of Seminole's ten member distribution cooperatives.

In determining the cost of service, it is necessary to make a number of subjective decisions as to how to account for various costs. Obviously, these are decisions that affect the results of the cost of service and the subsequent rate design. In this report we have laid out in detail not only the information from which the cost of service was calculated, but also the methodology and assumptions used in developing the unbundled cost of service. With a better understanding of the methodology and assumptions, the reader will better appreciate the results of this study.

Completing a cost-of-service study involves several phases. These include identifying the costs necessary to provide service, assigning or unbundling these utility costs to functions provided by Seminole and summarizing the results in a succinct and meaningful manner. This part of the report has been written to follow the methodology outlined above and describes in detail the procedure used to identify, define, assign, and summarize Seminole's costs of providing wholesale electric power to its member distribution systems.

In performing this study, Burns & McDonnell made use of Unbundle, its proprietary cost-of-service model, to assign costs. A complete copy of the output from the model is included as Appendix A to this report. Significant intermediary and final results have been extracted from the model and are included as tables in the body of this report.

In addition to providing the basis for wholesale rates, a thorough cost-of-service study will provide other benefits to Seminole. It will provide unbundled cost data that will be of value to Seminole as it prepares for deregulation. Unbundled cost information will help Seminole evaluate its ability to provide specific unbundled utility services in a deregulated market. Detailed cost breakdowns will also provide additional information to Seminole to help manage and operate its system.

REVENUE REQUIREMENT

Identifying all of the costs necessary to operate Seminole's electric system provides the foundation for the cost-of-service study and ultimately the final wholesale rate design recommendation. Simply stated, rates must be designed to collect *all* of the costs of operating an electric utility. These costs include operating costs, depreciation, interest, taxes and margins. In addition, other costs and revenue sources such as sales to non-members, non-operating margins, capital credits, etc. must be accounted for. In defining costs, the costs of operating the system for a complete 12-month period are used. A full year of cost information is necessary to recognize the seasonal variation of costs in operating an electric utility. For this reason, the first step in defining costs is to define a test year.

Test Year

Although there are a variety of ways to develop a test year, generally speaking test years can be broken into historical test years and future test years. Most other forms of test years are basically combinations of actual and projected cost information. Both historical and future test years offer advantages and disadvantages.

An historical test year method uses data developed from historical accounting and operating records. The advantage to using an historical test year is that the cost actually did occur and the data in the cost-of-service study can be verified by others such as regulators or intervenors. If an historical test year were to be used at this point, Burns & McDonnell would most likely need to look back to 1998, the most recent year for which audited financial information is available. This would result in developing rates that would be based on information that would be over two years old at the time that rates were actually implemented.

Using a future test year allows the analyst to design rates based on costs that are expected to be incurred during the period in which the rates are initially in effect. If reliable budgets are available, this approach produces rates that have a higher probability of producing the desired results. This approach is also useful when future conditions are expected to change or differ from actual historical year data.

Seminole has requested that Burns & McDonnell develop rates based on its budget for the year 2000. Given the advantages of using a future test year and the relationship of trust and accountability one would expect in a cooperative organization, this approach seems reasonable. In addition, Seminole's projected budgets have historically been very close to year-end actual costs. Therefore, Seminole's budget for 2000 was used as the basis for identifying costs for this cost-of-service study.

Year 2000 Budget

Seminole provided budget information for the year that is summarized as Table II-1. From this budget it can be seen that Utility Member Service Revenues are expected to be $553,789,741. This amount represents the revenue requirements that must be recovered from the proposed wholesale rates and thus the cost of service for the member distribution cooperatives. Revenues from other sources result in a total Operating Revenue and Patronage Capital of $568,221,117.

The cost of operating the Seminole system consists of operation & maintenance expense, depreciation & amortization expense, and other deductions. These costs total $573,590,034. To account for all costs of serving member systems, margins and capital credits and interest on long-term debt must be added and non-operating margins and other revenues must be subtracted. The budget was restated on Table II-2 to show how this cost build-up produced the total cost of service ($553,789,741) equal to the Utility Member Service Revenues. This table also shows a more detailed breakdown of the costs.

Production Expenses and Cost of Purchased Power were the two largest operating and maintenance expenses and together accounted for over $461 million or nearly 90 percent of the $514 million in Total Operation & Maintenance Expense. Transmission Operation & Maintenance Expenses accounted for approximately seven percent of the total Operations & Maintenance expenses with Administrative and General expenses accounting for approximately three percent. Depreciation was budgeted to exceed $25 million and Interest on Long Term Debt to exceed $30 million. Taxes and Other Deductions are expected to total less than $4 million.

The most significant of other Non-Operating Margins is interest of slightly over $7 million. Other Revenues are budgeted to exceed $14 million. The total of Other Revenues and Non-Operating Margins is budgeted to be $22 million.

Table II-1

YEAR 2000 BUDGET
Seminole Electric Cooperative, Inc.

Item	Year 2000 Budget
Utility Member Service Revenues	$ 553,789,741
Non-member Sales	8,006,085
Interruptible Sales	5,137,708
Martel Sales	62,806
Other Operating Revenues	1,224,777
Total Operating Revenue and Patronage Capital	**$ 568,221,117**
Production Expense	$243,299,011
Cost of Purchased Power	218,516,713
Transmission Expense - Operation	35,526,936
Transmission Expense - Maintenance	1,200,514
Administrative and General Expense	15,336,534
Total Operation & Maintenance Expense	**$513,879,708**
Depreciation and Amortization Expense	$25,581,072
Taxes	164,817
Interest on Long-Term Debt	30,145,557
Other Deductions	3,818,880
Total Expenses	**$573,590,034**
Patronage Capital or Operating Margins	**($5,368,917)**
Non Operating Margins - Interest	$7,010,135
Gain on Disposition of Clean Air Allowances	100,000
Non Operating Margins - Other	493,662
Other Capital Credits and Patronage Dividends	100,000
Patronage Capital or Margins	**$2,334,880**

Table II-2

DETAILED COST BREAKDOWN

Seminole Electric Cooperative, Inc.

Acct #	Account Name	Year 2000 Budget
	PRODUCTION EXPENSES	
500	Operations Supervision And Engineering	$2,681,634
501	Fuel Expense	162,184,362
502	Steam Expenses	7,720,824
505	Electric Expenses	1,694,210
506	Misc Steam Power Expenses	10,557,901
507	Power Plant Rents	28,641,657
510	Maintenance Supervision and Engineering	5,428,515
511	Maintenance of Structures	349,878
512	Maintenance of Power Plant	14,443,520
513	Maintenance of Electric Plant	1,105,936
514	Maintenance of Misc. Steam Plant	5,554,701
518	Nuclear Fuel Expense	648,000
528	Maintenance Supervision and Engineering	2,287,873
	COST OF PURCHASED POWER	
555	Purchased Power	$216,750,478
556	System Control and Load Dispatch	1,717,774
557	Other Power Supply Expenses	48,461
	TRANSMISSION EXPENSE - OPERATIONS	
560	Operations Supervision And Engineering	$177,341
562	Station Expenses	9,604
565	Transmission of Electricity by Others	34,051,675
566	Miscellaneous Transmission Expense	1,285,816
567	Rents	2,500
	TRANSMISSION EXPENSE - MAINTENANCE	
570	Maintenance of Station Equipment	$1,195,105
571	Maintenance of Overhead Lines	5,409
	ADMINISTRATIVE AND GENERAL EXPENSE	
920	Administrative & General Salaries	$10,805,074
921	Office Supplies And Expense	2,276,213
922	Administrative Expenses Transferred - Credit	(1,007,800)
923	Outside Services Employed	1,666,460
924	Property Insurance	35,944
925	Injuries And Damages	39,607
926	Employee Pensions and Benefits	58,306
930	General Advertising and Miscellaneous General Expenses	1,342,030
932	Maintenance Of General Plant	120,700
	TOTAL OPERATION AND MAINTENANCE EXPENSE	$513,879,708

Table II-2

DETAILED COST BREAKDOWN
Seminole Electric Cooperative, Inc.

Acct #	Account Name	Year 2000 Budget
	DEPRECIATION AND AMORTIZATION EXPENSE	
403.1	Steam Production Plant	$18,223,995
403.2	Nuclear Production Plant	1,061,449
403.5	Transmission Plant	3,854,282
403.7	General Plant	953,646
990	Depreciation Transferred	(23,785)
404	Amortization Leasehold Improvements	1,205,605
405	Miscellaneous Depreciation/Amortization	288,624
406	Amortization Electric Plant Acquisition	17,256
	TAXES	
408.1	Property Taxes	$8,618,067
408.2	Payroll Taxes	24,186
408.3	Payroll Taxes	1,731,795
408.4	Payroll Taxes	15,116
408.7	Taxes, Other	(12,282)
990.0	Overhead Allocation and Taxes Transferred	(10,212,065)
	OTHER DEDUCTIONS	
425	Miscellaneous Depreciation/Amortization	$72
426	Donations	38,120
428	Amortization of Debt Discount and Expense	3,780,688
	TOTAL OPERATING EXPENSE	**$543,444,477**
	REQUIRED MARGINS & PATRONAGE CAPITAL	
	REQUIRED MARGINS & PATRONAGE CAPITAL	$2,334,880
	NON-OPERATING MARGINS	
419	Non-Operating Margins - Interest	($7,010,135)
411	Gain on Disposition of Clean Air Allowances	(100,000)
421	Non-Operating Margins - Other	(493,662)
424	Other Capital Credits and Patronage Dividends	(100,000)
	INTEREST ON LONG-TERM DEBT	
427.0	Interest on Long-Term Debt	$30,145,557
	OTHER REVENUES	
	Interruptible Sales	($5,137,708)
	Non-Member Sales	(8,006,085)
	Martel Sales	(62,806)
456	Other Electric Revenues	(1,224,777)
	TOTAL COST OF SERVICE	**$553,789,741**

Rate Base

In addition to identifying all the costs for the test year, it is also necessary to define the rate base. The rate base represents the total investment required by Seminole to provide service to its member systems. It includes utility net of depreciation and an additional amount to recognize Seminole's investment in working capital to operate the system. Table II-3 summarizes the rate base for Seminole. The actual rate base numbers shown are not truly cost of service and are not added to the cost of service. Rather, they represent the investment needed to provide service and are used later to assign capital-related costs included in the year 2000 budget.

As shown on Table II-3, total utility plant net of depreciation is $489 million. This amount is based on a projected balance sheet for December 31, 2000, the end of the test year. Although this information is "projected" it provides a good indication of the relative investment and plant equipment. Since these dollars will not be directly recovered, but rather used as the basis for assigning patronage capital cost, they are appropriate for use in this study. Working capital is expected to be $56 million. This represents 15 days of power production and purchase power expense, 45 days of other operating expenses, and approximately $30 million in materials, supplies, and prepayments.

COST ASSIGNMENT

Having identified the costs to be included in the analysis, Burns & McDonnell turned to the next phase of the cost-of-service study, assigning costs to the appropriate utility functions. This phase is also known as the unbundling phase, in that total utility costs are broken out or unbundled by function. In this phase costs are assigned to the various functions or services that the utility provides. Breaking costs down into functions allows them to be used in rate design. Rates can then be designed to reflect how each customer or customer class uses the various functions or unbundled services of the utility.

Table II-4 lists the four major functions and associated sub-functions used in the cost-of-service study for Seminole. Also listed are the codes shown for each of the sub-functions. These codes are shown on a variety of tables and are provided to assist the reader in understanding how costs were tracked. The specific major functions were:

- Power Supply
- Transmission
- Consumer
- General

Table II-3

RATE BASE SUMMARY
Seminole Electric Cooperative, Inc.

Account Number	Item	Year 2000 Budget
301-303	Total Intangible Plant	$5,779,220
310-316	Total Production Plant - Steam	673,348,929
320-325	Total Production Plant - Nuclear	22,306,484
	Total Production Plant	**$701,434,633**
350	Land and Land Rights	$16,406,249
352	Structures and Improvements	-
353	Station Equipment	-
354-359	Other Transmission Plant	140,203,133
	Total Transmission Plant	**$156,609,382**
389	Land and Land Rights	$798,157
391	Office Furniture & Equipment	1,597,554
392	Transportation Equipment	748,182
397	Communication Equipment	5,649,731
398	Miscellaneous Equipment	15,591,733
	Total General Plant	**$24,385,357**
	All Other Utility Plant	-
107	Construction Work in Progress	0
	Total Utility Plant	**$882,429,372**
	Depreciation Reserve:	
108.1	Steam Plant	($281,169,188)
108.2	Nuclear Plant	($8,413,949)
108.5	Transmission Plant	(49,002,883)
108.7	General Plant	(12,791,254)
108.9	Cost of Removal - Nuclear	(94,379)
111.1	Transportation Lease	(23,444,300)
111.1	Intangible Plant (HPS-Acuera)	(2,311,850)
111.1	Leasehold Improvements - U2	(8,650,311)
115.1	Acquisition Adjustment	(429,202)
120.5	Nuclear Fuel	(6,504,475)
	Total Depreciation	**($392,811,791)**
	Net Plant	**$489,617,581**
	Working Capital:	
	Power Production	$9,998,589
	Purchase Power Expense	8,980,139
	Transmission	4,528,042
	Administrative & General	1,890,806
	Payroll & Property Taxes	1,279,342
	Working Funds	4,289
154	Plant Materials and Operating Supplies	17,545,183
165	Prepayments	12,021,018
	Working Capital	**$56,247,408**
	Deductions:	
235	Consumer Deposits	(3,981)
	TOTAL RATE BASE	**$545,861,008**

Table II-4

UTILITY SERVICES
Seminole Electric Cooperative, Inc.

	Unbundled Codes
1. Power Supply	
Demand	kW
Energy	kWh
2. Transmission	
Demand	T-kW
Access	ACC
3. Consumer	CONS
4. General	GENL

Assignment of Generation Investment Cost

As can be seen from a brief review of the costs identified in the previous section, the generation investment costs, i.e., depreciation, interest, patronage capital, etc., are a significant portion of the cost of service. How these costs are assigned can significantly impact the rate design process. To the extent that these costs are assigned to an energy- or demand-related function, they will impact the design of rates and its effect on high and low load factor consumers. Assigning investment-related costs for generation and transmission cooperatives is probably the single most controversial issue faced in most cost-of-service studies. For this reason, the following discussion of cost assignment is included before moving on to the discussion of the actual assignments used in the study. For this assignment, Burns & McDonnell evaluated a traditional form of investment cost assignment as well as an energy-based method and an equivalent peaker method.

Traditional Method. Traditionally, power supply costs are assigned either to power supply - energy or power supply - demand. Generally, there is little disagreement that fuel and variable operating cost should be assigned to the power supply - energy function. Traditionally, fixed costs including investment costs are assigned to the power supply - demand function. This approach helps ensure the fixed investment costs of generation resources (such as the depreciation) are recovered in the demand component of the resulting rates and are not subject to fluctuation and energy sales. Using this method, the investment cost (and fixed O&M cost) of a plant are recovered through the demand charge and the commodity cost of fuel and variable O&M are recovered through an energy charge. This type of assignment recognizes the cost-causation relationship for the utility as it exists today.

This approach protects the utility from changes in consumption patterns over what was expected. For example, if a baseload unit is installed and subsequently energy sales dropped off, the utility will still recover its fixed investment costs. Similarly, if peaking units are installed and energy growth exceeds demand growth, consumers will have paid for the increases in the cost of fuel. In a totally regulated environment this approach provides price signals to the consumer, i.e. use more energy and your bill will increase as fuel costs increase, increase your demand and your bill will increase as investment costs increase. Also, this approach minimizes the risk to the utility, and the utility in essence becomes a conduit for providing service with all cost changes being born by the consumer.

Energy Method. An alternative method to assigning power production costs is to assign all baseload generation investment costs to power supply - energy. The reasoning behind this assignment method is that baseload units are developed to produce kilowatt-hours. Therefore, the investment costs as well as the fuel and variable O&M cost should be recovered through an energy charge (investment costs of peaking units under this methodology are normally assigned to the power supply - demand function).

As the electric utility industry moves toward deregulation, the energy method of assigning investment costs for baseload generation is taking on greater prominence. Many merchant power producers are pricing their baseload products on a cents per kilowatt-hour basis. Under this scenario, utilities no longer provide direct price signals and conduits, but rather producers bear the risk and reward of making the proper investment decision. A power producer that builds a baseload facility prices his product based on the market. To the extent that all costs of producing power (both investment and fuel) are lower than the market, he receives the reward in increased profits. Similarly, to the extent that he misgauges the market, he bears the loss.

Equivalent Peaker Method. The equivalent peaker method is based on the type of generation resource and not whether the costs are fixed or variable. Peaking units are installed to provide capacity and the investment costs associated with this type of generation are assigned to the power supply - demand function. On the other hand, a baseload resource is installed to provide capacity, but also low-cost energy. Therefore, the investment costs for these units should be assigned to both the power supply - energy and power supply - demand function. Only that portion of the investment cost that would have been incurred with the peaking unit is assigned to the power supply - demand function, thus the term equivalent peaker method. The remaining investment costs are more appropriately assigned to the power supply - energy function. The principals of the equivalent peaker method are (1) increases in peak demand require the addition of peaking capacity only, and (2) utilities incur the cost of more expensive baseload units because of the additional lower cost energy they provide. Thus, the cost of peaking capacity can be properly regarded as peak-demand related and classified as power supply - demand while all other investment costs can be regarded as energy-related and assigned to the power supply - energy function.

