Florida Power
CORPORATION

JAMES A. MCGEE
SENIOR COUNSEL

January 9, 1998

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. 980001-EI

00547-98

00546-98

Dear Ms. Bayó:

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

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

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A Florida Progress Company

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause and generating performance incentive factor.	Docket No. 980001-EI Submitted for filing: January 12, 1998

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true copy of the Direct Testimony and Exhibits of Dario B. Zuloaga and Karl H. Wieland on behalf of Florida Power Corporation has been furnished to the following individuals by regular U.S. Mail this 9th day of January, 1998:

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ORIGINAL

Florida Power
CORPORATION

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 980001-EI

LEVELIZED FUEL COST FACTORS APRIL THROUGH SEPTEMBER 1998

DIRECT TESTIMONY AND EXHIBITS OF

KARL H. WIELAND

For Filing January 12, 1998

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FPSC-RECORDS/REPORTING

FLORIDA POWER CORPORATION

DOCKET NO. 980001-EI

Levelized Fuel and Capacity Cost Factors
April through September 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 April through September 1998. My testimony also presents a set of contingent fuel cost factors that contain three months of replacement fuel costs associated with the extended outage of the Crystal River 3 nuclear plant (CR3) which, in accordance with the stipulation approved by the Commission in Docket No. 970261-EI, Florida Power is entitled to recover over a 12-month period after CR3 has returned to service. Florida Power asks that these contingent fuel cost factors be approved for the April - September 1998 period subject to confirmation that CR3 has returned to service before the beginning of the period.

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 an additional combustion turbine to natural gas firing. Part F recomputes the Company's true-up balances through November 1997 to exclude replacement power cost- and related interest associated with the extended outage of CR3, as well as any costs associated with the Lake Cogen settlement recently disapproved by the Commission in Docket No. 961477-EQ. Part G calculates contingent fuel cost factors which include the stipulated replacement fuel costs that Florida Power will be entitled to recover if CR3 returns to service before the projection period.

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 2.015 ¢/kWh (before line loss adjustment). The basic factor consists of a fuel cost for the projection period of 2.0179 ¢/kWh (adjusted for jurisdictional losses), a GPIF reward of .00683 ¢/kWh, and an estimated true-up credit of 0.0117 ¢/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 1.291 On-peak and 0.842 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 2.018 ¢/kWh.

Q. What is the change in the fuel factor from the current to the projected period?

A. The average fuel factor increases from 1.821 to 2.015 cents per kWh, an increase of 10.7%.

Q. Please explain the reasons for the increase.

A. The primary reason for the increase in the fuel factor is that the summer period is typically a higher cost period than the winter period because of significantly higher consumption. System requirements (Schedule E-1, line 20) are 3,840 GWh or 24% higher during upcoming April - September summer period than they were during the prior October through March winter period. Since the least expensive sources of generation, nuclear and coal, are fully utilized during both periods, the additional generation required during the summer period is supplied by more expensive oil and gas fired units and by purchases. The change in fuel mix increases the cost of generation 8.6% from 1.6 to 1.74 cents/kWh. The prices for oil and coal in this projection are actually lower than prices forecast for the October through March period.

A more subtle but significant seasonal factor is the change in Unbilled Sales (line 21) between the summer and winter periods. Unbilled Sales change 1,164 GWh from the current winter period to the projected summer period. This change alone increases the fuel factor in the summer period by 0.14 cents/kWh or 8%.

There are no other unusual assumptions or events included in this projection that contribute to the increase in the fuel factor.

Q. In accordance with the stipulation approved by the Commission in Docket No. 970261-EI, Florida Power is entitled to recover $32.3 million (retail portion excluding interest) in replacement fuel costs over a 12-month period after CR3 returns to service and operates for 14 days. How has that recovery amount been treated in this filing?

A. Florida Power expects that CR3 will be fully operational, as defined in the stipulation, before the April - September 1998 projection period. However, since CR3's operational status cannot be known with certainty at the time of this filing, Florida Power has not included the stipulated recovery amount in the calculation of its fuel cost factors shown in the "E" Schedules of my exhibit. Instead, I have presented the calculation of contingent fuel cost factors that include the stipulated recovery amount in Part G of my exhibit.

Florida Power asks that these contingent fuel cost factors be approved in the event CR3 is fully operational at the time of the February hearings. In the event CR3's operational status cannot be confirmed at the time of the hearing, Florida Power asks that the contingent fuel cost factors be approved conditionally. Under this conditional approval, the contingent fuel cost factors would become effective for the April - September 1998 period only if Florida Power files a notice with the Commission by March 27, 1998 (the first day of

April cycle billings) certifying that CR3 has satisfied the operational requirements of the stipulation.

Q. What portion of the stipulated replacement fuel costs would be recovered through the contingent fuel cost factors during the April - September 1998 period?

A. Part G of my exhibit shows that $18,371,207, or 0.10705 cents per kWh (Schedule E1, line 28b), of the stipulated recovery amount would be recovered in the April - September 1998 period. This amount was calculated by taking the retail amount of stipulated replacement fuel costs ($32.3 million), adding interest ($2.28 million), then dividing the total by projected jurisdictional sales for the 12-month period from April 1998 through March 1999. The resulting factor of 0.10705 cents per kWh is then multiplied by projected sales for the upcoming April - September 1998 period to arrive at the $18.4 million six-month recovery amount.

Q. What will be the effect on residential rates of including the stipulated replacement fuel amount in the fuel cost factors for the April - September 1998 period?

A. Adding the stipulated replacement fuel amount will increase the fuel cost factors by 0.107 cents per kWh. The typical residential bill for 1,000 kWh would be $85.72, resulting in a $0.89 (1%) increase from current rates, instead of a $0.21 decrease without the replacement fuel amount, or a change or $1.10.

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

A. Line 4 shows the recovery of the costs associated with conversion of nine combustion turbine units to burn natural gas instead of distillate oil. Recovery of the conversion of Intercession City units 7 through 10, Debary units 7 & 9, Bartow units 2 & 4 and Suwannee unit 1 have already been approved by this Commission. In this filing the Company is requesting approval to add the conversion costs of an additional unit located at Suwannee beginning in June, 1998

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 405 MWs under a Unit Power Sales (UPS) agreement with the Southern Company. Beginning January 1998, the SERC ratings of the units supporting this purchase will be revised to 405 MW. The capacity payments associated with the UPS contract are based on the original contract of 400 MW. The additional 5 MW are the result of revised SERC ratings for the five units involved in the unit power purchase, providing a benefit to Florida Power Corporation in the form of reduced costs per kW. Both of these contracts have been in place and have been approved for cost recovery by the Commission. Capacity costs for these purchases are included in the capacity cost recovery factor.

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. Such non-fuel charges, if any, are reported on line 10.

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 703 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 the municipal utilities of Kissimmee and St. Cloud and with Georgia Power Company under which fuel costs are charged in a similar manner. 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 estimated true-up calculation implements the provision of the CR3 stipulation requiring the exclusion of all CR3 replacement fuel costs until after the unit has returned to normal operations. In order to calculate a proper true up amount for the April through September 1998 period, replacement fuel costs and associated interest, along with costs associated with the Lake Cogen settlement which had previously been included in fuel underrecovery balances reported in the Company's "A" Schedules, were removed. Part F of my exhibit shows the development of this adjustment. This results in a restated November 1997 balance of $9,053,198. The balance was projected to the end of March 1998, including interest estimated at the November ending rate of 0.462% per month. The development of the estimated true-up amount for the current October 1997 through March 1998 period is shown on Schedule E1B, Sheet 1 and summarized on Schedule E1A. The current period estimated over-recovery of $10,226,809 was combined with the prior period ending balance of $(8,219,498) for a total over-recovery of $2,007,311 at the end of March 1998. This results in an estimated true-up credit on line 28 of Schedule E1 (Basic) of 0.1170 ¢/kWh for application in the April through September 1998 projection period.

Q. What are the primary reasons for the projected March 1998 over-recovery of $2.0 million?

A. The $8.2 million actual under-recovery for the period ending September 1997 being rolled forward into the current period, and lower than expected oil prices, were the primary factors contributing to the $2.0 million over-recovery in March.

Q. Please explain the procedure for forecasting the unit cost of nuclear fuel.

A. The cost per million BTU of the nuclear fuel which will be in the reactor during the projection period (primarily Cycle 11, following the refueling outage) was developed from the projected cost of fuel added during the current period's refueling outage and the unamortized investment cost of the fuel remaining in the reactor from the prior cycle (Cycle 10). Cycle 11 consists of several "batches," of fuel assemblies which are separately accounted for throughout their life in several fuel cycles. The cost for each batch is determined from the actual cost incurred by the Company, which is audited and reviewed by the Commission's field auditors. The expected available energy from each batch over its life is developed from an evaluation of various fuel management schemes and estimated fuel cycle lengths. From this information, a cost per unit of energy (cents per million BTU) is calculated for each batch. However, since the rate of energy consumption is not uniform among the individual fuel assemblies and batches within the reactor core, an estimate of consumption within each batch must be made to properly weigh the batch unit costs in calculating a composite unit cost for the overall fuel cycle.

Q. How was the rate of energy consumption for each batch within Cycle 11 estimated for the upcoming projection period?

A. The consumption rate of each batch has been estimated by utilizing a core physics computer program which simulates reactor operations over the projection period. When this consumption pattern is applied to the individual batch costs, the resultant composite Cycle 11 is $0.327 per million BTU.

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 1997.

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 an econometric 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 Suwannee combustion turbine unit #3 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 & 9, Bartow Units 2 & 4 and Suwannee Unit 1 to burn natural gas. The Commission authorized the Company to recover the conversion cost, including a return on investment, over a five-year period in Order No. PSC-95-1089-FOF-EI dated September 5, 1995. The Company is asking the Commission for the same treåtment for one additional units. The conversion cost for Suwannee Unit 3 is $1.9 million. This cost was not part of the cost of the unit 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 $1.9 million conversion cost over a five year period beginning with the plant in-service date of June, 1998. The projected cost during the April 1998 through September 1998 period is $173,125 which consists of an amortization charge of $110,834 and a return (including income taxes) of $62,291 based on the Company's current cost of capital of 8.37%. The fuel savings for the same period are expected to be $225,000 resulting in a net benefit to customers of $51,875. During the five year amortization period, the conversion is estimated to reduce fuel cost by $3.2 million in nominal Dollars for a net benefit of $800,000.

A monthly schedule of amortization expenses and projected fuel savings for April through September 1998 is attached as Part E of my exhibit.

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. The Company is confident that interruptible gas will be available in sufficient quantity to power the two units at the site 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.

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

A. As it has done for previous conversions, the Company is willing to assume the risk for achieving projected 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.

<u>Sheet 1: Projected Capacity Payments.</u> This schedule contains system capacity payments for UPS, TECO and QF purchases. The retail portion of the capacity payments are calculated using separation factors from the Company's most recent Jurisdictional Separation Study.

<u>Sheet 2: Estimated/Actual True-Up.</u> 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 $4,007,164 is then carried forward to Sheet 1, to be refunded during the April through September 1998 period.

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

Sheet 4: Calculation of 12 CP and Annual Average Demand. The calculation of average 12 CP and annual average demand is based on 1996 load research data and the delivery efficiencies on Sheet 3.

Sheet 5: Calculation of Capacity Cost Recovery Factors. 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 capacity payments compared to the prior six-month period.

A. The increase in capacity payments from $143.2 million in the October 1997 through March 1998 period to $144.9 million for the April through September 1998 period is due to the escalation to the 1998 payment schedule. No new contracts begin before September 1998. The decrease in rates, exhibited on Sheet 5 of Part D on a cents per kWh basis, is due to the greater amount of kWh sales projected for the summer period as compared to the current period.

Q. Does this conclude your testimony?

A. Yes.

EXHIBITS TO THE TESTIMONY OF
KARL H. WIELAND

LEVELIZED FUEL COST FACTORS
APRIL THROUGH SEPTEMBER 1998

PART A - SALES FORECAST ASSUMPTIONS

SALES FORECAST ASSUMPTIONS

1. This forecast of customers, sales and peak demand utilizes the short-term load forecasting methodology developed for budgeting and financial planning purposes. The forecast was prepared in June 1997.

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. 117 (February 1997) as well as THE FLORIDA LONG-TERM ECONOMIC OUTLOOK, 1997.

4. FPC's phosphate mining customers are coming off a level of increased power consumption not seen in over a decade. Improved market conditions for phosphate rock, both at home and abroad, had firmed-up market prices and allowed for expansion of operations at new sites. Industry consolidation in the past few years assures a greater supply and demand balance in the years ahead. A short term reduction in power consumption from FPC will take place as IMC-Agrico moves mining operations out of FPC territory.

5. Florida Power Corporation (FPC) supplies load and energy service to wholesale customers on a "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, 1997. 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 projections of self-committed capacity of 703 MW in 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 Georgia Power Corporation, Oglethorpe Power Corporation and the Municipal Electric Authority of Georgia (MEAG). The Georgia Power and MEAG contracts are to supply 150 MW of summer capacity in 1998. The Oglethorpe Power contract, also a summer sale, is to supply 137 MW in 1998.

