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Florida
Power
CORPORATION

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July 1, 1997

Ms. Blanca S. Bayó, Director
Division of Records and Reporting
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: Docket No. 970001-EI

Dear Ms. Bayó:

Enclosed for filing in the subject docket are an original and ten copies each of the Direct Testimony and Exhibits of Dario B. Zuloaga and Karl H. Wieland on behalf of Florida Power Corporation. 06704-97 06705-97

Please acknowledge your receipt of the above filing on the enclosed copy of this letter and return to the undersigned. Also enclosed is a 3.5 inch diskette containing the above-referenced document in WordPerfect format. Thank you for your assistance in this matter.

Very truly yours,

James A. McGee

JAM/kp
Enclosure
cc: Parties of record

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CAF ______
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CERTIFICATE OF SERVICE
Docket No. 970001

I HEREBY CERTIFY that a true and correct copy of the Direct Testimony and Exhibits of Dario B. Zuloaga and Karl Wieland has been sent by regular U.S. mail to the following individuals this 1st day of July, 1997:

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FLORIDA POWER CORPORATION
DOCKET NO. 970001-EI

Levelized Fuel and Capacity Cost Factors
October 1997 through March 1998

DIRECT TESTIMONY OF
KARL H. WIELAND

Q. Please state your name and business address.

A. My name is Karl H. Wieland. My business address is Post Office Box 14042, St. Petersburg, Florida 33733.

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

A. I am employed by Florida Power Corporation as Director of Business Planning.

Q. Have the duties and responsibilities of your position with the Company remained the same since you last testified in this proceeding?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present for Commission approval the Company's levelized fuel and capacity cost factors for the period of October 1997 through March 1998. My testimony will also address the effect of the Federal Energy Regulatory Commission's (FERC) Orders 888 and 888-A on Schedule C broker sales.

Q. Do you have an exhibit to your testimony?

A. Yes. I have prepared an exhibit attached to my prepared testimony consisting of Parts A through G and the Commission's minimum filing requirements for these proceedings, Schedules E1 through E10 and H1, which contain the Company's levelized fuel cost factors and the supporting data. Parts A through C contain the assumptions which support the Company's cost projections, Part D contains the Company's capacity cost recovery factors and supporting data. Part E contains a calculation of costs the Company proposes to recover during the period for the conversion of one additional combustion turbine to natural gas firing. Part F recomputes the Company's true-up under-recovery balances through September 1997 to exclude replacement power costs and related interest associated with the current extended outage of the Crystal River 3 (CR3) nuclear plant. Part G provides an example of how Florida Power proposes to treat transmission charges associated with broker sales as a result of FERC Order 888.

FUEL COST RECOVERY

Q. **Please describe the levelized fuel cost factors calculated by the Company for the upcoming projection period.**

A. Schedule E1, page 1 of the "E" Schedules in my exhibit, shows the calculation of the Company's basic fuel cost factor of 1.823 ¢/kWh (before line loss adjustment). The basic factor consists of a fuel cost for the projection period of 1.76376 ¢/kWh (adjusted for jurisdictional losses), a GPIF penalty of 0.00172 ¢/kWh, a coal market price true-up credit of 0.0034 ¢/kWh and an estimated prior period true-up charge of 0.06286 ¢/kWh.

Utilizing this basic factor, Schedule E1-D shows the calculation and supporting data for the Company's levelized fuel cost factors for secondary, primary, and transmission metering tariffs. To accomplish this calculation, effective jurisdictional sales at the secondary level are calculated by applying 1% and 2% metering reduction factors to primary and transmission sales (forecasted at meter level). This is consistent with the methodology being used in the development of the capacity cost recovery factors.

Schedule E1-E develops the TOU factors 1.181 on-peak and 0.926 off-peak. The levelized fuel cost factors (by metering voltage) are then multiplied by the TOU factors, which results in the final fuel factors to be applied to customer bills during the projection period. The final fuel cost factor for residential service is 1.827 ¢/kWh.

Q. The Commission recently approved a stipulation between the parties in Docket No. 970261-EI which resolved all disputed issues regarding replacement power cost associated with the current extended outage of CR3. Has the stipulation been incorporated into this filing?

A. Yes. Because of the settlement stipulation, this filing is based on the nuclear unit operating normally both during the projection period (October 97 through March 98) and the reprojection period (June through September 1997). Furthermore, the March 1997 true-up balance and April-May actuals were restated to exclude replacement power costs for the nuclear outage. Part F of my exhibit shows the details of this calculation. The column titled "Variance" in each month contains the nuclear replacement cost on a system basis (line 4) as well as on a jurisdictional basis (line 6) computed using the methodology described below. The reduction in interest expense due to the removal of replacement fuel expenses is on line 8. Line 13 shows the cumulative effect of the monthly adjustments.

Q. How were replacement power costs for the nuclear outage computed?

A. The replacement costs were computed using the production cost program PROMOD. Actual data for load, fuel and purchased power prices, and unit availabilities were used in the calculations. PROMOD computes the difference in system costs with and without the nuclear unit. Crystal River 3 was assumed to operate at originally projected GPIF targets. The procedure used to compute replacement cost is the same as has been used in previous replacement cost determinations before this Commission.

Q. Is recovery of the $32.3 million (retail portion excluding interest) which the Company is entitled to collect after the nuclear unit restarts and operates for 14 days included in this filing?

A. No. Rate adjustments necessary to collect the amount over a 12 month period will be made by way of a separate filing.

Q. What is included in Schedule E1, line 4, "Adjustments to Fuel Cost"?

A. Line 4 shows costs for the conversion of combustion turbine units at Intercession City (units 7-10), Debary (units 7 and 9), Bartow (units 3 and 4), and Suwannee (unit 1) to burn natural gas instead of distillate fuel oil, and an annual payment to the Department of Energy for the decommissioning and decontamination of their enrichment facilities. All conversions except Debary unit 9 have been previously approved for recovery through the fuel clause by the Commission. Florida Power has also converted Debary unit 9 and is asking Commission approval to recover its conversion cost as well. The cost of peaker conversions included in line 4 is $1,782,000, the payment to the DOE is $1,438,000, for a total of $3,220,000.

Q. What is included in Schedule E1, line 6, "Energy Cost of Purchased Power"?

A. Line 6 includes energy costs for the purchase of 50 MWs from Tampa Electric Company and the purchase of 409 MWs under a Unit Power Sales (UPS) agreement with the Southern Company. Capacity costs for these purchases are included in the capacity cost recovery factor. Both of these contracts have been in place and have been approved for cost recovery by the Commission.

Q. What is included in Schedule E1, line 8, "Energy Cost of Economy Purchases (Non-Broker)"?

A. Line 8 includes energy costs for purchases from Seminole Electric Cooperative (SECI) for load following, off-peak hydroelectric purchases from the Southeast Electric Power Agency (SEPA), and miscellaneous economy purchases from within or outside the state which are not made through the Florida Broker System. The SECI contract is an ongoing contract under which the Company purchases energy from SECI at 95% of its avoided fuel cost. Purchases from SEPA are on an as-available basis. There are no capacity payments associated with either of these purchases. Other purchases may have non-fuel charges, but since such purchases are made only if the total cost of the purchase is lower than the Company's cost to generate the energy, it is appropriate to recover the associated non-fuel costs through the fuel adjustment clause rather than the capacity cost recovery factor.

Q. Has the Company included expenses related to the settlement of the Lake Cogen dispute approved on June 24?

A. No. Although the Commission has approved the Lake Cogen Settlement, the Company has elected to exclude the costs and benefits of the settlement until the final order is issued and all parties are in final agreement that the settlement should move forward.

Q. Please explain the entry on Schedule E1, line 17, "Fuel Cost of Stratified Sales."

A. The Company has a wholesale contract with Seminole for the sale of supplemental energy to supply the portion of their load in excess of 689 MW. The fuel costs charged to Seminole for these supplemental sales are calculated on a "stratified" basis, in a manner which recovers the higher cost of intermediate/peaking generation used to provide the energy. The Company also has wholesale contracts with Georgia Power Company, Oglethorpe Power Company, and the city of St. Cloud under which fuel costs are charged in a similar manner. Unlike interchange sales, the fuel costs of wholesale sales are normally included in the total cost of fuel and net power transactions used to calculate the average system cost per kWh for fuel adjustment purposes. However, since the fuel costs of the Stratified sales are not recovered on an average cost basis, an adjustment has been made to remove these costs and the related kWh sales from the fuel adjustment calculation in the same manner that interchange sales are removed from the calculation. This adjustment is necessary to avoid an over-recovery by the Company which would result from the treatment of these fuel costs on an average cost basis in this proceeding, while actually recovering the costs from these customers on a higher, stratified cost basis. The development of this adjustment is shown on Schedule E6.

Q. How was the estimated true-up shown on line 28 of Schedule E1 developed?

A. The true-up calculation implements the proposed settlement of the replacement fuel costs incurred during the extended outage of the Company's nuclear unit. The settlement allows the Company to recover $32.3 million in replacement fuel cost, plus interest, after the nuclear unit has operated successfully for 14 days. In order to calculate a proper true-up amount for the October 1997 through March 1998 period, replacement fuel costs and associated interest costs which had previously been included in fuel under-recovery balances reported in the Company's A-schedules were removed, resulting in a restated May 1997 balance of $(2,223,479). (Refer to Exhibit F for details). This balance was projected to the end of September 1997, including interest estimated at the May ending rate of 0.468% per month assuming that Crystal River unit 3 is operating. The development of the estimated true-up amount for the current April through September 1997 period is shown on Schedule E1B, Sheet 1 and summarized on Schedule E1A. The current period estimated over-recovery of $8,880,912 ($47,121,201 being collected during the current period less $38,240,289 current cycle under-recovery) was combined with the prior period ending balance of $(18,213,749) for a total under-recovery of $9,332,837 at the end of September 1997. This results in an estimated true-up charge on line 28 of Schedule E1 (Basic) of 0.06286 ¢/kWh for application in the October 1997 through March 1998 projection period.

Q. What are the primary reasons for the projected September 1997 under-recovery of $9.3 million?

A. The primary reason for the $9.3 million under-recovery at the end of September is due to the fact that the previous 6 month's under-recovery was amortized over twelve rather the normal six months. Although the portion of the previous under-recovery attributable to the nuclear outage has been excluded, the remaining non-nuclear portion is reflected in this true-up.

Q. How was the market price true-up for Powell Mountain coal purchases calculated?

A. The calculation was performed in accordance with the market pricing methodology approved by the Commission for Powell Mountain coal purchases in Docket No. 860001-EI-G and has been made available for Staff review. The true-up is based on the difference between the previously recovered cost of Powell Mountain coal purchases during 1995, and a calculated cost using the market price index for compliance coal in BOM District 8 for 1996, as adopted in Order No. 22401. The true-up amount of $505,000 also includes interest through May 1997.

Q. Would you give a brief overview of the procedure used in developing the projected fuel cost data from which the Company's basic fuel cost recovery factor was calculated?

A. Yes. The process begins with the fuel price forecast and the system sales forecast. These forecasts are input into PROMOD, along with purchased power information, generating unit operating characteristics, maintenance schedules, and other pertinent data. PROMOD then computes system fuel consumption, replacement fuel costs, and energy purchases and costs. This data is input into a fuel inventory model, which calculates average inventory fuel costs. This information is the basis for the calculation of the Company's levelized fuel cost factors and supporting schedules.

Q. What is the source of the system sales forecast?

A. The system sales forecast is made by the Forecasting section of the Business Planning Department using the most recently available data. The forecast used for this projection period was prepared in June 1996.

Q. Is the methodology used to produce the sales forecast for this projection period the same as previously used by the Company in these proceedings?

A. The methodology employed to produce the forecast for the projection period is the same as used in the Company's most recent filings, and was developed with a hybrid econometric/end-use forecasting model. The forecast assumptions are shown in Part A of my exhibit.

Q. **What is the source of the Company's fuel price forecast?**

A. The fuel price forecast was made by the Fuel and Special Projects Department based on forecast assumptions for residual oil, #2 fuel oil, natural gas, and coal. The assumptions for the projection period are shown in Part B of my exhibit. The forecasted prices for each fuel type are shown in Part C.

Q. **Please explain the basis for requesting recovery of the cost of converting a second combustion turbine unit at Debary to burn natural gas.**

A. In Docket No. 850001-EI-B, Order No. 14546 issued on July, 1985, the Commission addressed charges appropriate for recovery through the fuel clause:

> "Fossil fuel-related costs normally recovered through base rates but which were not recognized or anticipated in the cost levels used to determine current base rates and which, if expended, will result in fuel savings to customers. Recovery of such costs should be made on a case by case basis after Commission approval."

Since August of 1995, the Company has converted Intercession City units 7-10, Debary units 7 and 9, Bartow units 2 and 4, and

Suwannee unit 1 to burn natural gas. The Commission previously authorized the Company to recover the conversion cost, including a return on investment, over a five-year period for all units except Debary 9. The Company is asking the Commission for the same treatment for the second unit at Debary (unit 9). The estimated conversion cost for the four units at Bartow, Debary, and Suwannee was $7.5 million. The actual cost of conversion was $7.18 million. The additional cost to convert Debary unit 9 is $734,000 for a net incremental cost of $414,000. This conversion cost was not part of the cost of the Debary units when they were included in rate base as part of the 1993 test year.

Q. How is Florida Power proposing to recover the conversion cost?

A. The Company proposes to amortize the $734,000 conversion cost for Debary unit 9 over a five year period beginning with the plant in-service date of May, 1997. The same amortization period was approved for unit 7 and the units at Bartow and Suwannee. The projected cost during the October 1997 through March 1998 period is $113,791 which consists of an amortization charge of $73,398 and a return (including income taxes) of $40,393 based on the Company's current cost of capital of 8.37%. The fuel savings for the same period are expected to be $209,000 resulting in a net benefit to customers of $95,209. During the five year amortization period, the conversion produces fuel savings with a present value of $2.1 million which results in a net benefit to customers of $1.4 million. The above fuel savings were calculated assuming normal operation of Crystal River unit 3. These savings will grow after the amortization period if gas continues to be available.

A monthly schedule of amortization expenses and projected fuel savings is attached as Part E of my testimony.

Q. Why was Debary unit 9 not included in the original request for unit 7?

A. The company took a very conservative approach in its original assessment of gas availability for the Debary site. The Company has since become more confident of fuel availability which is critical to achieving the fuel savings.

Q. Why is the Company proposing a five-year amortization period rather than expensing the conversion cost or depreciating it over the life of the units?

A. The Company chose five years in order to align recovery of cost with anticipated benefits. The Company is relying on the availability of interruptible gas transportation for the delivery of gas to the site because firm (take or pay) contracts are not economical for a low capacity factor peaking site. Discussions with Florida Gas Transmission (FGT) and a private consultant's report indicate that they expect interruptible gas to be available in sufficient quantity to power the converted units for the next five years. The Company hopes that some gas will be available beyond that time which will yield additional savings, but we believe it more appropriate to recover costs during the time when the majority of benefits are expected to occur. Amortizing the conversion over the life of the units could burden future customers with costs that do not have corresponding benefits. Achieved fuel savings will be presented in the semi-annual true-up filings until the units are fully amortized.

Q. Have the conversions been completed?

A. Yes, the Company has completed conversion of all nine units. All are in operation.

Q. What is the Company proposing to do if expected fuel savings are not achieved?

A. The Company is willing to assume the risk for achieving fuel savings. If fuel savings during any annual period are less than the amortization and return costs, we will limit cost recovery to fuel savings and defer recovery of the difference to future periods. In no case will the Company collect an amount greater than the fuel savings, making this a no-lose proposition for customers.

CAPACITY COST RECOVERY

Q. How was the Capacity Cost Recovery factor developed?

A. The calculation of the capacity cost recovery factor (CCRF) is shown in Part D of my exhibit. The factor allocates capacity costs to rate classes in the same manner that they would be allocated if they were recovered in base rates. A brief explanation of the schedules in the exhibit follows.

Sheet 1: Projected Capacity Payments. This schedule contains system capacity payments for Southern Company UPS, TECO and QF purchases. The retail portion of the capacity payments are calculated using separation factors consistent with the Company's most recent calendar year jurisdictional separation study as used to support the Company's surveillance reports. The estimated jurisdictional recoverable capacity payments for the October 1997 through March 1998 period are $143,180,134.

Sheet 2: Estimated/Actual True-Up. This schedule presents the actual ending true-up balance after two months of the current period and re-forecasts the over/(under) recovery balances for the next four months to obtain an ending balance for the current period. This estimated/actual balance of $(8,361,941) is then carried forward to Sheet 1, to be collected during the October 1997 through March 1998 period.

Sheet 3: Development of Jurisdictional Loss Multipliers: The same delivery efficiencies and loss multipliers as presented on Schedule E1-F.

<u>Sheet 4: Calculation of 12 CP and Annual Average Demand.</u> The calculation of average 12 CF and annual average demand is based on load research data from April 1995 through March 1996 and the delivery efficiencies on Sheet 3.

<u>Sheet 5: Calculation of Capacity Cost Recovery Factors.</u> The total demand allocators in column (7) are computed by adding 12/13 of the 12 CP demand allocators to 1/13 of the annual average demand allocators. The CCRF for each secondary delivery rate class in cents per kWh is the product of total jurisdictional capacity costs (including revenue taxes) from Sheet 1, times the class demand allocation factor, divided by projected effective sales at the secondary level. The CCRF for primary and transmission rate classes reflect the application of metering reduction factors of 1% and 2% from the secondary CCRF.

Q. Please discuss the increase in jurisdictional capacity payments compared to the prior six-month period.

A. The increase in capacity payments from $137.6 million in the April through September 1997 period to $143.2 million for the October 1997 through March 1998 period is primarily due to the escalation provisions in the contracts which take effect in January of each year, and to the addition of expenses related to the Pasco Cogen settlement which was approved by the Commission on April 1, 1997.

GENERIC ISSUE

Q. **What impact, if any, do FERC Orders 888 and 888-A have on Florida Power's charges for economy, Schedule C, broker sales?**

A. For comparability reasons, these orders require recognition that Florida Power utilizes its transmission system when making off-system sales. To accomplish this, FERC established requirements in Order 888 related to two categories of wholesale power sales agreements.

The first category relates to any new wholesale power sales agreement executed after July 9, 1996. The utility providing the sale must have unbundled charges for generation and transmission service, and furthermore, if the utility is the transmission provider, the transmission service must be treated as if taken under the utility's open access transmission tariff.

The second category relates to economy sales agreements executed prior to July 9th, 1996. These agreements were required to be modified by December 31, 1996, to unbundle charges into component parts of generation and transmission. This has been interpreted by Florida Power to disassemble the existing charge into component parts—one represents the rate being charged for transmission under its open access tariff and the other being the generation charge obtained by difference.

Q. **What is the impact of FERC Order 888 to a purchaser of economy power from Florida Power?**

A. For the category of new agreements executed after July 9, 1996, the imposition of a separate transmission charge under the Company's open access tariff in addition to the generation transaction price would, of course, have the impact of increasing the cost of economy power to the purchaser.

For the category of existing economy sales agreements whose charges have simply been unbundled into two components, the purchaser would not realize any change in its purchase cost from Florida Power.

Q. Has the accounting of the Company's revenues from economy power sales changed as a result of Order 888?

A. Yes, there is a change. Prior to Order 888, revenues related to economy sales were recorded in Account 447, Sales for Resale. As a result of Order 888, separate subaccounts of Account 447 have been established to record the generation and transmission components of the sales.

Q. How should the revenues the Company realizes from economy sales be treated in establishing rates for its retail customers?

A. Since the retail customers are assigned in ratemaking the jurisdictional portion of the costs of facilities utilized by the Company in rendering economy sales, the retail customers should be credited with their jurisdictional portion of revenues collected from such sales. Order 888's unbundling requirement and revenue accounting requirement serves to recognize that the revenues from economy sales have a functional service relationship, i.e. generation service and transmission service. For Florida Power, jurisdictional responsibilities of these functions are different. Jurisdictional responsibility for retail customers is approximately 95% for generation-related and 75% for transmission-related.

Once the appropriate jurisdictional separation of the revenue components is accomplished, the credits to retail customers can be provided through (i) a current billing adjustment (ii) or recognized when base rates are established or (iii) a combination of these two.

The Company suggests that for the category of existing economy sales, the appropriate jurisdictional portions of both the generation and transmission components of economy sales be treated as a credit to the retail customers' fuel charge. For the category of new economy agreements entered into after July 9, 1996, the Company suggests the jurisdictional portion of generation-related revenues be treated as a credit to the fuel charge and the jurisdictional portion of transmission revenues be treated as a revenue credit when base rates are established.