In applying the equivalent peaker method to the Seminole system, Burns & McDonnell determined the date and cost of the installed baseload units. The cost of these units, expressed in dollars per kilowatt, was adjusted to 1998 using the Handy-Whitman Index of Public Utility Construction Costs. Installed costs for combustion turbines, taken from Resource Data International's POWERdat database, were similarly adjusted to 1998 costs.

The ratios of the investment cost of the equivalent peaker units (1998 dollars) to the investment cost of the baseload units (1998 dollars) were used to determine how much of the baseload investment cost should be allocated to the power supply - demand function. These ratios were:

Plant	Percent of Investment Cost Assigned to Power Supply – Demand	Percent of Investment Cost Assigned to Power Supply - Energy
Coal	46.3%	53.1%
Nuclear	35.9%	64.1%

All three methods of assigning production investment costs were considered in developing cost-based rates for Seminole. For this project, Burns & McDonnell selected the equivalent peaker method to assign generation investment costs. As the utility industry moves from a regulated to a deregulated business, we anticipate that there will be a shift from the traditional approach to the energy approach. Using the equivalent peaker method will prepare Seminole for expected changes in the future while recognizing that many traditional techniques are still appropriate or must still be employed. In the remaining sections of this report the equivalent peaker method provided the basis for subsequent analyses and rate design; however, summary results from the other two assignment methodologies have been included for comparison.

Rate Base Assignment

Rate base was assigned using the equivalent peaker method discussed above and is summarized on Table II-5. (The resulting rate base assignments for all three methods are compared on Table II-6). The resulting assignment of rate base provided the basis for assigning investment-related costs in the year 2000 budget (see following section). More specifically, the following assignments were made:

- Production plant was assigned by the equivalent peaker method, one of the three methods discussed above.
- Total transmission plant accounts were assigned directly to the transmission-demand function.
- Intangible plant was assigned in proportion to the subtotals for production and transmission plant.
- Office furniture and equipment were assigned to the consumer function.
- Communication equipment was assigned based on the proportion of the estimated utilization by each function.
- Miscellaneous equipment was assigned in proportion to the subtotals for production and transmission plant.

RATE BASE ASSIGNMENT
Seminole Electric Cooperative, Inc.

Equivalent Peaker Method

Account Number	Item	Year 2000 Budget	kW	KWH	ACC	T-KW	CONS	GENL	Description of Assignment
301-303	Total Intangible Plant	$5,779,220	$2,044,878	2,672,372	-	1,061,971	-	-	Prod/Xmsn Plant Ratio
310-316	Total Production Plant - Steam	673,348,929	293,551,261	379,797,668	-	-	-	-	KW, KWH - 625 MW
320-325	Total Production Plant - Nuclear	22,306,484	8,008,028	14,298,456	-	-	-	-	KW, KWH - CR3
	Total Production Plant	$701,434,633	$303,604,167	$396,768,496	$0	$1,061,971	$0	$0	
350	Land and Land Rights	$16,406,249	-	-	-	$16,406,249	-	-	T-KW
352	Structures and Improvements	-	-	-	-	-	-	-	T-KW
353	Station Equipment	-	-	-	-	-	-	-	T-KW
354-359	Other Transmission Plant	140,203,133	-	-	-	140,203,133	-	-	T-KW
	Total Transmission Plant	$156,609,382	$0	$0	$0	$156,609,382	$0	$0	
389	Land and Land Rights	$798,157	$282,414	$369,076	$0	$146,667	$0	$0	Prod/Xmsn Plant Ratio
391	Office Furniture & Equipment	1,597,554	-	-	-	-	1,597,554	-	CONS
392	Transportation Equipment	748,182	-	748,182	-	-	-	-	KWH
397	Communication Equipment	5,649,731	225,989	338,984	-	2,259,892	2,259,892	564,973	Standard/Judgment
398	Miscellaneous Equipment	15,591,733	5,516,867	7,209,780	-	2,865,086	-	-	Prod/Xmsn Plant Ratio
	Total General Plant	$24,385,357	$6,025,271	$8,666,022	$0	$5,271,645	$3,857,446	$564,973	
	All Other Utility Plant	-	-	-	-	-	-	-	Prod/Xmsn Plant Ratio
107	Construction Work in Progress	0	0	0	0	0	0	0	Prod/Xmsn Plant Ratio
	Total Utility Plant	$882,429,372	$309,629,437	$405,434,518	$0	$162,942,997	$3,857,446	$564,973	
	Depreciation Reserve:								
108 1	Steam Plant	(281,169,188)	(130,181,334)	(150,987,854)	0	0	0	0	KW, KWH - 625 MW Capac
108 2	Nuclear Plant	(8,413,949)	(3,020,608)	(5,393,341)	0	0	0	0	KW, KWH - CR3
108 5	Transmission Plant	(49,002,883)	0	0	0	(49,002,883)	0	0	Total Utility Plant Ratio
108 7	General Plant	(12,791,254)	(4,488,233)	(5,876,976)	0	(2,361,940)	(55,916)	(8,190)	Total Utility Plant Ratio
108 9	Cost of Removal - Nuclear	(94,379)	(33,882)	(60,497)	0	0	0	0	KW, KWH - CR3
111.1	Transportation Lease	(23,444,300)	0	(23,444,300)	0	0	0	0	KW, KWH - CR3
111 1	Intangible Plant (HPS-Acuera)	(2,311,850)	(818,008)	(1,069,024)	0	(424,818)	0	0	KW, KWH - CR3
111.1	Leasehold Improvements - U2	(8,650,311)	(4,005,094)	(4,645,217)	0	0	0	0	KW, KWH - CR3
115 1	Acquisition Adjustment	(429,202)	(154,084)	(275,118)	0	0	0	0	KW, KWH - CR3
120 5	Nuclear Fuel	(6,504,475)	0	(6,504,475)	0	0	0	0	KW, KWH - CR3
	Total Depreciation	($392,811,791)	($142,701,243)	($198,256,802)	$0	($51,789,641)	($55,916)	($8,190)	
	Net Plant	$489,617,581	$166,928,195	$207,177,716	$0	$111,153,356	$3,801,531	$556,784	
	Working Capital:								
	Power Production	9,998,589	986,671	9,011,919	0	0	0	0	Operating Expense
	Purchase Power Expense	$8,980,139	4,944,324	4,004,210	0	0	31,605	0	Operating Expense
	Transmission	4,528,042	0	0	4,198,152	329,890	0	0	T-KW
	Administrative & General	1,890,806	770,173	463,750	0	57,789	65,935	533,159	Admin & General Ratio
	Payroll & Property Taxes	1,279,342	914,809	226,632	0	44,460	29,032	64,410	Tax Expense Ratio
	Working Funds	4,289	0	0	0	0	4,289	0	Direct
154	Plant Materials and Operating Supplies	17,545,183	6,156,306	8,061,181	0	3,239,766	76,697	11,233	Total Utility Plant Ratio
165	Prepayments	12,021,018	4,217,970	5,523,089	0	2,219,714	52,549	7,696	Total Utility Plant Ratio
	Working Capital	$66,245,997	$18,976,923	$36,302,698	$4,198,152	$5,891,619	$260,106	$616,499	
	Deductions:								
235	Consumer Deposits	(3,981)	0	0	0	0	(3,981)	0	CONS
	TOTAL RATE BASE	$545,861,008	$184,918,447	$234,468,495	$4,198,152	$117,044,975	$4,057,656	$1,173,282	
	Rate Base Ratio	100 00%	33 88%	42 95%	0 77%	21 44%	0 74%	0 21%	

Table II-6

COMPARISON OF RATE BASE ASSIGNMENT
Seminole Electric Cooperative, Inc.

Assignment Method	Year 2000 Budget	kW	KWH	ACC	T-KW	CONS	GENL
TRADITIONAL	$545,861,008	$394,437,055	$24,949,888	$4,198,152	$117,044,975	$4,057,656	$1,173,282
EQUIVALENT PEAKER	**$545,861,008**	**$184,918,447**	**$234,468,495**	**$4,198,152**	**$117,044,975**	**$4,057,656**	**$1,173,282**
ENERGY	$545,861,008	$7,343,297	$412,043,646	$4,198,152	$117,044,975	$4,057,656	$1,173,282

- Transportation equipment consists of fuel transportation equipment and was therefore assigned the power supply – energy function..
- The depreciation reserves were assigned based on the corresponding plant.
- Working capital was assigned in the same ratio as the equivalent expense from the budget.
- Consumer deposits were assigned directly to the consumer function.

Year 2000 Budget Assignment

The budget costs identified in Table II-2 were assigned to the utility functions and sub-functions on Table II-7. Results of all three methods are compared on Table II-8. In addition to the rate base assignments discussed above, several assignment methodologies were used for other costs. These included the use of a cost-of-service ratio, payroll ratio and total utility plant ratio. These ratios were developed by adding the costs assigned to each of the functional categories and then dividing by the total cost. The actual ratios are shown at the end of Table II-7. In other cases, costs were directly assigned to specific functions.

Table II-7 summarizes the results from the Unbundle model that describe how the various costs in the year 2000 budget were assigned. More specifically, the costs were assigned as described below:

Power Production Expenses

- Operations supervision and engineering, and steam and nuclear maintenance supervision and engineering were assigned to power supply - demand. It was assumed that large portions of these costs were salaries and that the number of employees was dependent on the size of the plants.
- Steam, electric and miscellaneous steam power expenses depend on the amount of energy generated and were assigned to the power supply - energy function. Maintenance related to these items is also an expense incurred to produce electricity and was assigned to energy.
- The costs of fossil and nuclear fuel are dependent on the amount of energy produced and were therefore assigned to the power supply - energy function.
- The maintenance of structures is dependent on the size of the plants and was classified as a fixed expense assigned to the power supply - demand function.
- Power plant rents apply only to Palatka 2 generating unit and were assigned to power supply - demand and power supply - energy based on the equivalent peaker method.

Table II-7

Year 2000 Budget Assignment
Seminole Electric Cooperative, Inc.

Equivalent Peaker Method

Acct #		FY 2000 Budget Totals	KW	KWH	ACC	T-KW	CONS	GENL	Description of Assignment
	POWER PRODUCTION EXPENSES								
500	Operations Supervision And Engineering	2,681,634	2,681,634	0	0	0	0	0	KW
501	Fuel Expense	162,184,362	0	162,184,362	0	0	0	0	KWH
502	Steam Expenses	7,720,824	0	7,720,824	0	0	0	0	KWH
505	Electric Expenses	1,694,210	0	1,694,210	0	0	0	0	KWH
506	Misc Steam Power Expenses	10,557,901	0	10,557,901	0	0	0	0	KWH
507	Power Plant Rents	28,641,657	13,261,087	15,380,570	0	0	0	0	KW,KWH
510	Maintenance Supervision and Engineering	5,428,515	5,428,515	0	0	0	0	0	KW
511	Maintenance of Structures	349,878	349,878	0	0	0	0	0	KW
512	Maintenance of Boiler Plant	14,443,520	0	14,443,520	0	0	0	0	KWH
513	Maintenance of Electric Plant	1,105,936	0	1,105,936	0	0	0	0	KWH
514	Maintenance of Misc Steam Plant	5,554,701	0	5,554,701	0	0	0	0	KWH
518	Nuclear Fuel Expense	648,000	0	648,000	0	0	0	0	KWH
528	Maintenance Supervision and Engineering	2,287,873	2,287,873	0	0	0	0	0	KW
	PURCHASED POWER								
555	Purchased Power	216,750,478	118,545,653	97,435,770	0	0	769,055	0	KW,KWH, CONS - BY CONTRACT
556	System Control and Load Dispatch	1,717,774	1,717,774	0	0	0	0	0	KW
557	Other Power Supply Expenses	48,461	48,461	0	0	0	0	0	KW
	TRANSMISSION OPERATIONS EXPENSES								
560	Operations Supervision And Engineering	177,341	0	0	0	177,341	0	0	T-KW
562	Station Expenses	9,604	0	0	0	9,604	0	0	T-KW
565	Transmission of Electricity by Others	34,051,675	0	0	34,051,675	0	0	0	ACC
566	*Miscellaneous Transmission Expenses*	1,285,816	0	0	0	1,285,816	0	0	T-KW
567	Rents	2,500	0	0	0	2,500	0	0	T-KW
	TRANSMISSION MAINTENANCE EXPENSES								
570	Maintenance of Station Equipment	1,195,105	0	0	0	1,195,105	0	0	T-KW
571	Maintenance Of Overhead Lines	5,409	0	0	0	5,409	0	0	T-KW
	ADMINISTRATIVE AND GENERAL OPERATIONS EXPENSES								
920	Administrative & General Salaries	10,805,074	4,890,317	3,787,480	0	565,680	485,177	1,076,420	Personnel Function
921	Office Supplies And Expense	2,276,213	1,627,634	403,224	0	79,104	51,653	114,598	*PAYROLL RATIO*
922	Administrative Expenses Transferred - Credit	(1,007,800)	(353,620)	(463,036)	0	(186,093)	(4,405)	(645)	TOTAL UTILITY PLANT RATIO
923	Outside Services Employed	1,666,460	0	0	0	0	0	1,666,460	GENL
924	Property Insurance	35,944	12,612	16,515	0	6,637	157	23	TOTAL UTILITY PLANT RATIO
925	Injuries And Damages	39,607	28,321	7,016	0	1,376	899	1,994	PAYROLL RATIO
926	Employee Pensions and Benefits	58,306	41,692	10,329	0	2,026	1,323	2,935	PAYROLL RATIO
930	General Advertising and Miscellaneous General Expen	1,342,030	0	0	0	0	0	1,342,030	GENL
	ADMINISTRATIVE AND GENERAL MAINTENANCE EXPENSES								
932	Maintenance Of General Plant	120,700	0	0	0	0	0	120,700	GENL
	DEPRECIATION AND AMORTIZATION EXPENSE								
403.1	Steam Production Plant	18,223,995	8,437,710	9,786,285	0	0	0	0	KW,KWH
403.2	Nuclear Production Plant	1,061,449	381,060	680,389	0	0	0	0	KW,KWH
403.5	Transmission Plant	3,854,282	0	0	0	3,854,282	0	0	T-KW
403.7	General Plant	953,646	0	0	0	0	0	953,646	GENL
990.0	Depreciation Transferred	(23,785)	(8,346)	(10,928)	0	(4,392)	(104)	(15)	TOTAL UTILITY PLANT RATIO
404.0	Amortization Leasehold Improvements	1,205,605	558,195	647,410	0	0	0	0	KW,KWH
405.0	Miscellaneous Depreciation/Amortization	288,624	101,273	132,609	0	53,295	1,262	185	TOTAL UTILITY PLANT RATIO
406.0	Amortization Electric Plant Acquisition	17,256	6,195	11,061	0	0	0	0	KW,KWH

Year 2000 Budget Assignment
Seminole Electric Cooperative, Inc.