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. This forecast assumes that the regulatory environment and the obligation to serve will continue throughout the forecast horizon. The ability of wholesale customers to switch suppliers has ended the company's obligation to serve. As a result, the company does not plan generation resources unless a long-term contract is in place. Current customer contracts are expected to show annual declarations declining from their current levels and expire as terms run their course.

9. The economic outlook for this forecast calls for continued, moderate economic growth. No "shocks" to any supply or demand conditions in the national economy are expected and thus no economic recession is incorporated in this forecast. Unemployment is at 24-year lows nationwide, resulting in greater spending power for the consumer and a high level of optimism in the economy. Looking ahead, however, growth will be slower than recently experienced. Federal Reserve Board (FRB) efforts will keep inflationary pressures from building by applying tighter monetary policy. This will result in higher interest rates in the short term and slow the economy

   Personal income growth is expected to continue growing but not at the pace experienced in recent years. 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 expected to fair well in the years ahead as the State has positioned itself well for trade with Latin America. The strong dollar of late may stall further job gains in this sector temporarily, but the globalization of the world economy will encourage Florida 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.

EXHIBITS TO THE TESTIMONY OF KARL H. WIELAND

LEVELIZED FUEL COST FACTORS
APRIL THROUGH SEPTEMBER 1998

PART B - FUEL PRICE FORECAST ASSUMPTIONS

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 1998.

FPC Residual Fuel Oil (#6) and Distillate Fuel Oil (#2) prices were derived from PIRA forecasts and 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 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 1998. Gas supply prices were derived from PIRA, NYMEX and current spot market information.

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

EXHIBITS TO THE TESTIMONY OF
KARL H. WIELAND

LEVELIZED FUEL COST FACTORS
APRIL THROUGH SEPTEMBER 1998

PART C - FUEL PRICE FORECAST

Florida Power Corporation
Docket No. 980001-EI
Witness: K. H. Wieland
Exhibit No. ________
Part C
Sheet 1 of 4

FUEL PRICE FORECAST

#6 Fuel Oil

	1.0%		1.5%		2.5%	
Month	$/barrel	$/MMBtu's[1]	$/barrel	$/MMBtu's[1]	$/barrel	$/MMBtu[1]
Jan 1998	17.55	2.70	16.58	2.55	14.95	2.30
Feb 1998	17.55	2.70	16.58	2.55	14.95	2.30
Mar 1998	17.55	2.70	16.58	2.55	14.95	2.30
Apr 1998	16.25	2.50	15.60	2.40	14.95	2.30
May 1998	16.25	2.50	15.60	2.40	14.95	2.30
Jun 1998	16.25	2.50	15.60	2.40	14.95	2.30
Jul 1998	16.25	2.50	15.60	2.40	14.95	2.30
Aug 1998	16.25	2.50	15.60	2.40	14.95	2.30
Sep 1998	16.25	2.50	15.60	2.40	14.95	2.30

(1) 6.5 million BTU/barrel

Florida Power Corporation
Docket No. 980001-EI
Witness: K. H. Wieland
Exhibit No. ________
Part C
Sheet 2 of 4

FUEL PRICE FORECAST

#2 Fuel Oil

Month	$/barrel	¢/gallon	$/MMBtu's[1]
Jan 1998	26.08	62.1	4.50
Feb 1998	26.08	62.1	4.50
Mar 1998	25.83	61.5	4.45
Apr 1998	25.83	61.5	4.45
May 1998	25.83	61.5	4.45
Jun 1998	25.83	61.5	4.45
Jul 1998	25.83	61.5	4.45
Aug 1998	25.83	61.5	4.45
Sep 1998	25.83	61.5	4.45

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

Florida Power Corporation
Docket No. 980001-EI
Witness: K. H. Wieland
Exhibit No. ________
Part C
Sheet 3 of 4

FUEL PRICE FORECAST

Coal

	Crystal River 1 & 2			Crystal River 4 & 5		
Month	BTU/lb.	$/ton	$/MMBtu	BTU/lb.	$/ton	$/MMBtu
Jan 1998	12,689	41.89	1.650	12,512	49.71	1.986
Feb 1998	12,689	41.84	1.649	12,512	49.70	1.986
Mar 1998	12,689	41.89	1.651	12,513	49.66	1.984
Apr 1998	12,689	42.09	1.659	12,513	50.13	2.003
May 1998	12,695	41.78	1.646	12,513	49.35	1.972
Jun 1998	12,680	41.92	1.653	12,507	50.22	2.008
Jul 1998	12,694	42.02	1.655	12513	49.48	1.977
Aug 1998	12,676	42.25	1.666	12,507	50.27	2.010
Sep 1998	12,694	42.07	1.657	12,513	49.38	1.973

Florida Power Corporation
Docket No. 980001-EI
Witness: K. H. Wieland
Exhibit No. ________
Part C
Sheet 4 of 4

FUEL PRICE FORECAST

Natural Gas Supply

	INTO FLORIDA GAS TRANSMISSION [1]
Month	$/MMBtu
Jan 1998	2.90
Feb 1998	2.70
Mar 1998	2.50
Apr 1998	2.35
May 1998	2.35
Jun 1998	2.30
Jul 1998	2.30
Aug 1998	2.30
Sept 1998	2.30

[1] Transport cost not included

EXHIBITS TO THE TESTIMONY OF KARL H. WIELAND

LEVELIZED FUEL COST FACTORS
APRIL THROUGH SEPTEMBER 1998

PART D - CAPACITY COST RECOVERY CALCULATIONS

FLORIDA POWER CORPORATION
CAPACITY COST RECOVERY CLAUSE
PROJECTED CAPACITY PAYMENTS
For the Period of April through September 1998

Florida Power Corporation
Docket 980001-EI
Witness: K. H. Wieland
Exhibit No.
Part D
Sheet 1 of 5

	Apr-98	May-98	Jun-98	Jul-98	Aug-98	Sep-98	Total
Base Production Level Capacity Charges:							
1 Bay County Qualifying Facility	162,360	162,360	162,360	162,360	162,360	162,360	974,160
2 Eco Peat Qualifying Facility	949,402	949,402	949,402	949,402	949,402	949,402	5,696,412
3 General Peat Qualifying Facility	3,310,164	3,310,164	3,310,164	3,310,164	3,310,164	3,310,164	19,860,984
4 Auburndale LFC Qualifying Facility	511,480	511,480	511,480	511,480	511,480	511,480	3,068,880
5 Dade County Qualifying Facility	664,780	664,780	664,780	664,780	664,780	664,780	3,988,680
6 Lake County Qualifying Facility	307,403	307,403	307,403	307,403	307,403	307,403	1,844,418
7 Pasco County Qualifying Facility	554,530	554,530	554,530	554,530	554,530	554,530	3,327,180
8 Pinellas County 1&2 Qualifying Facility	1,320,023	1,320,023	1,320,023	1,320,023	1,320,023	1,320,023	7,920,138
9 El Dorado Qualifying Facility	1,712,053	1,712,053	1,712,053	1,712,053	1,712,053	1,712,053	10,272,318
10 Lake Cogen Qualifying Facility	1,827,325	1,827,325	1,827,325	1,827,325	1,827,325	1,827,325	10,963,950
11 Orange Cogen Qualifying Facility	1,552,277	1,552,277	1,552,277	1,552,277	1,552,277	1,552,277	9,313,662
12 Orlando Cogen Qualifying Facility	1,365,094	1,365,094	1,365,094	1,365,094	1,365,094	1,365,094	8,190,564
13 Pasco Cogen Qualifying Facility	2,803,012	2,803,012	2,803,012	2,803,012	2,803,012	2,803,012	16,818,072
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	308,530	308,530	308,530	308,530	308,530	308,530	1,851,180
16 Timber Energy 2 Qualifying Facility	115,740	115,740	115,740	115,740	115,740	115,740	694,440
17 Mulberry Energy Qualifying Facility	1,983,817	1,983,817	1,983,817	1,983,817	1,983,817	1,983,817	11,902,902
18 Royster Phosphates Qualifying Facility	710,101	710,101	710,101	710,101	710,101	710,101	4,260,606
19 Cargill Fertilizer Qualifying Facility	354,900	354,900	354,900	354,900	354,900	354,900	2,129,400
20 Panda Kathleen Qualifying Facility	0	0	0	0	0	0	0
21 US Agrichem Qualifying Facility	34,109	34,109	34,109	34,109	34,109	34,109	204,654
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	21,281,379	21,281,379	21,281,379	21,281,379	21,281,380	21,281,380	127,688,276
24 Base Production Jurisdictional Responsibility	95.476%	95.476%	95.476%	95.476%	95.476%	95.476%	95.476%
25 Base Level Jurisdictional Capacity Charges	20,318,609	20,318,609	20,318,609	20,318,609	20,318,610	20,318,610	121,911,656
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 (405 MW)	4,523,971	4,516,620	4,489,097	4,508,275	4,502,099	4,457,430	26,997,492
28 Capacity Sales	0	0	0	0	0	0	0
29 Subtotal - Intermediate Level Capacity Charges	4,995,338	4,987,987	4,960,464	4,979,642	4,973,466	4,928,797	29,825,694
30 Intermediate Production Jurisdictional Responsibility	84.311%	84.311%	84.311%	84.311%	84.311%	84.311%	84.311%
31 Intermediate Level Jurisdictional Capacity Charges	4,211,614	4,205,417	4,182,212	4,198,381	4,193,174	4,155,513	25,146,311
32 Sebring Base Rate Credits	(311,588)	(302,906)	(356,391)	(380,347)	(384,298)	(397,410)	(2,132,940)
33 Jurisdictional Capacity Payments (Lines 25+31+32)	24,218,636	24,221,120	24,144,430	24,136,643	24,127,486	24,076,713	144,925,029
34 Estimated/Actual True-Up Provision for the Period October 1997 through March 1998							(4,007,164)
35 Total (Sum of lines 33 & 34)							140,917,866
36 Revenue Tax Multiplier							1.00083
37 TOTAL RECOVERABLE CAPACITY PAYMENTS							141,034,828

FLORIDA POWER CORPORATION
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED / ACTUAL TRUE-UP
For the Period of October 1997 through March 1998

	Actual Oct-97	Actual Nov-97	Estimated Dec-97	Estimated Jan-98	Estimated Feb-98	Estimated Mar-98	Total	Original Estimate	Variance
Base Production Level Capacity Charges:									
1 Bay County Qualifying Facility	152,790	152,790	152,790	162,360	162,360	162,360	945,450	945,450	0
2 Eco Peat Qualifying Facility	903,762	903,762	903,762	949,402	949,402	949,402	5,559,492	5,559,492	0
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	19,268,964	0
4 Auburndale LFC Qualifying Facility	491,930	491,930	491,930	511,480	511,480	511,480	3,010,230	3,010,230	0
5 Dade County Qualifying Facility	348,095	494,913	632,960	664,780	664,780	664,780	3,470,308	3,893,220	(422,912)
6 Lake County Qualifying Facility	289,043	289,043	289,043	307,403	307,403	307,403	1,789,338	1,789,338	0
7 Pasco County Qualifying Facility	521,410	521,410	521,410	554,530	554,530	554,530	3,227,820	3,227,820	0
8 Pinellas County 1&2 Qualifying Facility	1,077,014	1,088,160	1,241,183	1,320,023	1,320,023	1,320,023	7,366,426	7,683,618	(317,192)
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	10,026,474	0
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	10,749,252	0
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	9,094,269	0
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	7,994,541	0
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	16,605,327	0
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	308,530	308,530	308,530	308,530	308,530	308,530	1,851,180	1,803,693	47,487
16 Timber Energy 2 Qualifying Facility	108,840	108,840	108,840	115,740	115,740	115,740	673,740	673,740	0
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	11,614,347	0
18 Royster Phosphates Qualifying Facility	675,964	675,964	675,964	710,101	710,101	710,101	4,158,195	4,158,195	0
19 Cargill Fertilizer Qualifying Facility	337,500	337,500	337,500	354,900	354,900	354,900	2,077,200	2,077,200	0
20 Panda Kathleen Qualifying Facility	0	0	0	0	0	0	0	0	0
21 US Agrichem Qualifying Facility	32,482	32,482	32,482	34,109	34,109	34,109	199,773	199,773	0
22 Tiger Bay (Eco Peat Lease Credit)	(66,667)	(66,667)	(66,667)	(66,667)	(66,667)	(66,667)	(400,002)	(400,000)	(2)
23 Subtotal - Base Level Capacity Charges	19,878,955	20,036,919	20,327,989	21,281,379	21,281,379	21,281,379	124,088,000	124,780,619	(692,619)
24 Base Production Jurisdictional Responsibility	95.476%	95.476%	95.476%	95.476%	95.476%	95.476%	95.476%	95.476%	-n/a-
25 Base Level Jurisdictional Capacity Charges	18,979,631	19,130,449	19,408,351	20,318,609	20,318,609	20,318,609	118,474,259	119,135,544	(661,285)
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)	4,448,831	4,481,548	4,481,548	4,571,419	4,505,015	4,557,801	27,046,162	28,251,984	(1,205,822)
28 Capacity Sales	(2,576)	(2,576)	0	0	0	0	(5,152)	0	(5,152)
29 Subtotal - Intermediate Level Capacity Charges	4,917,622	4,950,339	4,952,915	5,042,786	4,976,382	5,029,168	29,869,212	31,080,186	(1,210,974)
30 Intermediate Production Jurisdictional Responsibility	84.311%	84.311%	84.311%	84.311%	84.311%	84.311%	84.311%	84.311%	-n/a-
31 Intermediate Level Jurisdictional Capacity Charges	4,146,091	4,173,675	4,175,847	4,251,618	4,195,632	4,240,137	25,183,001	26,203,985	(1,020,983)
32 Sebring Base Rate Credits	(348,943)	(282,692)	(307,298)	(358,157)	(334,166)	(305,426)	(1,936,682)	(1,939,058)	2,376
33 Jurisdictional Capacity Payments (Lines 25+31+32)	22,776,779	23,021,432	23,275,900	24,212,071	24,180,076	24,253,320	141,720,578	143,400,470	(1,679,892)
34 Capacity Cost Recovery Revenues	30,158,479	23,877,290	24,131,326	25,698,437	24,781,239	23,601,044	152,247,815	151,762,411	485,404
35 Prior Period True-Up Provision	(1,098,928)	(1,098,928)	(1,098,928)	(1,098,928)	(1,098,928)	(1,098,925)	(6,593,565)	(8,361,941)	1,768,376
36 Current Period Capacity Revenues (Lines 34+35)	29,059,551	22,778,362	23,032,398	24,599,509	23,682,311	22,502,119	145,654,250	143,400,470	2,253,780
37 Current Period Over/(Under) Recovery (Lines 36-33)	6,282,772	(243,070)	(244,502)	387,438	(497,765)	(1,751,201)	3,933,672	0	3,933,672
38 Interest Provision for Month	3,305	5,633	9,610	15,062	19,954	19,928	73,492	(334,229)	407,721
39 Current Cycle Balance	6,286,077	6,048,640	5,813,748	6,216,248	5,738,437	4,007,164	4,007,164	(334,229)	4,341,393
40 Plus: Prior Period Balance	(6,593,565)	(6,593,565)	(6,593,565)	(6,593,565)	(6,593,565)	(6,593,565)	(6,593,565)	(8,361,941)	1,768,376
41 Plus: Cumulative True-Up Provision	1,098,928	2,197,856	3,296,784	4,395,712	5,494,640	6,593,565	6,593,565	8,361,941	(1,768,376)
42 End of Period Net True-Up (Line 39+40+41)	791,440	1,652,931	2,516,967	4,018,395	4,639,512	4,007,164	4,007,164	(334,229)	4,341,393