The above proposal results in similar ratemaking treatment as afforded retail customers before FERC's unbundling requirement. It varies only by the recognition that the transmission component of existing economy sales revenues be treated as a credit on a more proper iurisdictional basis of transmission-related responsibility.

Q. Please provide an example that shows the effect of Order 888 on the jurisdictional separation of economy sales.

A. Part G of my exhibit contains an example showing the jurisdictional treatment of an economy sale. The example is divided into three cases; Before Order 888, Existing Agreements Modified by Order 888, and New Unbundled Agreements. The left-most column shows the jurisdictional treatment prior to January 1, 1997. The middle column shows the treatment of existing economy sales agreements, as modified, in an unbundled tariff that is currently pending before the FERC. The right-most column shows the treatment of any new agreements executed after July 9, 1996.

For the purposes of the example, Florida Power is the seller and has an incremental cost of $20. The buyer has an incremental cost of $30. The savings are split, so the transaction price is $25 and the seller's margin on the sale is $5. The cost of transmission is $3.

Before Order 888, the entire $5 gain is credited to the fuel clause. Retail customers realize 95% of this amount ($4.75) and wholesale customers realize 5% ($0.25). The retail amount is allocated to customers and shareholders on an 80/20 basis.

The middle column shows how Order 888's requirement to unbundle existing economy sales tariffs changes the way revenues from these sales are allocated. The net revenue ($5) from the sale is divided into transmission revenue ($3) and generation margin ($2). The transmission revenue is allocated jurisdictionally, so $2.25 (75%) is credited to retail customers and $0.75 (25%) is credited to the wholesale customers. The margin on energy sales is allocated jurisdictionally as well. The retail customers are credited $1.90 (95%) and the wholesale customers are credited $0.10 (5%). Florida Power has not changed its policy regarding crediting the full jurisdictional retail portion of the sale to the fuel clause. In the example, this is $4.15 ($2.25 transmission + $1.90 margin). For wholesale customers, $0.10 is credited to the fuel clause and $0.75, the transmission portion, is credited to base rates.

In the right-most column, transmission is unbundled from the transaction and thus $3.00 is charged separately. The margin on the energy sale is still $5.00. The $5.00 margin and the $3.00 transmission revenue are jurisdictionally separated between the wholesale and retail customers. The margin portion is then credited to the fuel clause and the transmission portion is credited to the base rates of each, respectively.

Q. Does the Company's suggested treatment change the basis for the existing 80%/20% sharing of any gain realized by Florida Power in making an economy sale?

A. No, it doesn't. The 80/20 split still applies to the jurisdictional portion of all revenues credited to the fuel clause from economy sales exceeding the jurisdictional fuel cost incurred in making the sale.

Q. Does this conclude your testimony?

A. Yes.

SALES FORECAST ASSUMPTIONS

1. This five-year forecast of customers, sales and peak demand utilizes the short-term load forecasting methodology developed for budgeting and financial planning purposes. This forecast was prepared in June 1996.

2. Normal weather conditions are assumed. Normal weather is based on a ten-year average of service area weighted billing month degree days in order to project Kilowatt-hour sales. A ten-year average of service area weighted temperatures at time of system peak is used to forecast Megawatt peak demand.

3. The population projections produced by the Bureau of Economic and Business Research (BEBR) at the University of Florida provide the basis for development of the customer forecast. This forecast incorporates "Population Studies", Bulletin No. 114 (February 1996) as well as THE FLORIDA OUTLOOK, First Quarter 1996.

4. FPC's most energy intensive customers, its phosphate mining customers, have continued to expand operations inside the service area. Improved market conditions for phosphate rock, both at home and abroad, have firmed market prices and allowed for expansion of operations at new sites. Recent new mine operations in South Ft. Meade and in Ft. Green are boosting energy consumption by this

industry to 15-year highs. Industry consolidation in the past few years assures a greater supply and demand balance in the years ahead. The forecast calls for energy usage to remain at these high levels throughout the forecast horizon.

5. Florida Power Corporation (FPC) supplies load and energy service to wholesale customers on an "full", "partial" and "supplemental" requirements basis. Full requirements customers' demand and energy is assumed to grow at a rate that approximates their historical trend. Partial requirements customers' load is assumed to reflect the current contractual obligations received by FPC as of May 31, 1996. The forecast of energy and demand to the partial requirements customers reflect the nature of the stratified load they have contracted for, plus their ability to receive dispatched energy from the Florida broker system any time it is more economical to do so. FPC's arrangement with Seminole Electric Cooperative, Inc. (SECI) is to serve "supplemental" service over and above 703 MW in 1997 and 1998. SECI's projection of their system's supplemental demand and energy requirements has been incorporated into this forecast.

FPC has bulk power agreements with SECI, Georgia Power Corporation, and Oglethorpe Power Corporation. The Georgia Power contract is to supply 300 MW of summer peak load capacity in 1997. The Oglethorpe Power contract, also a summer sale, is to supply 50

MW in 1997.

6. This forecast includes cost effective amounts of demand and energy reductions from FPC'S dispatchable and nondispatchable DSM programs approved by the Florida Public Service Commission.

7. The expected energy and demand impacts of self-service cogeneration are subtracted from the forecast. The forecast assumes that FPC will supply the supplemental load of self-service cogeneration customers. While FPC offers "standby" service to all cogeneration customers, the forecast does not assume an unplanned need for standby power.

8. The economic outlook for this 5-year forecast calls for continued, moderate economic growth throughout the forecast horizon. No "shocks" to any supply or demand conditions in the national economy are expected and thus no economic recession is incorporated in this forecast. However, growth will be lower than that experienced in 1994 and 1995, reflecting an aging business cycle. Federal government efforts to balance the federal budget will place downward pressure on interest rates as we move through the forecast period. A consolidating Federal government will lighten demand for credit in the marketplace and be less of a consumer in the national economy.

Personal income growth is expected to continue growing but not at the pace experienced in recent years. As interest rates fall, so will the return on interest-bearing accounts and, correspondingly, income levels of Florida retirees. Employment growth will moderate from the strong pace experienced over the past two years resulting in reduced growth in total wages. Slower growth in hourly earnings as well as transfer payments is also seen as holding down income growth in the years ahead. Export-related job growth is also expected to fair well in the year ahead. The weak dollar and globalization of the world economy will encourage American exports as well as attract higher numbers of foreign tourists to Florida.

Average use per residential customer will continue to grow as electricity prices are projected to decline in real dollar terms. Also contributing to this trend are homebuilders' surveys reporting increased median square footage of new homes and new apartments constructed. New housing preferences have continued to demand larger living quarters than the current housing stock. Increasing electric appliance saturation rates also serves to boost average electric use per customer.

FUEL PRICE FORECAST ASSUMPTIONS

A. Residual Oil and Light Oil

The oil price forecast is based on expectations of normal weather and no radical changes in world energy markets (OPEC actions, governmental rule changes, etc.). It does anticipate a gradual return of crude oil exports from Iraq. Prices are based on expected contract structures, specifications, and spot market purchases for 1997 and 1998.

FPC Residual Fuel Oil (#6) and Distillate Fuel Oil (#2) prices were derived from PIRA forecasts as well as current market information.

Transportation to the Tampa Bay area plus applicable environment taxes were added to the above prices (an adjustment was later made to transportation costs for individual plant locations when purchased from locations other than Tampa Bay).

B. Coal

Coal price projections are provided by Electric Fuels Corporation and represent an estimate of EFC s price to Florida Power for coal delivered to the plant sites in accordance with the delivery schedules projected. The forecast is consistent with the coal supply and transportation agreements which EFC has or expects to have in place during 1997 and 1998 and estimated spot purchase volumes and prices for the period. It assumes environmental restrictions on coal quality remain in effect as per current permits: 2.1 lbs. per million BTU sulfur dioxide limit for Crystal River Units 1 and 2, and 1.2 lbs. per million BTU sulfur dioxide limit for Crystal River Units 4 and 5.

C. Natural Gas

The natural gas price forecast is based on the expectation of normal weather, no material changes in energy markets, government rule changes, etc. Prices are based on expected contract structures and spot market purchases for 1997 and 1998. Gas supply prices were derived from PIRA, NYMEX and current spot market conditions.

Transportation costs for Florida Gas Transmission pipeline firm transportation service is based on expected tariff rates. Interruptible transportation rates and availability are based on expected tariff rates and market conditions.

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FUEL PRICE FORECAST

#6 Fuel Oil

	1.0%		1.5%		2.5%	
Month	$/barrel	$/MMBtu's[1]	$/barrel	$/MMBtu's[1]	$/barrel	$/MMBtu[1]
May 1997	16.00	2.50	15.35	2.40	14.70	2.30
June 1997	16.00	2.50	15.35	2.40	14.70	2.30
July 1997	16.00	2.50	15.35	2.40	14.70	2.30
Aug. 1997	16.00	2.50	15.35	2.40	14.70	2.30
Sept. 1997	16.00	2.50	15.35	2.40	14.70	2.30
Oct. 1997	17.25	2.70	16.65	2.60	16.00	2.50
Nov. 1997	17.90	2.80	17.60	2.75	16.95	2.65
Dec. 1997	19.20	3.00	18.90	2.95	18.55	2.90
Jan. 1998	19.20	3.00	18.90	2.95	18.55	2.90
Feb. 1998	17.90	2.80	17.60	2.75	16.95	2.65
Mar. 1998	17.25	2.70	16.65	2.60	16.00	2.50

(1) 6.4 million BTU/barrel

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FUEL PRICE FORECAST

#2 Fuel Oil

Month	$/barrel	¢/gallon	$/MMBtu's[1]
May 1997	25.50	60.7	4.40
June 1997	25.50	60.7	4.40
July 1997	25.50	60.7	4.40
Aug. 1997	25.50	60.7	4.40
Sept. 1997	25.50	60.7	4.40
Oct. 1997	26.70	63.6	4.60
Nov. 1997	27.85	66.3	4.80
Dec. 1997	29.00	69.0	5.00
Jan. 1998	29.00	69.0	5.00
Feb. 1998	27.85	66.3	4.80
Mar. 1998	26.70	63.6	4.60

(1) 5.8 million BTU/barrel and 42 gallons per barrel

FUEL PRICE FORECAST

Coal

	Crystal River 1 & 2			Crystal River 4 & 5		
Month	BTU/lb.	$/ton	$/MMBtu	BTU/lb.	$/ton	$/MMBtu
May 1997	12,571	42.99	1.710	12,537	51.15	2.040
June 1997	12,567	42.71	1.699	12,534	51.09	2.038
July 1997	12,571	42.85	1.704	12,537	51.07	2.037
Aug. 1997	12,567	42.67	1.698	12,541	50.93	2.031
Sept. 1997	12,550	42.69	1.701	12,534	51.12	2.039
Oct. 1997	12,589	42.96	1.706	12,541	51.10	2.037
Nov. 1997	12,550	42.60	1.697	12538	50.02	2.019
Dec. 1997	12,587	43.04	1.710	12,547	50.84	2.026
Jan. 1998	12,611	43.02	1.706	12,500	50.61	2.024
Feb. 1998	12,611	43.02	1.706	12,500	50.61	2.024
Mar. 1998	12,611	43.02	1.706	12,500	50.61	2.024

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FUEL PRICE FORECAST

Natural Gas Supply

	INTO FLORIDA GAS TRANSMISSION [1]
Month	$/MMBtu
May 1997	2.25
June 1997	2.25
July 1997	2.25
Aug. 1997	2.25
Sept. 1997	2.25
Oct. 1997	2.30
Nov. 1997	2.30
Dec. 1997	2.50
Jan. 1998	2.50
Feb. 1998	2.30
Mar. 1998	2.15

[1] Transport cost not included

FLORIDA POWER CORPORATION
CAPACITY COST RECOVERY CLAUSE
PROJECTED CAPACITY PAYMENTS
For the Period of October 1997 through March 1998

Florida Power Corporation
Docket 970001-EI
Witness: K. H. Wieland
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	Oct-97	Nov-97	Dec-97	Jan-98	Feb-98	Mar-98	Total
Base Production Level Capacity Charges:							
1 Bay County Qualifying Facility	152,790	152,790	152,790	162,360	162,360	162,360	945,450
2 Eco Peat Qualifying Facility	903,762	903,762	903,762	949,402	949,402	949,402	5,559,492
3 General Peat Qualifying Facility	3,112,824	3,112,824	3,112,824	3,310,164	3,310,164	3,310,164	19,268,964
4 Auburndale LFC Qualifying Facility	491,930	491,930	491,930	511,480	511,480	511,480	3,010,230
5 Dade County Qualifying Facility	632,960	632,960	632,960	664,780	664,780	664,780	3,893,220
6 Lake County Qualifying Facility	289,043	289,043	289,043	307,403	307,403	307,403	1,789,338
7 Pasco County Qualifying Facility	521,410	521,410	521,410	554,530	554,530	554,530	3,227,820
8 Pinellas County 1&2 Qualifying Facility	1,241,183	1,241,183	1,241,183	1,320,023	1,320,023	1,320,023	7,683,618
9 El Dorado Qualifying Facility	1,630,105	1,630,105	1,630,105	1,712,053	1,712,053	1,712,053	10,026,474
10 Lake Cogen Qualifying Facility	1,755,759	1,755,759	1,755,759	1,827,325	1,827,325	1,827,325	10,749,252
11 Orange Cogen Qualifying Facility	1,479,146	1,479,146	1,479,146	1,552,277	1,552,277	1,552,277	9,094,269
12 Orlando Cogen Qualifying Facility	1,299,753	1,299,753	1,299,753	1,365,094	1,365,094	1,365,094	7,994,541
13 Pasco Cogen Qualifying Facility	2,732,097	2,732,097	2,732,097	2,803,012	2,803,012	2,803,012	16,605,327
14 Ridge Generating Station Qualifying Facility	800,946	800,946	800,946	800,946	800,946	800,946	4,805,676
15 Timber Energy 1 Qualifying Facility	292,701	292,701	292,701	308,530	308,530	308,530	1,803,693
16 Timber Energy 2 Qualifying Facility	108,840	108,840	108,840	115,740	115,740	115,740	673,740
17 Mulberry Energy Qualifying Facility	1,887,632	1,887,632	1,887,632	1,983,817	1,983,817	1,983,817	11,614,347
18 Royster Phosphates Qualifying Facility	675,964	675,964	675,964	710,101	710,101	710,101	4,158,195
19 Seminole Fertilizer (Cargill) Qualifying Facility	337,500	337,500	337,500	354,900	354,900	354,900	2,077,200
20 Panda Kathleen Qualifying Facility	0	0	0	0	0	0	0
21 US Agrichem Qualifying Facility	29,529	29,529	29,529	31,008	31,008	31,008	181,611
22 Tiger Bay (Eco Peat Lease Credit)	(66,667)	(66,667)	(66,667)	(66,667)	(66,666)	(66,666)	(400,000)
23 Subtotal - Base Level Capacity Charges	20,309,207	20,309,207	20,309,207	21,278,278	21,278,279	21,278,279	124,762,457
24 Base Production Jurisdictional Responsibility	95.389%	95.389%	95.389%	95.389%	95.389%	95.389%	95.389%
25 Base Level Jurisdictional Capacity Charges	19,372,749	19,372,749	19,372,749	20,297,137	20,297,138	20,297,138	119,009,660
Intermediate Production Level Capacity Charges:							
26 TECO Power Purchase	471,367	471,367	471,367	471,367	471,367	471,367	2,828,202
27 UPS Purchase (409 MW)	4,708,664	4,708,664	4,708,664	4,708,664	4,708,664	4,708,664	28,251,984
28 Capacity Sales	0	0	0	0	0	0	0
29 Subtotal - Intermediate Level Capacity Charges	5,180,031	5,180,031	5,180,031	5,180,031	5,180,031	5,180,031	31,080,186
30 Intermediate Production Jurisdictional Responsibility	84.007%	84.007%	84.007%	84.007%	84.007%	84.007%	84.007%
31 Intermediate Level Jurisdictional Capacity Charges	4,351,589	4,351,589	4,351,589	4,351,589	4,351,589	4,351,589	26,109,532
32 Sebring Base Rate Credits	(343,383)	(290,628)	(307,298)	(358,157)	(334,166)	(305,426)	(1,939,058)
33 Jurisdictional Capacity Payments (Lines 25+31+32)	23,380,955	23,433,710	23,417,040	24,290,568	24,314,560	24,343,300	143,180,134
34 Estimated/Actual True-Up Provision for the Period April through September 1997							8,361,941
35 Total (Sum of lines 33 & 34)							151,542,075
36 Revenue Tax Multiplier							1.00083
37 TOTAL RECOVERABLE CAPACITY PAYMENTS							151,667,854

FLORIDA POWER CORPORATION
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED / ACTUAL TRUE-UP
For the Period of April through September 1997