Equivalent Peaker Method

Acct #		FY 2000 Budget Totals	KW	KWH	ACC	T-KW	CONS	GENL	Description of Assignment
	OTHER EXPENSES								
408.1	Property Taxes	8,618,067	3,023,933	3,959,594	0	1,591,350	37,673	5,518	TOTAL UTILITY PLANT RATIO
408.2	Payroll Taxes	24,186	17,294	4,284	0	841	549	1,218	PAYROLL RATIO
408.3	Payroll Taxes	1,731,795	1,238,341	306,782	0	60,184	39,299	87,189	PAYROLL RATIO
408.4	*Payroll Taxes*	15,116	10,809	2,678	0	525	343	761	PAYROLL RATIO
408.7	Taxes, Other	(12,282)	0	0	0	0	0	(12,282)	GENL
990.0	Overhead Allocation and Taxes Transferred	(10,212,065)	(3,583,240)	(4,691,960)	0	(1,885,686)	(44,641)	(6,538)	TOTAL UTILITY PLANT RATIO
425	Miscellaneous Depreciation/Amortization	72	25	33	0	13	0	0	TOTAL UTILITY PLANT RATIO
426	Donations	38,120	0	0	0	0	0	38,120	GENL
428	Amortization of Debt Discount and Expense	3,780,688	1,326,579	1,737,047	0	698,114	16,527	2,421	TOTAL UTILITY PLANT RATIO
	TOTAL OPERATING EXPENSE	543,444,477	162,077,661	333,052,605	34,051,675	7,513,032	1,354,766	5,394,737	
	ANNUAL INVESTMENT COST:								
Y	**Target Margin Dollar Amount**								
	Required Margins & Patronage Capital	2,334,880	819,270	1,072,767	0	431,142	10,207	1,495	TOTAL UTILITY PLANT RATIO
	Required Margins & Patronage Capital	2,334,880	819,270	1,072,767	0	431,142	10,207	1,495	
	Non-Operating Margins								
419	Non Operating Margins - Interest	(7,010,135)	(2,165,317)	(4,181,016)	(425,280)	(168,738)	(18,693)	(51,090)	COS RATIO - PREL.
411	Gain on Disposition of Clean Air Allowances	(100,000)	(100,000)	0	0	0	0	0	KW
421	Non Operating Margins - Other	(493,662)	(152,484)	(294,432)	(29,949)	(11,883)	(1,316)	(3,598)	COS RATIO - PREL.
424	*Other Capital Credits and Patronage Dividends*	*(100,000)*	*0*	*0*	*0*	*0*	*0*	*(100,000)*	*GENL*
	Required Operating Margins	(5,368,917)	(1,598,532)	(3,402,682)	(455,229)	250,522	(9,803)	(153,193)	
427	Interest on L-T Debt	30,145,557	10,577,563	13,850,456	0	5,566,460	131,778	19,301	TOTAL UTILITY PLANT RATIO
	Total Interest & Op. Margins	24,776,640	8,979,031	10,447,775	(455,229)	5,816,981	121,975	(133,893)	
	Total Operating Expense	543,444,477	162,077,661	333,052,605	34,051,675	7,513,032	1,354,766	5,394,737	
	Less Other Revenues								
	Interruptable Sales	(5,137,708)	0	(5,137,708)	0	0	0	0	KWH
	Non-Member Sales	(8,006,085)	0	(8,006,085)	0	0	0	0	KWH
	Martel Sales	(62,806)	0	(62,806)	0	0	0	0	KWH
456	Other Electric Revenues	(1,224,777)	0	0	0	0	0	(1,224,777)	GENL
	TOTAL COST OF SERVICE	553,789,741	171,056,692	330,293,781	33,596,446	13,330,013	1,476,741	4,036,067	
	Cost-of-Service Ratio	1.000	0.309	0.596	0.061	0.024	0.003	0.007	
	Non-Power Supply COS Ratio	1.000	0.000	0.000	0.000	0.707	0.078	0.214	
SUMMARY OF COST OF SERVICE									
Power Production		243,299,011	24,008,987	219,290,024	0	0	0	0	
Purchased Power		218,516,713	120,311,888	97,435,770	0	0	769,055	0	
Transmission Operations Expenses		35,526,936	0	0	34,051,675	1,475,261	0	0	
Transmission Maintenance Expenses		1,200,514	0	0	0	1,200,514	0	0	
Administrative And General Operations Expenses		15,215,834	6,246,957	3,761,527	0	468,731	534,804	4,203,816	
Administrative And General Maintenance Expenses		120,700	0	0	0	0	0	120,700	
Depreciation		25,581,072	9,476,087	11,246,826	0	3,903,185	1,158	953,816	
Taxes & Other		*3,983,697*	*2,033,742*	*1,318,458*	*0*	*465,341*	*49,750*	*116,406*	
Total Interest & Op. Margins		32,480,437	11,396,832	14,923,223	0	5,997,602	141,985	20,796	
Non-operating Margins		(7,703,797)	(2,417,801)	(4,475,449)	(455,229)	(180,620)	(20,010)	(154,688)	
Non-Member Sales		(8,006,085)	0	(8,006,085)	0	0	0	0	
Interruptible Sales		(5,137,708)	0	(5,137,708)	0	0	0	0	
Martel Sales		(62,806)	0	(62,806)	0	0	0	0	
Other Op. Revenue		(1,224,777)	0	0	0	0	0	(1,224,777)	
Cost of Service		553,789,741	171,056,692	330,293,781	33,596,446	13,330,013	1,476,741	4,036,067	

Table II-7

Year 2000 Budget Assignment
Seminole Electric Cooperative, Inc.

Equivalent Peaker Method

Acct #	FY 2000 Budget Totals	KW	KWH	ACC	T-KW	CONS	GENL	Description of Assignment
COS Excluding Payroll & Gross Receipts Tax, Req'd Margins, & Int. on LT Debt								
Required Operating Margins	32,280,437	11,296,832	14,923,223	0	5,997,602	141,985	(79,204)	
Total Op Exp	543,444,477	162,077,661	333,052,605	34,051,675	7,513,032	1,354,766	5,394,737	
Cost of Service (excl. nonoperating interest and other income)	561,293,538	173,374,493	334,769,229	34,051,675	13,510,634	1,496,751	4,090,755	
COS Ratio (Prelim.)	**1.000**	**0.309**	**0.596**	**0.061**	**0.024**	**0.003**	**0.007**	
Non-Power Supply COS Ratio (Prelim.)	*1.000*	*0.000*	*0.000*	*0.000*	*0.707*	*0.078*	*0.214*	
RATIOS								
Power Production	1.000	0.099	0.901	0.000	0.000	0.000	0.000	
Purchased Power	1.000	0.551	0.446	0.000	0.000	0.004	0.000	
Transmission	1.000	0.000	0.000	0.927	0.073	0.000	0.000	
Admin. & General	1.000	0.407	0.245	0.000	0.031	0.035	0.282	
Taxes (Payroll & Property)	1.000	0.413	0.412	0.000	0.159	0.008	0.008	
Cost of Service Ratio	1.000	0.309	0.596	0.061	0.024	0.003	0.007	
PAYROLL RATIO								
Operations Supervision And Engineering	2,681,634	2,681,634	0	0	0	0	0	
Maintenance Supervision and Engineering	5,428,515	5,428,515	0	0	0	0	0	
Maintenance Supervision and Engineering	2,287,873	2,287,873	0	0	0	0	0	
Operations Supervision And Engineering	177,341	0	0	0	177,341	0	0	
Administrative & General Salaries	10,805,074	4,890,317	3,787,480	0	565,680	485,177	1,076,420	
Total	21,380,437	15,288,339	3,787,480	0	743,021	485,177	1,076,420	
Payroll Ratio	1.000	0.715	0.177	0.000	0.035	0.023	0.050	
TOTAL UTILITY PLANT RATIO								
Production Plant Ratio	1.000	0.433	0.567	0.000	0.000	0.000	0.000	
Transmission Plant Ratio	1.000	0.000	0.000	0.000	1.000	0.000	0.000	
Prod/Xmsn/Dist Plant Ratio	1.000	0.354	0.462	0.000	0.184	0.000	0.000	
Total Utility Plant Ratio	1.000	0.351	0.459	0.000	0.185	0.004	0.001	

Table II-8

COMPARISON OF YEAR 2000 BUDGET ASSIGNMENT
Seminole Electric Cooperative, Inc.

Assignment Method	Year 2000 Budget	kW	KWH	ACC	T-KW	CONS	GENL
TRADITIONAL	$553,789,741	$211,041,972	$290,308,500	$33,596,446	$13,330,013	$1,476,741	$4,036,067
EQUIVALENT PEAKER	**$553,789,741**	**$171,056,692**	**$330,293,781**	**$33,596,446**	**$13,330,013**	**$1,476,741**	**$4,036,067**
ENERGY	$553,789,741	$136,967,004	$364,383,468	$33,596,446	$13,330,013	$1,476,741	$4,036,067

Purchased Power

- Purchased power supply costs were assigned 55% to the power supply - demand function, 44.6% to the power supply - energy function and .4% to the consumer function consistent with Seminole's purchased power contracts.
- System control and load dispatch and other power supply expenses are fixed with respect to capacity purchased and were assigned 100% to the power –supply - demand function.

Transmission Operation Expense

- Operations supervision and engineering was assigned to transmission-demand since large portions of these costs are salaries and the number of employees is dependent on the capability of the facilities.
- Station expenses, miscellaneous transmission expenses and rents are dependent on the capability of facilities, based on capacity requirements, and were assigned to transmission-demand.
- Transmission of electricity by others or to others was directly assigned to the transmission access function.

Transmission Maintenance Expense

- Transmission maintenance expenses related to station equipment and overhead lines are dependent on the demand capability of the facilities and were therefore assigned to transmission-demand.

Administrative and General O&M Expense

- Based on a brief review of payroll provided by Seminole staff, administrative and general salaries were assigned to various functions.
- Office supplies and expenses, injuries and damages, and employee pension and benefits were assigned to all categories using the payroll ratio.
- Administrative expense-transferred credit and property insurance were assigned to all categories based on the total utility plant ratio.
- Outside services employed and general advertising and miscellaneous general were all considered general services and were therefore assigned to that function.
- Maintenance of general plant was considered to be a general service and was therefore assigned to the general function.

Depreciation and Amortization Expense

- Steam depreciation and nuclear production depreciation were assigned with the equivalent peaker method (as well as the traditional and energy methods for comparison).
- Transmission plant is based on the capacity of the facilities and therefore, depreciation was assigned to transmission-demand.
- Depreciation transferred, miscellaneous depreciation and amortization, and amortization of electric plant acquisition were assigned based on the total utility plant ratio.
- General plant was assigned to the general category.
- Amortization of leasehold improvements applies only to Palatka #2 and was assigned consistent with the equivalent peaker method.

Other Expenses

- Property tax, overhead allocated tax transferred, miscellaneous depreciation and amortization, and amortization of debt discount and expense were assigned based on the total utility plant ratio.
- Payroll taxes (social security, state unemployment and federal unemployment) were assigned based on the payroll ratio.
- Other taxes and donations were assigned to the general category.

Annual Investment Cost

- Required margins and patronage capital were assigned based on the total utility plant ratio.
- Interest from non-operating margins and other non-operating margins were assigned using the cost-of-service ratio.
- Disposition of clean air allowances depends on the capability of the units and therefore, the gain was assigned to the demand function.
- Other capital credits and patronage dividends were assigned to the general function.
- Interest on long-term debt was assigned based on the total utility plant ratio.
- Revenue from non-member sales was assigned to energy.
- Other electric revenues were assigned to the general function.

COST ALLOCATION

Generally, the next step in a cost-of-service study is to allocate the unbundled costs to the appropriate customer classes. In this part of a study, costs are allocated based on various classes use of different services, i.e., kWh, kW, meters, etc. For this study, Seminole requested that all member distribution systems be considered as one class. To the extent that all member cooperatives receive the same level of service, this is an appropriate approach. Actual allocation between the various member systems then becomes covered in the actual rate design, which is discussed in Part III of this report. For these reasons, there were no allocation of costs in this study.

SUMMARY

The unbundled costs listed on Table II-7 were subsequently summarized into the following major areas:

- **Power supply - energy** – Power supply energy costs are expected to vary directly with the production or purchase of energy measured in kilowatt-hours (kWh). The power supply energy portion of Seminole's budgeted costs totaled $330,293,781. Power supply energy costs included Seminole's expenditures associated with electricity generation and purchases. Power supply - energy costs were defined as the costs incurred to meet the energy needs of the consumers and consisted primarily of fuel costs and variable generation operation and maintenance (O&M) costs.

- **Power supply - demand** – Power supply - demand costs are expected to vary directly with the capacity installed or purchased to meet the demand requirements of Seminole's system measured in kilowatts (kW). The power supply - demand portion of Seminole's budgeted costs totaled $171,056,692. Power supply - demand costs were defined as the costs incurred to meet the peak demand needs of the customers and included Seminole's expenditures associated with electricity generation and purchases. These costs consisted primarily of the equivalent peaker portion of investment costs for Seminole's generation resources, fixed generation O&M costs, and demand-related purchased power costs.

- **Transmission** – Transmission costs are expected to vary directly with the transmission capacity installed or purchased to meet the transmission demand requirements of Seminole's system measured in kilowatts (kW). The transmission demand portion of Seminole's budgeted costs totaled $46,926,459. Transmission demand costs were defined as the costs incurred to transmit the peak demands of Seminole's customers and consisted primarily of transmission facilities and operating expenses.

- **Consumer** – Consumer costs for the Seminole system totaled $1,476,741. Consumer service costs included expenditures that are directly related to providing member services to Seminole's ten distribution cooperatives.

- **General** – General costs totaled $4,036,067. These general costs are necessary to support all of the above functions of the utility. For this reason, the general costs wre broken down into sub-functions in proportion of the subtotal of the costs for power supply – energy, power supply – demand, transmission, and consumer costs.

These costs have been summarized in Table II-9. The costs are expressed in total dollars and in cents per kilowatt-hours. Also, the costs have been expressed in dollars per unit cost where the applicable units are: kilowatt-hours for power supply - energy, coincident kilowatts for power -supply - demand, coincident peak demand kilowatts for transmission, and number of consumers for consumer costs. The general service costs, split up by their contribution to the other four functional categories (Power supply – energy, power supply – demand, transmission and consumer) are also shown on Table II-9. These costs reflect the equivalent peaker method of assignment. Table II-10 has been provided to compare the cost summary using the traditional and energy methods for assigning costs. The costs included in Table II-9 for the equivalent peaker method has provided the basis for designing rates which are discussed in the next part of this report.

Table II-9

SUMMARY OF COST-OF-SERVICE
Seminole Electric Cooperative, Inc.

Equivalent Peaker Method

Category	Cost	Cents/kWh	Applicable Unit Cost	Unit
Power Supply - Energy	$330,293,781	2.71	2.71	cents per kWh
Power Supply - Demand	171,056,692	1.40	$5.79	per kW*
Transmission	46,926,460	0.38	$1.59	per kW*
Consumer	1,476,741	0.01	$12,306.18	per consumer per month
General				
Power Supply - Energy	$2,424,882	0.02	0.02	cents per kWh
Power Supply - Demand	$1,255,828	0.01	$0.04	per kW*
Transmission	$344,515	0.00	$0.01	per kW*
Consumer	$10,842	0.00	$90.35	per consumer per month
Total	$553,789,741	4.54		

* Per sum of monthly coincident peak.

Table II-10

SUMMARY OF COST-OF-SERVICE FOR ALTERNATIVE METHODS

Seminole Electric Cooperative, Inc.

Traditional Method

Category	Cost	Cents/kWh	Applicable Unit Cost	Unit
Power Supply - Energy	$290,308,500	2.38	2.38	cents per kWh
Power Supply - Demand	211,041,972	1.73	$7.15	per kW*
Transmission	46,926,460	0.38	$1.59	per kW*
Consumer	1,476,741	0.01	$12,306.18	per consumer
General				
Power Supply - Energy	2,131,327	0.02	0.02	cents per kWh
Power Supply - Demand	1,549,384	0.01	$0.05	per kW*
Transmission	344,515	0.00	$0.01	per kW*
Consumer	10,842	0.00	$90.35	per consumer per month
	$553,789,741	4.54		

Energy Method

Category	Cost	Cents/kWh	Applicable Unit Cost	Unit
Power Supply - Energy	$364,383,468	2.99	2.99	cents per kWh
Power Supply - Demand	136,967,004	1.12	$4.64	per kW*
Transmission	46,926,460	0.38	$1.59	per kW*
Consumer	1,476,741	0.01	$12,306.18	per consumer per month
General				
Power Supply - Energy	2,675,155	0.02	0.02	cents per kWh
Power Supply - Demand	1,005,556	0.01	$0.03	per kW*
Transmission	344,515	0.00	$0.01	per kW*
Consumer	10,842	0.00	$90.35	per consumer per month
	$553,789,741	4.54		

* Per sum of monthly coincident peak.

PART III - RATE DESIGN

PART III
WHOLESALE RATE DESIGN

Having completed the cost-of-service study as discussed in the previous part of this report, Burns & McDonnell's efforts then turned to developing wholesale rates for Seminole to charge its member distribution systems. Good cost information provides the basis for rate design. Other factors such as revenue stability, rate stability, practicality, social and environmental objectives, etc. should also be considered when rates are designed. However, Seminole requested that Burns & McDonnell only consider the cost of service for this assignment. Therefore, the rates discussed in this part of the report are cost-based only and did not consider other rate-making criteria.

Costs developed in Part II of this report provided the basis for the rate design. Appropriate billing determinants were identified that provided the basis for applying rates to recover the costs previously discussed. Per unit rates were developed for wholesale service to the member distribution cooperatives. As a final step, the proposed rates were applied to the billing units so Seminole could see the effects that the proposed rates would have on each member cooperative. The remainder of this report describes in greater detail the methodology used to develop cost-based wholesale rates.

COSTS

For reasons discussed in Part II of this report, Burns & McDonnell used the cost-of-service study results that were based on the equivalent peaker method of assigning costs to design the proposed wholesale rates. The costs were combined into three major categories: commodity, capacity, and customer costs. These costs are summarized on Table III-1. Commodity costs included the power supply – energy costs. Capacity costs included the power supply – demand and transmission costs. Customer costs included the consumer costs. General costs were included in each category based on the sub-function breakdown discussed in Part II. The three major categories of costs provided the basis for developing three separate charges to recover revenues from the member distribution cooperatives on a cost basis.

Although the equivalent peaker costs provided the basis for the recommended rates, costs from the traditional method and the energy method were also evaluated. The resulting rates have been included at the end of this section of the report.

Table III-1

COST TO BE RECOVERED THROUGH WHOLESALE RATES
Seminole Electric Cooperative, Inc.