Florida Power Corporation
Docket 980001-EI
Witness: K. H. Wieland
Exhibit No. ________
Part D
Sheet 3 of 5

FLORIDA POWER CORPORATION
DEVELOPMENT OF JURISDICTIONAL DELIVERY LOSS MULTIPLIERS
BASED ON ACTUAL CALENDAR YEAR 1996 DATA
FOR THE PERIOD OF: APR-98 THROUGH SEP-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 April through September 1998

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	8,577,174	0.515	3,802.44	0.9386594	4,050.93	8,577,174	0.9386594	9,137,685	2,086.23
II. General Service Non-Demand									
Transmission	0	0.662	0.00	0.9740000	0.00	0	0.9740000	0	0.00
Primary	3,710	0.662	1.28	0.9640000	1.33	3,710	0.9640000	3,849	0.88
Secondary	626,251	0.662	215.[illegible]3	0.9386594	230.10	626,251	0.9386594	667,176	152.32
Total Gen Serv Non-Demand	629,961				231.42	629,961		671,025	153.20
III. GS - 100% L.F.	27,440	1.000	6.26	0.9386594	6.67	27,440	0.9386594	29,233	6.67
IV. General Service Demand									
SS-1 - Transmission	4,259	1.218	0.80			4,259			
GSD-1 - Transmission	1,856	0.807	0.53			1,856			
Total Transmission	6,115		1.32	0.9740000	1.36	6,115	0.9740000	6,278	1.43
SS-1 - Primary	0	1.218	0.00			0			
GSD-1 - Primary	1,294,852	0.807	366.33			1,294,852			
Total Primary	1,294,852		366.33	0.9640000	380.01	1,294,852	0.9640000	1,343,207	306.67
GSD - Secondary	5,104,896	0.807	1,444.24	0.9386594	1,538.62	5,104,896	0.9386594	5,438,497	1,241.67
Total Gen Serv Demand	6,405,863				1,919.99	6,405,863		6,787,982	1,549.77
V. Curtailable Service									
CS - Primary	91,517	0.966	21.63			91,517			
SS-3 - Primary	2,490	1.039	0.55			2,490			
Total Primary	94,007		22.18	0.9640000	23.01	94,007	0.9640000	97,518	22.26
CS - Secondary	966	0.966	0.23	0.9386594	0.24	966	0.9386594	1,029	0.23
Total Curtailable Service	94,973		22.41		23.25	94,973		98,547	22.50
VI. Interruptible Service									
IS - Transmission	279,861	1.044	61.20			279,861			
SS-2 - Transmission	84,924	1.044	18.57			84,924			
Total Transmission	364,785		79.77	0.9740000	81.90	364,785	0.9740000	374,523	85.51
IS - Primary	937,725	1.044	205.07			937,725			
SS-2 - Primary	2,454	1.044	0.54			2,454			
Total Primary	940,179		205.61	0.9640000	213.28	940,179	0.9640000	975,289	222.67
IS - Secondary	2,012	1.044	0.44	0.9386594	0.47	2,012	0.9386594	2,143	0.49
Total Interruptible Service	1,306,976				295.66	1,306,976		1,351,955	308.67
VII. Lighting Service	119,106	3.779	7.20	0.9386594	7.67	119,106	0.9386594	126,889	28.97
Total Retail	**17,161,493**				**6,535.59**	**17,161,493**		**18,203,317**	**4,156.01**

FLORIDA POWER CORPORATION
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF CAPACITY COST RECOVERY FACTOR
For the Period of April through September 1998

Florida Power Corporation
Docket 980001-EI
Witness K H Wieland
Exhibit No
Part D
Sheet 5 of 5

	(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 (Apr'98 - Sep'98)	(10) Capacity Cost Recovery Factor (c/Kwh)
	Mw	%	Mw	%	12/13 * (2)	1/13 * (4)	(5) + (6)	(7) * Total		
I. Residential Service	4,050.93	61.983%	2,086.23	50.198%	57.215%	3.861%	61.076%	86,138,678	8,577,174	1.004
II. General Service Non-Demand										
Transmission									0	0.779
Primary									3,673	0.787
Secondary									626,251	0.795
Total Gen Serv Non-Demand	231.42	3.541%	153.20	3.686%	3.269%	0.284%	3.552%	5,009,758	629,924	
III. GS - 100% L.F.	6.67	0.102%	6.67	0.161%	0.094%	0.012%	0.107%	150,370	27,440	0.548
IV. General Service Demand										
Transmission									5,993	0.648
Primary									1,281,903	0.655
Secondary									5,104,896	0.662
Total Gen Service Demand	1,919.99	29.377%	1,549.77	37.290%	27.118%	2.868%	29.986%	42,290,791	6,392,792	
V. Curtailable Service										
Transmission									0	0.544
Primary									93,067	0.549
Secondary									966	0.555
Total Curtailable Service	23.25	0.356%	22.50	0.541%	0.328%	0.042%	0.370%	521,826	94,033	
VI. Interruptible Service										
Transmission									357,489	0.509
Primary									930,778	0.514
Secondary									2,012	0.519
Total Interruptible Service	295.66	4.524%	308.67	7.427%	4.176%	0.571%	4.747%	6,695,078	1,290,279	
VII. Lighting Service	7.67	0.117%	28.97	0.697%	0.108%	0.054%	0.162%	228,327	119,106	0.192
Total Retail	**6,535.59**	**100.000%**	**4,156.01**	**100.000%**	**92.308%**	**7.692%**	**100.000%**	**141,034,828**	**17,130,748**	**0.82181**

EXHIBITS TO THE TESTIMONY OF KARL H. WIELAND

LEVELIZED FUEL COST FACTORS
APRIL THROUGH SEPTEMBER 1998

PART E
SUWANNEE 3 GAS CONVERSION

FLORIDA POWER CORPORATION
DOCKET 980001-EI
WITNESS: K.H. WIELAND
EXHIBIT NO. ____________
PART E

SUWANNEE P3 GAS CONVERSION
SUMMARY OF COSTS AND SAVINGS - 5 YEAR RECOVERY
FOR THE PERIOD APRIL, 1998 THROUGH SEPTEMBER, 1998

		1998						
		APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	TOTAL
1	BEGINNING BALANCE	$ -	$ -	$ -	$ 1,900,000	$ 1,900,000	$ 1,900,000	$ -
2	ADD INVESTMENT	-	-	1,900,000	-	-	-	1,900,000
3	LESS: RETIREMENTS	-	-	-	-	-	-	-
4	ENDING BALANCE	-	-	1,900,000	1,900,000	1,900,000	1,900,000	1,900,000
5								
6								
7	AVERAGE BALANCE	-	-	950,000	1,900,000	1,900,000	1,900,000	
8	DEPRECIATION RATE	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	
9	DEPRECIATION EXPENSE	-	-	15,833	31,667	31,667	31,667	110,834
10	LESS RETIREMENTS	-	-	-	-	-	-	-
11	BEGINNING BALANCE DEPRECIATION	-	-	-	15,833	47,500	79,167	-
12	ENDING BALANCE DEPRECIATION	-	-	15,833	47,500	79,167	110,834	110,834
13								
14								
15	ENDING NET INVESTMENT	$ -	$ -	$ 1,884,167	$ 1,852,500	$ 1,820,833	$ 1,789,166	$ 1,789,166
16								
17								
18	AVERAGE INVESTMENT	$ -	$ -	$ 942,084	$ 1,868,334	$ 1,836,667	$ 1,805,000	
19	ALLOWED EQUITY RETURN	.42667%	.42667%	.42667%	.42667%	.42667%	.42667%	
20	EQUITY COMPONENT AFTER-TAX	-	-	4,020	7,972	7,836	7,701	27,529
21	CONVERSION TO PRE-TAX	1.62800	1.62800	1.62800	1.62800	1.62800	1.62800	
22	EQUITY COMPONENT PRE-TAX	-	-	6,545	12,978	12,757	12,537	44,817
23								
24	ALLOWED DEBT RETURN	.27083%	.27083%	.27083%	.27083%	.27083%	.27083%	
25	DEBT COMPONENT	-	-	2,551	5,060	4,974	4,889	17,474
26								
27	TOTAL RETURN REQUIREMENTS	-	-	9,096	18,038	17,731	17,426	
28								
29	TOTAL DEPRECIATION & RETURN	$ -	$ -	$ 24,929	$ 49,705	$ 49,398	$ 49,093	$ 173,125
30								
31	ESTIMATED FUEL SAVINGS (EXCLUDES COGENS)	-	-	-	34,000	85,000	106,000	225,000
32	TOTAL DEPRECIATION & RETURN	-	-	24,929	49,705	49,398	49,093	173,125
33	ONE-TIME METERING COST	-	-	-	-	-	-	-
34	NET BENEFIT (COST) TO RATEPAYER	$ -	$ -	$ (24,929)	$ (15,705)	$ 35,602	$ 56,907	$ 51,875
35								

36 DEPRECIATION EXPENSE IS CALCULATED BASED UPON AN PERIOD THROUGH MAY 2003

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%

EXHIBITS TO THE TESTIMONY OF
KARL H. WIELAND

LEVELIZED FUEL COST FACTORS
APRIL THROUGH SEPTEMBER 1998

PART F
EXCLUSION OF CR3 REPLACEMENT FUEL COSTS
FROM ACTUAL TRUE-UP BALANCES

Florida Power Corporation
Docket 980001-EI
Witness K. H. Wieland
Exhibit No. ________
Part F
Sheet 1 of 1

FLORIDA POWER CORPORATION
FUEL & PURCHASED POWER COST RECOVERY CLAUSE
COMPARISON OF PROJECTED FILING VS. ADJUSTED DATA
FOR THE PERIOD OF OCTOBER 1997 - MARCH 1998

Schedule A2

Line No	Description	Sep-97			Oct-97			Nov-97		
		Filed	Adjusted	Variance	Filed	Adjusted	Variance	Filed	Adjusted	Variance
3	Total Jurisdictional Fuel Revenue	$62,303,876	$62,303,876	$0	$51,828,425	$51,828,425	$0	$41,922,284	$41,922,284	$0
4	Adjusted Total Fuel and Net Power Transaction	70,351,632	70,506,792	155,160	57,177,192	57,390,062	212,870	44,069,400	44,185,831	116,431
5	Jurisdictional Sales % of Total Sales	96.36%	96.36%	0	96.65%	93.65%	0	95.81%	95.81%	0
6	Jurisdictional Fuel and Net Power Transactions (Line 4 * Line 5 * .16%)	67,899,298	68,049,049	149,751	55,350,175	55,556,243	206,068	42,290,449	42,402,180	111,731
7	True Up Provision for the Month Over/(Under) Collection	(5,596,422)	(5,745,173)	(149,751)	(3,521,750)	(3,727,818)	(206,068)	(368,165)	(479,896)	(111,731)
8	Interest Provision for the Month	(230,053)	(209,631)	20,422	(218,655)	(43,003)	175,652	(171,501)	4,609	176,110
9	True Up & Interest Provision Beg of Month/Period	(53,394,955)	(48,642,180)	4,752,775	(46,424,975)	(8,219,498)	38,205,477	(37,692,634)	482,428	38,175,062
10	True Up Collected/(Refunded)	1,545,652	1,545,652	0	1,510,382	1,510,382	0	1,510,382	1,510,382	0
11	End of Period Total Net True Up	(57,674,776)	(53,051,332)	4,623,446	(48,654,998)	(10,479,937)	38,175,061	(36,721,918)	1,517,523	38,239,440
12	Other - Nuc Repl & Lake Settlement	11,249,803	44,831,834	33,582,031	10,962,365	10,962,365	0	7,535,675	7,535,675	0
13	End of Period Total Net True Up	($46,424,975)	($8,219,498)	$38,205,477	($37,692,633)	$482,428	$38,175,061	($29,186,243)	$9,053,198	$38,239,440

Notes:

Line 4 - Removes monthly Lake Cogen settlement (28% capacity and energy credits) payments from purchased power expense.