Florida Power Corporation
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		Actual Apr-97	Actual May-97	Estimated Jun-97	Estimated Jul-97	Estimated Aug-97	Estimated Sep-97	Total	Original Estimate	Variance
	Base Production Level Capacity Charges:									
1	Bay County Qualifying Facility	152,790	152,790	152,790	152,790	152,790	152,790	916,740	916,740	0
2	Eco Peat Qualifying Facility	903,762	903,762	903,762	903,762	903,762	903,762	5,422,572	5,422,572	0
3	General Peat Qualifying Facility	3,112,824	3,112,824	3,112,824	3,112,824	3,112,824	3,112,824	18,676,944	18,676,944	0
4	Auburndale LFC Qualifying Facility	491,930	491,930	491,930	491,930	491,930	491,930	2,951,580	2,951,580	0
5	Dade County Qualifying Facility	585,764	579,074	579,074	579,074	579,074	579,074	3,481,134	3,797,760	(316,626)
6	Lake County Qualifying Facility	578,085	289,043	289,043	289,043	289,043	289,043	2,023,300	1,734,258	289,042
7	Pasco County Qualifying Facility	521,410	521,410	521,410	521,410	521,410	521,410	3,128,460	3,128,460	0
8	Pinellas County 1&2 Qualifying Facility	1,241,183	1,241,183	1,241,183	1,241,183	1,241,183	1,241,183	7,447,098	7,447,098	0
9	El Dorado Qualifying Facility	1,630,105	1,630,105	1,630,105	1,630,105	1,630,105	1,630,105	9,780,630	9,780,630	0
10	Lake Cogen Qualifying Facility	1,755,759	1,755,759	1,755,759	1,755,759	1,755,759	1,755,759	10,534,554	13,075,158	(2,540,604)
11	Orange Cogen Qualifying Facility	1,479,146	1,479,146	1,479,146	1,479,146	1,479,146	1,479,146	8,874,876	8,874,876	0
12	Orlando Cogen Qualifying Facility	1,299,753	1,299,753	1,299,753	1,299,753	1,299,753	1,299,753	7,798,518	7,798,518	0
13	Pasco Cogen Qualifying Facility	2,732,097	2,732,097	2,732,097	2,732,097	2,732,097	2,732,097	16,392,582	12,956,292	3,436,290
14	Ridge Generating Station Qualifying Facility	800,946	800,946	800,946	800,946	800,946	800,946	4,805,676	4,805,676	0
15	Timber Energy 1 Qualifying Facility	292,701	308,530	292,701	292,701	292,701	292,701	1,772,035	1,756,206	15,829
16	Timber Energy 2 Qualifying Facility	108,840	108,840	108,840	108,840	108,840	108,840	653,040	653,040	0
17	Mulberry Energy Qualifying Facility	1,887,632	1,887,632	1,887,632	1,887,632	1,887,632	1,887,632	11,325,792	11,325,792	0
18	Royster Phosphates Qualifying Facility	675,964	675,964	675,964	675,964	675,964	675,964	4,055,784	4,055,784	0
19	Seminole Fertilizer (Cargill) Qualifying Facility	337,500	337,500	337,500	337,500	337,500	337,500	2,025,000	2,025,000	0
20	Panda Kathleen Qualifying Facility	0	0	0	0	0	0	0	0	0
21	US Agrichem Qualifying Facility	29,529	29,529	29,529	29,529	29,529	29,529	177,174	177,174	0
22	Tiger Bay (Eco Peat Lease Credit)	(402,667)	(66,667)	(66,667)	(66,667)	(66,667)	(66,667)	(736,002)	(399,996)	(336,006)
23	Subtotal - Base Level Capacity Charges	20,215,053	20,271,150	20,255,321	20,255,321	20,255,321	20,255,321	121,507,487	120,959,562	547,925
24	Base Production Jurisdictional Responsibility	95.389%	95.389%	95.389%	95.389%	95.389%	95.389%	95.389%	94.711%	-n/a-
25	Base Level Jurisdictional Capacity Charges	19,282,937	19,336,447	19,321,348	19,321,348	19,321,348	19,321,348	115,904,777	114,562,008	1,342,769
	Intermediate Production Level Capacity Charges:									
26	TECO Power Purchase	471,367	471,367	471,367	471,367	471,367	471,367	2,828,202	2,828,202	0
27	UPS Purchase (409 MW)	4,437,089	4,680,096	4,708,664	4,708,664	4,708,664	4,708,664	27,951,841	28,251,984	(300,143)
28	Capacity Sales	(2,280)	(2,561)	(2,561)	(2,561)	(2,561)	(2,561)	(15,085)	0	(15,085)
29	Subtotal - Intermediate Level Capacity Charges	4,906,176	5,148,902	5,177,470	5,177,470	5,177,470	5,177,470	30,764,958	31,080,186	(315,228)
30	Intermediate Production Jurisdictional Responsibility	84.007%	84.007%	84.007%	84.007%	84.007%	84.007%	84.007%	80.851%	-n/a-
31	Intermediate Level Jurisdictional Capacity Charges	4,121,531	4,325,438	4,349,437	4,349,437	4,349,437	4,349,437	25,844,718	25,128,642	716,076
32	Sebring Base Rate Credits	(301,494)	(271,519)	(345,245)	(369,038)	(372,579)	(396,929)	(2,056,804)	(2,078,566)	21,762
33	Jurisdictional Capacity Payments (Lines 25+31+32)	23,102,974	23,390,366	23,325,540	23,301,747	23,298,206	23,273,856	139,692,691	137,612,084	2,080,607
34	Capacity Cost Recovery Revenues	17,880,856	18,004,900	22,770,135	24,796,347	25,455,068	25,584,225	134,491,531	136,364,260	(1,872,729)
35	Prior Period True-Up Provision	(471,092)	(471,092)	(471,092)	(471,092)	(471,092)	(471,092)	(2,826,552)	1,247,824	(4,074,376)
36	Current Period Capacity Revenues (Lines 34+35)	17,409,764	17,533,808	22,299,043	24,325,255	24,983,976	25,113,133	131,664,979	137,612,084	(5,947,105)
37	Current Period Over/(Under) Recovery (Lines 36-33)	(5,693,210)	(5,856,558)	(1,026,497)	1,023,508	1,685,770	1,839,277	(8,027,712)	0	(8,027,712)
38	Interest Provision for Month	(54,014)	(51,143)	(65,458)	(63,543)	(55,195)	(44,875)	(334,229)	(257,482)	(76,747)
39	Current Cycle Balance	(5,747,224)	(11,654,926)	(12,746,881)	(11,789,917)	(10,156,342)	(8,361,941)	(8,361,941)	(257,482)	(8,104,459)
40	Plus: Prior Period Balance	(2,826,552)	(2,826,552)	(2,826,552)	(2,826,552)	(2,826,552)	(2,826,552)	(2,826,552)	1,247,824	(4,074,376)
41	Plus: Cumulative True-Up Provision	471,092	942,184	1,413,276	1,884,368	2,355,460	2,826,552	2,826,552	(1,247,824)	4,074,376
42	End of Period Net True-Up (Line 39+40+41)	(8,102,684)	(13,539,294)	(14,160,157)	(12,729,101)	(10,627,434)	(8,361,941)	(8,361,941)	(257,482)	(8,104,459)

FLORIDA POWER CORPORATION
DEVELOPMENT OF JURISDICTIONAL DELIVERY LOSS MULTIPLIERS
BASED ON ACTUAL CALENDAR YEAR 1996 DATA
FOR THE PERIOD OF: OCT-97 THROUGH MAR-98

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Energy Delivered				Energy Required @ Source			
Class Loads	Sales Mwh	Unbilled Mwh	Total Mwh	% of Total	Delivery Efficiency	Mwh (3) / (5)	% of Total	Jurisdictional Loss Multiplier
I. CLASS LOADS:								
A. RETAIL								
1. Transmission	700,743	(3,908)	696,835		0.9740000	715,436		
2. Distribution Primary	4,420,059	(24,645)	4,395,414		0.9640000	4,559,558		
3. Distribution Secondary	25,663,995	(143,096)	25,520,899		0.9386594	27,188,668		
Total Retail	30,784,797	(171,649)	30,613,148	96.10%	0.9429974	32,463,662	96.25%	1.0016
B. WHOLESALE								
1. Source Level	459,070	14,228	473,298		1.0000000	473,298		
2. Transmission	678,311	(10,576)	667,735		0.9740000	685,560		
3. Distribution Primary	101,592	(674)	100,918		0.9640000	104,687		
4. Distribution Secondary	0	0	0		0.9386594	0		
Total Wholesale	1,238,973	2,978	1,241,951	3.90%	0.9829100	1,263,545	3.75%	0.9609
Total Class Loads	32,023,770	(168,671)	31,855,099	100.00%	0.9444926	33,727,207	100.00%	1.0000
II. NON-CLASS LOADS								
1. Company Use	165,344	0	165,344		0.9386594	176,149		
2. Seminole Electric	813,616	(54,596)	759,020		1.0000000	759,020		
3. Kissimmee	10,313	(394)	9,919		0.9740000	10,184		
4. St. Cloud	4,199	(160)	4,039		0.9740000	4,147		
5. Interchange	618,985	0	618,985		0.9740000	635,508		
6. SEPA	21,646	0	21,646		0.9740000	22,224		
Total Non-Class Loads	1,634,103	(55,150)	1,578,953		0.9824052	1,607,232		
Total System	33,657,873	(223,821)	33,434,052		0.9462171	35,334,439		

FLORIDA POWER CORPORATION
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF AVERAGE 12 CP AND ANNUAL AVERAGE DEMAND
For the Period of October1997 through March 1998

Florida Power Corporation
Docket 970001-EI
Witness: K. H. Wieland
Exhibit No.
Part D
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Rate Class	(1) Mwh Sales @ Meter Level	(2) 12 CP Load Factor	(3) Average CP MW @ Meter Level (1)/4380hrs/(2)	(4) Delivery Efficiency Factor	(5) Average CP MW @ Source Level (3)/(4)	(6) Mwh Sales @ Meter Level	(7) Delivery Efficiency Factor	(8) Source Level Mwh (6)/(7)	(9) Annual Average Demand (8)/4380hrs
I. Residential Service	7,210,803	0.515	3,196.7	0.9386594	3,405.6	7,210,803	0.9386594	7,682,023	1,753.9
II. General Service Non-Demand									
Transmission	0	0.662	0.0	0.9740000	0.0	0	0.9740000	0	0.0
Primary	3,377	0.662	1.2	0.9640000	1.2	3,377	0.9640000	3,503	0.8
Secondary	569,953	0.662	196.6	0.9386594	209.4	569,953	0.9386594	607,199	138.6
Total Gen Serv Non-Demand	573,330				210.7	573,330		610,702	139.4
III. GS - 100% L.F.	22,934	1.000	5.2	0.9386594	5.5	22,934	0.9386594	24,433	5.6
IV. General Service Demand									
SS-1 - Transmission	4,641	1.218	0.9			4,641			
GSD-1 - Transmission	1,560	0.807	0.4			1,560			
Total Transmission	6,201		1.3	0.9740000	1.3	6,201	0.9740000	6,367	1.5
SS-1 - Primary	0	1.218	0.0			0			
GSD-1 - Primary	1,088,155	0.807	307.9			1,088,155			
Total Primary	1,088,155		307.9	0.9640000	319.4	1,088,155	0.9640000	1,128,791	257.7
GSD - Secondary	4,290,000	0.807	1,213.7	0.9386594	1,293.0	4,290,000	0.9386594	4,570,348	1,043.5
Total Gen Serv Demand	5,384,356				1,613.7	5,384,356		5,705,506	1,302.6
V. Curtailable Service									
CS - Primary	88,553	0.966	20.9			88,553			
SS-3 - Primary	4,814	1.039	1.1			4,814			
Total Primary	93,367		22.0	0.9640000	22.8	93,367	0.9640000	96,853	22.1
CS - Secondary	934	0.966	0.2	0.9386594	0.2	934	0.9386594	995	0.2
Total Curtailable Service	94,301		22.2		23.0	94,301		97,849	22.3
VI. Interruptible Service									
IS - Transmission	234,712	1.044	51.3			234,712			
SS-2 - Transmission	71,300	1.044	15.6			71,300			
Total Transmission	306,013		66.9	0.9740000	68.7	306,013	0.9740000	314,181	71.7
IS - Primary	1,149,287	1.044	251.3			1,149,287			
SS-2 - Primary	2,061	1.044	0.5			2,061			
Total Primary	1,151,348		251.8	0.9640000	261.2	1,151,348	0.9640000	1,194,344	272.7
IS - Secondary	2,287	1.044	0.5	0.9386594	0.5	2,287	0.9386594	2,437	0.6
Total Interruptible Service	1,459,648				330.4	1,459,648		1,510,963	345.0
VII. Lighting Service	100,749	3.779	6.1	0.9386594	6.5	100,749	0.9386594	107,333	24.5
Total Retail	14,846,121				5,595.5	14,846,121		15,738,808	3,593.3

FLORIDA POWER CORPORATION
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF CAPACITY COST RECOVERY FACTOR
For the Period of October 1997 through March 1998

	(1) Average 12 CP Demand	(2)	(3) Annual Average Demand	(4)	(5) 12/13 of 12 CP	(6) 1/13 of Annual Demand	(7) Demand Allocation	(8) Dollar Allocation	(9) Effective Mwh's @ Secondary Level	(10) Capacity Cost Recovery Factor
	Mw	%	Mw	%	12/13 * (2)	1/13 * (4)	(5) + (6)	(7) * Total	(Oct'97 - Mar'98)	(c/Kwh)
I. Residential Service	3,405.6	60.863%	1,753.9	48.809%	56.181%	3.754%	59.936%	90,903,149	7,210,603	1.261
II. General Service Non-Demand										
Transmission									0	0.979
Primary									3,343	0.989
Secondary									569,953	0.999
Total Gen Serv Non-Demand	210.7	3.765%	139.4	3.880%	3.476%	0.298%	3.774%	5,724,270	573,296	
III. GS - 100% L.F.	5.5	0.099%	5.6	0.155%	0.091%	0.012%	0.103%	156,726	22,934	0.683
IV. General Service Demand										
Transmission									6,077	0.813
Primary									1,077,273	0.822
Secondary									4,290,000	0.830
Total Gen Service Demand	1,613.7	28.840%	1,302.6	36.251%	26.622%	2.788%	29.410%	44,605,467	5,373,350	
V. Curtailable Service										
Transmission									0	0.681
Primary									92,433	0.688
Secondary									934	0.695
Total Curtailable Service	23.0	0.412%	22.3	0.622%	0.380%	0.048%	0.428%	648,874	93,367	
VI. Interruptible Service										
Transmission									299,892	0.638
Primary									1,139,835	0.644
Secondary									2,287	0.651
Total Interruptible Service	330.4	5.905%	345.0	9.600%	5.451%	0.738%	6.189%	9,387,224	1,442,014	
VII. Lighting Service	6.5	0.116%	24.5	0.682%	0.107%	0.052%	0.160%	242,143	100,749	0.240
Total Retail	5,595.5	100.000%	3,593.3	100.000%	92.308%	7.692%	100.000%	151,667,854	14,816,514	1.02160

FLORIDA POWER CORPORATION
DOCKET 970001-EI
WITNESS: K.H. WIELAND
EXHIBIT NO. ______________
PART E

DEBARY 9 GAS CONVERSION
SUMMARY OF COSTS AND SAVINGS - 5 YEAR RECOVERY
FOR THE PERIOD OCTOBER, 1997 THROUGH MARCH, 1998

		1997			1998			
		OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	MARCH	TOTAL
1	BEGINNING BALANCE	$ 734,000	$ 734,000	$ 734,000	$ 734,000	$ 734,000	$ 734,000	$ 734,000
2	ADD INVESTMENT	-	-	-	-	-	-	-
3	LESS RETIREMENTS	-	-	-	-	-	-	-
4	ENDING BALANCE	734,000	734,000	734,000	734,000	734,000	734,000	734,000
5								
6								
7	AVERAGE BALANCE	734,000	734,000	734,000	734,000	734,000	734,000	
8	DEPRECIATION RATE	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	
9	DEPRECIATION EXPENSE	12,233	12,233	12,233	12,233	12,233	12,233	73,398
10	LESS RETIREMENTS	-	-	-	-	-	-	-
11	BEGINNING BALANCE DEPRECIATION	-	12,233	24,466	36,699	48,932	61,165	-
12	ENDING BALANCE DEPRECIATION	12,233	24,466	36,699	48,932	61,165	73,398	73,398
13								
14								
15	ENDING NET INVESTMENT	$ 721,767	$ 709,534	$ 697,301	$ 685,068	$ 672,835	$ 660,602	$ 660,602
16								
17								
18	AVERAGE INVESTMENT	$ 727,884	$ 715,651	$ 703,418	$ 691,185	$ 678,952	$ 666,719	
19	ALLOWED EQUITY RETURN	.42667%	.42667%	.42667%	.42667%	.42667%	.42667%	
20	EQUITY COMPONENT AFTER-TAX	3,106	3,053	3,001	2,949	2,897	2,845	17,851
21	CONVERSION TO PRE-TAX	1.62800	1.62800	1.62800	1.62800	1.62800	1.62800	
22	EQUITY COMPONENT PRE-TAX	5,057	4,970	4,886	4,801	4,716	4,632	29,062
23								
24	ALLOWED DEBT RETURN	.27083%	.27083%	.27083%	.27083%	.27083%	.27083%	
25	DEBT COMPONENT	1,971	1,938	1,905	1,872	1,839	1,806	11,331
26								
27	TOTAL RETURN REQUIREMENTS	7,028	6,908	6,791	6,673	6,555	6,438	
28								
29	TOTAL DEPRECIATION & RETURN	$ 19,261	$ 19,141	$ 19,024	$ 18,906	$ 18,788	$ 18,671	$ 113,791
30								
31	ESTIMATED FUEL SAVINGS (EXCLUDES COGENS)	18,000	23,000	40,000	52,000	30,000	46,000	209,000
32	TOTAL DEPRECIATION & RETURN	19,261	19,141	19,024	18,906	18,788	18,671	113,791
33	ONE-TIME METERING COST	-	-	-	-	-	-	-
34	NET BENEFIT (COST) TO RATEPAYER	$ (1,261)	$ 3,859	$ 20,976	$ 33,094	$ 11,212	$ 27,329	$ 95,209
35								

36 DEPRECIATION EXPENSE IS CALCULATED BASED UPON AN PERIOD THROUGH JUNE 2001.
37 RETURN ON AVERAGE INVESTMENT IS CALCULATED USING AN ANNUAL RATE OF 8.37% (EQUITY 5.12%, DEBT 3.25%).
38 THIS IS THE MIDPOINT AUTHORIZED BY THE FPSC IN DOCKET NO. 91-0890-EI.
39 RETURN REQUIREMENT IS CALCULATED BASED UPON A COMBINED STATUTORY INCOME TAX RATE OF 38.575%

Florida Power Corporation
Docket 970001-EI
Witness: K. H. Wieland
Exhibit No. __________
Part F
Sheet 1 of 3

FUEL & PURCHASED POWER COST RECOVERY CLAUSE
COMPARISON OF ACTUAL FILING VS. ADJUSTED DATA
FOR THE PERIOD OF SEPTEMBER 1996 - MAY 1997

Fuel Adjustment Schedule A2
Page 3 of 4

Line		Sep-96			Oct-96			Nov-96		
No.	Description	Filed	Adjusted	Variance	Filed	Adjusted	Variance	Filed	Adjusted	Variance
3	Total Jurisdictional Fuel Revenue	$61,781,517	$61,781,517	$0	$44,220,331	$44,220,331	$0	$40,804,981	$40,804,981	$0
4	Adjusted Total Fuel and Net Power Transaction	64,480,025	52,371,025	(12,109,000)	58,562,338	47,113,338	(11,449,000)	55,187,776	44,954,776	(10,233,000)
5	Jurisdictional Sales % of Total Sales	95.47%	95.47%	0	94.19%	94.19%	0	97.09%	97.09%	0
6	Jurisdictional Fuel and Net Power Transactions (Line 4 * Line 5 * .13%)	61,639,107	50,063,616	(11,575,491)	55,231,574	44,433,742	(10,797,832)	53,651,468	43,703,333	(9,948,135)
7	True Up Provision for the Month Over/(Under) Collection	142,410	11,717,901	11,575,491	(11,011,243)	(213,411)	10,797,832	(12,846,487)	(2,898,352)	9,948,135
8	Interest Provision for the Month	(268,243)	(242,083)	26,160	(273,539)	(196,866)	76,673	(293,359)	(169,558)	123,801
9	True Up & Interest Provision Beg of Month/Period	(59,910,059)	(59,910,059)	0	(59,049,902)	(47,448,250)	11,601,651	(62,526,903)	(40,050,747)	22,476,156
10	True Up Collected/(Refunded)	985,990	985,990	0	7,807,781	7,807,781	0	7,807,781	7,807,781	0
11	End of Period Total Net True Up	(59,049,902)	(47,448,250)	11,601,651	(62,526,903)	(40,050,747)	22,476,156	(67,858,968)	(35,310,875)	32,548,092
12	Other	0	0	0	0	0	0	0	0	0
13	End of Period Total Net True Up	($59,049,902)	($47,448,250)	$11,601,651	($62,526,903)	($40,050,747)	$22,476,156	($67,858,968)	($35,310,875)	$32,548,092

Florida Power Corporation
Docket 970001-EI
Witness: K. H. Wieland
Exhibit No. ________
Part F
Sheet 2 of 3

FUEL & PURCHASED POWER COST RECOVERY CLAUSE
COMPARISON OF ACTUAL FILING VS. ADJUSTED DATA
FOR THE PERIOD OF SEPTEMBER 1996 - MAY 1997

Fuel Adjustment Schedule A2
Page 3 of 4

Line No.	Description	Dec-96 Filed	Dec-96 Adjusted	Dec-96 Variance	Jan-97 Filed	Jan-97 Adjusted	Jan-97 Variance	Feb-97 Filed	Feb-97 Adjusted	Feb-97 Variance
3	Total Jurisdictional Fuel Revenue	$37,123,952	$37,123,952	$0	$41,522,721	$41,522,721	$0	$37,899,679	$37,899,679	$0
4	Adjusted Total Fuel and Net Power Transaction	63,331,921	51,481,921	(11,850,000)	59,032,294	48,467,294	(10,565,000)	43,184,663	34,736,663	(8,448,000)
5	Jurisdictional Sales % of Total Sales	96.52%	96.52%	0	96.43%	96.43%	0	96.12%	96.12%	0
6	Jurisdictional Fuel and Net Power Transactions (Line 4 * Line 5 * 13%)	61,207,437	49,754,948	(11,452,489)	56,998,843	46,797,770	(10,201,074)	41,563,060	33,432,286	(8,130,774)
7	True Up Provision for the Month Over/(Under) Collection	(24,083,485)	(12,630,996)	11,452,489	(15,476,122)	(5,275,049)	10,201,074	(3,663,381)	4,467,393	8,130,774
8	Interest Provision for the Month	(360,985)	(179,182)	181,803	(419,567)	(185,473)	234,094	(429,024)	(150,867)	278,157
9	True Up & Interest Provision Beg of Month/Period	(67,858,968)	(35,310,875)	32,548,092	(84,495,656)	(40,313,272)	44,182,384	(92,583,565)	(37,966,012)	54,617,552
10	True Up Collected/(Refunded)	7,807,781	7,807,781	0	7,807,781	7,807,781	0	7,807,781	7,807,781	0
11	End of Period Total Net True Up	(84,495,656)	(40,313,272)	44,182,384	(92,583,565)	(37,966,012)	54,617,552	(88,868,189)	(25,841,705)	63,026,484
12	Other	0	0	0	0	0	0	0	0	0
13	End of Period Total Net True Up	($84,495,656)	($40,313,272)	$44,182,384	($92,583,565)	($37,966,012)	$54,617,552	($88,868,189)	($25,841,705)	$63,026,484