Equivalent Peaker Method

Category	Cost
Commodity	$332,718,663
Capacity	219,583,495
Customer	1,487,583
Total Cost of Service	$553,789,741

BILLING UNITS

Having determined the costs to be collected, the next task in designing wholesale rates was to identify the billing units that would be applied to the resulting rates. Table III-2 summarizes the billing units that were selected for recovering each of the three cost categories.

The most common billing unit is kilowatt-hour sales to distribution members. As shown on Table III-2, 12,194,143,481 megawatt- hours of sales to the member cooperatives are expected during the year 2000. Kilowatt-hour sales will be the billing units to which the commodity portion of the wholesale rate is applied.

The sum of monthly coincident peaks provided the basis for developing the billing units for capacity costs. Since monthly capacity costs are a function of Seminole's monthly peak demand, it was felt that each cooperative's contribution to this peak demand should provide the basis for billing for this service. Table III-2 not only shows Seminole's total system demand on a monthly basis, but also each member system's monthly contribution to this demand.

The number of member systems was considered the unit by which to charge customer costs. As shown on Table III-2, Seminole provides service to ten member cooperatives.

PROPOSED RATES

Having defined the costs and the billing units, developing the proposed rates basically became a matter of dividing costs by billing units. The proposed cost-based rates for Seminole's member systems are summarized in Table III-3. The commodity charge of 2.73 cents per kilowatt-hour is applied to all energy sales. The capacity charge is applied to the members' contribution to Seminole's monthly peak. The actual rate was developed by dividing the sum of monthly capacity costs by the sum of Seminole's monthly peak demand and then dividing this result by 12. Since the billing units used to determine this rate were the sum of the 12 months' demands, no ratchet is included in this rate. Finally, the customer charge is a monthly charge assessed to each member system.

To provide an indication of how these rates would collect revenue from the 10 member systems, a table was prepared showing revenue from each cooperative. Table III-4 shows the expected revenue that will be received from each cooperative each month during the year 2000. Revenues have been summed by

Table III-2

BILLING UNITS
Seminole Electric Cooperative, Inc.

Units	Central Florida	Clay	Glades	Lee County	Peace River	Sumter
kWh Purchased	401,047,636	2,522,169,887	325,643,638	2,671,165,760	387,811,955	1,658,790,641
Sum of Monthly Coincident Peaks (kW)	973,941	5,908,709	657,585	5,966,874	880,499	4,304,641
Customer	1	1	1	1	1	1

Units	Suwannee	Talquin	Tri-County	Withlacoochee	Total
kWh Purchased	302,701,398	856,509,058	185,508,871	2,882,794,637	**12,194,143,481**
Sum of Monthly Coincident Peaks (kW)	723,965	2,122,127	414,093	7,584,148	**29,536,582**
Customer	1	1	1	1	**10**

Table III-3

PROPOSED WHOLESALE RATES
Seminole Electric Cooperative, Inc.

Equivalent Peaker Method

Commodity	2.73	cents per kWh
Capacity	$7.43	kW per month Monthly member contribution to SECI peak.
Customer Charge	$12,397	per member

Table III-4

MONTHLY BILLS WITH PROPOSED RATES
Seminole Electric Cooperative, Inc.

Equivalent Peaker Method

Units	Central Florida	Clay	Glades	Lee County	Peace River	Sumter
January	$1,656,541	$10,195,368	$1,214,475	$11,306,915	$1,684,652	$7,239,933
February	1,481,331	9,660,678	1,191,767	9,933,126	1,624,597	7,091,542
March	1,378,580	8,393,220	1,121,679	9,405,689	1,475,112	5,881,887
April	1,227,159	7,483,793	1,065,837	7,993,188	1,161,454	5,344,565
May	1,547,623	8,908,334	1,198,484	9,496,042	1,454,208	5,797,651
June	1,628,952	10,087,907	1,122,408	10,465,147	1,440,174	6,693,342
July	1,827,155	10,927,590	1,234,758	11,030,244	1,466,897	6,764,056
August	1,763,708	10,996,674	1,205,653	11,296,672	1,496,500	6,973,244
September	1,546,178	10,332,414	1,136,832	9,983,467	1,371,622	6,834,014
October	1,266,492	8,387,213	1,115,749	9,101,109	1,320,076	6,166,370
November	1,396,082	8,058,179	1,105,602	7,884,849	1,292,685	6,120,190
December	1,612,149	9,462,148	1,209,418	9,494,855	1,488,160	6,504,212
Total	$18,331,950	$112,893,517	$13,922,661	$117,391,303	$17,276,138	$77,411,006

Table III-4

MONTHLY BILLS WITH PROPOSED RATES
Seminole Electric Cooperative, Inc.

Equivalent Peaker Method

Units	Suwannee	Talquin	Tri-County	Withlacoochee	Total
January	$1,215,046	$3,777,937	$755,694	$13,127,872	**$52,174,433**
February	1,057,095	3,507,823	688,617	12,509,221	**48,745,799**
March	1,002,212	3,094,052	643,969	11,105,249	**43,501,650**
April	850,145	2,481,014	523,224	8,194,651	**36,325,028**
May	1,020,013	3,128,227	645,867	10,914,815	**44,111,264**
June	1,359,290	3,481,410	738,004	11,754,541	**48,771,176**
July	1,535,292	3,774,000	872,878	11,878,011	**51,310,881**
August	1,461,497	3,659,002	796,122	12,390,266	**52,039,337**
September	1,194,176	3,319,344	717,592	11,092,593	**47,528,233**
October	902,073	2,533,270	555,755	9,231,077	**40,579,184**
November	989,420	2,960,941	623,669	10,164,278	**40,595,896**
December	1,203,908	3,578,195	727,487	12,826,330	**48,106,861**
Total	$13,790,167	$39,295,216	$8,288,877	$135,188,905	**$553,789,741**

columns to show each member's expected annual cost and by month to show how the revenue would be collected throughout the year.

Rates Under Alternate Assignment Methodologies

To provide an indication of how assigning the investment costs of baseload generation would affect the rates, rates were also calculated using the traditional and energy methods. These rates have been summarized in a manner similar to the recommended rates on Table III-5 and Table III-6. Similarly, the affect of these rates on the member systems has also been included and is shown on Table III-7 and Table III-8.

Table III-9 was included to compare the effect of using different assignment methods on each of the member systems. The average cost of service, expressed in cents per kilowatt-hour, was calculated for each member cooperative using each of the three assignment methods.

As stated in Part II of this report, the equivalent peaker method was selected because it was felt that it would provide a fair allocation of costs between member systems. It was also felt that it would produce results that would allow Seminole to further its transition from the traditional utility world to the future, competitive electric power industry.

Table III-5

PROPOSED WHOLESALE RATES
Seminole Electric Cooperative, Inc.

Traditional Method

Commodity	2.40	cents per kWh
Capacity	$8.80	kW per month Monthly member contribution to SECI peak.
Customer Charge	$12,397	per member

Table III-6

PROPOSED WHOLESALE RATES
Seminole Electric Cooperative, Inc.

Energy Method

Commodity	3.01	cents per kWh
Capacity	$6.27	kW per month Monthly member contribution to SECI peak.
Customer Charge	$12,397	per member

Table III-7

MONTHLY BILLS WITH PROPOSED RATES

Seminole Electric Cooperative, Inc.

Traditional Method

Units	Central Florida	Clay	Glades	Lee County	Peace River	Sumter
January	$1,675,549	$10,255,418	$1,209,142	$11,515,179	$1,716,791	$7,370,046
February	1,506,050	9,789,564	1,189,805	10,076,766	1,660,017	7,265,400
March	1,385,185	8,410,072	1,106,896	9,376,788	1,480,182	5,959,856
April	1,222,610	7,456,033	1,054,878	7,877,018	1,144,199	5,327,109
May	1,543,069	8,854,675	1,180,581	9,383,639	1,433,107	5,748,860
June	1,624,626	9,987,437	1,098,899	10,351,277	1,420,088	6,691,612
July	1,811,324	10,832,542	1,208,820	10,866,392	1,441,928	6,733,432
August	1,748,219	10,897,836	1,182,499	11,123,787	1,464,468	6,952,972
September	1,535,631	10,247,430	1,113,190	9,839,107	1,353,334	6,816,807
October	1,260,424	8,326,028	1,101,489	8,984,150	1,297,300	6,157,579
November	1,401,207	8,063,544	1,096,850	7,742,520	1,281,005	6,166,813
December	1,621,499	9,499,550	1,200,713	9,568,460	1,503,457	6,611,529
Total	$18,335,395	$112,620,130	$13,743,762	$116,705,082	$17,195,876	$77,802,015

Table III-7

MONTHLY BILLS WITH PROPOSED RATES
Seminole Electric Cooperative, Inc.

Traditional Method

Units	Suwannee	Talquin	Tri-County	Withlacoochee	Total
January	$1,228,203	$3,845,041	$761,021	$13,439,201	**$53,015,591**
February	1,075,403	3,593,714	700,928	12,878,680	**49,736,328**
March	1,008,080	3,146,710	645,183	11,269,672	**43,788,625**
April	844,287	2,452,101	514,451	8,116,031	**36,008,717**
May	1,001,919	3,110,445	636,225	10,883,638	**43,776,157**
June	1,355,027	3,463,510	732,037	11,710,285	**48,434,797**
July	1,520,381	3,738,374	860,732	11,775,152	**50,789,078**
August	1,450,349	3,614,186	783,353	12,329,768	**51,547,436**
September	1,192,516	3,307,208	709,383	11,035,385	**47,149,991**
October	896,801	2,502,285	546,885	9,216,401	**40,289,342**
November	995,113	3,001,032	624,570	10,267,313	**40,639,967**
December	1,209,493	3,585,379	726,046	13,087,585	**48,613,711**
Total	$13,777,572	$39,359,986	$8,240,813	$136,009,112	**$553,789,742**

Table III-8

MONTHLY BILLS WITH PROPOSED RATES
Seminole Electric Cooperative, Inc.

Energy Method

Units	Central Florida	Clay	Glades	Lee County	Peace River	Sumter
January	$1,640,336	$10,144,172	$1,219,022	$11,129,358	$1,657,252	$7,129,004
February	1,460,257	9,550,796	1,193,439	9,810,665	1,594,399	6,943,318
March	1,372,949	8,378,852	1,134,282	9,430,328	1,470,791	5,815,414
April	1,231,037	7,507,459	1,075,179	8,092,230	1,176,164	5,359,447
May	1,551,504	8,954,081	1,213,747	9,591,873	1,472,198	5,839,248
June	1,632,640	10,173,564	1,142,450	10,562,228	1,457,299	6,694,817
July	1,840,652	11,008,623	1,256,873	11,169,937	1,488,184	6,790,164
August	1,776,913	11,080,939	1,225,392	11,444,066	1,523,809	6,990,527
September	1,555,169	10,404,868	1,156,987	10,106,542	1,387,214	6,848,685
October	1,271,666	8,439,377	1,127,906	9,200,823	1,339,494	6,173,865
November	1,391,713	8,053,604	1,113,065	8,006,193	1,302,642	6,080,441
December	1,604,176	9,430,261	1,216,839	9,432,103	1,475,119	6,412,719
Total	$18,329,014	$113,126,596	$14,075,182	$117,976,345	$17,344,567	$77,077,649

Table III-8

MONTHLY BILLS WITH PROPOSED RATES
Seminole Electric Cooperative, Inc.

Energy Method

Units	Suwannee	Talquin	Tri-County	Withlacoochee	**Total**
January	$1,203,828	$3,720,727	$751,153	$12,862,446	**$51,457,299**
February	1,041,487	3,434,597	678,122	12,194,237	**47,901,317**
March	997,208	3,049,159	642,934	10,965,070	**43,256,987**
April	855,140	2,505,663	530,703	8,261,679	**36,594,701**
May	1,035,440	3,143,388	654,087	10,941,395	**44,396,962**
June	1,362,926	3,496,671	743,090	11,792,272	**49,057,957**
July	1,548,004	3,804,373	883,234	11,965,704	**51,755,747**
August	1,471,000	3,697,210	807,008	12,441,844	**52,458,709**
September	1,195,591	3,329,691	724,590	11,141,366	**47,850,705**
October	906,568	2,559,687	563,316	9,243,589	**40,826,291**
November	984,567	2,926,761	622,902	10,076,435	**40,558,324**
December	1,199,146	3,572,070	728,715	12,603,595	**47,674,744**
Total	$13,800,906	$39,239,997	$8,329,854	$134,489,633	**$553,789,741**

Table III-9

COMPARISON OF COST TO MEMBER SYSTEMS WITH DIFFERENT ASSIGNMENT METHODS
Seminole Electric Cooperative, Inc.

(cents/kWh)

Units	Central Florida	Clay	Glades	Lee County	Peace River	Sumter
TRADITIONAL	4.57	4.47	4.22	4.37	4.43	4.69
EQUIVALENT PEAKER	4.57	4.48	4.28	4.39	4.45	4.67
ENERGY	4.57	4.49	4.32	4.42	4.47	4.65

Units	Suwannee	Talquin	Tri-County	Withlacoochee	Average
TRADITIONAL	4.55	4.60	4.44	4.72	**$4.54**
EQUIVALENT PEAKER	4.56	4.59	4.47	4.69	**$4.54**
ENERGY	4.56	4.58	4.49	4.67	**$4.54**

PART IV - CONCLUSIONS AND RECOMMENDATIONS

PART IV
CONCLUSIONS AND RECOMMENDATIONS

This study was based on information provided by Seminole, including the 2000 budget numbers, and other sources. The information was also used by Burns & McDonnell to make certain assumptions with respect to conditions that may exist in the future. These assumptions provided the basis for this cost-of-service and rate design study.

ASSUMPTIONS

Important assumptions made in performing the cost-of-service study and rate design are that:

1. energy and demand will *be* as forecast for Seminole and its members;
2. costs will be as budgeted by Seminole; and
3. all member cooperatives will be considered as one customer class.

CONCLUSIONS

Based on the cost-of-service study and rate design. Burns & McDonnell concludes that:

1. Seminole will need to meet a load of 37,907 MW and produce 12,194,143,000 kWh for its members in 2000.

2. The total cost of service for Seminole to provide service to its ten member distribution systems in the year 2000, will be $553,789,741;

3. This total cost of service can be assigned to the major utility functions using the equivalent peaker method to:
   - Commodity costs - $332,718,663;
   - Capacity costs - $219,583,495; and
   - Consumer cost - $1,487,583.

4. Using the traditional method of assigning costs transfers $40,278,836 from power supply – energy to power supply – demand. The total cost of service can be assigned to the major utility functions using the traditional method to:

- Commodity costs - $292,439,827;
- Capacity costs - $259,862,331; and
- Consumer cost - $1,487,583.

5. Using the energy method of assigning costs transfers $34,339,960 from power supply – demand to power supply – energy. The total cost of service for Seminole in the year 2000 using the energy method consists of:
   - Commodity costs - $367,058,623;
   - Capacity costs - $185,243,535; and
   - Consumer cost - $1,487,583.

6. The following rates (based on the equivalent peaker method of assigning costs) are cost-based and can provide the basis for designing wholesale rates for Seminole's ten members systems:
   - Commodity costs - $332,718,663;
   - Capacity costs - $219,583,495; and
   - Consumer cost - $1,487,583.

RECOMMENDATIONS

Based on conclusions as stated above, it is recommended that:

1. The equivalent peaker method be used for the assignment of costs;

2. Assignments based on the equivalent peaker method be the basis for developing final rates;

3. Seminole compare the cost-based rates with Seminole's existing rates to consider rate stability;

4. Seminole compare the cost-based rates with its strategic plans and other long- and short-term goals;

5. Seminole modify the rates, if necessary, after making comparisons with existing rates and Seminole and member goals:

6. Seminole implement the rate among its member systems;

7. Seminole's cost of service be re-evaluated regularly to ensure full cost recovery;

8. Seminole continue to review the effectiveness of its rates, especially if changes in member status or the electric utility occur;

9. Seminole continue to position itself to be prepared as changes occur through the deregulation of the electric utility industry; and

10. Seminole continue to position itself to be prepared as changes occur through the deregulation of the electric utility industry and consider investigating the appropriateness of rate concepts in the future including time-of-use rates, performance-based rates and accelerated recovery of investments.

APPENDIX A – OUTPUT FROM MODEL

STATEMENT OF OPERATIONS

Seminole Electric Cooperative, Inc.

Source: RUS Form 12a, Section A. Statement of Operations, for Year Ended 1998.