Line 12 - Removes Lake Cogen settlement (28% capacity and energy credits) payments through August 1997 and Nuclear Replacement Costs through November 1997 from the True-Up balance.

EXHIBITS TO THE TESTIMONY OF KARL H. WIELAND

LEVELIZED FUEL COST FACTORS
APRIL THROUGH SEPTEMBER 1998

PART G
CALCULATION OF CONTINGENT FUEL COST FACTORS
INCLUDING STIPULATED CR3 REPLACEMENT FUEL COSTS

FLORIDA POWER CORPORATION
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE
ESTIMATED FOR THE PERIOD OF: APRIL 1998 THROUGH SEPTEMBER 1998
SCHEDULE E1 - INCLUDING NUCLEAR REPLACEMENT COST

			DOLLARS	MWH	CENTS/KWH
1	Fuel Cost of System Net Generation		246,483,156	14,463,054	1.70423
2	Spent Nuclear Fuel Disposal Cost		2,870,107	3,069,633 *	0.09350
3	Nuclear Fuel Replacement Cost		0	0	0.00000
4	Adjustment to Fuel Cost		1,891,000	0	0.00000
5	TOTAL COST OF GENERATED POWER		251,244,263	14,463,054	1.73715
6	Energy Cost of Purchased Power (Excl. Econ & Cogens) (E7)		21,484,690	1,197,350	1.79435
7	Energy Cost of Sch. C,X Economy Purchases (Broker) (E9)		16,709,910	610,000	2.73933
8	Energy Cost of Economy Purchases (Non-Broker) (E9)		1,485,854	43,800	3.39236
9	Energy Cost of Schedule E Economy Purchases (E9)		0	0	0.00000
10	Capacity Cost of Economy Purchases (E9)		0	0 *	0.00000
11	Payments to Qualifying Facilities (E8)		83,252,679	4,021,143	2.07037
12	TOTAL COST OF PURCHASED POWER		122,933,133	5,872,293	2.09344
13	TOTAL AVAILABLE KWH			20,335,347	
14	Fuel Cost of Economy Sales	(E6)	(5,027,600)	(300,000)	1.67587
14a	Gain on Economy Sales - 80%	(E6)	(1,363,200)	(300,000) *	0.45440
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)	(9,883,064)	(491,211)	2.01198
18	TOTAL FUEL COST AND GAINS ON POWER SALES		(16,273,864)	(791,211)	2.05683
19	Net Inadvertent Interchange			0	
20	TOTAL FUEL AND NET POWER TRANSACTIONS		357,903,532	19,544,136	1.83126
21	Net Unbilled		10,775,579	(588,425)	0.06070
22	Company Use		1,664,613	(90,900)	0.00940
23	T & D Losses		20,138,636	(1,099,716)	0.11340
24	Adjusted System KWH Sales		357,903,532	17,765,095	2.01476
25	Wholesale KWH Sales (Excluding Supplemental Sales)		(12,157,075)	(603,602)	2.01409
26	Jurisdictional KWH Sales		345,746,457	17,161,493	2.01466
27	Jurisdictional KWH Sales Adjusted for Line Losses x	1.0016	346,299,651	17,161,433	2.01789
28	Prior Period True-Up (E1-B, Sheet 1)**		(2,007,311)	17,161,493	(0.01170)
28a	Market Price True-Up **		0	17,161,493	0.00000
28b	Nuclear Replacement Cost (E1-C)		18,371,207	17,161,493	0.10705
29	Total Jurisdictional Fuel Cost		362,663,547	17,161,493	2.11324
30	Revenue Tax Factor				1.00083
31	Fuel Cost Adjusted for Taxes		362,964,558	17,161,493	2.11499
32	GPIF **		1,172,147	17,161,493	0.00683
33	Fuel Factor Adjusted for taxes including GPIF		364,136,705	17,161,493	2.12182
34	Total Fuel Cost Factor (rounded to the nearest .001 cents/ KWH)				2.122

* 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: APR-98 THROUGH SEP-98
SCHEDULE E1-C - INCLUDING NUCLEAR REPLACEMENT COST

1.	TOTAL AMOUNT OF ADJUSTMENTS:	
	A. Generating Performance Incentive Reward / (Penalty)	$1,172,147
	B. True-Up (Over) / Under Recovery	($2,007,311)
	C. Market Price True-Up	$0
	D. Nuclear Replacement Cost (1)	$18,371,207
2.	JURISDICTIONAL MWH SALES	17,161,493 Mwh
3.	ADJUSTMENT FACTORS:	
	A. Generating Performance Incentive Factor	0.00683 Cents/kwh
	B. True-Up Factor	-0.01170 Cents/kwh
	C. Market Price True-Up Factor	0.00000 Cents/kwh
	D. Nuclear Replacement Cost	0.10705 Cents/kwh

(1)	Total Recoverable Nuclear Replacement Cost	$34,575,250
	MWH Sales 4/98 - 9/98	17,161,493
	MWH Sales 10/98 - 3/99	15,136,937
	Annual MWH Sales	32,298,430
	Replacement Cost (cents/kwh)	0.10705
	Nuclear Replacement Cost to be recovered 4/98 - 9/98 (17,161,493 MWH x 1.0705)	$18,371,207

FLORIDA POWER CORPORATION
CALCULATION OF LEVELIZED FUEL ADJUSTMENT FACTORS
(PROJECTED PERIOD)
FOR THE PERIOD OF: APR-98 THROUGH SEP-98
SCHEDULE E1-D - INCLUDING NUCLEAR REPLACEMENT COST

1	Period Jurisdictional Fuel Cost (E1, line 27)	$346,299,651	
2	Prior Period True-Up (E1, line 28)	(2,007,311)	
3	Market Price True-Up (E1, line 28a)	0	
3	Nuclear Replacement Cost (E1, line 28b)	18,371,207	
4	Regulatory Assessment Fee (E1, line 30)	301,011	
5	Generating Performance Incentive Factor (GPIF) (E1, line 32)	1,172,147	
6	Total Jurisdictional Fuel Cost	$364,136,705	
7	Jurisdictional Sales	17,161,493	Mwh
8	Jurisdictional Cost per Kwh Sold (Line 6 / Line7 / 10)	2.122	Cents/kwh
9	Effective Jurisdictional Sales (See Below)	17,130,748	Mwh

LEVELIZED FUEL FACTORS:

10	**Fuel Factor at Secondary Metering (Line 6 / Line 9 / 10)**	**2.126**	Cents/kwh
11	**Fuel Factor at Primary Metering (Line 10 * 99%)**	**2.105**	Cents/kwh
12	**Fuel Factor at Transmission Metering (Line 10 * 98%)**	**2.083**	Cents/kwh

	JURISDICTIONAL SALES (MWH)	
METERING VOLTAGE:	METER	SECONDARY
Distribution Secondary	14,[illegible]7,845	14,457,845
Distribution Primary	2,332,748	2,309,421
Transmission	370,900	363,482
Total	17,161,493	17,130,748

FLORIDA POWER CORPORATION
CALCULATION OF FINAL FUEL COST FACTORS
FOR THE PERIOD OF: APR-98 THROUGH SEP-98
SCHEDULE E1-E - INCLUDING NUCLEAR REPLACEMENT COST

		(1)	(2)	(3)
			Time of Use	
Line:	Metering Voltage	Levelized Factors Cents/Kwh	On-Peak Multiplier 1.291	Off-Peak Multiplier 0.842
1.	Distribution Secondary	2.126	2.745	1.790
2.	Distribution Primary	2.105	2.718	1.772
3.	Transmission	2.083	2.689	1.754
4.	Lighting Service	1.969	--	--

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 2.126 * (18.7% * On-Peak Multiplier 1.291 + 81.3% * Off-Peak Multiplier 0.842).

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)
04/98	842,837	18,677,268	2.216	1,667,413	30,613,703	1.836	2,510,250	49,290,971	1.964
05/98	1,143,776	28,891,782	2.526	2,009,207	35,844,253	1.784	3,152,983	64,736,036	2.053
06/98	1,199,644	34,573,740	2.882	2,169,733	39,554,233	1.823	3,369,377	74,127,973	2.200
07/98	1,318,377	45,207,147	3.429	2,460,417	51,939,403	2.111	3,778,794	97,146,550	2.571
08/98	1,310,516	44,727,911	3.413	2,417,663	48,715,909	2.015	3,728,179	93,443,820	2.506
09/98	1,216,170	35,609,458	2.928	2,239,136	43,058,585	1.923	3,455,306	78,668,043	2.277
TOTAL	7,031,320	207,687,306	2.954	12,963,569	249,726,086	1.926	19,994,889	457,413,392	2.288
MARGINAL FUEL COST			ON-PEAK			OFF-PEAK			AVERAGE
WEIGHTING MULTIPLIER			1.291			0.842			1.000

FLORIDA POWER CORPORATION
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE
ESTIMATED FOR THE PERIOD OF: APRIL 1998 THROUGH SEPTEMBER 1998
SCHEDULE E2 - INCLUDING NUCLEAR REPLACEMENT COST

	DESCRIPTION		Apr-98	May-98	Jun-98	Jul-98	Aug-98	Sep-98	TOTAL
1	Fuel Cost of System Net Generation		$28,005,111	$36,774,111	$41,193,532	$49,194,911	$48,206,865	$43,108,626	$246,483,156
1a	Nuclear Fuel Disposal Cost		480,871	489,775	467,080	482,650	482,650	467,080	2,870,107
1b	Adjustments to Fuel Cost		300,000	312,000	320,000	322,000	320,000	317,000	1,891,000
2	Fuel Cost of Power Sold		(313,600)	(606,000)	(611,200)	(1,406,400)	(1,088,400)	(1,002,000)	(5,027,600)
2a	Fuel Cost of Stratified Sales		(871,000)	(442,063)	(446,394)	(1,798,578)	(2,721,827)	(3,603,202)	(9,883,064)
2b	Gains on Power Sales		(90,880)	(181,760)	(181,760)	(363,520)	(272,640)	(272,640)	(1,363,200)
3	Fuel Cost of Purchased Power		1,418,850	3,380,250	3,570,650	4,652,650	4,529,420	3,932,870	21,484,690
3a	Recov Non-Fuel Cost of Econ Purch		0	0	0	0	0	0	0
3b	Payments to Qualifying Facilities		11,772,951	13,019,107	14,004,499	15,133,658	15,068,248	14,254,216	83,252,679
4	Fuel Cost of Economy Purchases		1,472,790	2,354,923	3,278,774	4,344,368	3,903,407	2,841,502	18,195,764
5	Total Fuel & Net Power Transactions		$42,1[illegible],093	$55,100,343	$61,595,181	$70,561,739	$68,427,723	$60,043,452	$357,903,532
6	Adjusted System Sales	MWH	2,393,249	2,506,363	2,962,315	3,226,325	3,323,659	3,353,184	17,765,095
7	System Cost per KWH Sold	c/kwh	1.7622	2.1984	2.0793	2.1871	2.0588	1.7906	2.0148
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	1.7651	2.2019	2.0826	2.1906	2.0621	1.7935	2.0179
8	Prior Period True-Up *	c/kwh	-0.0144	-0.0138	-0.0117	-0.0107	-0.0104	-0.0104	-0.0117
8a	Market Price True-Up *	c/kwh	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
8b	Nuclear Replacement Cost *	c/kwh	0.1319	0.1260	0.1071	0.0983	0.0955	0.0947	0.1070
9	Total Jurisdictional Fuel Expense	c/kwh	1.8826	2.3142	2.1781	2.2781	2.1472	1.8779	2.1132
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	1.8841	2.3161	2.1799	2.2800	2.1489	1.8795	2.1150
12	GPIF	c/kwh	0.0084	0.0080	0.0068	0.0063	0.0061	0.0060	0.0068
13	Total Fuel Cost Factor (rounded .001)	c/kwh	1.893	2.324	2.187	2.286	2.155	1.885	2.122