Florida Power Corporation
Docket 970001-EI
Witness K. H. Wieland
Exhibit No ________
Part F
Sheet 3 of 3

FUEL & PURCHASED POWER COST RECOVERY CLAUSE
COMPARISON OF ACTUAL FILING VS. ADJUSTED DATA
FOR THE PERIOD OF SEPTEMBER 1996 - MAY 1997

Fuel Adjustment Schedule A2
Page 3 of 4

Line No.	Description	Mar-97 Filed	Mar-97 Adjusted	Mar-97 Variance	Apr-97 Filed	Apr-97 Adjusted	Apr-97 Variance	May-97 Filed	May-97 Adjusted	May-97 Variance
3	Total Jurisdictional Fuel Revenue	$36,653,875	$36,653,875	$0	$44,075,773	$44,075,773	$0	$44,474,095	$44,474,095	$0
4	Adjusted Total Fuel and Net Power Transaction	50,851,294	42,577,294	(8,274,000)	49,838,957	40,330,957	(9,508,000)	60,042,464	50,177,464	(9,865,000)
5	Jurisdictional Sales % of Total Sales	96.72%	96.72%	0	97.22%	97.22%	0	97.39%	97.39%	0
6	Jurisdictional Fuel and Net Power Transactions (Line 4 * Line 5 * .13%)	49,247,310	41,234,294	(8,013,016)	48,516,423	39,260,729	(9,255,694)	58,551,374	48,931,360	(9,620,013)
7	True Up Provision for the Month Over/(Under) Collection	(12,593,435)	(4,580,419)	8,013,016	(4,440,650)	4,815,044	9,255,694	(14,077,279)	(4,457,265)	9,620,013
8	Interest Provision for the Month	(425,276)	(112,903)	312,373	(442,155)	(56,309)	385,846	(445,205)	(18,268)	426,937
9	True Up & Interest Provision Beg of Month/Period	(88,868,189)	(25,841,705)	63,026,484	(89,565,627)	(18,213,754)	71,351,873	(86,594,899)	(5,601,485)	80,993,414
10	True Up Collected/(Refunded)	7,807,781	7,807,781	0	7,853,534	7,853,534	0	7,853,534	7,853,534	0
11	End of Period Total Net True Up	(94,079,118)	(22,727,245)	71,351,873	(86,594,899)	(5,601,485)	80,993,414	(93,263,849)	(2,223,484)	91,040,364
12	Other (Pasco Allocation & Lake)	4,513,491	4,513,491	0	0	0	0	0	0	0
13	End of Period Total Net True Up	($89,565,627)	($18,213,754)	$71,351,873	($86,594,899)	($5,601,485)	$80,993,414	($93,263,849)	($2,223,484)	$91,040,364

FLORIDA POWER CORPORATION
Docket No. 970001-EI
Witness: K.H. Wieland
Exhibit No. _____
Part G

Florida Power Corporation
Example of a Schedule C Sale By FPC

	Before Order 888	Existing Agreements Modified by Order 888	New Unbundled Agreements
FPC's Incremental Cost	$ 20.00	$ 20.00	$ 20.00
Buyer's Incremental Cost	30.00	30.00	30.00
Transaction Price	25.00	25.00	25.00
FPC's Transmission Rate	---	3.00	3.00
Margin	5.00	2.00	5.00
Purchaser's Cost	25.00	25.00	28.00
Jurisdictional Treatment of Transmission and Gain			
Retail Portion of Transmission (75%)	---	2.25	2.25
Wholesale Portion of Transmission (25%)	---	0.75	0.75
Retail Portion of Margin (95%)	4.75	1.90	4.75
Wholesale Portion of Margin (5%)	0.25	0.10	0.25
Amount Credited to Retail before 80%/20% split			
Fuel Clause	4.75	4.15	4.75
Base Rates	---	---	2.25
Total	4.75	4.15	7.00
Amount Credited to Wholesale			
Fuel Clause	0.25	0.10	0.25
Base Rates	---	0.75	0.75
Total	0.25	0.85	1.00

EXHIBITS TO THE TESTIMONY OF
KARL H. WIELAND

LEVELIZED FUEL COST FACTORS
OCTOBER 1997 THROUGH MARCH 1998

SCHEDULES E1 THROUGH E10 AND H1

FLORIDA POWER CORPORATION
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE
ESTIMATED FOR THE PERIOD OF: OCTOBER 1997 THROUGH MARCH 1998

			DOLLARS	MWH	CENTS/KWH
1.	Fuel Cost of System Net Generation		211,168,796	11,744,226	1.79806
2.	Spent Nuclear Fuel Disposal Cost		1,456,091	1,557,317 *	0.09350
3.	Nuclear Fuel Replacement Cost		(28,063,000)	0	0.00000
4.	Adjustment to Fuel Cost		3,220,000	0	0.00000
5	TOTAL COST OF GENERATED POWER		187,781,886	11,744,226	1.59893
6.	Energy Cost of Purchased Power (Excl. Econ & Cogens) (E7)		12,758,320	678,935	1.87917
7.	Energy Cost of Sch. C,X Economy Purchases (Broker) (E9)		10,117,800	380,000	2.66258
8.	Energy Cost of Economy Purchases (Non-Broker) (E9)		759,930	33,182	2.29019
9.	Energy Cost of Schedule E Economy Purchases (E9)		0	0	0.00000
10.	Capacity Cost of Economy Purchases (E9)		344,540	15,182 *	2.26940
11.	Payments to Qualifying Facilities (E8)		75,138,623	3,631,591	2.06903
12.	TOTAL COST OF PURCHASED POWER		99,119,213	4,723,708	2.09833
13.	TOTAL AVAILABLE KWH			16,467,934	
14.	Fuel Cost of Economy Sales	(E6)	(6,690,300)	(377,000)	1.77462
14a.	Gain on Economy Sales - 80%	(E6)	(1,973,160)	(377,000) *	0.52338
15.	Fuel Cost of Other Power Sales	(E6)	0	0	0.00000
15a.	Gain on Other Power Sales	(E6)	0	0	0.00000
16.	Fuel Cost of Unit Power Sales	(E6)	0	0	0.00000
16a.	Gain on Unit Power Sales	(E6)	0	0	0.00000
17.	Fuel Cost of Stratified Sales	(E6)	(8,535,000)	(387,284)	2.20381
18.	TOTAL FUEL COST AND GAINS ON POWER SALES		(17,198,460)	(764,284)	2.25027
19.	Net Inadvertent Interchange			0	
20.	TOTAL FUEL AND NET POWER TRANSACTIONS		269,702,639	15,703,650	1.71745
21.	Net Unbilled		(9,892,540)	576,001	(0.06460)
22.	Company Use		1,561,164	(90,900)	0.01020
23.	T & D Losses		14,933,640	(869,523)	0.09750
24.	Adjusted System KWH Sales		269,702,639	15,319,228	1.76055
25	Wholesale KWH Sales (Excluding Supplemental Sales)		(8,271,424)	(473,107)	1.74832
26.	Jurisdictional KWH Sales		261,431,215	14,846,121	1.76094
27.	Jurisdictional KWH Sales Adjusted for Line Losses x	1.0016	261,849,505	14,846,121	1.76376
28.	Prior Period True-Up (E1-B, Sheet 1)**		9,332,837	14,846,121	0.06286
28a.	Market Price True-Up **		(505,000)	14,846,121	(0.00340)
29.	Total Jurisdictional Fuel Cost		270,677,342	14,846,121	1.82322
30.	Revenue Tax Factor				1.00083
31.	Fuel Cost Adjusted for Taxes		270,902,004	14,846,121	1.82473
32.	GPIF **		(255,522)	14,846,121	(0.00172)
33.	Fuel Factor Adjusted for taxes including GPIF		270,646,482	14,846,121	1.82301
34.	Total Fuel Cost Factor (rounded to the nearest .001 cents/ KWH)				1.823

* For Informational Purposes Only

** Based on Jurisdictional Sales

FLORIDA POWER CORPORATION
CALCULATION OF TOTAL TRUE-UP
(PROJECTED PERIOD)
ESTIMATED FOR THE PERIOD OF: OCT-97 THROUGH MAR-98

1.	ESTIMATED OVER/(UNDER) RECOVERY (2 months actual, 4 months projected) (Schedule E1-B, Sheet 1)	$8,880,912
2.	FINAL TRUE-UP (6 months prior period) (Schedule E1-B, Sheet 1)	(18,213,749)
3.	TOTAL OVER/(UNDER) RECOVERY (Line 1 + Line 2)	($9,332,837)
4.	OVER/(UNDER) RECOVERY (To be included in projected period)	($9,332,837)
5.	JURISDICTIONAL MWH SALES (Projected Period)	14,846,121 Mwh
6.	TRUE-UP FACTOR (To be included in projected period) (Line 3 / Line 4 / 10)	0.06286 Cents/kwh

SCHEDULE E1-B
Sheet 1

FLORIDA POWER CORPORATION
CALCULATION OF ESTIMATED TRUE-UP
RE-ESTIMATED FOR THE PERIOD OF: APRIL 1997 THROUGH SEPTEMBER 1997

DESCRIPTION		ADJUSTED ACTUALS		ESTIMATED				TOTAL
		Apr-97	May-97	Jun-97	Jul-97	Aug-97	Sep-97	PERIOD
REVENUE								
1 Jurisdictional KWH Sales		2,268,366	2,275,058	2,810,524	3,060,620	3,141,926	3,157,868	16,714,362
2 Jurisdictional Fuel Factor (Pre-Tax)		2.292	2.303	2.325	2.325	2.325	2.325	
3 Total Jurisdictional Fuel Revenue		52,001,193	52,399,514	65,354,801	71,170,433	73,061,090	73,431,799	387,418,831
4 Less: True-Up Provision		(7,853,534)	(7,853,534)	(7,853,534)	(7,853,534)	(7,853,534)	(7,853,531)	(47,121,201)
5 Less: GPIF Provision		(71,886)	(71,886)	(71,886)	(71,886)	(71,886)	(71,886)	(431,316)
6 Less: Replacement Cost Refund		0	0	0	(23,175,298)	(7,100,753)	(7,136,782)	(37,412,833)
7 Net Fuel Revenue		44,075,773	44,474,094	57,429,381	40,069,715	58,034,917	58,369,600	302,453,481
FUEL EXPENSE								
8 Total Cost of Generated Power		22,538,280	33,415,391	37,455,283	42,195,201	42,964,187	39,609,962	218,178,304
9 Total Cost of Purchased Power		18,622,580	17,995,638	25,137,182	28,053,387	28,430,397	25,823,472	144,062,656
10 Total Cost of Power Sales		(829,903)	(1,233,565)	(363,272)	(1,766,710)	(3,366,460)	(2,932,736)	(10,492,646)
11 Total Fuel and Net Power		40,330,957	50,177,464	62,229,193	68,481,878	68,028,124	62,500,698	351,748,314
12 Jurisdictional Percentage		97.22%	97.39%	96.39%	96.51%	96.43%	96.31%	96.64%
13 Jurisdictional Loss Multiplier		1.0013	1.0013	1.0016	1.0016	1.0016	1.0016	1.0016
14 Jurisdictional Fuel Cost		39,260,729	48,931,360	60,078,691	66,197,607	65,704,479	60,290,733	340,463,601
COST RECOVERY								
15 Net Fuel Revenue Less Expense		4,815,044	(4,457,266)	(2,649,311)	(26,127,892)	(7,669,562)	(1,921,133)	
16 Interest Provision	(1)	(56,309)	(18,268)	1,772	(28,804)	(71,270)	(57,291)	
17 Current Cycle Balance		4,758,735	283,202	(2,364,337)	(28,521,033)	(36,261,865)	(38,240,289)	
18 Plus: Prior Period Balance	(2)	(18,213,749)	(18,213,749)	(18,213,749)	(18,213,749)	(18,213,749)	(18,213,749)	
19 Plus: Cumulative True-Up Provision		7,853,534	15,707,068	23,560,602	31,414,136	39,267,670	47,121,201	
20 Total Retail Balance		(5,601,480)	(2,223,479)	2,982,516	(15,320,646)	(15,207,944)	(9,332,837)	

(1) Interest for the period calculated at the May 1997 rate of .468% (monthly).
(2) Revised Jurisdictional True-Up Balance

FLORIDA POWER CORPORATION

COMPARISON OF ACTUAL/REVISED ESTIMATE VS. ORIGINAL ESTIMATE OF THE FUEL AND PURCHASED POWER COST RECOVERY FACTOR

ESTIMATED FOR THE PERIOD OF: APRIL 1997 THROUGH SEPTEMBER 1997

		DOLLARS				MWH				CENTS/KWH			
		Actual / Rev Estimate	Original Estimate	------Difference------ Amount	%	Actual / Rev Estimate	Original Estimate	Difference Amount	%	Actual / Rev Estimate	Original Estimate	----Difference---- Amount	%
1	Fuel Cost of System Net Generation	285,915,822	248,196,433	37,719,389	15.2	13,074,738	14,195,910	(1,121,172)	(7.9)	2.1868	1.7484	0.4384	25.1
2	Spent Nuclear Fuel Disposal Cost	0	2,826,190	(2,826,190)	(100.0)	0 *	3,022,663 *	(3,022,663)	(100.0)	0.0000	0.0935	(0.0935)	(100.0)
3	Nuclear Fuel Replacement Cost	(69,386,450)	0	(69,386,450)	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
4	Adjustment to Fuel Cost	1,648,932	1,403,322	245,610	17.5	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
5	TOTAL COST OF GENERATED POWER	218,178,304	252,425,945	(34,247,641)	(13.6)	13,074,738	14,195,910	(1,121,172)	(7.9)	1.6687	1.7782	(0.1095)	(6.2)
6	Energy Cost of P. P. (Excl. Econ & Cogens)	32,677,471	23,994,980	8,682,491	36.2	1,628,894	1,248,361	380,533	30.5	2.0061	1.9221	0.0840	4.4
7	Energy Cost of Sch. C,X Econ Purch (Broker)	30,233,643	18,582,810	11,650,833	62.7	909,925	630,000	279,925	44.4	3.3227	2.9497	0.3730	12.6
8	Energy Cost of Economy Purch (Non-Broker)	4,404,379	1,708,387	2,695,992	157.8	213,733	85,551	128,182	149.8	2.0607	1.9969	0.0638	3.2
9	Energy Cost of Schedule E Economy Purch	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
10	Capacity Cost of Economy Purchases	682,853	685,336	(2,483)	(0.4)	63,024 *	61,971 *	1,053	1.7	1.0835	1.1059	(0.0224)	(2.0)
11	Payments to Qualifying Facilities	76,064,309	79,049,660	(2,985,351)	(3.8)	3,577,233	3,893,407	(316,174)	(8.1)	2.1263	2.0303	0.0960	4.7
12	TOTAL COST OF PURCHASED POWER	144,062,655	124,021,173	20,041,482	16.2	6,329,785	5,857,319	472,466	8.1	2.2759	2.1174	0.1586	7.5
13	TOTAL AVAILABLE KWH					19,404,523	20,053,229	(648,706)	(3.2)	--	--	--	--
14	Fuel Cost of Economy Sales	(1,152,294)	(9,378,410)	8,226,116	(87.7)	(60,339)	(470,000)	409,661	(87.2)	1.9097	1.9954	(0.0857)	(4.3)
14a	Gain on Economy Sales - 80%	(209,150)	(1,848,720)	1,639,570	(88.7)	(60,339) *	(470,000) *	409,661	(87.2)	0.3466	0.3933	(0.0467)	(11.9)
15	Fuel Cost of Other Power Sales	(517,132)	0	(517,132)	0.0	(20,526)	0	(20,526)	0.0	2.5194	0.0000	2.5194	0.0
15a	Gain on Other Power Sales	(81,976)	0	(81,976)	0.0	(20,526) *	0 *	(20,526)	0.0	0.3994	0.0000	0.3994	0.0
16	Fuel Cost of Unit Power Sales	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
16a	Gain on Unit Power Sales	0	0	0	0.0	0 *	0 *	0	0.0	0.0000	0.0000	0.0000	0.0
17	Fuel Cost of Stratified Sales	(8,532,093)	(9,016,247)	484,154	(5.4)	(314,965)	(332,765)	17,800	(5.3)	2.7089	2.7095	(0.0006)	(0.0)
18	TOTAL FUEL COST & GAINS ON POWER SALES	(10,492,645)	(20,243,377)	9,750,732	(48.2)	(395,830)	(802,765)	406,935	(50.7)	2.6508	2.5217	0.1291	5.1
19	Net Inadvertent Interchange					2,368	0	2,368	0.0	--	--	--	--
20	TOTAL FUEL & NET POWER TRANSACTIONS	351,748,314	356,203,741	(4,455,427)	(1.3)	19,011,061	19,250,464	(239,403)	(1.2)	1.8502	1.8504	(0.0001)	(0.0)
21	Net Unbilled	13,463,785 *	11,527,993 *	1,935,792	16.8	(613,499)	(623,012)	9,513	(1.5)	0.0779	0.0660	0.0118	17.9
22	Company Use	1,824,143 *	1,681,981 *	142,162	8.5	(83,120)	(90,900)	7,780	(8.6)	0.0105	0.0096	0.0009	9.5
23	T & D Losses	22,410,710 *	19,931,959 *	2,478,751	12.4	(1,021,180)	(1,077,191)	56,011	(5.2)	0.1296	0.1142	0.0154	13.5
24	Adjusted System KWH Sales	351,748,314	356,203,741	(4,455,427)	(1.3)	17,293,262	17,459,361	(166,099)	(1.0)	2.0340	2.0402	(0.0062)	(0.3)
25	Wholesale KWH Sales (Excl Suppl. Sales)	(12,325,656)	(12,809,353)	483,697	(3.8)	(578,900)	(627,876)	48,976	(7.8)	2.1292	2.0401	0.0890	4.4
26	Jurisdictional KWH Sales	339,422,658	343,394,388	(3,971,730)	(1.2)	16,714,362	16,831,485	(117,123)	(0.7)	2.0307	2.0402	(0.0095)	(0.5)
27	Jurisd KWH Sales Adj for Line Losses	339,939,470	343,840,801	(3,901,331)	(1.1)	16,714,362	16,831,485	(117,123)	(0.7)	2.0338	2.0428	(0.0090)	(0.4)
28	Prior Period True-Up **	47,121,201	47,121,201	0	0.0	16,714,362	16,831,485	(117,123)	(0.7)	0.2819	0.2800	0.0020	0.7
28a	Market Price True-Up **	0	0	0	0.0	16,714,362	16,831,485	(117,123)	(0.7)	0.0000	0.0000	0.0000	0.0
29	Total Jurisdictional Fuel Cost	387,060,671	390,962,002	(3,901,331)	(1.0)	16,714,362	16,831,485	(117,123)	(0.7)	2.3157	2.3228	(0.0071)	(0.3)
30	Revenue Tax Factor									1.00083	1.00083	0.0000	0.0
31	Fuel Cost Adjusted for Taxes									2.3177	2.3247	(0.0071)	(0.3)
32	GPIF **	431,674	431,674	0	0.0	16,714,362	16,831,485	(117,123)	(0.7)	0.0026	0.0026	0.0000	0.7
34	Total Fuel Cost Factor									2.320	2.327	(0.007)	(0.3)

* For Informational Purposes Only
** Based on Jurisdictional Sales

FLORIDA POWER CORPORATION
CALCULATION OF GENERATING PERFORMANCE INCENTIVE AND TRUE-UP ADJUSTMENT FACTORS

ESTIMATED FOR THE PERIOD OF: OCT-97 THROUGH MAR-98

1. TOTAL AMOUNT OF ADJUSTMENTS:	
A. Generating Performance Incentive Reward / (Penalty)	($255,522)
B. True-Up (Over) / Under Recovery	$9,332,837
C. Market Price True-Up	($505,000)
2. JURISDICTIONAL MWH SALES	14,846,121 Mwh
3. ADJUSTMENT FACTORS:	
A. Generating Performance Incentive Factor	-0.00172 Cents/kwh
B. True-Up Factor	0.06286 Cents/kwh
C. Market Price True-Up Factor	-0.00340 Cents/kwh

FLORIDA POWER CORPORATION
CALCULATION OF LEVELIZED FUEL ADJUSTMENT FACTORS
(PROJECTED PERIOD)
FOR THE PERIOD OF: OCT-97 THROUGH MAR-98

1.	Period Jurisdictional Fuel Cost (E1, line 27)	$261,849,505	
2.	Prior Period True-Up (E1, line 28)	9,332,837	
3.	Market Price True-Up (E1, line 28a)	(505,000)	
4.	Regulatory Assessment Fee (E1, line 30)	224,662	
5.	Generating Performance Incentive Factor (GPIF) (E1, line 32)	(255,522)	
6.	Total Jurisdictional Fuel Cost	$270,646,482	
7.	Jurisdictional Sales	14,846,121	Mwh
8.	Jurisdictional Cost per Kwh Sold (Line 6 / Line7 / 10)	1.823	Cents/kwh
9.	Effective Jurisdictional Sales (See Below)	14,816,514	Mwh

LEVELIZED FUEL FACTORS:

10.	Fuel Factor at Secondary Metering (Line 6 / Line 9 / 10)	**1.827**	Cents/kwh
11.	Fuel Factor at Primary Metering (Line 10 * 99%)	**1.809**	Cents/kwh
12.	Fuel Factor at Transmission Metering (Line 10 * 98%)	**1.790**	Cents/kwh

	JURISDICTIONAL SALES (MWH)	
METERING VOLTAGE:	METER	SECONDARY
Distribution Secondary	12,197,660	12,197,660
Distribution Primary	2,336,247	2,312,885
Transmission	312,214	305,970
Total	14,846,121	14,816,514

FLORIDA POWER CORPORATION
CALCULATION OF FINAL FUEL COST FACTORS
FOR THE PERIOD OF: OCT-97 THROUGH MAR-98

Line:	Metering Voltage	(1) Levelized Factors Cents/Kwh	(2) Time of Use On-Peak Multiplier 1.181	(3) Time of Use Off-Peak Multiplier 0.926
1.	Distribution Secondary	1.827	2.158	1.692
2.	Distribution Primary	1.809	2.136	1.675
3.	Transmission	1.790	2.114	1.658
4.	Lighting Service	1.779	--	--

Col. (1) Lines 1-3 Copied from Schedule E1-D.
Col. (2) Calculated as Col. (1) * On-Peak Multiplier
Col. (3) Calculated as Col. (1) * Off-Peak Multiplier
Line 4 Calculated as secondary rate 1.827 * (18.7% * On-Peak Multiplier 1.181 + 81.3% * Off-Peak Multiplier 0.926).