	Item	1998 Year End
1.	Electric Energy Revenues	**548,631,677**
2.	Income From Leased Property (Net)	-
3.	Other Operating Revenue and Income	**11,306,105**
4.	**Total Oper. Revenue & Patronage Capital** (1 thru 3)	**559,937,782**
5.	Operations Expense - Production - Excluding Fuel	**53,911,443**
6.	Operations Expense - Production - Fuel	**168,291,838**
7.	Operations Expense - Other Power Supply	**207,608,605**
8.	Operations Expense - Transmission	**23,849,089**
9.	Operations Expense - Distribution	-
10.	Operations Expense - Consumer Accounts	-
11.	Operations Expense - Consumer Service & Information	-
12.	Operations Expense - Sales	-
13.	Operations Expense - Administrative & General	**14,842,678**
14.	**Total Operation Expense** (5 thru 13)	**468,503,653**
15.	Maintenance Expense - Production	**25,468,879**
16.	Maintenance Expense - Transmission	**934,086**
17.	Maintenance Expense - Distribution	-
18.	Maintenance Expense - General Plant	**196,784**
19.	**Total Maintenance Expense** (15 thru 18)	**26,599,749**
20.	Depreciation and Amortization Expense	**24,964,220**
21.	Taxes	**89,430**
22.	Interest on Long-Term Debt	**34,150,418**
23.	Interest Charged to Construction - Credit	**(176,522)**
24.	Other Interest Expense	**675,481**
25.	Other Deductions	**14,058,636**
26.	**Total Cost of Electric Service** (14 plus 19 thru 25)	**568,865,065**
27.	**Operating Margins** (4 minus 26)	**(8,927,283)**
28.	Interest Income	**10,269,310**
29.	Allowances for Funds Used During Construction	-
30.	Incomes (Loss) from Equity Investments	**254,070**
31.	Other Nonoperating Income (Net)	**732,205**
32.	Generation and Transmission Capital Credits	-
33.	Other Capital Credits and Patronage Dividends	**166,764**
34.	Extraordinary Items	-
35.	***Net Patronage Capital or Margins*** (27 thru 34)	**2,495,066**

BALANCE SHEET

Seminole Electric Cooperative, Inc.
Source: RUS Form 12a, Section B. Balance Sheet, for Year Ended 1998.

ASSETS AND OTHER DEBITS	1998 Year End
1. Total Utility Plant in Service	845,908,346
2. Construction Work in Progress	15,252,830
3. **Total Utility Plant** (1+2)	861,161,176
4. Accum. Provision for Depreciation & Amort.	337,141,968
5. **Net Utility Plant** (3-4)	524,019,208
6. Non-Utility Property (Net)	-
7. Investments in Subsidiary Companies	4,472,683
8. Invest. In Assoc. Org. - Patronage Capital	547,193
9. Invest. In Assoc. Org. - Other - Gen. Funds	17,928
10. Invest. In Assoc. Org. - Nongen. Funds	7,247,150
11. Investments in Economic Development Projects	-
12. Other Investments	-
13. Special Funds	91,548,374
14. **Total Other Property and Investments** (6 thru 13)	103,833,328
15. Cash - General Funds	25,103
16. Cash - Construction Funds - Trustee	113,672
17. Special Funds	-
18. Temporary Investments	71,285,386
19. Notes Receivable (Net)	-
20. Accounts Receivable - Sales of Energy (Net)	21,932,202
21. Accounts Receivable - Other (Net)	885,931
22. Fuel Stock	37,796,297
23. Materials and Supplies - Electric and Other	17,545,183
24. Prepayments	2,722,430
25. Other Current and Accrued Assets	77,016
26. **Total Current and Accrued Assets** (15 thru 25)	152,383,220
27. Unamortized Debt Disc. & Extraordinary Prop. Losses	4,216,048
28. Regulatory Assets	3,932,178
29. Other Deferred Debits	48,747,783
30. Accumulated Deferred Income Taxes	2,675,843
31. **Total Assets and Other Debits** (5+14+26 thru 30)	839,807,608

LIABILITIES AND OTHER CREDITS	
32. Memberships	1,000
33. Patronage Capital	-
a. Assigned and Assignable	79,309,964
b. Retired This Year	676,441
c. Retired Prior Years	13,144,828
d. Net Patronage Capital	65,488,695
34. Operating Margins - Prior Years	-
35. Operating Margins - Current Year	(8,760,519)
36. Non-Operating Margins	11,255,585
37. Other Margins and Equities	31,715
38. **Total Margins and Equities** (32 plus 33d thru 37)	68,016,476
39. Long-Term Debt - REA (Net)	7,371,070
(Payments-Unapplied)	-
40. Long-Term Debt - Other - Econ. Devel. (Net)	-
41. Long-Term Debt - FFB - REA Guaranteed	420,832,678
42. Long-Term Debt - Other - REA Guaranteed	-
43. Long-Term Debt - Other (Net)	206,414,147
44. **Total Long-Term Debt** (39 thru 43)	634,617,895
45. Obligations Under Capital Leases - Noncurrent	18,581,800
46. Accumulated Operating Provisions	5,392,515
47. **Total Other Noncurrent Liabilities** (42+43)	23,974,315
48. Notes Payable	18,697,049
49. Accounts Payable	24,624,492
50. Taxes Accrued	101,034
51. Interest Accrued	819,591
52. Other Current and Accrued Liabilities	34,686,632
53. **Total Current & Accrued Liabilities** (45 thru 48)	78,928,798
54. Deferred Credits	31,594,281
55. Accumulated Deferred Income Taxes	2,675,843
56. **Total Liabilities and Other Credits** (36+41+44+49 thru 51)	839,807,608

PLANT-IN-SERVICE

Seminole Electric Cooperative, Inc.

Sources RUS Form 12a, Annual Supplement Section A Utility Plant for Year Ended 1998 and 1999 & 2000 Capital Budget

	Item	Total	kW	KWH	ACC	T-KW	CONS	GENL	Description of Assignment
1	Total Intangible Plant (301 - 303)	5,779,220	2,044,878	2,672,372	-	1,061,971	-	-	Prod/Xmsn Plant Ratio
2	Total Production Plant - Steam (310 - 316)	673,348,929	293,551,261	379,797,668					KW, KWH - 625 MW Capacity
3	Total Production Plant - Nuclear (320 - 325)	22,306,484	8,008,028	14,298,456					KW, KWH - CR3
4	Total Production Plant - Hydro (330 - 336)	-							KW
5	Total Production Plant - Other (340 - 346)	-							KW
6	**SUBTOTAL - Production (2 thru 5)**	**695,655,413**	**301,559,289**	**394,096,124**	-	-	-	-	
7	Land and Land Rights (350)	16,406,249				16,406,249			T-KW
8	Structures and Improvements (352)					-			T-KW
9	Station Equipment (353)					-			T-KW
10	Other Transmission Plant (354 - 359)	140,203,133				140,203,133			T-KW
11	**SUBTOTAL - Transmission Plant (7 thru 10)**	**156,609,382**	-	-	-	**156,609,382**	-	-	OP-T, OP-S, OP-D, CONS
12	Land and Land Rights (360)	-							OP-T, OP-S, OP-D, CONS
13	Structures and Improvements (361)	-							OP-T, OP-S, OP-D
14	Station Equipment (362)	-							Dist Plant Ratio
15	Other Distribution Plant (363 - 373)	-							
16	**SUBTOTAL - Distribution (12 thru 15)**	-	-	-	-	-	-	-	Prod/Xmsn Plant Ratio
17	Land and Land Rights (389)	798,157	282,414	369,076	-	146,667			Prod/Xmsn Plant Ratio
18	Structures and Improvements (390)	-							CONS
19	Office Furniture & Equipment (391)	1,597,554					1,597,554		KWH
20	Transportation Equipment (392)	748,182		748,182					
21	Stores, Tools, Shop, Garage, and Lab Equipment (393, 394, 395)	-							9% to 11 Functional Areas 9% to 11 Functional Areas
22	Power - Operated Equipment (396)	-							Standard/Judgment
23	Communication Equipment (397)	5,649,731	225,989	338,984		2,259,892	2,259,892	564,973	Prod/Xmsn Plant Ratio
24	Miscellaneous Equipment (398)	15,591,733	5,516,867	7,209,780		2,865,086			Prod/Xmsn Plant Ratio
25	Other Tangible Property (399)	-							
26	**SUBTOTAL - General Plant (16 thru 24)**	**24,385,357**	**6,025,271**	**8,666,022**	-	**5,271,645**	**3,857,446**	**564,973**	Prod/Xmsn Plant Ratio
27	Other Utility Plant (101, 114, 120)	-	-	-	-	-	-	-	
28	**SUBTOTAL (1 + 5 + 12 + 16 + 26 + 27)**	**882,429,372**	**309,629,437**	**405,434,518**	-	**162,942,997**	**3,857,446**	**564,973**	Prod/Xmsn Plant Ratio
29	Construction Work in Progress (107)	-	-	-	-	-	-	-	
30	**TOTAL UTILITY PLANT (28 + 29)**	**882,429,372**	**309,629,437**	**405,434,518**	-	**162,942,997**	**3,857,446**	**564,973**	

SUBTOTALS	Total	kW	KWH	ACC	T-KW	CONS-D	GENL
Subtotal - Production Plant	695,655,413	301,559,289	394,096,124	-	-	-	-
Subtotal - Transmission Plant	156,609,382	-	-	-	156,609,382	-	-
Subtotal - Distribution	-	-	-	-	-	-	-
Total Prod/Xmsn/Dist Plant	852,264,795	301,559,289	394,096,124	-	156,609,382	-	-
Subtotal - General	24,385,357	6,025,271	8,666,022	-	5,271,645	3,857,446	564,973
Intangibles	5,779,220	2,044,878	2,672,372	-	1,061,971	-	-
All Other Utility Plant	0	-	-	-	-	-	-
CWIP	-	-	-	-	-	-	-
Total Utility Plant	882,429,372	309,629,437	405,434,518	-	162,942,997	3,857,446	564,973
RATIO CALCULATION							
Production Plant Ratio	**1.000**	**0.433**	**0.567**	-	-	-	-
Transmission Plant Ratio	**1.000**	-	-	-	**1.000**	-	-
Distribution Plant Ratio, Excluding Other Dist	-	-	-	-	-	-	-
Prod/Xmsn/Dist Plant Ratio	**1.000**	**0.354**	**0.462**	-	**0.184**	-	-
Total Utility Plant Ratio	**1.000**	**0.351**	**0.459**	-	**0.185**	**0.004**	**0.001**

TRIAL BALANCE

Seminole Electric Cooperative, Inc. G&T Cooperative

Source: General Ledger Balance, for Year Ended 1998

Verify range names "Acct" and "Acct_Bal" extend to bottom of list.

Add or delete accounts as necessary.

ACCT	DESCRIPTION	1998 Year End Balance
101.000	ELECTRIC PLANT IN SERVICE	$2,455
101.111	LEASED ASSET-TRANSPORTATION LEASES	39,328,927
107.100	CONSTRUCTION WORK IN PROGRESS	15,244,930
108.100	DEPRECIATION STEAM PLANT	(244,903,148)
108.200	DEPRECIATION NUCLEAR PROD. PLANT	(6,293,017)
108.500	DEPRECIATION TRANSMISSION	(41,296,661)
108.703	DEPRECIATION GENERAL PLANT	(11,139,899)
108.910	COST OF REMOVAL - NUCLEAR CLEARING	(94,379)
111.103	ACCUMULATED AMORTIZATION	(18,452,426)
111.120	ACCUMULATED AMORTIZATION	(1,734,479)
111.120	ACCUMULATED AMORTIZATION	(6,334,080)
114.100	ACQUISITION ADJUSTMENT	557,902
115.100	ACCUMULATED AMORTIZATION - ACQUISITION ADJUSTMENT	(394,689)
120.100	NUCLEAR FUEL IN PROCESS	131,755
120.200	NUCLEAR FUEL STOCK	1,132,962
120.300	NUCLEAR FUEL IN REACTOR	1,852,050
120.400	SPENT NUCLEAR FUEL	4,331,020
120.500	ACC. AMORTIZATION - NUCLEAR FUEL	(6,504,475)
123.105	PATRONAGE CAPITAL	547,193
123.110	SECI INVESTMENT	2,330,000
123.225	CFC	3,475,112
123.230	OTHER INVESTMENT IN ASSOCIATE ORGANIZATIONS	9,517
123.235	INVESTMENT IN CFC	8,411
123.245	SUBTERM CERTIFICATE - TBT	3,772,039
128.220	POL CNTRL BOND FUND	252,675
128.225	INT REC PC BOND FUND	995
128.305	SPECIAL FUND DSR	14,632,000
128.315	DSR DISCOUNT	(43,750)
128.329	AMORT DSR DISCOUNT	10,208
128.335	ACRD INT REC DSR	121,527
128.400	TRANS SERVICES	36,290,483
128.410	INTEREST - LLB	28,761,533
128.507	NUCLEAR DECOMM TRUST FUND	2,532,149
128.517	NDTF INTEREST RECEIVABLE	71,349
131.111	CASH, OPERATING	(9,522,108)
131.205	CAST, TRUST	113,672
134.107	NDTF TRADING	1,202,975
135.100	PETTY CASH	1,000
135.200	TRAVEL ADVANCES	3,289
136.200	CASH EQUIVILANT INVESTMENT	83,256,000
136.210	CASH EQUIVILANT ACCR INTEREST	11,809
142.105	ACCOUNTS RECEIVABLE - ELECTRIC	17,613,707
142.114	ACCOUNTS RECEIVABLE - INTCH	4,318,496
142.225	ACCOUNTS RECEIVABLE - MEMBER WORKORDERS	7,096
143.200	ACCOUNTS RECEIVABLE - BY-PRODUCT SALES	25,013
143.240	ACCOUNTS RECEIVABLE - MISCELLANEOUS	662,829
143.250	ACCOUNTS RECEIVABLE - RENT	125
143.270	ACCOUNTS RECEIVABLE - PC LOAD REPAYMENT	188,536
143.280	ACCOUNTR RECEIVABLE - MEDICAL INS NON-EMPLOYEES	2,331
151.100	COAL - CURRENT YEAR	163,297,720
151.109	COAL - CONSUMMED CURRENT YEAR	(129,379,042)
151.200	PETROLEUM COKE INVENTORY	10,001,812
151.209	PETCOKE - CONSUMED CURRENT	(6,864,572)
151.300	FUEL OIL - CURRENT YEAR	947,747
151.309	FUEL OIL - CONSUMED CURRENT YEAR	(938,688)
151.309	FUEL OIL - ACCUMULATED HISTORY	78,222
152.100	FUEL STOCK EXP - CURRENT YEAR	3,426,183
152.107	PETCOKE HANDLING	(124,252)
152.109	FUEL STOCK EXP TSF - CURRENT YEAR	(2,659,834)
154.110	MATERIALS & SUPPLIES - I&H MMIS	15,750,647
154.117	MATERIALS & SUPPLIES - LIMESTONE	160,610
154.120	MATERIALS & SUPPLIES - CRYSTAL RIVER	558,031

ACCT	DESCRIPTION	1998 Year End Balance
154.140	MATERIALS & SUPPLIES	1,073,850
154.145	MATERIALS & SUPPLIES	3,331
154.145	MMIS CLEARING	158
154.300	GASOLINE INVENTORY	557
165.100	PPD CR3	3,193,643
165.104	PPD FPC	6,490,000
165.109	PPD COAL	2,083,442
165.200	PPD TRAVEL EXPENSE	9,239
165.300	PPD OTHER	204,775
165.305	PPD PC FEES	29,755
165.400	PPD UNIT 2 LEASE FEES	10,163
171.105	INT INC REC - CFC	77,016
173.105	ACCUMULATED FUEL	(9,804,007)
173.210	ACCRUED SALES	(105,679)
174.100	CAPITALIZED ACCRUED P/R	7,900
181.109	UMAMORTIZED DEBT EXPENSE - OPEN	330,358
181.119	UNAMORTIZED DEBT EXPENSE - CLOSED	3,885,690
182.329	U1 LEASE	3,932,178
183.100	PRELIMINARY SURVEY & INVESTMENT	132,888
184.019	OVERHEAD ALLOCATION - PR	1,525,910
184.029	OVERHEAD ALLOCATION - PR	(1,514,815)
184.240	ACCOUNTS PAYABLE SUSPENSE	429
184.270	OVERHEAD ALLOCATION - CLEARING	(32,787)
186.509	DEF DEBITS - COAL TRANSPORTATION	1,574,202
189.119	UNAMORTIZED DEBT - CLOSED	41,816,422
189.139	REFINANCE C8-BASIS	5,245,534
190.000	DEFERRED INCOME TAX ASSET	46,015,231
190.010	ALLOWANCE - DEFERRED INCOME TAX ASSET	(43,339,388)
200.100	MEMBERSHIPS ISSUED	(1,000)
201.100	SECI PAT CAP ASSIGNED	(76,804,197)
201.106	TAX MARGINS ASSIGNED	(101,555,936)
201.110	PAT CAPITAL RET THIS YEAR	676,441
201.120	PRIOR YEARS' RETIREMENTS	13,144,828
201.200	PATRONAGE CAPITAL ASSIGNABLE	(2,705,767)
201.206	TAX MARGINS ASSIGNABLE	101,555,936
201.300	ACRUED STOCK ISSUED	(2,330,000)
208.000	DONATED CAPITAL	(31,715)
221.105	PRTN LTD-PC S&H	(137,650,000)
224.125	L ST PRTN LTD-CFC	(8,743,919)
224.145	PRTN LTD-REA	(5,963,425)
224.155	PRTN LTD-REA C8	(429,406,593)
224.305	PRTN LTD-RUS	(7,634,743)
224.600	FINANCE OBL UNIT I LEASE	(63,916,264)
227.000	NON-CURRENT CAPITAL LEASE	(18,581,800)
228.100	PROPERTY INSURANCE	(185,667)
228.300	FAS 112 PROV FOR PENSION & BENEFITS	(356,500)
228.310	PROVISION FOR PENSION & BENEFITS - SERP	(143,626)
228.320	FAS 106 SICK LEAVE POST RETIREMENT BENEFIT	(2,740,384)
228.328	FAS 106 MEDICAL/OTHER POST RETIREMENT	(1,663,416)
228.400	CR3 OUTAGE RESERVES - CYCLE #11	(302,922)
232.100	ACCOUNTS PAYABLE GENERAL	(6,212,856)
232.200	ACCOUNTS PAYABLE POWER	(8,705,391)
232.300	ACCOUNTS PAYABLE CRIII	(95,070)
235.100	RENTAL SECURITY DEPOSITS	(3,981)
236.200	FUTA TAX PAYABLE	(350)
236.300	FICA/OASDI TAX PAYABLE	(16,547)
236.310	FICA/MEDICARE TAX PAYABLE	(4,996)
236.400	SUTA TAX PAYABLE	(121)
236.500	STATE SALES TAX	31,741
236.505	ACCR STATE SALES TAX - U2 LEASE	(3,511)
236.550	ACCR HILLS CO SALES TAX	(371)
236.600	ACCR GROSS RECEIPTS TAX	(21)
236.700	ACCRUED STATE SALESTAX	(106,858)
237.305	ACCR INTEREST PC	(819,591)
241.200	FED W/W - PAYABLE	9,978
242.200	ACCR PAYROLL	(345,602)
242.310	ACCR VACATION	(770,537)
242.505	ACCR MISC FEE	(132,314)