* Based on Jurisdictional Sales Only

FLORIDA POWER CORPORATION
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE
ESTIMATED FOR THE PERIOD OF: APRIL 1998 THROUGH SEPTEMBER 1998
SCHEDULE E10 - INCLUDING NUCLEAR REPLACEMENT COST

	DESCRIPTION		Apr-98	May-98	Jun-98	Jul-98	Aug-98	Sep-98	Period Average	Prior Residential Bill *	Apr-98 vs. Prior
1	Base Rate Revenues	($)	49.05	49.05	49.05	49.05	49.05	49.05	49.05	49.05	0.00
2	Fuel Recovery Factor	(c/kwh)	2.122	2.122	2.122	2.122	2.122	2.122	2.122	1.825	
3	Fuel Cost Recovery Revenues	($)	21.26	21.26	21.26	21.26	21.26	21.26	21.26	18.25	3.01
4	Capacity Cost Recovery Revenues	($)	10.04	10.04	10.04	10.04	10.04	10.04	10.04	12.61	-2.57
5	Energy Conservation Cost Revenues	($)	3.23	3.23	3.23	3.23	3.23	3.23	3.23	2.80	0.43
6	Gross Receipt Taxes	($)	2.14	2.14	2.14	2.14	2.14	2.14	2.14	2.12	0.02
7	Total Revenues	($)	85.72	85.72	85.72	85.72	85.72	85.72	85.72	84.83	0.89

* Actual Residential Billing for Mar-98

EXHIBITS TO THE TESTIMONY OF KARL H. WIELAND

LEVELIZED FUEL COST FACTORS
APRIL THROUGH SEPTEMBER 1998

SCHEDULES E1 THROUGH E10 AND H1

FLORIDA POWER CORPORATION
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE
ESTIMATED FOR THE PERIOD OF: APRIL 1998 THROUGH SEPTEMBER 1998

			DOLLARS	MWH	CENTS/KWH
1.	Fuel Cost of System Net Generation *		246,483,156	14,463,054	1.70423
2.	Spent Nuclear Fuel Disposal Cost		2,870,107	3,069,633 *	0.09350
3.	Nuclear Fuel Replacement Cost		0	0	0.00000
4.	Adjustment to Fuel Cost		1,891,000	0	0.00000
5.	TOTAL COST OF GENERATED POWER		251,244,263	14,463,054	1.73715
6.	Energy Cost of Purchased Power (Excl. Econ & Cogens) (E7)		21,484,690	1,197,350	1.79435
7.	Energy Cost of Sch. C,X Economy Purchases (Broker) (E9)		16,709,910	610,000	2.73933
8.	Energy Cost of Economy Purchases (Non-Broker) (E9)		1,485,854	43,800	3.39236
9.	Energy Cost of Schedule E Economy Purchases (E9)		0	0	0.00000
10.	Capacity Cost of Economy Purchases (E9)		0	0 *	0.00000
11.	Payments to Qualifying Facilities (E8)		83,252,679	4,021,143	2.07037
12.	TOTAL COST OF PURCHASED POWER		122,933,133	5,872,293	2.09344
13.	TOTAL AVAILABLE KWH			20,335,347	
14.	Fuel Cost of Economy Sales	(E6)	(5,027,600)	(300,000)	1.67587
14a.	Gain on Economy Sales - 80%	(E6)	(1,363,200)	(300,000) *	0.45440
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)	(9,883,064)	(491,211)	2.01198
18.	TOTAL FUEL COST AND GAINS ON POWER SALES		(16,273,864)	(791,211)	2.05683
19.	Net Inadvertent Interchange			0	
20.	TOTAL FUEL AND NET POWER TRANSACTIONS		357,903,532	19,544,136	1.83126
21.	Net Unbilled		10,775,579	(588,425)	0.06070
22.	Company Use		1,664,613	(90,900)	0.00940
23.	T & D Losses		20,138,636	(1,099,716)	0.11340
24.	Adjusted System KWH Sales		357,903,532	17,765,095	2.01476
25.	Wholesale KWH Sales (Excluding Supplemental Sales)		(12,157,075)	(603,602)	2.01409
26.	Jurisdictional KWH Sales		345,746,457	17,161,493	2.01466
27.	Jurisdictional KWH Sales Adjusted for Line Losses x	1.0016	346,299,651	17,161,493	2.01789
28.	Prior Period True-Up (E1-B, Sheet 1)**		(2,007,311)	17,161,493	(0.01170)
28a.	Market Price True-Up **		0	17,161,493	0.00000
28b.	Nuclear Replacement Cost (E1-C)		0	17,161,493	0.00000
29.	Total Jurisdictional Fuel Cost		344,292,340	17,161,493	2.00619
30.	Revenue Tax Factor				1.00083
31.	Fuel Cost Adjusted for Taxes		344,578,103	17,161,493	2.00786
32.	GPIF **		1,172,147	17,161,493	0.00683
33.	Fuel Factor Adjusted for taxes including GPIF		345,750,250	17,161,493	2.01469
34.	Total Fuel Cost Factor (rounded to the nearest .001 cents/ KWH)				2.015

* For Informational Purposes Only

** Based on Jurisdictional Sales

SCHEDULE E1-A

FLORIDA POWER CORPORATION
CALCULATION OF TOTAL TRUE-UP
(PROJECTED PERIOD)
ESTIMATED FOR THE PERIOD OF: APR-98 THROUGH SEP-98

1	ESTIMATED OVER/(UNDER) RECOVERY (2 months actual, 4 months projected) (Schedule E1-B, Sheet 1)	$10,226,809
2	FINAL TRUE-UP (6 months prior period) (Schedule E1-B, Sheet 1)	(8,219,498)
3	TOTAL OVER/(UNDER) RECOVERY (Line 1 + Line 2)	$2,007,311
4	OVER/(UNDER) RECOVERY (To be included in projected period)	$2,007,311
5	JURISDICTIONAL MWH SALES (Projected Period)	17,161,493 Mwh
6	TRUE-UP FACTOR (To be included in projected period) (Line 3 / Line 4 / 10)	-0.01170 Cents/kwh

FLORIDA POWER CORPORATION
CALCULATION OF ESTIMATED TRUE-UP
RE-ESTIMATED FOR THE PERIOD OF: OCTOBER 1997 THROUGH MARCH 1998

DESCRIPTION		ADJUSTED ACTUALS Oct-97	ADJUSTED ACTUALS Nov-97	ESTIMATED Dec-97	ESTIMATED Jan-98	ESTIMATED Feb-98	ESTIMATED Mar-98	TOTAL PERIOD
REVENUE								
1 Jurisdictional KWH Sales		2,926,130	2,386,064	2,364,071	2,517,596	2,427,741	2,312,121	14,933,723
2 Jurisdictional Fuel Factor (Pre-Tax)		1.821	1.818	1.820	1.820	1.820	1.820	
3 Total Jurisdictional Fuel Revenue		53,296,255	43,390,114	43,018,527	45,812,191	44,177,117	42,073,203	271,767,408
4 Less: True-Up Provision		(1,510,382)	(1,510,382)	(1,510,382)	(1,510,382)	(1,510,382)	(1,510,379)	(9,062,289)
5 Less: GPIF Provision		42,552	42,552	42,552	42,552	42,552	42,550	255,310
6 Less: Other		0	0	0	0	0	0	0
7 Net Fuel Revenue		51,828,425	41,922,284	41,550,697	44,344,361	42,709,287	40,605,374	262,960,429
FUEL EXPENSE								
8 Total Cost of Generated Power		45,112,088	33,349,288	41,288,696	36,643,442	32,941,109	31,209,715	220,544,338
9 Total Cost of Purchased Power		18,008,717	17,165,989	16,982,613	15,513,837	13,711,800	16,394,365	97,777,321
10 Total Cost of Power Sales		(5,730,743)	(6,329,446)	(1,024,380)	(1,610,960)	(2,274,300)	(2,581,960)	(19,551,789)
11 Total Fuel and Net Power		57,390,062	44,185,831	57,246,929	50,546,319	44,378,609	45,022,120	298,769,870
12 Jurisdictional Percentage		96.65%	95.81%	96.89%	97.08%	97.24%	97.07%	96.80%
13 Jurisdictional Loss Multiplier		1.0016	1.0016	1.0016	1.0016	1.0016	1.0016	1.0016
14 Jurisdictional Fuel Cost		55,556,243	42,402,180	55,555,296	49,148,879	43,222,805	43,772,897	289,658,300
COST RECOVERY								
15 Net Fuel Revenue Less Expense		(3,727,818)	(479,896)	(14,004,599)	(4,804,518)	(513,518)	(3,167,522)	
16 Interest Provision	(1)	(43,003)	4,609	12,964	19,715	14,500	13,042	
17 Current Cycle Balance		(3,770,821)	(4,246,108)	(18,237,742)	(23,022,545)	(23,521,563)	(26,676,044)	
18 Nuclear Replacement Cost		10,962,365	18,498,040	27,840,564	27,840,564	27,840,564	27,840,564	
19 Plus: Prior Period Balance	(2)	(8,219,498)	(8,219,498)	(8,219,498)	(8,219,498)	(8,219,498)	(8,219,498)	
20 Plus: Cumulative True-Up Provision		1,510,382	3,020,764	4,531,146	6,041,528	7,551,910	9,062,289	
21 Total Retail Balance		482,428	9,053,198	5,914,470	2,640,049	3,651,413	2,007,311	

(1) Interest for the period calculated at the November 1997 rate of .462% (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 OCTOBER 1997 THROUGH MARCH 1998