DEVELOPMENT OF TIME OF USE MULTIPLIERS

	ON-PEAK PERIOD			OFF-PEAK PERIOD			TOTAL		
Mo/Yr	System MWH Requirements	Marginal Cost	Average Marginal Cost (¢/kWh)	System MWH Requirements	Marginal Cost	Average Marginal Cost (¢/kWh)	System MWH Requirements	Marginal Cost	Average Marginal Cost (¢/kWh)
10/97	974,308	27,280,624	2.800	1,856,063	38,791,717	2.090	2,830,371	66,072,341	2.334
11/97	704,636	18,813,781	2.670	1,821,960	37,532,376	2.060	2,526,596	56,346,157	2.230
12/97	757,078	21,652,431	2.860	1,931,163	44,030,516	2.280	2,688,241	65,682,947	2.443
01/98	786,098	19,573,840	2.490	2,063,028	39,403,835	1.910	2,849,126	58,977,675	2.070
02/98	708,648	15,944,580	2.250	1,840,232	32,940,153	1.790	2,548,880	48,884,733	1.918
03/98	740,174	17,912,211	2.420	1,907,536	39,485,995	2.070	2,647,710	57,398,206	2.168
TOTAL	4,670,942	121,177,467	2.594	11,419,982	232,184,592	2.033	16,090,924	353,362,059	2.196

	ON-PEAK	OFF-PEAK	AVERAGE
MARGINAL FUEL COST WEIGHTING MULTIPLIER	1.181	0.926	1.000

FLORIDA POWER CORPORATION
DEVELOPMENT OF JURISDICTIONAL DELIVERY LOSS MULTIPLIERS
BASED ON ACTUAL CALENDAR YEAR 1996 DATA
FOR THE PERIOD OF: OCT-97 THROUGH MAR-98

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Energy Delivered				Energy Required @ Source			
Class Loads	Sales Mwh	Unbilled Mwh	Total Mwh	% of Total	Delivery Efficiency	Mwh (3) / (5)	% of Total	Jurisdictional Loss Multiplier
I. CLASS LOADS:								
A. RETAIL								
1. Transmission	700,743	(3,908)	696,835		0.9740000	715,436		
2. Distribution Primary	4,420,059	(24,645)	4,395,414		0.9640000	4,559,558		
3. Distribution Secondary	25,663,995	(143,096)	25,520,899		0.9386594	27,188,668		
Total Retail	30,784,797	(171,649)	30,613,148	96.10%	0.9429974	32,463,662	96.25%	1.0016
B. WHOLESALE								
1. Source Level	459,070	14,228	473,298		1.0000000	473,298		
2. Transmission	678,311	(10,576)	667,735		0.9740000	685,560		
3. Distribution Primary	101,592	(674)	100,918		0.9640000	104,687		
4. Distribution Secondary	0	0	0		0.9386594	0		
Total Wholesale	1,238,973	2,978	1,241,951	3.90%	0.9829100	1,263,545	3.75%	0.9609
Total Class Loads	32,023,770	(168,671)	31,855,099	100.00%	0.9444926	33,727,207	100.00%	1.0000
II. NON-CLASS LOADS								
1. Company Use	165,344	0	165,344		0.9386594	176,149		
2. Seminole Electric	813,616	(54,596)	759,020		1.0000000	759,020		
3. Kissimmee	10,313	(394)	9,919		0.9740000	10,184		
4. St. Cloud	4,199	(160)	4,039		0.9740000	4,147		
5. Interchange	618,985	0	618,985		0.9740000	635,508		
6. SEPA	21,646	0	21,646		0.9740000	22,224		
Total Non-Class Loads	1,634,103	(55,150)	1,578,953		0.9824052	1,607,232		
Total System	33,657,873	(223,821)	33,434,052		0.9462171	35,334,439		

FLORIDA POWER CORPORATION
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE
ESTIMATED FOR THE PERIOD OF: OCTOBER 1997 THROUGH MARCH 1998

	DESCRIPTION		Oct-97	Nov-97	Dec-97	Jan-98	Feb-98	Mar-98	TOTAL
1	Fuel Cost of System Net Generation		$37,839,010	$33,274,285	$39,867,318	$36,614,017	$32,244,755	$31,329,410	$211,168,795
1a	Nuclear Fuel Disposal Cost		0	0	0	501,542	453,007	501,542	1,456,091
1b	Adjustments to Fuel Cost		(8,317,000)	(8,079,000)	(9,329,000)	296,000	294,000	292,000	(24,843,000)
2	Fuel Cost of Power Sold		(223,200)	(245,400)	(1,125,000)	(1,541,700)	(1,741,000)	(1,814,000)	(6,690,300)
2a	Fuel Cost of Stratified Sales		(2,943,000)	(2,032,000)	(270,000)	(249,000)	(1,104,000)	(1,937,000)	(8,535,000)
2b	Gains on Power Sales		(61,920)	(77,400)	(309,600)	(473,040)	(525,600)	(525,600)	(1,973,160)
3	Fuel Cost of Purchased Power		3,824,280	2,189,600	2,431,540	1,374,540	893,090	2,045,270	12,758,320
3a	Recov Non-Fuel Cost of Econ Purch		116,095	112,350	116,095	0	0	0	344,540
3b	Payments to Qualifying Facilities		12,773,692	12,275,502	13,368,752	12,489,879	11,472,239	12,758,559	75,138,623
4	Fuel Cost of Economy Purchases		3,126,750	2,085,480	1,213,430	1,640,680	1,223,940	1,587,450	10,877,730
5	Total Fuel & Net Power Transactions		$46,134,707	$39,503,417	$45,963,535	$50,652,918	$43,210,431	$44,237,631	$269,702,639
6	Adjusted System Sales	MWH	2,945,704	2,461,098	2,470,997	2,579,188	2,475,294	2,386,947	15,319,228
7	System Cost per KWH Sold	c/kwh	1.5662	1.6052	1.8601	1.9639	1.7456	1.8534	1.7606
7a	Jurisdictional Loss Multiplier	x	1.0016	1.0016	1.0016	1.0016	1.0016	1.0016	1.0016
7b	Jurisdictional Cost per KWH Sold	c/kwh	1.5687	1.6077	1.8631	1.9671	1.7485	1.8563	1.7638
8	Prior Period True-Up *	c/kwh	0.0548	0.0655	0.0649	0.0621	0.0646	0.0671	0.0629
8a	Market Price True-Up *	c/kwh	-0.0178	0.0000	0.0000	0.0000	0.0000	0.0000	-0.0034
9	Total Jurisdictional Fuel Expense	c/kwh	1.6057	1.6732	1.9280	2.0291	1.8130	1.9234	1.8232
10	Revenue Tax Multiplier	x	1.00083	1.00083	1.00083	1.00083	1.00083	1.00083	1.00083
11	Fuel Cost Factor Adjusted for Taxes	c/kwh	1.6070	1.6745	1.9296	2.0308	1.8145	1.9250	1.8247
12	GPIF	c/kwh	-0.0015	-0.0018	-0.0018	-0.0017	-0.0018	-0.0018	-0.0017
13	Total Fuel Cost Factor (rounded .001)	c/kwh	1.605	1.673	1.928	2.029	1.813	1.923	1.823

* Based on Jurisdictional Sales Only

FLORIDA POWER CORPORATION
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ESTIMATED FOR THE PERIOD OF: OCT-97 THROUGH MAR-98

			Oct-97	Nov-97	Dec-97	Jan-98	Feb-98	Mar-98	TOTAL
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL		10,378,679	3,929,885	7,583,346	4,448,673	2,871,764	6,233,313	35,442,660
2	LIGHT OIL		86,829	169,175	535,706	757,743	402,960	269,389	2,220,792
3	COAL		25,264,973	26,212,029	28,063,184	25,852,672	23,914,390	18,508,301	147,315,449
4	GAS		1,775,564	2,612,351	3,320,358	3,662,270	3,053,677	4,153,407	18,777,627
5	NUCLEAR		0	0	0	1,828,034	1,651,129	1,828,034	5,307,196
6	OTHER		336,966	350,845	364,724	364,724	350,845	336,966	2,105,069
7	TOTAL	$	37,839,010	33,274,285	39,867,318	36,614,017	32,244,765	31,329,410	211,168,794
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL		425,336	146,093	260,415	134,661	85,494	241,252	1,[illegible]3,251
9	LIGHT OIL		1,392	2,747	8,515	12,097	6,650	4,562	35,963
10	COAL		1,406,613	1,480,894	1,571,412	1,433,440	1,354,649	1,043,370	8,290,486
11	GAS		63,342	91,322	107,383	98,116	74,877	132,269	567,309
12	NUCLEAR		0	0	0	536,409	484,499	536,409	1,557,317
13	OTHER		0	0	0	0	0	0	0
14	TOTAL	MWH	1,896,683	1,721,156	1,947,725	2,214,731	2,006,169	1,957,862	11,744,226
	UNITS OF FUEL BURNED								
15	HEAVY OIL	BBL	626,047	226,046	401,690	235,203	163,291	375,499	2,027,766
16	LIGHT OIL	BBL	3,102	5,910	17,772	25,126	13,907	9,757	75,573
17	COAL	TON	527,166	554,646	584,931	531,357	500,209	384,474	3,082,683
18	GAS	MCF	689,654	958,537	1,106,709	1,046,327	797,864	1,366,290	5,964,271
19	NUCLEAR	MMBTU	0	0	0	5,539,496	5,003,421	5,539,496	16,082,413
20	OTHER	BBL	12,069	12,069	12,069	12,069	12,069	12,069	72,414
	BTUS BURNED (MMBTU)								
21	HEAVY OIL		4,006,701	1,446,692	2,570,819	1,505,302	1,044,996	2,403,190	12,977,700
22	LIGHT OIL		17,969	34,280	103,076	145,730	80,660	56,589	438,334
23	COAL		13,252,414	13,939,681	14,703,246	13,357,339	12,573,700	9,662,818	77,489,203
24	GAS		689,654	958,537	1,106,709	1,046,327	797,864	1,366,290	5,964,271
25	NUCLEAR		0	0	0	5,539,496	5,003,421	5,539,496	16,082,413
26	OTHER		70,000	70,000	70,000	70,000	70,000	70,000	420,000
27	TOTAL	MMBTU	18,036,657	16,449,190	18,563,851	21,663,194	19,570,646	19,088,378	113,381,915
	GENERATION MIX (% MWH)								
28	HEAVY OIL		22.43%	8.49%	13.37%	6.08%	4.26%	12.32%	11.01%
29	LIGHT OIL		0.07%	0.16%	0.44%	0.55%	0.33%	0.23%	0.31%
30	COAL		74.17%	86.05%	80.68%	64.72%	67.52%	53.29%	70.59%
31	GAS		3.34%	5.31%	5.51%	4.43%	3.73%	6.76%	4.83%
32	NUCLEAR		0.00%	0.00%	0.00%	24.22%	24.15%	27.40%	13.26%
33	OTHER		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
34	TOTAL	%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	FUEL COST PER UNIT								
35	HEAVY OIL	$/BBL	16.57	17.39	18.88	18.91	17.59	16.60	17.48
36	LIGHT OIL	$/BBL	27.67	28.62	30.14	30.16	28.97	27.61	29.39
37	COAL	$/TON	47.93	47.27	47.98	47.71	47.81	48.14	47.79
38	GAS	$/MCF	2.57	2.73	3.00	3.69	3.83	3.06	3.15
39	NUCLEAR	$/MMBTU	0.00	0.00	0.00	0.33	0.33	0.33	0.33
40	OTHER	$/BBL	27.92	29.07	30.22	30.22	29.07	27.92	29.07
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL		2.59	2.72	2.95	2.96	2.75	2.59	2.73
42	LIGHT OIL		4.77	4.94	5.20	5.20	5.00	4.76	5.07
43	COAL		1.91	1.88	1.91	1.90	1.90	1.92	1.90
44	GAS		2.58	2.73	3.00	3.70	3.83	3.06	3.15
45	NUCLEAR		0.00	0.00	0.00	0.33	0.33	0.33	0.33
46	OTHER		4.81	5.01	5.21	5.21	5.01	4.81	5.01
47	TOTAL	$/MMBTU	2.10	2.02	2.15	1.69	1.65	1.64	1.86
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL		9,420	9,903	9,872	11,179	12,223	9,961	10,036
49	LIGHT OIL		12,923	12,479	12,105	12,047	12,129	12,404	12,189
50	COAL		9,422	9,412	9,357	9,318	9,282	9,261	9,347
51	GAS		10,903	10,496	10,306	10,664	10,656	10,294	10,497
52	NUCLEAR		0	0	0	10,327	10,327	10,327	10,327
53	OTHER		0	0	0	0	0	0	0
54	TOTAL	BTU/KWH	9,510	9,557	9,530	9,781	9,755	9,750	9,653
	GENERATED FUEL COST PER KWH (C/KWH)								
55	HEAVY OIL		2.44	2.69	2.91	3.30	3.36	2.58	2.74
56	LIGHT OIL		6.17	6.16	6.29	6.26	6.06	5.91	6.18
57	COAL		1.80	1.77	1.79	1.77	1.77	1.77	1.78
58	GAS		2.81	2.86	3.09	3.94	4.08	3.14	3.31
59	NUCLEAR		0.00	0.00	0.00	0.34	0.34	0.34	0.34
60	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
61	TOTAL	C/KWH	2.00	1.93	2.05	1.65	1.61	1.60	1.80

FLORIDA POWER CORPORATION
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Oct-97

(A) PLANT/UNIT		(B) NET CAPACITY (MW)	(C) NET GENERATION (MWH)	(D) CAPACITY FACTOR (%)	(E) EQUIV AVAIL FACTOR (%)	(F) OUTPUT FACTOR (%)	(G) AVG NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)		(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MMBTU)	(L) AS BURNED FUEL COST (3)	(M) FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3	756	0	0.0	0.0	0.0	0	NUCLEAR	0	MMBTU	1.00	0	0	0.00
2 ANCLOTE	1	503	185,253	52.2	97.0	76.5	9,292	HEAVY OIL	283,483	BBLS	6.40	1,814,291	4,719,991	2.42
3 ANCLOTE	1		0				0	LIGHT OIL	0	BBLS	5.80	0	0	0.00
4 ANCLOTE	2	503	176,325	47.1	97.3	82.3	9,307	HEAVY OIL	256,415	BBLS	6.40	1,641,057	4,269,312	2.42
5 ANCLOTE	2		0				0	LIGHT OIL	0	BBLS	5.80	0	0	0.00
6 BARTOW	1	115	37,793	44.2	97.8	84.3	10,072	HEAVY OIL	59,477	BBLS	6.40	380,651	951,828	2.52
7 BARTOW	1		0				0	LIGHT OIL	0	BBLS	5.80	0	0	0.00
8 BARTOW	2	117	14,889	17.1	98.9	86.3	10,615	HEAVY OIL	24,695	BBLS	6.40	158,047	395,117	2.65
9 BARTOW	3	208	204	5.6	9.2	83.4	9,803	HEAVY OIL	312	BBLS	6.40	2,000	5,000	2.45
10 BARTOW	3		8,473				10,155	GAS	86,043	MCF	1.00	86,043	197,900	2.34
11 CRYSTAL RIVER	1	372	231,386	83.6	84.9	98.5	9,562	COAL	87,798	TONS	25.20	2,212,513	3,771,808	1.63
12 CRYSTAL RIVER	1		0				0	LIGHT OIL	0	BBLS	5.80	0	0	0.00
13 CRYSTAL RIVER	2	468	309,911	89.0	90.0	99.3	9,575	COAL	117,754	TONS	25.20	2,967,390	5,058,707	1.63
14 CRYSTAL RIVER	2		0				0	LIGHT OIL	0	BBLS	5.80	0	0	0.00
15 CRYSTAL RIVER	4	697	366,152	70.6	73.1	96.4	9,363	COAL	136,585	TONS	25.10	3,428,281	6,979,489	1.91
16 CRYSTAL RIVER	4		0				0	LIGHT OIL	0	BBLS	5.80	0	0	0.00
17 CRYSTAL RIVER	5	697	499,164	96.3	97.1	99.6	9,304	COAL	185,029	TONS	25.10	4,644,222	9,454,970	1.89
18 CRYSTAL RIVER	5		0				0	LIGHT OIL	0	BBLS	5.80	0	0	0.00
19 SUWANNEE	1	33	296	1.4	100.0	95.5	12,342	HEAVY OIL	571	BBLS	6.40	3,653	11,873	4.01
20 SUWANNEE	1		57				12,787	GAS	729	MCF	1.00	729	1,676	2.94
21 SUWANNEE	2	32	279	1.3	100.0	95.9	12,535	HEAVY OIL	546	BBLS	6.40	3,497	11,366	4.07
22 SUWANNEE	2		31				12,988	GAS	403	MCF	1.00	403	926	2.99
23 SUWANNEE	3	80	297	0.7	99.9	86.6	11,803	HEAVY OIL	548	BBLS	6.40	3,505	11,393	3.84
24 SUWANNEE	3		3,665				12,228	GAS	44,816	MCF	1.00	44,816	103,076	2.81
25 AVON PARK	1-2	58	182	0.4	100.0	95.1	14,988	LIGHT OIL	470	BBLS	5.80	2,724	13,112	7.20
26 BARTOW	1-4	187	1,071	0.8	100.0	93.9	13,105	GAS	14,035	MCF	1.00	14,035	32,282	3.01
27 BAYBORO	1-4	188	11	0.0	100.0	78.0	13,126	LIGHT OIL	25	BBLS	5.80	144	681	6.19
28 DEBARY	1-10	656	490	2.8	99.8	99.0	12,329	LIGHT OIL	1,042	BBLS	5.80	6,041	29,446	6.01
29 DEBARY	1-10		13,020				12,445	GAS	162,034	MCF	1.00	162,034	372,678	2.86
30 HIGGINS	1-4	128	164	0.7	99.9	98.7	15,409	LIGHT OIL	436	BBLS	5.80	2,527	11,860	7.23
31 HIGGINS	1-4		499				14,457	GAS	7,214	MCF	1.00	7,214	16,592	3.33
32 INT CITY	1-10	614	44	1.8	99.9	99.8	13,158	LIGHT OIL	100	BBLS	5.80	579	2,711	6.16
33 INT CITY	1-10		7,952				12,071	GAS	95,989	MCF	1.00	95,989	220,774	2.78
34 INT CITY	11	143	479	0.5	100.0	67.0	11,881	LIGHT OIL	981	BBLS	5.80	5,691	26,650	5.56
35 PORT ST. JOE	1	15	0	0.0	0.0	0.0	0	LIGHT OIL	0	BBLS	5.80	0	0	0.00
36 RIO PINAR	1	15	0	0.0	0.0	0.0	0	LIGHT OIL	0	BBLS	5.80	0	0	0.00
37 SUWANNEE	1-3	162	16	1.7	100.0	92.9	12,859	LIGHT OIL	35	BBLS	5.80	208	998	6.23
38 SUWANNEE	1-3		2,092				12,731	GAS	26,633	MCF	1.00	26,633	61,256	2.93
39 TURNER	1-4	160	6	0.0	100.0	93.8	12,784	LIGHT OIL	13	BBLS	5.80	77	374	6.23
40 UNIV OF FLA.	1	38	26,382	98.5	98.5	100.0	9,539	GAS	251,658	MCF	1.00	251,658	426,858	1.62
41 OTHER - START UP		-	0	-	-	-	-	LIGHT OIL	12,069	BBLS	5.80	70,000	336,986	0.00
42 OTHER - GAS TRANSP.		-	0	-	-	-	-	GAS TRANSP	-	-	-	-	341,546	-
43 TOTAL		6,943	1,898,583				9,510					18,036,657	37,839,010	2.00