ACCT	DESCRIPTION	1998 Year End Balance
242.510	ACCR CONTROLLABLE EDXP	(1,619,544)
242.527	ACCR CR3 - DISP COST	(29,988)
242.530	RETENTION - CURRENT CONTRACTS	(1,055,604)
242.540	DEDUCTIONS	(173,566)
242.560	ACC LEASE - PMT - U2	(1,262,262)
242.563	ACC LEASE	(2,552,310)
242.570	ACCR PUR PWR PAYABLE	(11,136,237)
242.580	ACCRUED FUEL INVENTORY PAYABLE	(6,404,272)
242.585	OTHER STL-U2 EST COMPL	(100,000)
242.600	MMIS UNMATCHED RECEIPTS	22,361
242.700	COAL SURVEY ADJUSTMENT	(106,938)
242.800	PREPAID POWER BILLING	(8,019,282)
242.950	ACCRUED BANK SERVICE CHARGES	(3,058)
243.000	CURRENT CAPITAL LEASE	(2,699,135)
253.050	MEMBER RELATED DEFERRED CREDIT	(1,023)
253.100	CR3 DECOMMISSION COST	(3,806,723)
253.400	U2 DEF LEASE FINANCE	(14,090,009)
253.405	U2 W080040 DEF FIN	1,826,272
253.460	DEFERRED CR - MISC	(656)
253.600	UNEARNED INCOME-CITY OCALA	(7,677)
256.100	DEF GAIN - SALE OF UNIT 2	(35,243,381)
256.109	AMORTIZATION OF DEFERRED GAINS-UNIT 2	19,728,914
283.000	DEFFERED INCOME TAX LIABILITY	(2,675,843)
301.000	INTANGIBLE PLANT - ACUERA	8,828
303.000	INTANGIBLE PLANT - HPS	5,772,394
310.000	LAND AND LAND RIGHTS	4,862,393
311.000	STRUCTURES & IMPROVEMENTS	69,756,946
312.000	BOILER PLANT EQUIPMENT	350,352,866
314.000	TURBOGENERATOR UNITS	110,896,606
315.000	ACCESSORY ELECTRIC EQUIPMENT	35,137,553
316.000	MISC POWER PLANT EQUIPMENT	36,792,274
320.000	LAND AND LAND RIGHTS	635
321.000	STRUCTURES & IMPROVEMENTS	3,733,987
322.000	REACTOR PLANT EQUIPMENT	4,199,494
323.000	TURBOGENERATOR UNITS	1,543,534
324.000	ACCESSORY ELECTRIC EQUIPMENT	1,901,714
325.000	MISC POWER PLANT EQUIPMENT	396,531
350.000	LAND AND LAND RIGHTS	16,406,249
352.000	STRUCTURES & IMPROVEMENTS	3,287,838
353.000	STATION EQUIPMENT	26,865,918
354.000	TOWERS AND FIXTURES	30,000,860
355.000	POLES AND FIXTURES	39,857,112
356.000	OH CONDUCTORS & DEVICES	38,528,113
359.000	ROADS AND TRAILS	1,399,465
389.000	LAND AND LAND RIGHTS	798,157
390.000	STRUCTURES & IMPROVEMENTS	7,448,923
391.000	OFFICE FURNITURE & EQUIPMENT	3,760,317
392.000	TRANSPORTATION EQUIPMENT	818,046
393.000	STORES EQUIPMENT	43,443
394.000	TOOLS, SHOP, & GARAGE EQUIPMENT	183,291
395.000	LABORATORY EQUIPMENT	202,030
396.000	POWER OPERATED EQUIPMENT	210,916
397.000	COMMUNICATION EQUIPMENT	5,722,993
398.000	MISC EQUIPMENT	90,530
399.000	OTHER TANGIBLE PROPERTY	44,611
403.049	DEPRECIATION EXPENSE-TRANSFERRED	(6,900)
403.108	DEPRECIATION EXPENSE-SECI COMMON	17,973,063
403.208	DEPRECIATION EXPENSE-CRYSTAL RIVER	1,100,909
403.508	DEPRECIATION EXPENSE	3,858,097
403.718	DEPRECIATION EXPENSE-GENERAL PLANT	588,001
403.768	DEPRECIATION EXPENSE-EMS HDWR	17,253
403.708	DEPRECIATION HDQTRS LEASED	41,597
404.018	AMORTIZATION OF LEASEHOLD IMPROVEMENTS	1,066,337
405.008	AMORTIZATION EXPENSE-HPS INT	288,606
406.048	AMORTIZATION EXPENSE-CR3 AQUIS ADJ	17,259
408.049	OVERHEAD TRANSFERS	(10,247,160)
408.108	PROPERTY TAX	8,558,061
408.118	PROPERTY TAX-HQ ALLOCABLE	194,160

ACCT	DESCRIPTION	1998 Year End Balance
408.218	FEDERAL UNEMPLOYMENT TAX	18,504
408.318	FEDERAL FICA TAXES	1,532,399
408.418	STATE UNEMPLOYMENT TAX	5,803
408.708	OTHER TAXES	68,863
408.799	TAXES TRANSFERRED	(20,230)
409.040	INCOME TAXES	10,000
411.800	GAINS/DISP OF CLEAN AIR ALLOWANCES	(59,080)
419.011	CTC & SCTC	(1,213,798)
419.020	LLB EQUITY	(3,437,965)
419.021	BOND FUNDS	(1,277,238)
419.041	SECI, ACUERA AND NONCASH EQUILIVENT	(3,993,203)
419.061	WHOLESALE RATE CASE REFUND	(416,714)
419.071	MISC INTEREST INCOME	(17,289)
419.085	INTEREST INCOME	(22,855)
421.007	NDTF TRADING SEC UNREALIZED GAINS	(232,875)
421.100	GAIN ON DISPOSAL OF PROPERTY	(10,014,919)
421.316	COLL ALLOW	(780)
421.340	LEASE INC-ACUERA GROUND LEASE	(175,601)
421.344	NON-OPERATING INCOME	(287,765)
421.400	MISCELLANEOUS NON-OPERATING INCOME	(190,927)
424.100	CAPITAL CREDITS - CFC	(166,572)
424.205	CAPITAL CREDITS - CLAY	(192)
425.008	AMORTIZATION-ACUERA CORP	75
426.104	DONATIONS	10,406
426.304	PENALTIES	1,700
426.404	CIVIC, POLITICAL & REL EXP	14,016
426.504	OTHER DEDUCTIONS - WRITE OFFS	9,995,683
427.105	INTEREST EXPENSE	388,989
427.205	INTEREST EXPENSE	28,257,024
427.225	WEEKLY INTEREST EXPENSE	2,612,750
427.235	1984H SEMIS INTEREST EXPENSE	2,227,733
427.240	U1 LEASE INTEREST EXPENSE	663,922
427.315	IDC, INTEREST EXPENSE - 9905	(176,622)
428.105	AMORTIZATION EXPENSE - BOND COSTS	3,083,629
428.225	1948H WEEKLYS	814,806
428.235	1984H SEMIS	197,192
428.247	NDT - TRUSTEE FEES	284
431.105	INTEREST - MEMBER EARLY PAYMENT	302,918
431.115	INTEREST EXPENSE - MEMBER MISCELLANEOUS	343,374
431.205	INTEREST EXPENSE	29,192
447.140	MEMBER SALES	(541,130,005)
447.147	ACCRUED REVENUES	(221,600)
447.150	INTERRUPTIBLE POWER SALES	(1,832,270)
447.160	MARTEL DEL PT REVENUE	(67,329)
447.200	INTERCHANGE SALES	(5,125,446)
447.300	LOAD FOLLOWING SALES	(255,027)
456.210	TFUC	(806,365)
456.220	TFUC - 86 NON-MEMBERS	(30,711)
456.237	TFUC - WHEELING REVENUE	(139,881)
456.247	OFF-SYSTEM SALES WHEELING	(176,679)
456.304	MISCELLANEOUS OPERATING REVENUE	(157,470)
500.017	1ST AID SUPPLIES & SAFETY	579
500.017	SALARIES & MEALS	1,691,669
500.019	EMPLOYEE MEMBERSHIP	1,301,700
500.208	TRAINING - EXISTING REQUIREMENTS	10,626
500.209	OVERHEAD TRANSFERS	955
500.218	NEW TRAINING	2,912
500.219	APPLIED OVERHEAD	573
501.017	ALLOCATION OF ACCOUNTS 151 AND 152	160,347,525
501.027	COST OF IGNITION OIL	853,238
501.037	INBAND FUEL	(397,254)
501.047	ALLOCATION OF PETCOKE	8,978,824
501.517	GENERAL OPERATING SUPPLIES	89,217,387
501.518	MISCELLANEOUS OPERATING SUPPLIES	191,283
501.519	OUTSIDE SERVICES	83,941,347
501.527	GENERAL OPERATING SUPPLIES	26,158
501.528	SALARIES	1,123,286
501.529	OTHER OUTSIDE SERVICES	2,237,199

ACCT	DESCRIPTION	1998 Year End Balance
501.537	EQUIPMENT FUELS	39,511
501.999	TSFD 501.51, 501.52, 502.53	(176,776,200)
502.017	CHEMICALS AND FUELS	119,210
502.018	SALARIES	755,868
502.019	VENDOR LABOR	1,080,322
502.028	SALARIES	8,277
502.029	OVERHEAD TRANSFERS - PR HOURS	180
502.037	MISCELLANEOUS	2,352,126
502.038	SALARIES	881,538
502.039	OVERHEAD	45,337
502.047	CHEMICALS AND FUELS	1,415,866
502.049	OTHER OUTSIDE SERVICES	706,894
502.057	GENERAL OPERATING SUPPLIES	275,524
502.058	SALARIES	210,988
502.059	OVERHEAD TRANSFERS - PR HOURS	5,444
502.208	TRAINING - EXISTING REQUIREMENTS	13,130
502.209	OVERHEAD TRANSFERS - PR HOURS	1,576
502.218	NEW TRAINING	4,219
502.219	OVERHEAD TRANSFERS - PR HOURS	1,091
505.017	CHEMICALS	949,231
505.018	SALARIES	619,597
505.019	OVERHEAD TRANSFERS - PR	301,914
506.017	OPERATING/MAINTENANCE	562,775
506.018	SALARIES	1,117,623
506.019	OTHER OUTSIDE SERVICES	8,863,758
506.208	TRAINING - EXISTING REQUIREMENTS	471
506.209	APPLIED OVERHEAD	195
507.205	U2	29,250,235
510.017	TOOLS UNDER $500	1,713
510.018	SALARIES	1,149,249
510.019	OVERHEAD TRANSFERS	507,088
510.208	TRAINING - EXISTING REQUIREMENTS	26,378
510.209	OVERHEAD TRANSFERS	7,884
510.218	NEW TRAINING	17,798
510.219	OVERHEAD TRANSFERS	6,451
511.017	GENERAL OPERATING SUPPLIES	142,347
511.018	SALARIES	38,977
511.019	CONTRACT LABOR	1,498,175
512.017	GENERAL OPERATING SUPPLIES	73,659
512.018	SALARIES	2,311
512.019	CONTRACT LABOR	1,028,652
512.027	GENERAL OPERATING SUPPLIES	406,713
512.028	SALARIES	321,620
512.029	OVERHEAD TRANSFERS	250,516
512.037	GENERAL OPERATING SUPPLIES	286,327
512.038	SALARIES	171,516
512.039	OVERHEAD TRANSFERS	144,843
512.047	GENERAL OPERATING SUPPLIES	27,916
512.048	SALARIES	32,857
512.049	OVERHEAD TRANSFERS	17,389
512.057	GENERAL OPERATING SUPPLIES	562,998
512.058	SALARIES	246,845
512.059	OVERHEAD TRANSFERS	1,016,490
512.067	GENERAL OPERATING SUPPLIES	353,775
512.068	SALARIES	346,876
512.069	OVERHEAD TRANSFERS	451,175
512.077	GENERAL OPERATING SUPPLIES	79,516
512.078	SALARIES	60,957
512.079	OVERHEAD TRANSFERS	2,019
512.087	GENERAL OPERATING SUPPLIES	387,091
512.088	SALARIES	43,449
512.089	OVERHEAD TRANSFERS	67,353
512.097	GENERAL OPERATING SUPPLIES	36,851
512.098	SALARIES	61,852
512.099	OVERHEAD TRANSFERS	1,707
512.107	GENERAL OPERATING SUPPLIES	117,130
512.108	SALARIES	55,765
512.109	OVERHEAD TRANSFER	491,270

ACCT	DESCRIPTION	1998 Year End Balance
512.127	GENERAL OPERATING SUPPLIES	127,225
512.128	SALARIES	124,810
512.129	OVERHEAD TRANSFER	2,054,221
512.137	GENERAL OPERATING SUPPLIES	36,870
512.138	SALARIES	19,147
512.139	OVERHEAD TRANSFER	6,124
512.147	GENERAL OPERATING SUPPLIES	400,778
512.148	SALARIES	15,638
512.149	OVERHEAD TRANSFER	344,021
512.157	GENERAL OPERATING SUPPLIES	762,258
512.158	SALARIES	175,288
512.159	OVERHEAD TRANSFERS	2,114,128
512.167	GENERAL OPERATING SUPPLIES	330,257
512.168	SALARIES	15,560
512.169	OVERHEAD TRANSFER	571,210
512.178	SALARIES	315
512.179	OVERHEAD TRANSFER	198,182
513.017	GENERAL OPERATING SUPPLIES	250,991
513.018	SALARIES	99,937
513.019	OVERHEAD TRANSFER	261,034
513.027	GENERAL OPERATING SUPPLIES	(37,130)
513.028	SALARIES	12,580
513.029	OVERHEAD TRANSFERS	89,407
513.037	GENERAL OPERATING SUPPLIES	40,298
513.038	SALARIES	232,527
513.039	OVERHEAD TRANSFERS	686,435
513.047	GENERAL OPERATING SUPPLIES	29,972
513.048	SALARIES	18,899
513.049	OVERHEAD TRANSFERS	254
513.057	GENERAL OPERATING SUPPLIES	41,201
513.058	SALARIES	61,394
513.059	OVERHEAD TRANSFERS	550,070
513.067	GENERAL OPERATING SUPPLIES	402
513.068	SALARIES	6,088
513.069	OVERHEAD TRANSFERS	8
514.017	GENERAL OPERATING SUPPLIES	338,905
514.018	SALARIES	1,394,572
514.019	OVERHEAD TRANSFERS	1,754,862
514.027	GENERAL OPERATING SUPPLIES	70,239
514.028	SALARIES	64,147
514.029	OVERHEAD TRANSFERS	18,783
514.037	GENERAL OPERATING SUPPLIES	25,283
514.038	SALARIES	14,379
517.039	OVERHEAD TRANSFERS	17,081
514.047	GENERAL OPERATING SUPPLIES	373,039
514.048	SALARIES	2,881
514.049	OVERHEAD TRANSFERS	143,366
517.010	OPER SUPV & ENGINEERING	755,081
518.017	NUCLEAR FUEL	509,506
520.010	STEAM EXPENSES CR3	4,614
521.010	STEAM OTHER SOURCES CR3	1,302
524.010	MISC NUCLEAR POWER EXP CR3	469,031
524.019	OVERHEAD TFR-PROP TAX	128,872
525.010	RENTS CR3	138
528.010	MAINT SUPV & ENG CR3	754,134
529.010	MAINT OF STRUCTURES CR3	107,890
530.010	MAINT REACTOR PLT EQUIP	147,331
531.010	MAINT ELECTRIC PLANT CR3	28,673
532.010	MAINT MISC NUCL PLT CR3	31,622
555.100	INTERRUPTIBLE POWER-NONFUEL	939,573
555.107	INTERRUPTIBLE POWER-FUEL	883,324
555.110	FULL REQUIREMENTS - NON-FUEL	1,567,321
555.117	FULL REQUIREMENTS - FUEL	1,211,776
555.120	PARTIAL REQUIREMENTS - NON-FUEL	89,061,720
555.127	PARTIAL REQUIREMENTS - FUEL	32,307,947
555.160	MARTEL DEL PT PURCHASES	87,329
555.200	INTERCHANGE - NONFUEL	46,291,673
555.207	INTERCHANGE - FUEL	32,448,253