	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	223,520,368	211,168,795	12,351,573	5.8	11,841,038	11,744,226	96,812	0.8	1.8877	1.7981	0.0896	5.0
2. Spent Nuclear Fuel Disposal Cost	1,456,091	1,456,091	0	0.0	1,557,317 *	1,557,317 *	0	0.0	0.0935	0.0935	0.0000	0.0
3. Nuclear Fuel Replacement Cost	(28,910,243)	(28,063,000)	(847,243)	3.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
4. Adjustment to Fuel Cost	(4,432,122)	3,220,000	(7,652,122)	(237.6)	(283,314)	0	(283,314)	0.0	1.5644	0.0000	1.5644	0.0
5. TOTAL COST OF GENERATED POWER	191,634,094	187,781,886	3,852,208	2.1	11,557,724	11,744,226	(186,502)	(1.6)	1.6581	* 1.5989	0.0591	3.7
6. Energy Cost of P. P. (Excl. Econ & Cogens)	10,485,563	12,758,320	(2,272,757)	(17.8)	588,344	678,935	(90,591)	(13.3)	1.7822	1.8792	(0.0970)	(5.2)
7. Energy Cost of Sch. C,X Econ Purch (Broker)	7,578,132	10,117,800	(2,539,668)	(25.1)	369,980	380,000	(10,020)	(2.6)	2.0483	2.6626	(0.6143)	(23.1)
8. Energy Cost of Economy Purch (Non-Broker)	2,452,013	759,930	1,692,083	222.7	96,581	33,182	63,399	191.1	2.5388	2.2902	0.2486	10.9
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	227,200	344,540	(117,340)	(34.1)	0 *	15,182 *	(15,182)	(100.0)	0.0000	2.2694	(2.2694)	(100.0)
11. Payments to Qualifying Facilities	77,034,413	75,138,623	1,895,790	2.5	3,813,396	3,631,591	181,805	5.0	2.0201	2.0690	(0.0489)	(2.4)
12. TOTAL COST OF PURCHASED POWER	97,777,321	99,119,213	(1,341,892)	(1.4)	4,868,301	4,723,708	144,593	3.1	2.0084	2.0983	(0.0899)	(4.3)
13. TOTAL AVAILABLE KWH					16,426,025	16,467,934	(41,909)	(0.3)	--	--	--	--
14. Fuel Cost of Economy Sales	(4,664,365)	(6,690,300)	2,025,935	(30.3)	(261,480)	(377,000)	115,520	(30.6)	1.7838	1.7746	0.0092	0.5
14a Gain on Economy Sales - 80%	(1,151,504)	(1,973,160)	821,656	(41.6)	(261,480) *	(377,000) *	115,520	(30.6)	0.4404	0.5234	(0.0830)	(15.9)
15. Fuel Cost of Other Power Sales	(3,966,087)	0	(3,966,087)	0.0	(177,117)	0	(177,117)	0.0	2.2392	0.0000	2.2392	0.0
15a Gain on Other Power Sales	(883,055)	0	(883,055)	0.0	(177,117) *	0 *	(177,117)	0.0	0.4986	0.0000	0.4986	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	(8,886,778)	(8,535,000)	(351,778)	4.1	(419,590)	(387,284)	(32,306)	8.3	2.1180	2.2038	(0.0858)	(3.9)
18. TOTAL FUEL COST & GAINS ON POWER SALES	(19,551,789)	(17,198,460)	(2,353,329)	13.7	(858,187)	(764,284)	(93,903)	12.3	2.2783	2.2503	0.0280	1.2
19. Net Inadvertent Interchange					3,301	0	3,301	0.0	--	--	--	--
20. TOTAL FUEL & NET POWER TRANSACTIONS	269,859,626	269,702,639	156,987	0.1	15,571,139	15,703,650	(132,511)	(0.8)	1.7331	1.7175	0.0156	0.9
21. Net Unbilled	(11,706,010) *	(9,892,540) *	(1,812,470)	18.3	610,709	576,001	34,708	6.0	(0.0759)	(0.0646)	(0.0113)	17.5
22. Company Use	2,782,309 *	1,561,164 *	1,221,145	78.2	(145,167)	(90,900)	(54,267)	59.7	0.0180	0.0102	0.0078	76.9
23. T & D Losses	11,631,948 *	14,933,640 *	(3,301,692)	(22.1)	(606,897)	(869,523)	262,626	(30.2)	0.0754	0.0975	(0.0221)	(22.7)
24. Adjusted System KWH Sales	269,859,626	269,702,639	156,987	0.1	15,429,784	15,319,228	110,556	0.7	1.7490	1.7605	(0.0116)	(0.7)
25. Wholesale KWH Sales (Excl Suppl. Sales)	(9,561,108)	(8,271,424)	(1,289,684)	15.6	(496,061)	(473,107)	(22,954)	4.9	1.9274	1.7483	0.1791	10.2
26. Jurisdictional KWH Sales	260,298,518	261,431,215	(1,132,697)	(0.4)	14,933,723	14,846,121	87,602	0.6	1.7430	1.7609	(0.0179)	(1.0)
27. Jurisd KWH Sales Adj for Line Losses	260,714,996	261,849,505	(1,134,509)	(0.4)	14,933,723	14,846,121	87,602	0.6	1.7458	1.7638	(0.0179)	(1.0)
28. Prior Period True-Up **	9,062,289	9,062,289	0	0.0	14,933,723	14,846,121	87,602	0.6	0.0607	0.0610	(0.0004)	(0.6)
28a Market Price True-Up **	0	(505,000)	505,000	(100.0)	14,933,723	14,846,121	87,602	0.6	0.0000	(0.0034)	0.0034	(100.0)
29. Total Jurisdictional Fuel Cost	269,777,285	270,406,794	(629,509)	(0.2)	14,933,723	14,846,121	87,602	0.6	1.8065	1.8214	(0.0149)	(0.8)
30. Revenue Tax Factor									1.00083	1.00083	0.0000	0.0
31. Fuel Cost Adjusted for Taxes									1.8080	1.8229	(0.0149)	(0.8)
32. GPIF **	(255,522)	(255,522)	0	0.0	14,933,723	14,846,121	87,602	0.6	(0.0017)	(0.0017)	0.0000	(0.6)
33. Other												
34. Total Fuel Cost Factor									1.806	1.821	(0.015)	(0.8)

* For Informational Purposes Only
** Based on Jurisdictional Sales

SCHEDULE E1-C

FLORIDA POWER CORPORATION
CALCULATION OF GENERATING PERFORMANCE INCENTIVE AND TRUE-UP ADJUSTMENT FACTORS
ESTIMATED FOR THE PERIOD OF: APR-98 THROUGH SEP-98

1.	TOTAL AMOUNT OF ADJUSTMENTS	
	A. Generating Performance Incentive Reward / (Penalty)	$1,172,147
	B. True-Up (Over) / Under Recovery	($2,007,311)
	C. Market Price True-Up	$0
	D. Nuclear Replacement Cost	$0
2.	JURISDICTIONAL MWH SALES	17,161,493 Mwh
3.	ADJUSTMENT FACTORS:	
	A. Generating Performance Incentive Factor	0.00683 Cents/kwh
	B. True-Up Factor	-0.01170 Cents/kwh
	C. Market Price True-Up Factor	0.00000 Cents/kwh
	D. Nuclear Replacement Cost	0.00000 Cents/kwh

FLORIDA POWER CORPORATION
CALCULATION OF LEVELIZED FUEL ADJUSTMENT FACTORS
(PROJECTED PERIOD)
FOR THE PERIOD OF: APR-98 THROUGH SEP-98

1	Period Jurisdictional Fuel Cost (E1, line 27)	$346,299,651	
2	Prior Period True-Up (E1, line 28)	(2,007,311)	
3	Market Price True-Up (E1, line 28a)	0	
3	Nuclear Replacement Cost (E1, line 28b)	0	
4	Regulatory Assessment Fee (E1, line 30)	285,763	
5	Generating Performance Incentive Factor (GPIF) (E1, line 32)	1,172,147	
6	Total Jurisdictional Fuel Cost	$345,750,250	
7	Jurisdictional Sales	17,161,493	Mwh
8	Jurisdictional Cost per Kwh Sold (Line 6 / Line7 / 10)	2.015	Cents/kwh
9	Effective Jurisdictional Sales (See Below)	17,130,748	Mwh

LEVELIZED FUEL FACTORS:

10	Fuel Factor at Secondary Metering (Line 6 / Line 9 / 10)	**2.018**	Cents/kwh
11	Fuel Factor at Primary Metering (Line 10 * 99%)	**1.998**	Cents/kwh
12	Fuel Factor at Transmission Metering (Line 10 * 98%)	**1.978**	Cents/kwh

	JURISDICTIONAL SALES (MWH)	
METERING VOLTAGE:	METER	SECONDARY
Distribution Secondary	14,457,845	14,457,845
Distribution Primary	2,332,748	2,309,421
Transmission	370,900	363,482
Total	17,161,493	17,130,748

FLORIDA POWER CORPORATION
CALCULATION OF FINAL FUEL COST FACTORS
FOR THE PERIOD OF: APR-98 THROUGH SEP-98

		(1)	(2)	(3)
			——Time of Use——	
Line:	Metering Voltage	Levelized Factors Cents/Kwh	On-Peak Multiplier 1.291	Off-Peak Multiplier 0.842
1.	Distribution Secondary	2.018	2.605	1.699
2.	Distribution Primary	1.998	2.579	1.682
3.	Transmission	1.978	2.554	1.665
4.	Lighting Service	1.869	--	--

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 2.018 * (18.7% * On-Peak Multiplier 1.291 + 81.3% * Off-Peak Multiplier 0.842).

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)
04/98	842,837	18,677,268	2.216	1,667,413	30,613,703	1.836	2,510,250	49,290,971	1.964
05/98	1,143,776	28,891,782	2.526	2,009,207	35,844,253	1.784	3,152,983	64,736,035	2.053
06/98	1,199,644	34,573,740	2.882	2,169,733	39,554,233	1.823	3,369,377	74,127,973	2.200
07/98	1,318,377	45,207,147	3.429	2,460,417	51,939,403	2.111	3,778,794	97,146,550	2.571
08/98	1,310,516	44,727,911	3.413	2,417,663	48,715,909	2.015	3,728,179	93,443,820	2.506
09/98	1,216,170	35,609,458	2.928	2,239,136	43,058,585	1.923	3,455,306	78,668,043	2.277
TOTAL	7,031,320	207,687,306	2.954	12,963,569	249,726,086	1.926	19,994,889	457,413,392	2.288

	ON-PEAK	OFF-PEAK	AVERAGE
MARGINAL FUEL COST WEIGHTING MULTIPLIER	1.291	0.842	1.000

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

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Energy Delivered				Energy Required @ Source			Jurisdictional
Class Loads	Sales Mwh	Unbilled Mwh	Total Mwh	% of Total	Delivery Efficiency	Mwh (3) / (5)	% of Total	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	([illegible]38,671)	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: APRIL 1998 THROUGH SEPTEMBER 1998

	DESCRIPTION		Apr-98	May-98	Jun-98	Jul-98	Aug-98	Sep-98	TOTAL
1	Fuel Cost of System Net Generation		$28,005,111	$36,774,111	$41,193,532	$49,194,911	$48,206,865	$43,108,626	$246,483,156
1a	Nuclear Fuel Disposal Cost		480,871	489,775	467,080	482,650	482,650	467,080	2,870,107
1b	Adjustments to Fuel Cost		300,000	312,000	320,000	322,000	320,000	317,000	1,891,000
2	Fuel Cost of Power Sold		(313,600)	(606,000)	(611,200)	(1,406,400)	(1,088,400)	(1,002,000)	(5,027,600)
2a	Fuel Cost of Stratified Sales		(871,000)	(442,063)	(446,394)	(1,798,578)	(2,721,827)	(3,603,202)	(9,883,064)
2b	Gains on Power Sales		(90,880)	(181,760)	(181,760)	(363,520)	(272,640)	(272,640)	(1,363,200)
3	Fuel Cost of Purchased Power		1,418,850	3,380,250	3,570,650	4,652,650	4,529,420	3,932,870	21,484,690
3a	Recov Non-Fuel Cost of Econ Purch		0	0	0	0	0	0	0
3b	Payments to Qualifying Facilities		11,772,951	13,019,107	14,004,499	15,133,658	15,068,248	14,254,216	83,252,679
4	Fuel Cost of Economy Purchases		1,472,790	2,354,923	3,278,774	4,344,368	3,903,407	2,841,502	18,195,764
5	Total Fuel & Net Power Transactions		$42,175,093	$55,100,343	$61,595,181	$70,561,739	$68,427,723	$60,043,452	$357,903,532
6	Adjusted System Sales	MWH	2,393,249	2,506,363	2,962,315	3,226,325	3,323,659	3,353,184	17,765,095
7	System Cost per KWH Sold	c/kwh	1.7622	2.1984	2.0793	2.1871	2.0588	1.7906	2.0148
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	1.7651	2.2019	2.0826	2.1906	2.0621	1.7935	2.0179
8	Prior Period True-Up *	c/kwh	-0.0144	-0.0138	-0.0117	-0.0107	-0.0104	-0.0104	-0.0117
8a	Market Price True-Up *	c/kwh	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
8b	Nuclear Replacement Cost *	c/kwh	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
9	Total Jurisdictional Fuel Expense	c/kwh	1.7507	2.1882	2.0709	2.1798	2.0517	1.7832	2.0062
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	1.7521	2.1900	2.0726	2.1816	2.0534	1.7846	2.0079
12	GPIF	c/kwh	0.0084	0.0080	0.0068	0.0063	0.0061	0.0060	0.0068
13	Total Fuel Cost Factor (rounded .001)	c/kwh	1.761	2.198	2.079	2.188	2.059	1.791	2.015

* Based on Jurisdictional Sales Only

SCHEDULE E3

FLORIDA POWER CORPORATION
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ESTIMATED FOR THE PERIOD OF: APR-98 THROUGH SEP-98