FLORIDA POWER CORPORATION
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Nov-97

(A) PLANT/UNIT		(B) NET CAPACITY (MW)	(C) NET GENERATION (MWH)	(D) CAPACITY FACTOR (%)	(E) EQUIV AVAIL FACTOR (%)	(F) OUTPUT FACTOR (%)	(G) AVG NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MMBTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3	767	0	0.0	0.0	0.0	0	NUCLEAR	0 MMBTU	1.00	0	0	0.00
2 ANCLOTE	1	517	0	0.0	0.0	0.0	0	HEAVY OIL	0 BBLS	6.40	0	0	0.00
3 ANCLOTE	1		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
4 ANCLOTE	2	517	92,147	24.8	74.5	50.2	9,720	HEAVY OIL	139,948 BBLS	6.40	895,669	2,463,089	2.67
5 ANCLOTE	2		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
6 BARTOW	1	117	13,418	15.9	99.3	85.6	10,295	HEAVY OIL	21,584 BBLS	6.40	138,138	365,851	2.73
7 BARTOW	1		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
8 BARTOW	2	119	8,325	9.7	99.4	78.7	10,713	HEAVY OIL	13,935 BBLS	6.40	89,186	236,203	2.84
9 BARTOW	3	213	31,390	48.2	95.0	88.7	9,998	HEAVY OIL	49,027 BBLS	6.40	313,774	831,012	2.65
10 BARTOW	3		39,424				10,356	GAS	408,275 MCF	1.00	408,275	939,032	2.38
11 CRYSTAL RIVER	1	373	239,881	89.3	94.3	95.0	9,615	COAL	91,526 TONS	25.20	2,306,456	3,899,009	1.63
12 CRYSTAL RIVER	1		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
13 CRYSTAL RIVER	2	469	300,517	89.0	90.3	99.3	9,575	COAL	114,185 TONS	25.20	2,877,450	4,864,261	1.62
14 CRYSTAL RIVER	2		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
15 CRYSTAL RIVER	4	717	443,792	86.0	84.7	90.9	9,379	COAL	165,830 TONS	25.10	4,162,325	8,294,801	1.87
16 CRYSTAL RIVER	4		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
17 CRYSTAL RIVER	5	717	496,604	96.2	97.4	99.6	9,248	COAL	183,006 TONS	25.10	4,593,450	9,153,958	1.84
18 CRYSTAL RIVER	5		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
19 SUWANNEE	1	34	272	1.6	100.0	95.4	12,351	HEAVY OIL	525 BBLS	6.40	3,359	11,417	4.20
20 SUWANNEE	1		114				12,795	GAS	1,459 MCF	1.00	1,459	3,355	2.94
21 SUWANNEE	2	33	244	1.0	100.0	98.8	12,572	HEAVY OIL	479 BBLS	6.40	3,063	10,425	4.27
22 SUWANNEE	2		2				13,025	GAS	28 MCF	1.00	28	60	3.00
23 SUWANNEE	3	80	297	7.2	100.0	88.1	11,778	HEAVY OIL	547 BBLS	6.40	3,498	11,888	4.00
24 SUWANNEE	3		3,824				12,202	GAS	46,660 MCF	1.00	46,660	107,319	2.81
25 AVON PARK	1-2	64	217	0.5	100.0	98.9	14,518	LIGHT OIL	543 BBLS	5.80	3,150	15,790	7.28
26 BARTOW	1-4	217	1,353	0.9	100.0	98.6	12,679	GAS	17,155 MCF	1.00	17,155	39,456	2.92
27 BAYBORO	1-4	232	8	0.0	100.0	69.0	13,073	LIGHT OIL	18 BBLS	5.80	105	514	6.42
28 DEBARY	1-10	708	504	1.2	99.9	98.7	12,225	LIGHT OIL	1,062 BBLS	5.80	6,161	31,253	6.20
29 DEBARY	1-10		6,356				12,438	GAS	79,056 MCF	1.00	79,056	181,829	2.86
30 HIGGINS	1-4	158	249	0.9	99.9	97.7	14,876	LIGHT OIL	639 BBLS	5.80	3,704	18,118	7.28
31 HIGGINS	1-4		731				13,988	GAS	10,225 MCF	1.00	10,225	23,518	3.22
32 INT CITY	1-10	744	680	1.4	99.9	98.5	12,548	LIGHT OIL	1,484 BBLS	5.80	8,608	42,016	6.12
33 INT CITY	1-10		6,887				11,888	GAS	81,873 MCF	1.00	81,873	188,307	2.73
34 INT CITY	11	169	977	0.8	100.0	91.8	11,506	LIGHT OIL	1,938 BBLS	5.80	11,241	54,869	5.62
35 PORT ST. JOE	1	18	0	0.0	0.0	0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
36 RIO PINAR	1	18	0	0.0	0.0	0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
37 SUWANNEE	1-3	201	85	2.0	100.0	92.8	12,308	LIGHT OIL	180 BBLS	5.80	1,046	5,274	6.20
38 SUWANNEE	1-3		2,845				12,390	GAS	35,250 MCF	1.00	35,250	81,074	2.85
39 TURNER	1-4	200	21	0.0	100.0	98.4	12,581	LIGHT OIL	46 BBLS	5.80	264	1,340	6.38
40 UNIV OF FLA.	1	42	29,780	98.5	98.5	100.0	9,352	GAS	278,559 MCF	1.00	278,559	476,402	1.60
41 OTHER - START UP		-	0	-	-	-	-	LIGHT OIL	12,069 BBLS	5.80	70,000	350,845	0.00
42 OTHER - GAS TRANSP.		-	0	-	-	-	-	GAS TRANSP.	-	-	-	572,000	-
43 TOTAL		7,522	1,721,1[illegible]				9,557				16,449,190	33,274,285	1.93

FLORIDA POWER CORPORATION
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Dec-97

(A) PLANT/UNIT		(B) NET CAPACITY (MW)	(C) NET GENERATION (MWH)	(D) CAPACITY FACTOR (%)	(E) EQUIV AVAIL FACTOR (%)	(F) OUTPUT FACTOR (%)	(G) AVG NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)		(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MMBTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3	767	0	0.0	0.0	0.0	0	NUCLEAR	0	MMBTU	1.00	0	0	0.00
2 ANCLOTE	1	517	124,680	32.4	81.2	50.6	9,644	HEAVY OIL	187,847	BBLS	6.40	1,202,221	3,550,309	2.85
3 ANCLOTE	1		0				0	LIGHT OIL	0	BBLS	5.80	0	0	0.00
4 ANCLOTE	2	517	101,381	26.4	97.0	39.0	10,054	HEAVY OIL	159,263	BBLS	6.40	1,019,285	3,010,075	2.97
5 ANCLOTE	2		0				0	LIGHT OIL	0	BBLS	5.80	0	0	0.00
6 BARTOW	1	117	6,888	7.9	99.6	83.6	10,304	HEAVY OIL	11,090	BBLS	6.40	70,974	205,714	2.99
7 BARTOW	1		0				0	LIGHT OIL	0	BBLS	5.80	0	0	0.00
8 BARTOW	2	119	5,232	5.9	99.6	82.0	10,555	HEAVY OIL	8,629	BBLS	6.40	55,224	160,083	3.06
9 BARTOW	3	213	21,123	50.0	94.1	62.0	9,900	HEAVY OIL	32,675	BBLS	6.40	209,118	606,115	2.87
10 BARTOW	3		58,123				10,256	GAS	596,109	MCF	1.00	596,109	1,490,274	2.56
11 CRYSTAL RIVER	1	373	255,988	92.2	94.3	98.1	9,589	COAL	97,407	TONS	25.20	2,454,669	4,192,419	1.64
12 CRYSTAL RIVER	1		0				0	LIGHT OIL	0	BBLS	5.80	0	0	0.00
13 CRYSTAL RIVER	2	469	310,534	89.0	90.3	99.3	9,519	COAL	117,301	TONS	25.20	2,955,973	5,048,614	1.63
14 CRYSTAL RIVER	2		0				0	LIGHT OIL	0	BBLS	5.80	0	0	0.00
15 CRYSTAL RIVER	4	717	494,082	92.6	94.7	97.9	9,285	COAL	182,771	TONS	25.10	4,587,551	9,292,076	1.88
16 CRYSTAL RIVER	4		0				0	LIGHT OIL	0	BBLS	5.80	0	0	0.00
17 CRYSTAL RIVER	5	717	510,808	95.8	97.4	99.1	9,211	COAL	187,452	TONS	25.10	4,705,052	9,530,074	1.87
18 CRYSTAL RIVER	5		0				0	LIGHT OIL	0	BBLS	5.80	0	0	0.00
19 SUWANNEE	1	34	488	2.3	100.0	92.5	12,490	HEAVY OIL	952	BBLS	6.40	6,095	22,238	4.56
20 SUWANNEE	1		94				12,940	GAS	1,216	MCF	1.00	1,216	3,041	3.24
21 SUWANNEE	2	33	470	2.0	100.0	99.6	12,582	HEAVY OIL	923	BBLS	6.40	5,904	21,541	4.58
22 SUWANNEE	2		10				13,014	GAS	130	MCF	1.00	130	325	3.25
23 SUWANNEE	3	80	173	4.3	99.9	91.5	11,554	HEAVY OIL	312	BBLS	6.40	1,999	7,293	4.22
24 SUWANNEE	3		2,395				11,970	GAS	28,668	MCF	1.00	28,668	71,670	2.99
25 AVON PARK	1-2	64	407	0.9	99.9	97.8	15,301	LIGHT OIL	1,074	BBLS	5.80	6,228	32,447	7.97
26 BARTOW	1-4	217	2,047	1.3	100.0	98.8	12,567	GAS	25,725	MCF	1.00	25,725	64,312	3.14
27 BAYBORO	1-4	232	178	0.1	100.0	90.3	13,211	LIGHT OIL	405	BBLS	5.80	2,352	12,017	6.75
28 DEBARY	1-10	788	4,035	1.5	99.9	98.3	11,671	LIGHT OIL	8,119	BBLS	5.80	47,092	248,210	6.15
29 DEBARY	1-10		4,776				11,711	GAS	55,932	MCF	1.00	55,932	139,829	2.93
30 HIGGINS	1-4	158	469	1.3	99.8	99.1	16,074	LIGHT OIL	1,300	BBLS	5.80	7,539	38,369	8.18
31 HIGGINS	1-4		1,116				14,325	GAS	15,987	MCF	1.00	15,987	39,967	3.58
32 INT CITY	1-10	744	644	1.4	99.9	96.8	13,017	LIGHT OIL	1,445	BBLS	5.80	8,383	42,580	6.61
33 INT CITY	1-10		7,003				11,540	GAS	80,815	MCF	1.00	80,815	202,037	2.89
34 INT CITY	11	169	1,814	1.4	99.9	91.7	10,962	LIGHT OIL	3,428	BBLS	5.80	19,885	101,002	5.57
35 PORT ST. JOE	1	18	2	0.0	100.0	92.6	16,024	LIGHT OIL	6	BBLS	5.80	32	168	8.40
36 RIO PINAR	1	18	3	0.0	100.0	83.3	15,799	LIGHT OIL	8	BBLS	5.80	47	248	8.26
37 SUWANNEE	1-3	201	114	0.8	100.0	96.8	12,922	LIGHT OIL	254	BBLS	5.80	1,473	7,719	6.77
38 SUWANNEE	1-3		1,040				13,733	GAS	14,282	MCF	1.00	14,282	35,706	3.43
39 TURNER	1-4	200	849	0.6	99.9	77.9	11,832	LIGHT OIL	1,732	BBLS	5.80	10,045	52,946	6.24
40 UNIV OF FLA.	1	42	30,779	98.5	98.5	100.0	9,352	GAS	287,845	MCF	1.00	287,845	542,671	1.76
41 OTHER - START UP		-	1	-	-	-	-	LIGHT OIL	12,069	BBLS	5.80	70,000	364,724	0.00
42 OTHER - GAS TRANSP.		-	0	-	-	-	-	GAS TRANSP	-	-	-	-	730,327	-
43 TOTAL		7,522	1,947,725				9,526					18,553,851	39,867,318	2.05

SCHEDULE E4

FLORIDA POWER CORPORATION
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Jan-98

(A) PLANT/UNIT		(B) NET CAPACITY (MW)	(C) NET GENERATION (MWH)	(D) CAPACITY FACTOR (%)	(E) EQUIV AVAIL FACTOR (%)	(F) OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MMBTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3	767	538,409	94.0	94.3	100.0	10,327	NUCLEAR	5,539,496 MMBTU	1.00	5,539,496	1,828,034	0.34
2 ANCLOTE	1	517	78,098	19.8	97.1	28.8	10,862	HEAVY OIL	129,149 BBLS	6.40	826,555	2,440,920	3.21
3 ANCLOTE	1		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
4 ANCLOTE	2	517	47,449	12.3	97.2	19.6	11,824	HEAVY OIL	87,662 BBLS	6.40	561,037	1,656,812	3.49
5 ANCLOTE	2		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
6 BARTOW	1	117	4,177	4.8	99.8	89.5	10,235	HEAVY OIL	6,680 BBLS	6.40	42,752	123,913	2.97
7 BARTOW	1		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
8 BARTOW	2	119	3,530	4.0	99.8	86.2	10,465	HEAVY OIL	5,772 BBLS	6.40	36,941	107,072	3.03
9 BARTOW	3	213	2,365	32.5	94.8	48.1	10,569	HEAVY OIL	3,906 BBLS	6.40	24,998	72,448	3.06
10 BARTOW	3		49,132			-	10,949	GAS	537,946 MCF	1.00	537,946	1,344,866	2.74
11 CRYSTAL RIVER	1	373	232,227	83.7	94.3	89.0	9,601	COAL	88,477 TONS	25.20	2,229,611	3,806,265	1.64
12 CRYSTAL RIVER	1		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
13 CRYSTAL RIVER	2	469	310,533	89.0	90.3	99.3	9,279	COAL	114,343 TONS	25.20	2,881,436	4,919,022	1.58
14 CRYSTAL RIVER	2		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
15 CRYSTAL RIVER	4	717	398,448	74.7	94.7	79.0	9,323	COAL	147,987 TONS	25.10	3,714,731	7,490,140	1.88
16 CRYSTAL RIVER	4		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
17 CRYSTAL RIVER	5	717	492,240	92.3	97.4	95.5	9,208	COAL	180,540 TONS	25.10	4,531,561	9,137,144	1.86
18 CRYSTAL RIVER	5		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
19 SUWANNEE	1	34	485	2.0	100.0	99.6	12,555	HEAVY OIL	951 BBLS	6.40	6,089	22,216	4.58
20 SUWANNEE	1		16				13,007	GAS	208 MCF	1.00	208	520	3.25
21 SUWANNEE	2	33	472	2.0	100.0	99.6	12,559	HEAVY OIL	926 BBLS	6.40	5,926	21,627	4.58
22 SUWANNEE	2		9				13,011	GAS	117 MCF	1.00	117	293	3.25
23 SUWANNEE	3	80	87	2.2	99.6	93.5	11,544	HEAVY OIL	157 BBLS	6.40	1,004	3,664	4.21
24 SUWANNEE	3		1,229				11,980	GAS	14,899 MCF	1.00	14,899	36,747	2.99
25 AVON PARK	1-2	64	461	1.0	99.9	98.4	15,240	LIGHT OIL	1,211 BBLS	5.80	7,026	36,606	7.94
26 BARTOW	1-4	217	2,567	1.6	99.9	99.0	12,585	GAS	32,308 MCF	1.00	32,308	80,764	3.15
27 BAYBORO	1-4	232	365	0.2	100.0	95.4	13,165	LIGHT OIL	828 BBLS	5.80	4,805	24,556	6.73
28 DEBARY	1-10	768	5,719	1.6	99.9	99.2	11,620	LIGHT OIL	11,458 BBLS	5.80	66,455	350,283	6.12
29 DEBARY	1-10		4,728				11,684	GAS	55,219 MCF	1.00	55,219	138,048	2.92
30 HIGGINS	1-4	158	560	1.5	99.9	99.1	16,006	LIGHT OIL	1,545 BBLS	5.80	8,963	45,620	8.15
31 HIGGINS	1-4		1,202				14,314	GAS	17,205 MCF	1.00	17,205	43,014	3.58
32 INT CITY	1-10	744	1,081	1.5	99.9	99.8	12,989	LIGHT OIL	2,421 BBLS	5.80	14,041	71,319	6.60
33 INT CITY	1-10		7,482				11,534	GAS	86,087 MCF	1.00	86,087	215,167	2.88
34 INT CITY	11	169	2,278	1.8	99.9	98.9	10,892	LIGHT OIL	4,274 BBLS	5.80	24,790	125,917	5.53
35 PORT ST. JOE	1	18	8	0.1	100.0	88.9	16,014	LIGHT OIL	22 BBLS	5.80	128	671	8.39
36 RIO PINAR	1	18	9	0.1	100.0	100.0	15,798	LIGHT OIL	25 BBLS	5.80	142	743	8.26
37 SUWANNEE	1-3	201	233	0.8	100.0	97.9	12,905	LIGHT OIL	518 BBLS	5.80	3,007	15,755	6.76
38 SUWANNEE	1-3		994				13,798	GAS	13,715 MCF	1.00	13,715	34,288	3.45
39 TURNER	1-4	200	1,365	0.9	99.9	99.4	11,821	LIGHT OIL	2,823 BBLS	5.80	16,372	86,292	6.23
40 UNIV OF FLA.	1	42	30,779	98.5	98.5	100.0	9,352	GAS	287,845 MCF	1.00	287,845	523,953	1.70
41 OTHER - START UP		-	0	-	-	-	-	LIGHT OIL	12,069 BBLS	5.80	70,000	364,724	0.00
42 OTHER - GAS TRANSP.		-	0	-	-	-	-	GAS TRANSP.	- -	-	-	1,444,812	-
43 TOTAL		7,522	2,214,731				9,781				21,663,194	38,814,017	1.65

SCHEDULE E4

FLORIDA POWER CORPORATION
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Feb-98