ACCT	DESCRIPTION	1998 Year End Balance
555.280	RESERVES - NON-FUEL	386,257
555.287	RESERVES - FUEL	5,523
555.300	LOAD FOLLOWING - NON-FUEL	49,938
555.307	LOAD FOLLOWING - FUEL	332,909
556.010	OPS & LOAD CONTROL CR3	303
556.017	GENERAL OPERATING SUPPLIES	23,807
556.018	SALARIES	1,112,563
556.019	OVERHEAD TRANSFERS	440,365
557.017	USE CHARGE & PARTICIPATION ALLOCATION	517,590
557.019	INSURANCE CR3	(37,566)
560.018	SALARIES	111,949
560.019	OVERHEAR TRANSFERS	47,793
562.018	UTILITIES & FURNITURE	7,629
565.100	TFUC	86,850
565.200	WHEELING	22,215,355
565.207	WHEELING - FUEL	50,374
566.017	1ST AID SUP & SAFETY EQUIPMENT	81
566.180	SALARIES	41,062
566.019	OVERHEAD TRANSFERS	1,286,390
567.019	RENT - OTHER	1,608
570.017	GENERAL OPERATING SUPPLIES	50,814
570.018	SALARIES	378,057
570.019	OVERHEAD TRANSFERS	396,454
571.017	GENERAL OPERATING SUPPLIES	4,741
571.019	OTHER OUTSIDE SERVICES	104,020
920.018	SALARIES	2,291,840
920.019	OVERHEAD TRANSFERS	1,817,588
920.048	SALARIES	548,356
920.068	SALARIES	3,593,179
920.069	OVERHEAD TRANSFERS	2,288,260
921.017	GENERAL OPERATING SUPPLIES	35,678
921.018	TRAVEL	1,622,395
921.019	OTHER OUTSIDE SERVICES	129,597
921.048	SALARIES	30,042
921.068	TRAVEL	226,408
922.049	PAYROLL TFS'D - DIRECT	(648,011)
923.018	TEMPORARY HELP	189,428
923.019	LEGAL	1,038,229
923.049	TEMPORARY HELP TSF - INDIRECT	(11,241)
923.069	FINANCIAL AND OTHER	573,795
924.049	OVERHEAD TRANSFERS	(387,934)
924.069	OTHER PROPERTY	424,877
925.019	INSURANCE	615,028
925.049	INSURANCE AND OVERHEAD TRANSFERS	(987,890)
925.069	INSURANCE AND OVERHEAD TRANSFERS	414,732
926.018	BENEFITS	8,034,706
926.049	OVERHEAD TRANSFERS	(8,128,853)
930.019	TRAINING	128,931
930.029	OVERHEAD TRANSFER - PROPERTY TAX & PROPERTY INS	210,393
930.049	MISC EXP TSFD - DIRECT	(3,318)
930.068	PROFESSIONAL DEVELOPMENT	245,958
930.069	OTHER OUTSIDE SERVICES	552,801
932.019	OTHER OUTSIDE SERVICES	196,784

POWER REQUIREMENTS DATA BASE

Seminole Electric Cooperative, Inc.

Source: RUS Form 12a, Sales of Electricity, for Year Ended 1998.

Rate Class	Data	Total
1. Sales for Resale - RUS Borrowers	Consumers	10
	kWh Sold	8,945,919,000
	Revenue	$420,529,947
2. Sales for Resale - Special Sales to RUS Borrowers	Consumers	2
	kWh Sold	53,143,000
	Revenue	$1,899,599
3. Sales for Resale - Others	Consumers	27
	kWh Sold	2,786,908,000
	Revenue	$126,202,131
4. Sales to Ultimate Consumers	Consumers	-
	kWh Sold	-
	Revenue	$0
5. Other Sales to Public Authorities	Consumers	-
	kWh Sold	-
	Revenue	$0
6. Other Sales	Consumers	-
	kWh Sold	-
	Revenue	$0
7. TOTAL No. Consumers (1a thru 6a)		39
8. TOTAL kWh Sold (1b thru 6b)		11,785,970,000
9. TOTAL Revenue Received From Sales of Electric Revenue (1c thru 6c)		$548,631,677
10. Total kWh Generated		9,263,609,000
11. Total kWh Purchased		2,842,345,000
12. Cost of Generation		$300,726,664
13. Cost of Purchases		$205,551,542
14. Cost of Purchases and Generation		$506,278,206
15. Interchange - kWh - Net		(21,303)
16. Wheeling - kWh - Net		1,072
17. Total Energy Available - kWh		12,105,933,769
18. Total Energy Sold - kWh		11,785,970,000
19. Energy Furnished Without Charge - kWh		-
20. Energy Used - kWh		-
21. Total Energy Accounted For - kWh		11,785,970,000
22. Energy Losses - kWh		319,963,769
23. Energy Losses - Percentage		2.71%
24. Peak Demand - kW		2,555,063

CLASS DATA VERIFICATION

Seminole Electric Cooperative, Inc.

Compares Form 12a Data to Rate Class Summaries

Form 12a Classifications	Code	Form 12a Data			Summarized Rate Class Data			Variance from Form 12a		
		Consumers	kWh Sold	Revenue	Consumers	kWh Sold	Revenue	Consumers	kWh Sold	Revenue
Sales for Resale - RUS Borrowers	1	10	8,945,919,000	420,529,947	10	11,565,891,000	541,351,605		29.3%	28.7%
Sales for Resale - Special Sales to RUS Borrowers	2	2	53,143,000	1,899,599	-	-	-	-100.0%	-100.0%	-100.0%
Sales for Resale - Others	3	27	2,786,908,000	126,202,131	-	-	-	-100.0%	-100.0%	-100.0%
Sales to Ultimate Consumers	4	-	-	-	-	-	-			
Other Sales to Public Authorities	5	-	-	-	-	-	-			
Other Sales	6	-	-	-	-	-	-			
Total		39	11,785,970,000	548,631,677	10	11,565,891,000	541,351,605	-74.4%	-1.9%	-1.3%

Seminole Electric Cooperative, Inc. Rate Classes & Other Splits	Class Summarized in Form 12a Classification Code	Actual FY 1998			Forecasted FY 2000		
		Consumers	kWh Sold	Revenue	Projected Consumers	Projected kWh Sold	Projected Revenue
Sales for Resale - Member Sales	1	10	11,565,891,000	541,351,605	10	**12,194,143,481**	**553,789,741**
0	-	-	-	-	-	-	-
0	-	-	-	-	-	-	-
0	-	-	-	-	-	-	-
0	-	-	-	-	-	-	-
0	-	-	-	-	-	-	-
0	-	-	-	-	-	-	-
0	-	-	-	-	-	-	-
0	-	-	-	-	-	-	
0	-	-	-	-	-	-	
0	-	-	-	-	-	-	
0	-	-	-	-	-	-	
0	-	-	-	-	-	-	
0	-	-	-	-	-	-	
0	-	-	-	-	-	-	
Total Sales		10	11,565,891,000	541,351,605	10	12,194,143,481	553,789,741

Caclulation of Total Sales for FY 2000	
FY 1998	
Purchased Power	2,842,345,000
Generation	9,263,609,000
Energy Reqmts	12,105,954,000
Total Class Sales	11,565,891,000
Losses	540,063,000
Losses	4.46%
FY 2000	
Purchased Power	3,394,850,000
Generation	9,624,832,000
Energy Reqmts	13,019,682,000
Total Class Sales	12,194,143,481
Assumed Losses	825,538,519
Assumed Losses	6.34%

ASSIGNMENT OF COSTS

Seminole Electric Cooperative, Inc.

Acct #		FY 2000 Budget Totals	KW	KWH	ACC	T-KW	CONS	GENL	Description of Assignment
	POWER PRODUCTION EXPENSES								
500	Operations Supervision And Engineering	2,681,634	2,681,634						KW
501	Fuel Expense	162,184,362		162,184,362					KWH
502	Steam Expenses	7,720,824		7,720,824					KWH
505	Electric Expenses	1,694,210		1,694,210					KWH
506	Misc Steam Power Expenses	10,557,901		10,557,901					KWH
507	Power Plant Rents	28,641,657	13,261,087	15,380,570					KW,KWH
510	Maintenance Supervision and Engineering	5,428,515	5,428,515						KW
511	Maintenance of Structures	349,878	349,878						KW
512	Maintenance of Boiler Plant	14,443,520		14,443,520					KWH
513	Maintenance of Electric Plant	1,105,936		1,105,936					KWH
514	Maintenance of Misc. Steam Plant	5,554,701		5,554,701					KWH
518	Nuclear Fuel Expense	648,000		648,000					KWH
528	Maintenance Supervision and Engineering	2,287,873	2,287,873						KW
	PURCHASED POWER								
555	Purchased Power	216,750,478	118,545,653	97,435,770			769,055		KW,KWH, CONS - BY CONTRACT
556	System Control and Load Dispatch	1,717,774	1,717,774						KW
557	Other Power Supply Expenses	48,461	48,461						KW
	TRANSMISSION OPERATIONS EXPENSES								
560	Operations Supervision And Engineering	177,341				177,341			T-KW
562	Station Expenses	9,604				9,604			T-KW
565	Transmission of Electricity by Others	34,051,675			34,051,675				ACC
566	Miscellaneous Transmission Expenses	1,285,816				1,285,816			T-KW
567	Rents	2,500				2,500			T-KW
	TRANSMISSION MAINTENANCE EXPENSES								
570	Maintenance of Station Equipment	1,195,105				1,195,105			T-KW
571	Maintenance Of Overhead Lines	5,409				5,409			T-KW
	ADMINISTRATIVE AND GENERAL OPERATIONS EXPENSES								
920	Administrative & General Salaries	10,805,074	4,890,317	3,787,480	0	565,680	485,177	1,076,420	Personnel Function
921	Office Supplies And Expense	2,276,213	1,627,634	403,224	0	79,104	51,653	114,598	PAYROLL RATIO
922	Administrative Expenses Transferred - Credit	(1,007,800)	(353,620)	(463,036)	0	(186,093)	(4,405)	(645)	TOTAL UTILITY PLANT RATIO
923	Outside Services Employed	1,666,460						1,666,460	GENL
924	Property Insurance	35,944	12,612	16,515	0	6,637	157	23	TOTAL UTILITY PLANT RATIO
925	Injuries And Damages	39,607	28,321	7,016	0	1,376	899	1,994	PAYROLL RATIO
926	Employee Pensions and Benefits	58,306	41,692	10,329	0	2,026	1,323	2,935	PAYROLL RATIO
930	General Advertising and Miscellaneous General Expenses	1,342,030						1,342,030	GENL
	ADMINISTRATIVE AND GENERAL MAINTENANCE EXPENSES								
932	Maintenance Of General Plant	120,700						120,700	GENL

Acct #		FY 2000 Budget Totals	KW	KWH	ACC	T-KW	CONS	GENL	Description of Assignment
	DEPRECIATION AND AMORTIZATION EXPENSE								
403 1	Steam Production Plant	18,223,995	8,437,710	9,786,285					KW,KWH
403 2	Nuclear Production Plant	1,061,449	381,060	680,389					KW,KWH
403.5	Transmission Plant	3,854,282				3,854,282			T-KW
403.7	General Plant	953,646						953,646	GENL
990.0	Depreciation Transferred	(23,785)	(8,346)	(10,928)	0	(4,392)	(104)	(15)	TOTAL UTILITY PLANT RATIO
404.0	Amortization Leasehold Improvements	1,205,605	558,195	647,410					KW,KWH
405.0	Miscellaneous Depreciation/Amortization	288,624	101,273	132,609	0	53,295	1,262	185	TOTAL UTILITY PLANT RATIO
406.0	Amortization Electric Plant Acquisition	17,256	6,195	11,061					KW,KWH
	OTHER EXPENSES								
408.1	Property Taxes	8,618,067	3,023,933	3,959,594	0	1,591,350	37,673	5,518	TOTAL UTILITY PLANT RATIO
408.2	Payroll Taxes	24,186	17,294	4,284	0	841	549	1,218	PAYROLL RATIO
408.3	Payroll Taxes	1,731,795	1,238,341	306,782	0	60,184	39,299	87,189	PAYROLL RATIO
408.4	Payroll Taxes	15,116	10,809	2,678	0	525	343	761	PAYROLL RATIO
408.7	Taxes, Other	(12,282)						(12,282)	GENL
990.0	Overhead Allocation and Taxes Transferred	(10,212,065)	(3,583,240)	(4,691,960)	0	(1,885,686)	(44,641)	(6,538)	TOTAL UTILITY PLANT RATIO
425	Miscellaneous Depreciation/Amortization	72	25	33	0	13	0	0	TOTAL UTILITY PLANT RATIO
426	Donations	38,120						38,120	GENL
428	Amortization of Debt Discount and Expense	3,780,688	1,326,579	1,737,047	0	698,114	16,527	2,421	TOTAL UTILITY PLANT RATIO
	TOTAL OPERATING EXPENSE	543,444,477	162,077,661	333,052,605	34,051,675	7,513,032	1,354,766	5,394,737	
	ANNUAL INVESTMENT COST:								
Y	**Target Margin Dollar Amount**								
	Required Margins & Patronage Capital	2,334,880	819,270	1,072,767	0	431,142	10,207	1,495	TOTAL UTILITY PLANT RATIO
	Required Margins & Patronage Capital	2,334,880	819,270	1,072,767	0	431,142	10,207	1,495	
	Non-Operating Margins								
419	Non Operating Margins - Interest	(7,010,135)	(2,165,317)	(4,181,016)	(425,280)	(168,738)	(18,693)	(51,090)	COS RATIO - PREL.
411	Gain on Disposition of Clean Air Allowances	(100,000)	(100,000)						KW
421	Non Operating Margins - Other	(493,662)	(152,484)	(294,432)	(29,949)	(11,883)	(1,316)	(3,598)	COS RATIO - PREL.
424	Other Capital Credits and Patronage Dividends	(100,000)						(100,000)	GENL
	Required Operating Margins	(5,368,917)	(1,598,532)	(3,402,682)	(455,229)	250,522	(9,803)	(153,193)	
427	Interest on L-T Debt	30,145,557	10,577,563	13,850,456	0	5,566,460	131,778	19,301	TOTAL UTILITY PLANT RATIO
	Total Interest & Op. Margins	24,776,640	8,979,031	10,447,775	(455,229)	5,816,981	121,975	(133,893)	
	Total Operating Expense	543,444,477	162,077,661	333,052,605	34,051,675	7,513,032	1,354,766	5,394,737	
	Less Other Revenues								
	Interruptable Sales	(5,137,708)		(5,137,708)					KWH
	Non-Member Sales	(8,006,085)		(8,006,085)					KWH
	Martel Sales	(62,806)		(62,806)					KWH
456	Other Electric Revenues	(1,224,777)						(1,224,777)	GENL
	TOTAL COST OF SERVICE	553,789,741	171,056,692	330,293,781	33,596,446	13,330,013	1,476,741	4,036,067	
	Cost-of-Service Ratio	**1.000**	**0.309**	**0.596**	**0.061**	**0.024**	**0.003**	**0.007**	
	Non-Power Supply COS Ratio	**1.000**	**0.000**	**0.000**	**0.000**	**0.707**	**0.078**	**0.214**	
SUMMARY OF COST OF SERVICE									
Power Production		243,299,011	24,008,987	219,290,024	0	0	0	0	
Purchased Power		218,516,713	120,311,888	97,435,770	0	0	769,055	0	
Transmission Operations Expenses		35,526,936	0	0	34,051,675	1,475,261	0	0	
Transmission Maintenance Expenses		1,200,514	0	0	0	1,200,514	0	0	
Administrative And General Operations Expenses		15,215,834	6,246,957	3,761,527	0	468,731	534,804	4,203,816	

ASSIGNMENT OF COSTS

Seminole Electr operative, Inc.