			Apr-98	May-98	Jun-98	Jul-98	Aug-98	Sep-98	TOTAL
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL		7,991,940	8,644,101	9,119,131	12,794,853	11,700,799	10,349,234	60,599,837
2	LIGHT OIL		8,046	38,304	308,332	791,877	959,368	330,873	2,383,597
3	COAL		15,530,583	23,034,876	25,597,369	26,906,055	27,534,864	25,865,279	144,467,715
4	GAS		2,383,675	2,837,223	4,106,190	6,623,136	5,895,458	4,510,730	26,456,411
5	NUCLEAR		1,784,402	1,793,442	1,736,055	1,793,924	1,793,924	1,736,055	10,617,802
6	OTHER		326,466	326,466	326,466	326,466	326,466	326,466	1,958,793
7	TOTAL	$	28,008,111	36,774,111	41,193,532	48,194,911	48,206,865	43,108,626	246,483,156
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL		331,646	357,144	373,933	536,292	486,090	428,974	2,514,079
9	LIGHT OIL		135	629	5,266	12,866	16,496	5,458	40,851
10	COAL		876,883	1,304,854	1,432,497	1,521,141	1,538,299	1,463,306	8,136,969
11	GAS		48,285	66,838	106,364	190,188	167,379	122,468	701,522
12	NUCLEAR		514,301	523,024	499,551	516,203	516,203	499,551	3,069,633
13	OTHER		0	0	0	0	0	0	0
14	TOTAL	MWH	1,771,250	2,253,289	2,417,611	2,776,690	2,734,457	2,519,757	14,463,054
	UNITS OF FUEL BURNED								
15	HEAVY OIL	BBL	513,551	555,994	586,004	822,116	751,260	665,363	3,894,298
16	LIGHT OIL	BBL	303	1,443	11,541	28,121	35,670	12,009	89,087
17	COAL	TON	329,574	490,858	544,003	576,184	582,031	554,632	3,077,281
18	GAS	MCF	578,929	804,056	1,273,739	2,259,751	1,989,860	1,445,468	8,351,802
19	NUCLEAR	MMBTU	5,346,673	5,434,674	5,260,772	5,436,134	5,436,134	5,260,772	32,175,158
20	OTHER	BBL	12,069	17,069	12,069	12,069	12,069	12,069	72,414
	BTUS BURNED (MMBTU)								
21	HEAVY OIL		3,298,729	3,508,360	3,750,434	5,281,545	4,808,064	4,258,321	24,923,443
22	LIGHT OIL		1,759	8,368	66,935	163,100	206,888	69,653	516,703
23	COAL		8,284,639	12,336,236	13,675,200	14,483,720	14,630,477	13,942,087	77,352,359
24	GAS		578,929	804,056	1,273,739	2,259,751	1,989,860	1,445,468	8,351,802
25	NUCLEAR		5,346,673	5,434,674	5,260,772	5,436,134	5,436,134	5,260,772	32,175,158
26	OTHER		70,000	70,000	70,000	70,000	70,000	70,000	420,000
27	TOTAL	MMBTU	17,588,729	22,211,694	24,097,069	27,674,250	27,141,434	25,046,298	143,739,465
	GENERATION MIX (% MWH)								
28	HEAVY OIL		18.72%	15.85%	15.47%	19.31%	17.84%	17.02%	17.38%
29	LIGHT OIL		0.01%	0.03%	0.22%	0.46%	0.61%	0.22%	0.28%
30	COAL		49.51%	57.91%	59.25%	54.78%	56.46%	58.07%	56.26%
31	GAS		2.7?%	2.97%	4.40%	6.85%	6.14%	4.86%	4.85%
32	NUCLEAR		29.04%	23.25%	20.66%	18.59%	18.95%	19.83%	21.22%
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	15.56	15.55	15.56	15.56	15.57	15.55	15.56
36	LIGHT OIL	$/BBL	26.53	26.55	26.72	26.73	26.79	26.72	26.74
37	COAL	$/TON	47.12	46.93	47.05	46.70	47.31	46.64	46.95
38	GAS	$/MCF	4.12	3.65	3.22	2.93	2.96	3.12	3.17
39	NUCLEAR	$/MMBTU	0.33	0.33	0.33	0.33	0.33	0.33	0.33
40	OTHER	$/BBL	27.05	27.05	27.05	27.05	27.05	27.05	27.05
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL		2.43	2.43	2.43	2.43	2.43	2.43	2.43
42	LIGHT OIL		4.57	4.58	4.61	4.61	4.62	4.61	4.61
43	COAL		1.88	1.87	1.87	1.86	1.88	1.86	1.87
44	GAS		4.12	3.65	3.22	2.93	2.96	3.12	3.17
45	NUCLEAR		0.33	0.33	0.33	0.33	0.33	0.33	0.33
46	OTHER		4.66	4.66	4.66	4.66	4.66	4.66	4.66
47	TOTAL	$/MMBTU	1.59	1.66	1.71	1.79	1.78	1.72	1.72
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL		9,910	9,963	10,030	9,8??	9,891	9,927	9,914
49	LIGHT OIL		13,029	13,304	12,711	12,678	12,540	12,762	12,648
50	COAL		9,448	9,454	9,546	9,522	9,511	9,528	9,506
51	GAS		11,990	12,030	11,975	11,882	11,888	11,803	11,905
52	NUCLEAR		10,396	10,379	10,531	10,531	10,531	10,531	10,482
53	OTHER		0	0	0	0	0	0	0
54	TOTAL	BTU/KWH	9,919	9,857	9,967	9,967	9,962	9,940	9,938
	GENERATED FUEL COST PER KWH (C/KWH)								
55	HEAVY OIL		2.41	2.42	2.44	2.39	2.41	2.41	2.41
56	LIGHT OIL		5.96	6.09	5.86	5.84	5.79	5.88	5.83
57	COAL		1.77	1.77	1.79	1.77	1.79	1.77	1.78
58	GAS		4.94	4.39	3.86	3.48	3.52	3.68	3.77
59	NUCLEAR		0.34	0.34	0.35	0.35	0.35	0.35	0.35
60	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
61	TOTAL	C/KWH	1.58	1.63	1.70	1.77	1.77	1.71	1.70

FLORIDA POWER CORPORATION
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Apr-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	514,301	93.1	93.1	100.0	10,396	NUCLEAR	5,346,873 MMBTU	1.00	5,346,873	1,784,402	0.34
2 ANCLOTE	1	517	174,048	46.8	96.5	63.8	9,726	HEAVY OIL	264,499 BBLS	6.40	1,692,791	4,128,178	2.37
3 ANCLOTE	1		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
4 ANCLOTE	2	517	140,282	37.7	96.1	51.2	9,944	HEAVY OIL	217,963 BBLS	6.40	1,394,964	• 3,400,225	2.42
5 ANCLOTE	2		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
6 BARTOW	1	117	6,783	8.1	99.6	83.1	10,901	HEAVY OIL	11,553 BBLS	6.40	73,941	172,723	2.56
7 BARTOW	2	119	7,240	8.5	99.5	83.8	10,910	HEAVY OIL	12,342 BBLS	6.40	78,988	184,512	2.55
8 BARTOW	3	213	3,195	12.1	96.8	28.4	14,052	HEAVY OIL	7,015 BBLS	6.40	44,898	104,875	3.28
9 BARTOW	3		15,289				14,558	GAS	222,577 MCF	1.00	222,577	523,067	3.42
10 CRYSTAL RIVER	1	373	69,948	26.0	31.0	84.2	9,835	COAL	27,299 TONS	25.20	687,939	1,149,021	1.64
11 CRYSTAL RIVER	1		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
12 CRYSTAL RIVER	2	469	247,756	73.4	77.2	96.4	9,760	COAL	95,956 TONS	25.20	2,418,089	4,038,800	1.63
13 CRYSTAL RIVER	2		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
14 CRYSTAL RIVER	4	717	67,410	13.1	15.9	81.9	9,517	COAL	25,556 TONS	25.10	641,541	1,281,393	1.90
15 CRYSTAL RIVER	4		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
16 CRYSTAL RIVER	5	717	491,769	95.3	98.3	96.8	9,226	COAL	180,759 TONS	25.10	4,537,061	9,061,466	1.84
17 CRYSTAL RIVER	5		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
18 SUWANNEE	1	34	7	0.1	100.0	100.0	13,695	HEAVY OIL	15 BBLS	6.40	96	288	4.09
19 SUWANNEE	1		10				14,188	GAS	142 MCF	1.00	142	333	3.33
20 SUWANNEE	2	33	0	0.0	100.0	0.0	0	HEAVY OIL	0 BBLS	6.40	0	0	0.00
21 SUWANNEE	2		18				13,690	GAS	246 MCF	1.00	246	578	3.21
22 SUWANNEE	3	80	91	0.2	100.0	68.9	11,562	HEAVY OIL	164 BBLS	6.40	1,052	3,142	3.45
23 SUWANNEE	3		0				0	GAS	0 MCF	1.00	0	0	0.00
24 AVON PARK	1-2	64	20	0.0	100.0	69.3	16,326	LIGHT OIL	56 BBLS	5.80	327	1,523	7.61
25 BARTOW	1-4	217	0	1.0	100.0	92.8	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
26 BARTOW	1-4		1,628				12,670	GAS	20,601 MCF	1.00	20,601	48,413	2.98
27 BAYBORO	1-4	232	0	0.0	0.0	0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
28 DEBARY	1-10	766	0	0.0	99.9	99.1	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
29 DEBARY	1-10		3,722				12,410	GAS	46,190 MCF	1.00	46,190	108,547	2.92
30 HIGGINS	1-4	156	50	0.3	99.9	97.1	14,014	LIGHT OIL	121 BBLS	5.80	701	3,183	6.37
31 HIGGINS	1-4		280				13,516	GAS	3,784 MCF	1.00	3,784	8,894	3.18
32 INT CITY	1-10	744	46	0.3	99.9	98.8	11,016	LIGHT OIL	87 BBLS	5.80	507	2,313	5.03
33 INT CITY	1-10		1,453				12,849	GAS	18,670 MCF	1.00	18,670	43,874	3.02
34 INT CITY	11	169	19	0.0	100.0	56.2	11,839	LIGHT OIL	39 BBLS	5.80	225	1,027	5.40
35 PORT ST. JOE	1	0	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	0	0.0	100.0	62.7	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
38 SUWANNEE	1-3		72				12,521	GAS	902 MCF	1.00	902	2,119	2.94
39 TURNER	1-4	200	0	0.0	0.0	0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
40 UNIV OF FLA.	1	42	25,815	85.4	85.4	100.0	10,297	GAS	265,817 MCF	1.00	265,817	413,137	1.60
41 OTHER - START UP		-	0	-	-	-	-	LIGHT OIL	12,069 BBLS	5.80	70,000	326,466	0.00
42 OTHER - GAS TRANSP.		-	0	-	-	-	-	GAS TRANSP	-	-	-	1,234,725	-
43 TOTAL		7,504	1,771,250				9,919				17,568,729	28,005,111	1.58

SCHEDULE E4

FLORIDA POWER CORPORATION
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: May-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	758	523,824	83.1	93.1	100.0	10,375	NUCLEAR	5,434,674 MMBTU	1.00	5,434,674	1,793,442	0.34
2 ANCLOTE	1	503	187,221	44.7	96.8	87.4	9,895	HEAVY OIL	258,539 BBLS	6.40	1,654,652	4,033,214	2.41
3 ANCLOTE	1		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
4 ANCLOTE	2	503	159,989	42.7	96.4	83.0	9,821	HEAVY OIL	245,477 BBLS	6.40	1,571,058	3,829,448	2.39
5 ANCLOTE	2		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
6 BARTOW	1	115	11,841	13.8	99.3	85.0	10,880	HEAVY OIL	20,130 BBLS	6.40	128,830	300,938	2.54
7 BARTOW	2	117	13,908	16.0	99.0	84.4	10,944	HEAVY OIL	23,779 BBLS	6.40	152,187	355,500	2.56
8 BARTOW	3	208	3,690	19.9	96.7	46.8	12,188	HEAVY OIL	7,014 BBLS	6.40	44,893	104,888	2.84
9 BARTOW	3		27,126				12,604	GAS	341,898 MCF	1.00	341,898	803,458	2.96
10 CRYSTAL RIVER	1	372	107,085	38.7	45.0	86.2	9,891	COAL	42,023 TONS	25.20	1,058,980	1,756,721	1.64
11 CRYSTAL RIVER	1		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
12 CRYSTAL RIVER	2	408	298,698	85.8	89.1	97.8	9,709	COAL	115,077 TONS	25.20	2,899,942	4,807,920	1.61
13 CRYSTAL RIVER	2		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
14 CRYSTAL RIVER	4	697	400,925	77.3	95.2	80.8	9,431	COAL	150,842 TONS	25.10	3,781,124	7,434,201	1.85
15 CRYSTAL RIVER	4		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
16 CRYSTAL RIVER	5	697	498,178	96.1	98.2	97.4	9,228	COAL	183,115 TONS	25.10	4,598,190	8,038,733	1.61
17 CRYSTAL RIVER	5		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
18 SUWANNEE	1	33	4	0.3	100.0	94.5	13,734	HEAVY OIL	9 BBLS	6.40	55	164	4.10
19 SUWANNEE	1		74				14,228	GAS	1,053 MCF	1.00	1,053	2,474	3.34
20 SUWANNEE	2	32	0	0.0	100.0	0.0	0	HEAVY OIL	0 BBLS	6.40	0	0	0.00
21 SUWANNEE	2		92				13,728	GAS	1,263 MCF	1.00	1,263	2,968	3.23
22 SUWANNEE	3	80	513	0.9	100.0	73.7	13,037	HEAVY OIL	1,045 BBLS	6.40	6,688	19,970	3.89
23 SUWANNEE	3		0				0	GAS	0 MCF	1.00	0	0	0.00
24 AVON PARK	1-2	58	69	0.2	100.0	93.0	16,727	LIGHT OIL	257 BBLS	5.80	1,489	6,843	7.80
25 BARTOW	1-4	187	0	2.7	99.8	94.5	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
26 BARTOW	1-4		3,764				12,941	GAS	48,710 MCF	1.00	48,710	114,468	3.04
27 BAYBORO	1-4	188	16	0.0	100.0	85.1	12,117	LIGHT OIL	33 BBLS	5.80	194	902	5.64
28 DEBARY	1-10	651	4	1.9	99.8	90.6	12,008	LIGHT OIL	8 BBLS	5.80	48	228	5.71
29 DEBARY	1-10		9,094				12,427	GAS	113,011 MCF	1.00	113,011	265,578	2.92
30 HIGGINS	1-4	128	207	0.9	99.9	97.7	14,411	LIGHT OIL	514 BBLS	5.80	2,983	13,562	6.55
31 HIGGINS	1-4		678				14,055	GAS	9,529 MCF	1.00	9,529	22,394	3.30
32 INT CITY	1-10	614	167	1.4	99.9	99.5	11,408	LIGHT OIL	328 BBLS	5.80	1,905	8,695	5.21
33 INT CITY	1-10		6,099				12,913	GAS	78,756 MCF	1.00	78,756	185,078	3.03
34 INT CITY	11	143	146	0.1	100.0	68.1	11,981	LIGHT OIL	302 BBLS	5.80	1,749	7,983	5.47
35 PORT ST. JOE	1	0	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	0	0.0	100.0	90.4	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
38 SUWANNEE	1-3		337				12,674	GAS	4,271 MCF	1.00	4,271	10,037	2.98
39 TURNER	1-4	160	0	0.0	0.0	0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
40 UNIV OF FLA.	1	38	19,574	73.1	73.1	100.0	10,502	GAS	205,568 MCF	1.00	205,568	282,287	1.44
41 OTHER - START UP		-	0	-	-	-	-	LIGHT OIL	12,069 BBLS	5.80	70,000	326,468	0.00
42 OTHER - GAS TRANSP.		-	0	-	-	-	-	GAS TRANSP	-	-	-	1,248,465	-
43 TOTAL		6,928	2,253,269				9,657				22,211,894	38,774,111	1.63