	(A) PLANT/UNIT		(B) NET CAPACITY (MW)	(C) NET GENERATION (MWH)	(D) CAPACITY FACTOR (%)	(E) EQUIV AVAIL FACTOR (%)	(F) OUTPUT FACTOR (%)	(G) AVG NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MMBTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (C/KWH)
1	CRYS RIV NUC	3	767	464,499	94.0	94.3	100.0	10,327	NUCLEAR	5,003,421 MMBTU	1.00	5,003,421	1,651,129	0.34
2	ANCLOTE	1	517	47,200	13.6	97.3	20.9	11,942	HEAVY OIL	88,072 BBLS	6.40	563,662	1,550,072	3.28
3	ANCLOTE	1		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
4	ANCLOTE	2	517	31,198	9.0	97.3	14.7	12,979	HEAVY OIL	63,265 BBLS	6.40	404,893	1,113,455	3.57
5	ANCLOTE	2		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
6	BARTOW	1	117	2,518	3.2	99.8	83.1	10,375	HEAVY OIL	4,082 BBLS	6.40	26,124	69,188	2.75
7	BARTOW	1		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
8	BARTOW	2	119	1,841	2.3	99.9	81.0	10,648	HEAVY OIL	3,083 BBLS	6.40	19,603	51,917	2.82
9	BARTOW	3	213	2,116	28.9	95.0	39.8	10,868	HEAVY OIL	3,593 BBLS	6.40	22,997	60,905	2.88
10	BARTOW	3		38,434				11,259	GAS	410,210 MCF	1.00	410,210	943,484	2.59
11	CRYSTAL RIVER	1	373	213,797	85.3	94.3	90.7	9,597	COAL	81,421 TONS	25.20	2,051,810	3,502,732	1.64
12	CRYSTAL RIVER	1		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
13	CRYSTAL RIVER	2	469	280,481	89.0	90.3	99.3	9,271	COAL	103,188 TONS	25.20	2,600,339	4,439,151	1.58
14	CRYSTAL RIVER	2		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
15	CRYSTAL RIVER	4	717	413,840	85.9	94.7	90.8	9,217	COAL	151,967 TONS	25.10	3,814,383	7,691,033	1.86
16	CRYSTAL RIVER	4		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
17	CRYSTAL RIVER	5	717	446,531	92.7	97.4	95.9	9,198	COAL	163,633 TONS	25.10	4,107,192	8,281,474	1.85
18	CRYSTAL RIVER	5		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
19	SUWANNEE	1	34	295	1.3	100.0	99.7	12,427	HEAVY OIL	573 BBLS	6.40	3,668	12,459	4.22
20	SUWANNEE	1		0				0	GAS	0 MCF	1.00	0	0	0.00
21	SUWANNEE	2	33	284	1.3	100.0	98.9	12,490	HEAVY OIL	554 BBLS	6.40	3,547	12,055	4.24
22	SUWANNEE	2		0				0	GAS	0 MCF	1.00	0	0	0.00
23	SUWANNEE	3	80	44	1.4	100.0	98.5	11,453	HEAVY OIL	79 BBLS	6.40	504	1,713	3.89
24	SUWANNEE	3		697				11,865	GAS	8,270 MCF	1.00	8,270	19,021	2.73
25	AVON PARK	1-2	64	285	0.7	100.0	99.5	15,235	LIGHT OIL	749 BBLS	5.80	4,342	21,762	7.64
26	BARTOW	1-4	217	1,512	1.0	100.0	97.8	12,637	GAS	19,107 MCF	1.00	19,107	43,946	2.91
27	BAYBORO	1-4	232	230	0.1	100.0	94.4	13,139	LIGHT OIL	521 BBLS	5.80	3,022	14,844	6.45
28	DEBARY	1-10	766	2,959	1.1	99.9	99.1	11,622	LIGHT OIL	5,929 BBLS	5.80	34,389	174,436	5.90
29	DEBARY	1-10		2,608				11,653	GAS	30,391 MCF	1.00	30,391	69,899	2.68
30	HIGGINS	1-4	158	340	1.0	99.9	98.6	16,011	LIGHT OIL	939 BBLS	5.80	5,444	26,627	7.83
31	HIGGINS	1-4		731				14,312	GAS	10,462 MCF	1.00	10,462	24,063	3.29
32	INT CITY	1-10	744	694	1.0	99.9	98.8	12,999	LIGHT OIL	1,555 BBLS	5.80	9,021	44,033	6.34
33	INT CITY	1-10		4,494				11,528	GAS	51,807 MCF	1.00	51,807	119,156	2.65
34	INT CITY	11	169	1,268	1.1	100.0	89.3	11,010	LIGHT OIL	2,407 BBLS	5.80	13,961	68,143	5.37
35	PORT ST. JOE	1	18	6	0.0	100.0	95.2	16,015	LIGHT OIL	17 BBLS	5.80	96	484	8.07
36	RIO PINAR	1	18	6	0.0	100.0	83.3	15,794	LIGHT OIL	16 BBLS	5.80	95	477	7.95
37	SUWANNEE	1-3	201	143	0.6	100.0	97.3	12,515	LIGHT OIL	309 BBLS	5.80	1,790	9,022	6.31
38	SUWANNEE	1-3		600				12,702	GAS	7,621 MCF	1.00	7,621	17,529	2.92
39	TURNER	1-4	200	719	0.5	99.9	98.0	11,823	LIGHT OIL	1,466 BBLS	5.80	8,501	43,119	6.00
40	UNIV OF FLA.	1	42	27,801	98.5	98.5	100.0	9,352	GAS	259,995 MCF	1.00	259,995	426,102	1.53
41	OTHER - START UP		-	0	-	-	-	-	LIGHT OIL	12,069 BBLS	5.80	70,000	350,845	0.00
42	OTHER - GAS TRANSP.		-	0	-	-	-	-	GAS TRANSP.	-	-	-	1,390,477	-
43	TOTAL		7,522	2,008,169				9,755				19,570,646	32,244,755	1.61

SCHEDULE E4

FLORIDA POWER CORPORATION
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Mar-98

(A) PLANT/UNIT		(B) NET CAPACITY (MW)	(C) NET GENERATION (MWH)	(D) CAPACITY FACTOR (%)	(E) EQUIV AVAIL FACTOR (%)	(F) OUTPUT FACTOR (%)	(G) AVG NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MMBTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3	787	538,409	94.0	94.3	100.0	10,327	NUCLEAR	5,539,496 MMBTU	1.00	5,539,496	1,828,034	0.34
2 ANCLOTE	1	517	134,368	34.9	95.9	47.6	9,705	HEAVY OIL	203,758 BBLS	6.40	1,304,041	3,392,545	2.52
3 ANCLOTE	1		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
4 ANCLOTE	2	517	83,729	21.8	97.1	33.4	10,324	HEAVY OIL	135,065 BBLS	6.40	864,418	2,248,838	2.69
5 ANCLOTE	2		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
6 BARTOW	1	117	17,084	19.6	99.0	80.8	10,036	HEAVY OIL	26,758 BBLS	6.40	171,254	428,136	2.51
7 BARTOW	1		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
8 BARTOW	2	119	3,310	3.7	54.8	88.8	10,481	HEAVY OIL	5,421 BBLS	6.40	34,692	86,730	2.62
9 BARTOW	3	213	2,237	57.2	95.0	75.2	9,834	HEAVY OIL	3,437 BBLS	6.40	21,999	54,997	2.46
10 BARTOW	3		88,397				10,188	GAS	900,589 MCF	1.00	900,589	1,938,268	2.19
11 CRYSTAL RIVER	1	373	105,958	38.2	39.5	98.8	9,583	COAL	40,293 TONS	25.20	1,015,378	1,733,392	1.64
12 CRYSTAL RIVER	1		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
13 CRYSTAL RIVER	2	409	230,350	68.0	67.0	99.3	9,284	COAL	84,864 TONS	25.20	2,138,569	3,650,843	1.58
14 CRYSTAL RIVER	2		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
15 CRYSTAL RIVER	4	717	199,189	37.3	39.7	94.0	9,194	COAL	72,962 TONS	25.10	1,831,344	3,692,602	1.85
16 CRYSTAL RIVER	4		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
17 CRYSTAL RIVER	5	717	507,075	95.2	97.4	98.5	9,210	COAL	186,356 TONS	25.10	4,677,529	9,431,483	1.86
18 CRYSTAL RIVER	5		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
19 SUWANNEE	1	34	237	1.0	100.0	98.4	12,587	HEAVY OIL	466 BBLS	6.40	2,983	9,695	4.09
20 SUWANNEE	1		4				13,040	GAS	52 MCF	1.00	52	112	2.80
21 SUWANNEE	2	33	223	0.9	100.0	98.6	12,597	HEAVY OIL	439 BBLS	6.40	2,809	9,130	4.09
22 SUWANNEE	2		2				13,050	GAS	28 MCF	1.00	28	56	2.81
23 SUWANNEE	3	80	84	1.6	100.0	79.3	11,877	HEAVY OIL	156 BBLS	6.40	998	3,242	3.86
24 SUWANNEE	3		842				12,305	GAS	10,381 MCF	1.00	10,381	22,276	2.65
25 AVON PARK	1-2	64	264	0.6	100.0	97.1	14,532	LIGHT OIL	661 BBLS	5.80	3,836	18,468	7.00
26 BARTOW	1-4	217	1,919	1.2	100.0	99.1	12,691	GAS	24,354 MCF	1.00	24,354	52,381	2.73
27 BAYBORO	1-4	232	70	0.0	100.0	92.8	13,141	LIGHT OIL	159 BBLS	5.80	920	4,336	6.19
28 DEBARY	1-10	788	1,269	1.0	99.9	99.5	12,246	LIGHT OIL	2,679 BBLS	5.80	15,540	75,745	5.97
29 DEBARY	1-10		4,791				12,378	GAS	59,303 MCF	1.00	59,303	127,501	2.66
30 HIGGINS	1-4	158	302	1.1	99.9	98.5	13,982	LIGHT OIL	727 BBLS	5.80	4,217	19,789	6.55
31 HIGGINS	1-4		1,009				14,907	GAS	15,041 MCF	1.00	15,041	32,339	3.21
32 INT CITY	1-10	744	1,250	1.3	99.9	98.5	12,449	LIGHT OIL	2,683 BBLS	5.80	15,561	72,870	5.83
33 INT CITY	1-10		6,008				11,837	GAS	71,117 MCF	1.00	71,117	152,901	2.54
34 INT CITY	11	169	995	0.8	100.0	92.0	11,510	LIGHT OIL	1,975 BBLS	5.80	11,452	53,629	5.39
35 PORT ST. JOE	1	15	0	0.0	0.0	0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
36 RIO PINAR	1	16	0	0.0	0.0	0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
37 SUWANNEE	1-3	201	316	0.5	100.0	96.3	12,210	LIGHT OIL	665 BBLS	5.80	3,856	18,686	5.91
38 SUWANNEE	1-3		503				12,239	GAS	6,156 MCF	1.00	6,156	13,236	2.63
39 TURNER	1-4	200	96	0.1	100.0	68.8	12,538	LIGHT OIL	208 BBLS	5.80	1,204	5,867	6.11
40 UNIV OF FLA.	1	42	28,794	92.1	92.2	100.0	9,352	GAS	269,281 MCF	1.00	269,281	419,978	1.46
41 OTHER - START UP		-	0	-	-	-	-	LIGHT OIL	12,069 BBLS	5.80	70,000	336,966	0.00
42 OTHER - GAS TRANSP.		-	0	-	-	-	-	GAS TRANSP.	-	-	-	1,398,381	-
43 TOTAL		7,522	1,857,882				9,750				19,088,378	31,329,410	1.60

FLORIDA POWER CORPORATION
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD OF: Oct-97 THROUGH Mar-98

(A) PLANT/UNIT		(B) NET CAPACITY (MW)	(C) NET GENERATION (MWH)	(D) CAPACITY FACTOR (%)	(E) EQUIV AVAIL FACTOR (%)	(F) OUTPUT FACTOR (%)	(G) AVG NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MMBTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3	765	1,557,317	46.6	47.2	100.2	10,327	NUCLEAR	16,082,413 MMBTU	1.00	16,082,413	5,307,196	0.34
2 ANCLOTE	1	515	577,577	25.7	78.3	45.3	9,887	HEAVY OIL	892,308 BBLS	6.40	5,710,771	15,653,637	2.71
3 ANCLOTE	1		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
4 ANCLOTE	2	515	532,227	23.7	93.4	39.0	10,120	HEAVY OIL	841,618 BBLS	6.40	5,386,358	14,761,582	2.77
5 ANCLOTE	2		0				0	LIGHT OIL	0 BBLS	5.80	1	0	0.00
6 BARTOW	1	117	81,858	16.1	99.2	83.5	10,138	HEAVY OIL	129,671 BBLS	6.40	829,894	2,144,429	2.62
7 BARTOW	1		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
8 BARTOW	2	119	37,127	7.2	92.0	83.5	10,604	HEAVY OIL	61,514 BBLS	6.40	393,693	1,037,102	2.79
9 BARTOW	3	212	59,435	38.8	80.5	59.7	10,009	HEAVY OIL	92,950 BBLS	6.40	594,883	1,630,476	2.74
10 BARTOW	3		279,983				10,498	GAS	2,939,173 MCF	1.00	2,939,173	6,851,821	2.45
11 CRYSTAL RIVER	1	373	1,279,235	78.6	83.6	94.5	9,592	COAL	486,922 TONS	25.20	12,270,435	20,905,625	1.63
12 CRYSTAL RIVER	1		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
13 CRYSTAL RIVER	2	469	1,742,328	85.1	88.4	99.3	9,425	COAL	651,634 TONS	25.20	16,421,166	27,980,599	1.61
14 CRYSTAL RIVER	2		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
15 CRYSTAL RIVER	4	714	2,315,503	74.3	76.9	91.0	9,302	COAL	858,111 TONS	25.10	21,538,595	43,440,141	1.88
16 CRYSTAL RIVER	4		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
17 CRYSTAL RIVER	5	714	2,953,422	94.7	97.4	98.1	9,230	COAL	1,086,016 TONS	25.10	27,259,006	54,989,084	1.86
18 CRYSTAL RIVER	5		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
19 SUWANNEE	1	34	2,073	1.6	100.0	96.9	12,468	HEAVY OIL	4,038 BBLS	6.40	25,846	89,897	4.34
20 SUWANNEE	1		285				12,857	GAS	3,664 MCF	1.00	3,664	8,705	3.05
21 SUWANNEE	2	33	1,972	1.4	100.0	99.1	12,552	HEAVY OIL	3,868 BBLS	6.40	24,753	86,144	4.37
22 SUWANNEE	2		54				12,999	GAS	702 MCF	1.00	702	1,660	3.07
23 SUWANNEE	3	80	982	3.9	99.9	88.6	11,719	HEAVY OIL	1,798 BBLS	6.40	11,508	39,193	3.99
24 SUWANNEE	3		12,652				12,130	GAS	153,474 MCF	1.00	153,474	360,109	2.85
25 AVON PARK	1-2	63	1,816	0.7	100.0	98.5	15,036	LIGHT OIL	4,708 BBLS	5.80	27,306	138,186	7.61
26 BARTOW	1-4	212	10,469	1.1	100.0	98.8	12,674	GAS	132,682 MCF	1.00	132,682	313,121	2.99
27 BAYBORO	1-4	225	862	0.1	100.0	95.9	13,164	LIGHT OIL	1,956 BBLS	5.80	11,348	50,948	6.61
28 DEBARY	1-10	764	14,976	1.5	99.9	96.7	11,731	LIGHT OIL	30,290 BBLS	5.80	175,680	909,354	6.07
29 DEBARY	1-10		36,277				12,182	GAS	441,934 MCF	1.00	441,934	1,029,783	2.84
30 HIGGINS	1-4	153	2,084	1.1	99.9	99.8	15,544	LIGHT OIL	5,585 BBLS	5.80	32,394	160,384	7.70
31 HIGGINS	1-4		5,288				14,398	GAS	76,135 MCF	1.00	76,135	179,492	3.39
32 INT CITY	1-10	722	4,399	1.4	99.9	97.8	12,774	LIGHT OIL	9,689 BBLS	5.80	56,193	275,528	6.26
33 INT CITY	1-10		39,808				11,749	GAS	467,686 MCF	1.00	467,686	1,098,341	2.76
34 INT CITY	11	165	7,809	1.1	100.0	91.7	11,144	LIGHT OIL	15,004 BBLS	5.80	87,021	430,210	5.51
35 PORT ST. JOE	1	18	16	0.0	50.0	94.3	16,016	LIGHT OIL	44 BBLS	5.80	256	1,324	8.27
36 RIO PINAR	1	18	18	0.0	50.0	93.5	15,798	LIGHT OIL	49 BBLS	5.80	284	1,468	8.16
37 SUWANNEE	1-3	195	907	1.1	100.0	92.5	12,547	LIGHT OIL	1,962 BBLS	5.80	11,380	57,453	6.33
38 SUWANNEE	1-3		8,074				12,838	GAS	103,658 MCF	1.00	103,658	243,089	3.01
39 TURNER	1-4	193	3,076	0.4	100.0	96.2	11,854	LIGHT OIL	6,287 BBLS	5.80	36,463	189,938	6.17
40 UNIV OF FLA.	1	41	174,321	97.3	97.5	99.9	9,380	GAS	1,635,183 MCF	1.00	1,635,183	2,816,165	1.62
41 OTHER - START UP		-	0	-	-	-	-	LIGHT OIL	72,414 BBLS	5.80	420,000	2,105,089	0.00
42 OTHER - GAS TRANSP.		-	0	-	-	-	-	GAS TRANSP.	- -	-	-	5,875,343	-
43 TOTAL		7,425	11,744,226				9,653				113,361,915	211,168,794	1.80

FLORIDA POWER CORPORATION
INVENTORY ANALYSIS

ESTIMATED FOR THE PERIOD OF: OCT-97 THROUGH MAR-98

	HEAVY OIL		Oct-97	Nov-97	Dec-97	Jan-98	Feb-98	Mar-98	TOTAL
1	PURCHASES:								
2	UNITS	BBL	626,047	226,046	401,690	235,203	163,291	375,499	2,027,766
3	UNIT COST	$/BBL	16.65	17.60	18.90	18.90	17.60	16.65	17.54
4	AMOUNT	$	10,423,684	3,979,404	7,591,950	4,445,344	2,873,740	6,252,061	35,565,183
5	BURNED:								
6	UNITS	BBL	626,047	226,046	401,690	235,203	163,291	375,499	2,027,766
7	UNIT COST	$/BBL	16.57	17.39	18.88	18.91	17.59	16.60	17.48
8	AMOUNT	$	10,375,679	3,929,885	7,583,346	4,448,673	2,871,764	6,233,313	35,442,660
9	ENDING INVENTORY:								
10	UNITS	BBL	730,000	730,000	730,000	470,000	470,000	470,000	
11	UNIT COST	$/BBL	16.57	16.82	17.56	17.88	17.81	17.29	
12	AMOUNT	$	12,098,509	12,275,717	12,815,692	8,405,158	8,370,826	8,128,638	
13	DAYS SUPPLY:		36	97	56	62	81	39	
	LIGHT OIL								
14	PURCHASES:								
15	UNITS	BBL	3,102	5,910	17,772	25,126	13,907	9,757	75,573
16	UNIT COST	$/BBL	27.95	29.10	30.25	30.25	29.10	27.95	29.56
17	AMOUNT	$	86,697	171,992	537,606	760,066	404,693	272,699	2,233,722
18	BURNED:								
19	UNITS	BBL	3,102	5,910	17,772	25,126	13,907	9,757	75,573
20	UNIT COST	$/BBL	27.67	28.62	30.14	30.16	28.97	27.61	29.39
21	AMOUNT	$	85,829	169,175	535,706	757,743	402,960	269,389	2,220,792
22	ENDING INVENTORY:								
23	UNITS	BBL	500,000	500,000	500,000	340,000	340,000	340,000	
24	UNIT COST	$/BBL	27.67	27.69	27.79	27.90	27.94	27.94	
25	AMOUNT	$	13,836,650	13,844,865	13,899,823	9,484,620	9,500,707	9,500,771	
26	DAYS SUPPLY:		4999	2539	872	419	685	1080	
	COAL								
27	PURCHASES:								
28	UNITS	TON	523,000	517,000	517,000	450,000	450,000	450,000	2,907,000
29	UNIT COST	$/TON	48.17	47.86	48.15	48.08	48.08	48.08	48.07
30	AMOUNT	$	25,192,910	24,743,620	24,893,550	21,636,000	21,636,000	21,636,000	139,738,080
31	BURNED:								
32	UNITS	TON	527,166	554,546	584,931	531,357	500,209	384,474	3,082,683
33	UNIT COST	$/TON	47.89	47.27	47.90	47.71	47.81	48.14	47.79
34	AMOUNT	$	25,254,873	26,212,029	28,063,194	25,352,672	23,914,350	18,508,301	147,315,449
35	ENDING INVENTORY:								
36	UNITS	TON	475,000	437,454	369,523	288,166	237,957	303,483	
37	UNIT COST	$/TON	47.93	47.89	48.03	48.06	48.07	48.08	
38	AMOUNT	$	22,764,899	20,950,384	17,748,754	13,848,714	11,438,892	14,590,545	
39	DAYS SUPPLY:		29	25	22	20	15	21	
	GAS								
40	BURNED:								
41	UNITS	MCF	689,864	956,637	1,106,769	1,045,327	797,864	1,356,290	5,954,271
42	UNIT COST	$/MCF	2.57	2.73	3.00	3.69	3.83	3.06	3.15
43	AMOUNT	$	1,775,864	2,612,301	3,320,308	3,862,270	3,053,677	4,153,407	18,777,827
	NUCLEAR								
44	BURNED:								
45	UNITS	MMBTU	0	0	0	5,539,496	5,001,421	5,539,496	16,082,413
46	UNIT COST	$/MMBTU	0.00	0.00	0.00	0.33	0.33	0.33	0.33
47	AMOUNT	$	0	0	0	1,828,034	1,651,129	1,828,034	5,307,196