Acct #	FY 2000 Budget Totals	KW	KWH	ACC	T-KW	CONS	GENL	Description of Assignment
Administrative And General Maintenance Expenses	120,700	0	0	0	0	0	120,700	
Depreciation	25,581,072	9,476,087	11,246,826	0	3,903,185	1,158	953,816	
Taxes & Other	3,983,697	2,033,742	1,318,458	0	465,341	49,750	116,406	
Total Interest & Op. Margins	32,480,437	11,396,832	14,923,223	0	5,997,602	141,985	20,796	
Non-operating Margins	(7,703,797)	(2,417,801)	(4,475,449)	(455,229)	(180,620)	(20,010)	(154,688)	
Non-Member Sales	(8,006,085)	0	(8,006,085)	0	0	0	0	
Interruptible Sales	(5,137,708)	0	(5,137,708)	0	0	0	0	
Martel Sales	(62,806)	0	(62,806)	0	0	0	0	
Other Op. Revenue	(1,224,777)	0	0	0	0	0	(1,224,777)	
Cost of Service	553,789,741	171,056,692	330,293,781	33,596,446	13,330,013	1,476,741	4,036,067	
COS Excluding Payroll & Gross Receipts Tax, Req'd Margins, & Int. on LT Debt								
Required Operating Margins	32,280,437	11,296,832	14,923,223	0	5,997,602	141,985	(79,204)	
Total Op Exp	543,444,477	162,077,661	333,052,605	34,051,675	7,513,032	1,354,766	5,394,737	
Cost of Service (excl. nonoperating interest and other income)	561,293,538	173,374,493	334,769,229	34,051,675	13,510,634	1,496,751	4,090,755	
COS Ratio (Prelim.)	**1.000**	**0.309**	**0.596**	**0.061**	**0.024**	**0.003**	**0.007**	
Non-Power Supply COS Ratio (Prelim.)	**1.000**	**0.000**	**0.000**	**0.000**	**0.707**	**0.078**	**0.214**	
RATIOS								
Power Production	1.000	0.099	0.901	0.000	0.000	0.000	0.000	
Purchased Power	1.000	0.551	0.446	0.000	0.000	0.004	0.000	
Transmission	1 000	0.000	0.000	0.927	0.073	0.000	0.000	
Admin. & General	1.000	0.407	0.245	0.000	0.031	0.035	0.282	
Taxes (Payroll & Property)	1.000	0.413	0.412	0.000	0.159	0.008	0.008	
Cost of Service Ratio	1.000	0.309	0.596	0.061	0.024	0.003	0.007	
PAYROLL RATIO								
Operations Supervision And Engineering	2,681,634	2,681,634	0	0	0	0	0	
Maintenance Supervision and Engineering	5,428,515	5,428,515	0	0	0	0	0	
Maintenance Supervision and Engineering	2,287,873	2,287,873	0	0	0	0	0	
Operations Supervision And Engineering	177,341	0	0	0	177,341	0	0	
Administrative & General Salaries	10,805,074	4,890,317	3,787,480	0	565,680	485,177	1,076,420	
Total	21,380,437	15,288,339	3,787,480	0	743,021	485,177	1,076,420	
Payroll Ratio	1.000000	0.715	0.177	0.000	0.035	0.023	0.050	

RATE BASE

Seminole Electric Cooperative, Inc.

	RATE BASE CALCULATION	Total	kW	kWh	ACC	T-KW	T-KWH	CONS	GENL	Description of Assignment
	Total Utility Plant	882,429,372	309,629,437	405,434,518	0	162,942,997	0	3,857,446	564,973	Plant in Service
	Depreciation Reserve:									
108.1	Steam Plant	(281,169,188)	(130,181,334)	(150,987,854)						KW, KWH - 625 MW Capacity
108 2	Nuclear Plant	(8,413,949)	(3,020,608)	(5,393,341)						KW, KWH - CR3
108.5	Transmission Plant	(49,002,883)				(49,002,883)				Direct
108.7	General Plant	(12,791,254)	(4,488,233)	(5,876,976)	0	(2,361,940)	0	(55,916)	(8,190)	Total Utility Plant Ratio
108.9	Cost of Removal - Nuclear	(94,379)	(33,882)	(60,497)						KW, KWH - CR3
111.1	Transportation Lease	(23,444,300)		(23,444,300)						KW, KWH - 625 MW Capacity
111.1	Intangible Plant (HPS-Acuera)	(2,311,850)	(818,008)	(1,069,024)		(424,818)				Prod/Xmsn Plant Ratio
111.1	Leasehold Improvements - U2	(8,650,311)	(4,005,094)	(4,645,217)						KW, KWH - 625 MW Capacity
115.1	Acquisition Adjustment	(429,202)	(154,084)	(275,118)						KW, KWH - CR3
120.5	Nuclear Fuel	(6,504,475)		(6,504,475)						Direct
	Working Capital:									
	Power Production	9,998,589	986,671	9,011,919						Operating Expense
	Purchase Power Expense	8,980,139	4,944,324	4,004,210				31,605		Operating Expense
	Transmission	4,528,042			4,198,152	329,890	0			T-KW
	Administrative & General	1,890,806	770,173	463,750	0	57,789	0	65,935	533,159	Admin. & General Ratio
	Payroll & Property Taxes	1,279,342	914,809	226,632	0	44,460	0	29,032	64,410	Tax Expense Ratio
135	Working Funds	4,289						4,289		Direct
154	Plant Materials and Operating Supplies	17,545,183	6,156,306	8,061,181	0	3,239,766	0	76,697	11,233	Total Utility Plant Ratio
165	Prepayments	12,021,018	4,217,970	5,523,089	0	2,219,714	0	52,549	7,696	Total Utility Plant Ratio
	Deductions:									
235	Consumer Deposits	(3,981)						(3,981)		CONS
	TOTAL RATE BASE	545,861,008	184,918,447	234,468,495	4,198,152	117,044,975	0	4,057,656	1,173,282	
	Rate Base Ratio	1.000	0.339	0.430	0.008	0.214	0.000	0.007	0.002	1.000

Exhibit _____ (DEC-2)
Witness David E. Christianson
Docket # 981827-EC

Comparison of Revenue Collected with Energy, Demand, and Consumer Charges

BMcD Rates vs SECI-7B

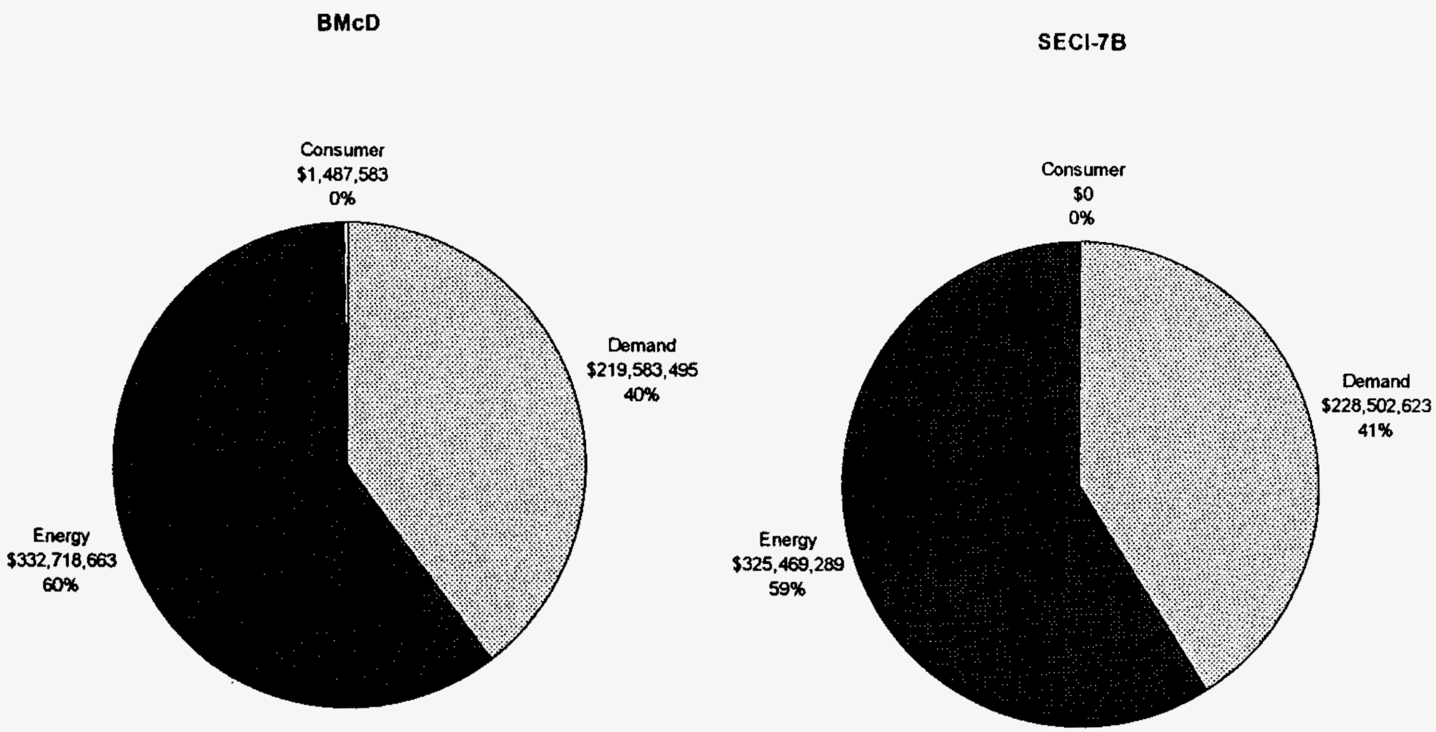
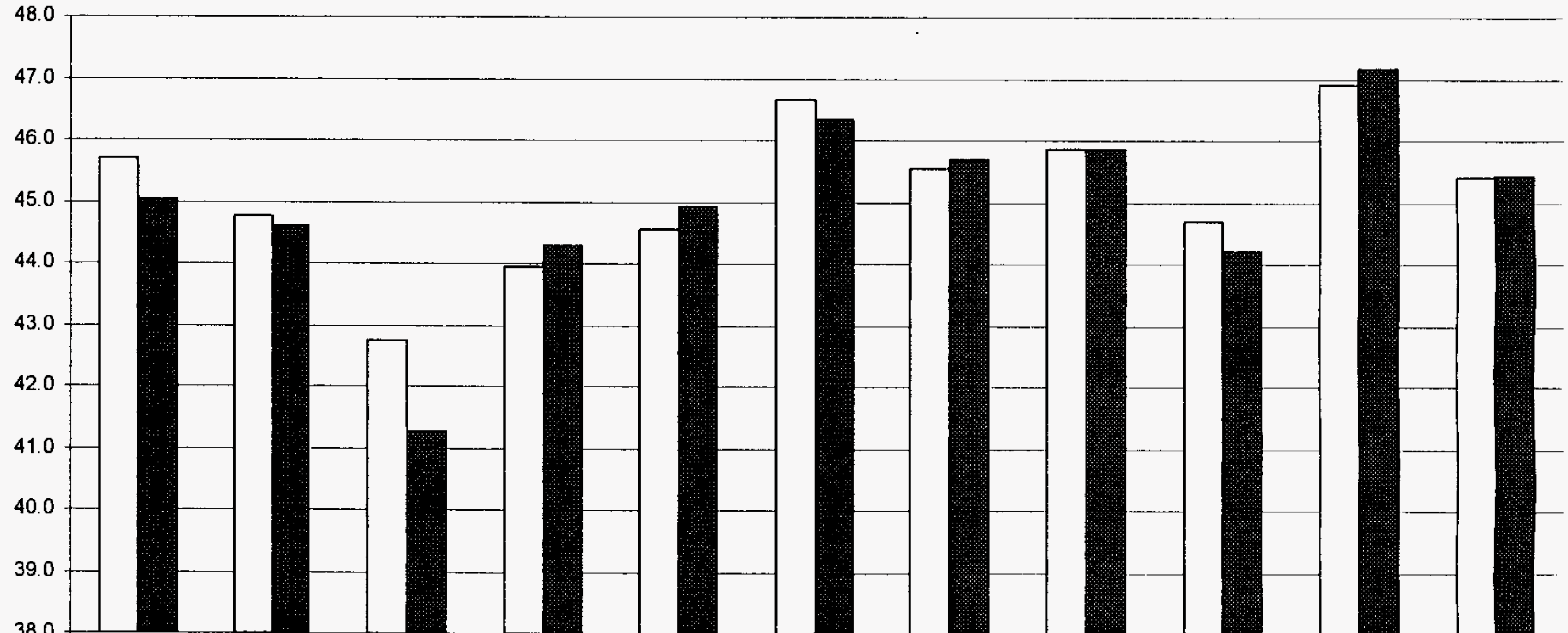


Exhibit _____ (DEC-3)
Witness David E. Christianson
Docket # 981827-EC

Comparison of Expected Average Wholesale Power Cost in 2000
BMcD Rates vs SECI-7b Rates
(mills/kWh)

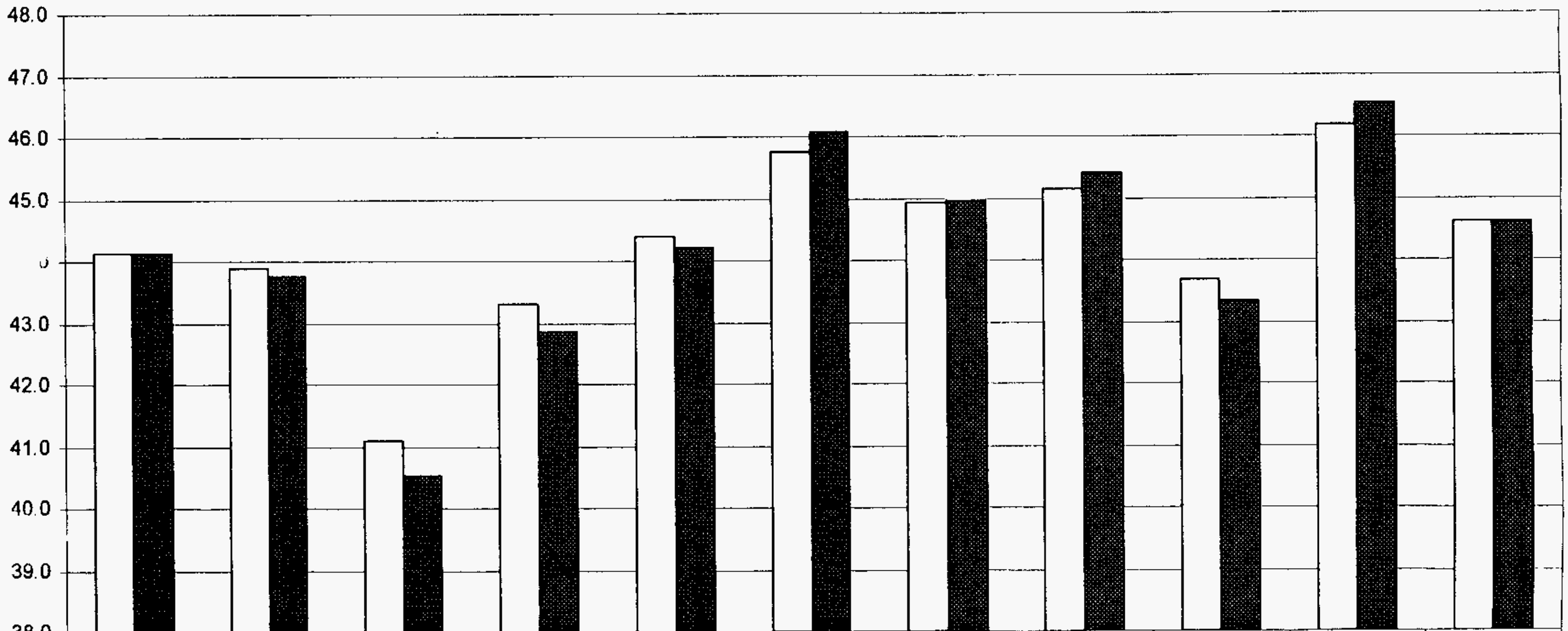


	Central Florida	Clay	Glades	Lee County	Peace River	Sumter	Suwannee	Talquin	Tri-County	Withlacooche	Total System
BMcD	45.7	44.8	42.8	43.9	44.5	46.7	45.6	45.9	44.7	46.9	45.4
SECI-7b	45.0	44.6	41.3	44.3	44.9	46.3	45.7	45.9	44.2	47.2	45.4

BMcD SECI-7b

Exhibit _____ (DEC-4)
Witness David E. Christianson
Docket # 981827-EC

Comparison of Expected Average Wholesale Power Cost in 2001
LCEC Alt 2 Rates vs SECI-7b Rates
(mills/kWh)



	Central Florida	Clay	Glades	Lee County	Peace River	Sumter	Suwannee	Talquin	Tri-County	Withlacooche	Total System
□ SECI-7b	44.1	43.9	41.1	43.3	44.4	45.8	44.9	45.1	43.7	46.2	44.6
■ LCEC	44.1	43.8	40.5	42.9	44.2	46.1	45.0	45.4	43.3	46.5	44.6

□ SECI-7b ■ LCEC