FLORIDA POWER CORPORATION
FUEL COST OF POWER SOLD
ESTIMATED FOR THE PERIOD OF: OCT-97 THROUGH MAR-98

(1) MONTH	(2) SOLD TO	(3) TYPE & SCHEDULE	(4) TOTAL KWH SOLD	(5) KWH WHEELED FROM OTHER SYSTEMS	(6) KWH FROM OWN GENERATION	(7) C/KWH (A) FUEL COST	(7) C/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJ (6) x (7)(A)	(9) TOTAL COST $ (6) x (7)(B)	(10) REFUNDABLE GAIN ON POWER SALES $
Oct-97	ECONSALE	C	12,000,000		12,000,000	1.860	2.505	223,200	300,600	61,920
	SALE D	D	0		0	0.000	0.000	0	0	0
	SALE F	F	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	123,092,000		123,092,000	2.391	2.391	2,943,000	2,943,000	0
	TOTAL		135,092,000		135,092,000	2.344	2.401	3,166,200	3,243,600	61,920
Nov-97	ECONSALE	C	15,000,000		15,000,000	1.636	2.281	245,400	342,150	77,400
	SALE D	D	0		0	0.000	0.000	0	0	0
	SALE F	F	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	91,300,000		91,300,000	2.226	2.226	2,032,000	2,032,000	0
	TOTAL		106,300,000		106,300,000	2.142	2.233	2,277,400	2,374,150	77,400
Dec-97	ECONSALE	C	60,000,000		60,000,000	1.875	2.520	1,125,000	1,512,000	309,600
	SALE D	D	0		0	0.000	0.000	0	0	0
	SALE F	F	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	13,302,000		13,302,000	2.030	2.030	270,000	270,000	0
	TOTAL		73,302,000		73,302,000	1.903	2.431	1,395,000	1,782,000	309,600
Jan-98	ECONSALE	C	90,000,000		90,000,000	1.713	2.370	1,541,700	2,133,000	473,040
	SALE D	D	0		0	0.000	0.000	0	0	0
	SALE F	F	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	14,239,000		14,239,000	1.749	1.749	249,000	249,000	0
	TOTAL		104,239,000		104,239,000	1.718	2.285	1,790,700	2,382,000	473,040
Feb-98	ECONSALE	C	100,000,000		100,000,000	1.741	2.398	1,741,000	2,398,000	525,600
	SALE D	D	0		0	0.000	0.000	0	0	0
	SALE F	F	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	58,714,000		58,714,000	1.880	1.880	1,104,000	1,104,000	0
	TOTAL		158,714,000		158,714,000	1.793	2.206	2,845,000	3,502,000	525,600
Mar-98	ECONSALE	C	100,000,000		100,000,000	1.814	2.471	1,814,000	2,471,000	525,600
	SALE D	D	0		0	0.000	0.000	0	0	0
	SALE F	F	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	86,637,000		86,637,000	2.236	2.236	1,937,000	1,937,000	0
	TOTAL		186,637,000		186,637,000	2.010	2.362	3,751,000	4,408,000	525,600
Oct-97 THRU Mar-98	ECONSALE	C	377,000,000		377,000,000	1.775	2.429	6,690,300	9,156,750	1,973,160
	SALE D	D	0		0	0.000	0.000	0	0	0
	SALE F	F	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	387,284,000		387,284,000	2.204	2.204	8,535,000	8,535,000	0
	TOTAL		764,284,000		764,284,000	1.992	2.315	15,225,300	17,691,750	1,973,160

FLORIDA POWER CORPORATION
PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGEN PURCHASES)
ESTIMATED FOR THE PERIOD OF: OCT-97 THROUGH MAR-98

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
							C/KWH		
MONTH	NAME OF PURCHASE	TYPE & SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ (7) x (8)(B)
Oct-97	EMERGENCY	A&B	13,000			13,000	6.892	9.846	1,280
	TECO	--	2,326,000			2,326,000	2.790	2.790	64,900
	UPS PURCHASE	UPS	214,328,000			214,328,000	1.753	1.753	3,758,100
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		216,667,000	0	0	216,667,000	1.765	1.765	3,824,280
Nov-97	EMERGENCY	A&B	11,000			11,000	7.000	10.000	1,100
	TECO	--	591,000			591,000	2.788	2.788	16,480
	UPS PURCHASE	UPS	124,273,000			124,273,000	1.748	1.748	2,172,020
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		124,875,000	0	0	124,875,000	1.753	1.753	2,189,600
Dec-97	EMERGENCY	A&B	557,000			557,000	7.106	10.151	56,540
	TECO	--	783,000			783,000	2.791	2.791	21,850
	UPS PURCHASE	UPS	134,260,000			134,260,000	1.753	1.753	2,353,150
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		135,600,000	0	0	135,600,000	1.781	1.793	2,431,540
Jan-98	EMERGENCY	A&B	4,630,000			4,630,000	7.105	10.150	469,940
	TECO	--	17,000			17,000	2.765	2.765	470
	UPS PURCHASE	UPS	48,068,000			48,068,000	1.881	1.881	904,130
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		52,715,000	0	0	52,715,000	2.340	2.607	1,374,540
Feb-98	EMERGENCY	A&B	1,490,000			1,490,000	7.113	10.162	151,410
	TECO	--	9,000			9,000	2.778	2.778	250
	UPS PURCHASE	UPS	39,418,000			39,418,000	1.881	1.881	741,430
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		40,917,000	0	0	40,917,000	2.072	2.183	893,090
Mar-98	EMERGENCY	A&B	108,000			108,000	7.181	10.259	11,080
	TECO	--	202,000			202,000	2.733	2.733	5,520
	UPS PURCHASE	UPS	107,851,000			107,851,000	1.881	1.881	2,028,670
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		108,161,000	0	0	108,161,000	1.888	1.891	2,045,270
Oct-97 THRU Mar-98	EMERGENCY	A&B	6,809,000			6,809,000	7.107	10.153	691,350
	TECO	--	3,928,000			3,928,000	2.787	2.787	109,470
	UPS PURCHASE	UPS	668,198,000			668,198,000	1.790	1.790	11,957,500
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		678,935,000	0	0	678,935,000	1.849	1.879	12,758,320

FLORIDA POWER CORPORATION
ENERGY PAYMENT TO QUALIFYING FACILITIES
ESTIMATED FOR THE PERIOD OF: OCT-97 THROUGH MAR-98

(1) MONTH	(2) NAME OF PURCHASE	(3) TYPE & SCHEDULE	(4) TOTAL KWH PURCHASED	(5) KWH FOR OTHER UTILITIES	(6) KWH FOR INTERRUPTIBLE	(7) KWH FOR FIRM	(8) C/KWH (A) ENERGY COST	(8) C/KWH (B) TOTAL COST	(9) TOTAL $ FOR FUEL ADJ (7) x (8)(A)
Oct-97	QUALIFYING FACILITIES	COGEN	618,037,000			618,037,000	2.067	5.367	12,773,692
	TOTAL		618,037,000	0	0	618,037,000	2.067	5.367	12,773,692
Nov-97	QUALIFYING FACILITIES	COGEN	598,722,000			598,722,000	2.050	5.457	12,275,502
	TOTAL		598,722,000	0	0	598,722,000	2.050	5.457	12,275,502
Dec-97	QUALIFYING FACILITIES	COGEN	618,676,000			618,676,000	2.161	5.458	13,368,752
	TOTAL		618,676,000	0	0	618,676,000	2.161	5.458	13,368,752
Jan-98	QUALIFYING FACILITIES	COGEN	618,676,000			618,676,000	2.019	5.470	12,489,879
	TOTAL		618,676,000	0	0	618,676,000	2.019	5.470	12,489,879
Feb-98	QUALIFYING FACILITIES	COGEN	558,804,000			558,804,000	2.053	5.874	11,472,239
	TOTAL		558,804,000	0	0	558,804,000	2.053	5.874	11,472,239
Mar-98	QUALIFYING FACILITIES	COGEN	618,676,000			618,676,000	2.062	5.513	12,758,559
	TOTAL		618,676,000	0	0	618,676,000	2.062	5.513	12,758,559
Oct-97 THRU Mar-98	QUALIFYING FACILITIES	COGEN	3,631,591,000			3,631,591,000	2.069	5.518	75,138,623
	TOTAL		3,631,591,000	0	0	3,631,591,000	2.069	5.518	75,138,623

SCHEDULE E9

FLORIDA POWER CORPORATION
ECONOMY ENERGY PURCHASES
ESTIMATED FOR THE PERIOD OF: OCT-97 THROUGH MAR-98

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				TRANSACTION COST		TOTAL $	COST IF GENERATED		
MONTH	PURCHASE	TYPE & SCHEDULE	TOTAL KWH PURCHASED	ENERGY COST C/KWH	TOTAL COST C/KWH	FOR FUEL ADJ (4) x (5)	(A) C/KWH	(B) $	FUEL SAVINGS (8)(B) - (7)
Oct-97	ECON PURCH	C	100,000,000	2.900	2.900	2,900,000	4.100	4,100,000	1,200,000
	OUC PURCH	J	8,084,000	1.750	3.186	141,460	3.226	260,790	119,330
	OTHER	--	3,000,000	2.843	2.843	85,290	2.843	85,290	0
	TOTAL		111,084,000	2.815	2.919	3,126,750	4.002	4,446,080	1,319,330
Nov-97	ECON PURCH	C	90,000,000	2.147	2.147	1,932,300	4.294	3,864,600	1,932,300
	OUC PURCH	J	3,859,000	1.750	4.661	67,530	2.819	108,785	41,255
	OTHER	--	3,000,000	2.855	2.855	85,650	2.855	85,650	0
	TOTAL		96,859,000	2.153	2.269	2,085,480	4.191	4,059,035	1,973,555
Dec-97	ECON PURCH	C	40,000,000	2.676	2.676	1,070,400	4.512	1,804,800	734,400
	OUC PURCH	J	3,239,000	1.750	5.335	56,690	2.591	83,922	27,232
	OTHER	--	3,000,000	2.878	2.878	86,340	2.878	86,340	0
	TOTAL		46,239,000	2.624	2.875	1,213,430	4.271	1,975,062	761,632
Jan-98	ECON PURCH	C	50,000,000	3.125	3.125	1,562,500	4.095	2,047,500	485,000
	OUC PURCH	J	0	0.000	0.000	0	0.000	0	0
	OTHER	--	3,000,000	2.606	2.606	78,180	2.606	78,180	0
	TOTAL		53,000,000	3.096	3.096	1,640,680	4.011	2,125,680	485,000
Feb-98	ECON PURCH	C	40,000,000	2.862	2.862	1,144,800	4.095	1,638,000	493,200
	OUC PURCH	J	0	0.000	0.000	0	0.000	0	0
	OTHER	--	3,000,000	2.638	2.638	79,140	2.638	79,140	0
	TOTAL		43,000,000	2.846	2.846	1,223,940	3.993	1,717,140	493,200
Mar-98	ECON PURCH	C	60,000,000	2.513	2.513	1,507,800	4.095	2,457,000	949,200
	OUC PURCH	J	0	0.000	0.000	0	0.000	0	0
	OTHER	--	3,000,000	2.655	2.655	79,650	2.655	79,650	(0)
	TOTAL		63,000,000	2.520	2.520	1,587,450	4.026	2,536,650	949,200
Oct-97 THRU Mar-98	ECON PURCH	C	380,000,000	2.663	2.663	10,117,800	4.187	15,911,900	5,794,100
	OUC PURCH	J	15,182,000	1.750	4.019	265,680	2.987	453,498	187,818
	OTHER	--	18,000,000	2.746	2.746	494,250	2.746	494,250	0
	TOTAL		413,182,000	2.633	2.716	10,877,730	4.080	16,859,648	5,981,918

SCHEDULE E10

FLORIDA POWER CORPORATION
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE
ESTIMATED FOR THE PERIOD OF: OCTOBER 1997 THROUGH MARCH 1998

	DESCRIPTION		Oct-97	Nov-97	Dec-97	Jan-98	Feb-98	Mar-98	Period Average	Prior Residential Bill *	Oct-97 vs. Prior
1	Base Rate Revenues	($)	49.05	49.05	49.05	49.05	49.05	49.05	49.05	49.05	0.00
2	Fuel Recovery Factor	(c/kwh)	1.823	1.823	1.823	1.823	1.823	1.823	1.823	2.327	
3	Fuel Cost Recovery Revenues	($)	18.27	18.27	18.27	18.27	18.27	18.27	18.27	23.32	-5.05
4	Capacity Cost Recovery Revenues	($)	12.61	12.61	12.61	12.61	12.61	12.61	12.61	9.93	2.68
5	Energy Conservation Cost Revenues	($)	2.80	2.80	2.80	2.80	2.80	2.80	2.80	2.80	0.00
6	Gross Receipt Taxes	($)	2.12	2.12	2.12	2.12	2.12	2.12	2.12	2.18	-0.06
7	Total Revenues	($)	84.85	84.85	84.85	84.85	84.85	84.85	84.85	87.28	-2.43

* Actual Residential Billing for Sep-97

FLORIDA POWER CORPORATION
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE

			Oct-94 thru Mar-95	Oct-95 thru Mar-96	Oct-96 thru Mar-97	Oct-97 thru Mar-98	1996 vs. 1995	1997 vs. 1996	1998 vs. 1997
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL		27,304,617	40,476,442	55,172,465	35,442,660	47.8%	36.3%	-35.8%
2	LIGHT OIL		4,310,603	11,590,105	11,143,642	2,220,792	168.9%	-3.9%	-80.1%
3	COAL		105,185,694	134,461,735	129,690,744	147,315,449	27.8%	-3.6%	13.7%
4	GAS		6,336,200	10,293,692	18,772,302	18,777,627	62.5%	82.4%	0.0%
5	NUCLEAR		14,476,383	9,861,094	0	5,307,196	-31.9%	-100.0%	0.0%
6	OTHER		1,781,540	1,476,275	1,438,386	2,105,069	-17.1%	-2.6%	46.3%
7	TOTAL	$	159,486,037	208,189,343	216,117,539	211,168,793	30.5%	3.8%	-2.3%
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL		1,138,375	1,715,067	2,006,781	1,293,261	50.7%	17.0%	-35.6%
9	LIGHT OIL		75,196	199,743	174,962	35,963	165.6%	-12.4%	-79.4%
10	COAL		6,089,277	7,480,460	7,171,939	8,290,486	27.0%	-4.1%	15.6%
11	GAS		275,579	380,228	553,787	567,209	38.0%	45.6%	2.4%
12	NUCLEAR		3,281,676	2,142,937	0	1,567,317	-34.7%	-100.0%	0.0%
13	OTHER		0	0	0	0	0.0%	0.0%	0.0%
14	TOTAL	MWH	10,660,103	11,918,435	9,907,469	11,744,226	11.8%	-16.9%	18.5%
	UNITS OF FUEL BURNED								
15	HEAVY OIL	BBL	1,828,115	2,654,196	3,113,248	2,027,766	45.2%	17.3%	-34.9%
16	LIGHT OIL	BBL	179,195	470,002	340,271	75,673	162.3%	-27.6%	-77.8%
17	COAL	TON	2,232,630	2,811,045	2,711,018	3,082,683	25.9%	-3.6%	13.7%
18	GAS	MCF	3,091,892	4,010,338	6,065,830	5,964,271	29.7%	51.3%	-1.8%
19	NUCLEAR	MMBTU	33,933,310	22,247,580	0	16,082,413	-34.4%	-100.0%	0.0%
20	OTHER	BBL	77,689	68,658	46,124	72,414	-11.6%	-34.3%	60.6%
	BTUS BURNED (MMBTU)								
21	HEAVY OIL		11,731,464	17,218,684	20,219,564	12,977,706	46.8%	17.4%	-35.8%
22	LIGHT OIL		1,060,120	2,614,118	1,989,949	438,324	148.9%	-23.9%	-78.0%
23	COAL		55,830,618	70,517,350	67,763,868	77,489,203	26.3%	-3.9%	14.4%
24	GAS		3,179,352	4,180,553	6,337,678	5,964,271	31.5%	51.6%	-6.0%
25	NUCLEAR		33,933,310	22,247,580	0	16,082,413	-34.4%	-100.0%	0.0%
26	OTHER		455,272	399,824	261,723	420,000	-12.2%	-34.5%	60.5%
27	TOTAL	MMBTU	106,190,126	117,178,109	96,572,782	113,361,917	10.4%	-17.6%	17.4%
	GENERATION MIX (% MWH)								
28	HEAVY OIL		10.68%	14.39%	20.26%	11.01%	34.8%	41.0%	-45.4%
29	LIGHT OIL		0.71%	1.68%	1.77%	0.31%	141.0%	6.0%	-84.9%
30	COAL		55.25%	62.76%	72.39%	70.59%	13.6%	15.3%	-2.5%
31	GAS		2.59%	3.19%	5.59%	4.83%	23.2%	75.2%	-14.3%
32	NUCLEAR		30.79%	17.98%	0.00%	13.29%	-41.6%	-100.1%	0.0%
33	OTHER		0.00%	0.00%	0.00%	0.00%	0.0%	0.0%	0.0%
34	TOTAL	%	100.00%	100.00%	100.00%	100.00%	0.0%	0.0%	0.0%
	FUEL COST PER UNIT								
35	HEAVY OIL	$/BBL	14.99	15.25	17.72	17.48	1.8%	16.2%	-1.4%
36	LIGHT OIL	$/BBL	24.06	24.66	32.75	29.39	2.5%	32.8%	-10.3%
37	COAL	$/TON	47.11	47.83	47.80	47.79	1.5%	-0.1%	0.0%
38	GAS	$/MCF	2.05	2.57	3.09	3.15	25.3%	20.5%	1.9%
39	NUCLEAR	$/MMBTU	0.43	0.44	0.00	0.33	4.0%	-100.0%	0.0%
40	OTHER	$/BBL	22.93	21.50	31.88	29.07	-6.2%	48.2%	-8.8%
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL		2.34	2.35	2.73	2.73	0.7%	16.1%	0.1%
42	LIGHT OIL		4.11	4.43	5.60	5.07	8.0%	26.3%	-9.5%
43	COAL		1.88	1.91	1.91	1.90	1.2%	0.3%	-0.6%
44	GAS		1.99	2.46	2.96	3.15	23.5%	20.3%	6.5%
45	NUCLEAR		0.43	0.44	0.00	0.33	3.7%	-100.0%	0.0%
46	OTHER		3.91	3.69	5.50	5.01	-5.6%	48.9%	-8.8%
47	TOTAL	$/MMBTU	1.50	1.78	2.24	1.86	18.2%	26.0%	-16.8%
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL		10,305	10,040	10,075	10,035	-2.6%	0.4%	-0.4%
49	LIGHT OIL		13,955	13,087	11,372	12,188	-6.3%	-13.1%	7.2%
50	COAL		9,480	9,427	9,448	9,347	-0.6%	0.2%	-1.1%
51	GAS		11,537	10,995	11,444	10,497	-4.7%	4.1%	-8.3%
52	NUCLEAR		10,340	10,382	0	10,327	0.4%	-100.0%	0.0%
53	OTHER		0	0	0	0	0.0%	0.0%	0.0%
54	TOTAL	BTU/KWH	9,961	9,832	9,747	9,653	-1.3%	-0.9%	-1.0%
	GENERATED FUEL COST PER KWH (C/KWH)								
55	HEAVY OIL		2.41	2.36	2.75	2.74	-1.9%	16.5%	-0.3%
56	LIGHT OIL		5.73	5.80	6.37	6.18	1.2%	9.8%	-3.0%
57	COAL		1.79	1.80	1.81	1.78	0.6%	0.6%	-1.7%
58	GAS		2.30	2.71	3.39	3.31	17.7%	25.2%	-2.3%
59	NUCLEAR		0.44	0.46	0.00	0.34	4.3%	-100.0%	0.0%
60	OTHER		0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
61	TOTAL	C/KWH	1.50	1.75	2.18	1.80	16.7%	24.9%	-17.6%