SCHEDULE E4

FLORIDA POWER CORPORATION
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Jun-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	745	499,551	93.1	93.1	100.0	10,531	NUCLEAR	5,260,772 MMBTU	1.00	5,260,772	1,738,058	0.35
2	ANCLOTE	1	503	188,755	48.6	97.2	78.8	9,878	HEAVY OIL	260,410 BBLS	6.40	1,666,624	4,062,397	2.41
3	ANCLOTE	1		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
4	ANCLOTE	2	503	181,178	44.5	96.8	74.6	9,927	HEAVY OIL	250,002 BBLS	6.40	1,600,014	3,900,034	2.42
5	ANCLOTE	2		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
6	BARTOW	1	115	17,228	20.8	99.0	89.3	10,812	HEAVY OIL	29,101 BBLS	6.40	186,248	436,083	2.53
7	BARTOW	2	117	19,775	23.5	98.6	90.9	10,784	HEAVY OIL	33,321 BBLS	6.40	213,254	498,147	2.52
8	BARTOW	3	208	3,738	25.2	96.7	57.8	11,603	HEAVY OIL	6,773 BBLS	6.40	43,349	101,280	2.71
9	BARTOW	3		34,062				12,021	GAS	409,459 MCF	1.00	409,459	941,750	2.76
10	CRYSTAL RIVER	1	369	241,828	91.0	92.9	98.1	9,803	COAL	94,073 TONS	25.20	2,370,640	3,943,541	1.63
11	CRYSTAL RIVER	1		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
12	CRYSTAL RIVER	2	464	291,802	87.3	89.1	99.4	9,804	COAL	113,447 TONS	25.20	2,858,838	4,756,701	1.63
13	CRYSTAL RIVER	2		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
14	CRYSTAL RIVER	4	697	412,888	82.3	95.2	88.0	9,449	COAL	155,433 TONS	25.10	3,901,380	7,605,828	1.89
15	CRYSTAL RIVER	4		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
16	CRYSTAL RIVER	5	697	486,161	96.9	96.3	98.2	9,347	COAL	181,049 TONS	25.10	4,544,334	8,092,259	1.87
17	CRYSTAL RIVER	5		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
18	SUWANNEE	1	33	502	2.1	100.0	95.0	14,015	HEAVY OIL	1,099 BBLS	6.40	7,036	21,008	4.18
19	SUWANNEE	1		6				14,520	GAS	87 MCF	1.00	87	200	3.34
20	SUWANNEE	2	32	310	2.4	100.0	96.7	13,552	HEAVY OIL	656 BBLS	6.40	4,201	12,544	4.05
21	SUWANNEE	2		232				14,040	GAS	3,257 MCF	1.00	3,257	7,482	3.23
22	SUWANNEE	3	80	2,451	4.3	99.9	88.1	12,117	HEAVY OIL	4,640 BBLS	6.40	29,699	88,679	3.62
23	SUWANNEE	3		0				0	GAS	0 MCF	1.00	0	0	0.00
24	AVON PARK	1-2	56	488	1.2	99.9	98.7	16,681	LIGHT OIL	1,402 BBLS	5.80	8,131	37,918	7.77
25	BARTOW	1-4	187	20	5.9	99.8	97.7	12,413	LIGHT OIL	43 BBLS	5.80	248	1,155	5.78
26	BARTOW	1-4		7,931				12,860	GAS	101,993 MCF	1.00	101,993	234,583	2.98
27	BAYBORO	1-4	186	742	0.5	100.0	91.8	12,092	LIGHT OIL	1,547 BBLS	5.80	8,972	41,752	5.63
28	DEBARY	1-10	656	618	3.7	99.7	99.9	12,185	LIGHT OIL	1,298 BBLS	5.80	7,530	35,795	5.79
29	DEBARY	1-10		16,782				12,388	GAS	207,862 MCF	1.00	207,862	478,082	2.85
30	HIGGINS	1-4	128	859	3.5	99.8	99.9	14,407	LIGHT OIL	2,134 BBLS	5.80	12,378	56,224	6.55
31	HIGGINS	1-4		2,363				14,005	GAS	33,094 MCF	1.00	33,094	78,118	3.22
32	INT CITY	1-10	614	2,519	4.5	99.8	99.9	11,868	LIGHT OIL	5,068 BBLS	5.80	29,392	134,138	5.33
33	INT CITY	1-10		17,233				12,845	GAS	221,358 MCF	1.00	221,358	509,123	2.95
34	INT CITY	11	0	0	0.0	0.0	0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
35	PORT ST. JOE	1	0	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	9	1.9	100.0	93.3	12,371	LIGHT OIL	19 BBLS	5.80	111	523	5.81
38	SUWANNEE	1-3		2,224				12,818	GAS	28,503 MCF	1.00	28,503	65,556	2.95
39	TURNER	1-4	160	11	0.0	100.0	45.8	15,908	LIGHT OIL	30 BBLS	5.80	175	827	7.52
40	UNIV OF FLA.	1	36	25,531	96.5	96.5	100.0	10,502	GAS	268,127 MCF	1.00	268,127	422,878	1.66
41	OTHER - START UP		-	0	-	-	-	-	LIGHT OIL	12,069 BBLS	5.80	70,000	326,466	0.00
42	OTHER - GAS TRANSP		-	0	-	-	-	-	GAS TRANSP	-	-	-	1,370,602	-
43	TOTAL		6,787	2,417,611				9,967				24,097,069	41,193,532	1.70

FLORIDA POWER CORPORATION
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Jul-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	745	518,203	93.1	93.1	100.0	10,531	NUCLEAR	5,436,134 MMBTU	1.00	5,436,134	1,793,924	0.35
2	ANCLOTE	1	503	228,321	61.0	98.5	83.8	9,621	HEAVY OIL	343,231 BBLS	6.40	2,196,678	1,354,389	2.35
3	ANCLOTE	1		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
4	ANCLOTE	2	503	217,078	58.0	98.1	79.1	9,632	HEAVY OIL	326,702 BBLS	6.40	2,090,895	• 5,098,557	2.35
5	ANCLOTE	2		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
6	BARTOW	1	115	38,881	45.2	98.0	91.3	10,565	HEAVY OIL	63,821 BBLS	6.40	408,453	954,122	2.47
7	BARTOW	2	117	40,123	48.1	97.4	94.8	10,463	HEAVY OIL	65,595 BBLS	6.40	419,807	980,643	2.44
8	BARTOW	3	208	3,773	42.7	98.2	98.0	10,668	HEAVY OIL	6,288 BBLS	6.40	40,243	94,005	2.49
9	BARTOW	3		62,284				11,050	GAS	688,238 MCF	1.00	688,238	1,582,848	2.54
10	CRYSTAL RIVER	1	369	251,880	91.7	92.9	98.8	9,801	COAL	97,878 TONS	25.20	2,466,520	4,112,824	1.63
11	CRYSTAL RIVER	1		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
12	CRYSTAL RIVER	2	464	301,322	87.3	89.1	99.4	9,802	COAL	117,205 TONS	25.20	2,953,558	4,924,941	1.63
13	CRYSTAL RIVER	2		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
14	CRYSTAL RIVER	4	697	462,739	89.2	95.2	93.2	9,380	COAL	172,928 TONS	25.10	4,340,492	8,556,478	1.85
15	CRYSTAL RIVER	4		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
16	CRYSTAL RIVER	5	697	505,420	97.5	98.2	98.8	9,345	COAL	188,173 TONS	25.10	4,723,150	9,310,815	1.84
17	CRYSTAL RIVER	5		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
18	SUWANNEE	1	33	1,130	[illegible]	100.0	94.0	14,082	HEAVY OIL	2,468 BBLS	6.40	15,813	47,514	4.20
19	SUWANNEE	1		73				14,589	GAS	1,085 MCF	1.00	1,085	2,449	3.36
20	SUWANNEE	2	32	692	5.8	99.8	95.5	13,720	HEAVY OIL	1,483 BBLS	6.40	9,494	28,349	4.10
21	SUWANNEE	2		699				14,214	GAS	9,936 MCF	1.00	9,936	22,852	3.27
22	SUWANNEE	3	80	6,514	10.9	99.8	83.9	12,291	HEAVY OIL	12,510 BBLS	6.40	80,064	239,085	3.67
23	SUWANNEE	3		0				0	GAS	0 MCF	1.00	0	0	0.00
24	AVON PARK	1-2	58	1,164	2.7	99.8	98.7	16,654	LIGHT OIL	3,342 BBLS	5.80	19,385	90,409	7.77
25	BARTOW	1-4	157	80	12.0	99.7	97.9	12,406	LIGHT OIL	128 BBLS	5.80	744	3,464	5.77
26	BARTOW	1-4		16,644				12,852	GAS	213,909 MCF	1.00	213,909	491,990	2.96
27	BAYBORO	1-4	188	1,904	1.4	100.0	92.5	12,084	LIGHT OIL	3,967 BBLS	5.80	23,008	107,098	5.62
28	DEBARY	1-10	656	1,592	7.6	99.4	99.8	12,193	LIGHT OIL	3,347 BBLS	5.80	19,411	92,270	5.80
29	DEBARY	1-10		35,514				12,364	GAS	439,805 MCF	1.00	439,805	1,011,562	2.85
30	HIGGINS	1-4	128	1,952	7.8	99.5	100.0	14,393	LIGHT OIL	4,844 BBLS	5.80	28,095	127,639	6.54
31	HIGGINS	1-4		5,509				14,000	GAS	77,128 MCF	1.00	77,128	177,390	3.22
32	INT CITY	1-10	614	6,119	9.6	99.3	99.8	11,669	LIGHT OIL	12,311 BBLS	5.80	71,403	325,667	5.33
33	INT CITY	1-10		37,748				12,832	GAS	484,382 MCF	1.00	484,382	1,114,079	2.95
34	INT CITY	11	0	0	0.0	0.0	0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
35	PORT ST. JOE	1	0	0	0.0	0.0	0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
36	RIO PINAR	1	15	3	0.0	100.0	100.0	16,171	LIGHT OIL	8 BBLS	5.80	49	227	7.57
37	SUWANNEE	1-3	162	33	4.5	99.9	94.2	12,342	LIGHT OIL	70 BBLS	5.80	407	1,911	5.79
38	SUWANNEE	1-3		5,338				12,788	GAS	68,226 MCF	1.00	68,226	156,920	2.94
39	TURNER	1-4	160	38	0.0	100.0	71.3	15,728	LIGHT OIL	103 BBLS	5.80	598	2,823	7.43
40	UNIV OF FLA.	1	36	26,382	98.5	98.5	100.0	10,502	GAS	277,064 MCF	1.00	277,064	435,990	1.65
41	OTHER - START UP		-	0	-	-	-	-	LIGHT OIL	12,069 BBLS	5.80	70,000	326,460	0.00
42	OTHER - GAS TRANSP.		-	0	-	-	-	-	GAS TRANSP	-	-	-	1,626,965	-
43	TOTAL		6,767	2,776,690				9,987				27,674,250	49,194,911	1.77

FLORIDA POWER CORPORATION
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Aug-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	745	516,203	93.1	93.1	100.0	10,531	NUCLEAR	5,438,134	MMBTU	1.00	5,438,134	1,793,924	0.35
2 ANCLOTE	1	503	208,815	56.1	98.7	81.8	9,703	HEAVY OIL	318,099	BBLS	6.40	2,035,835	4,952,348	2.37
3 ANCLOTE	1		0				0	LIGHT OIL	0	BBLS	5.80	0	0	0.00
4 ANCLOTE	2	503	200,382	53.5	98.3	77.5	9,736	HEAVY OIL	304,801	BBLS	6.40	1,950,724	4,754,891	2.37
5 ANCLOTE	2		0				0	LIGHT OIL	0	BBLS	5.80	0	0	0.00
6 BARTOW	1	115	29,795	34.8	98.4	91.3	10,638	HEAVY OIL	49,525	BBLS	6.40	316,959	740,397	2.48
7 BARTOW	2	117	34,382	39.5	97.7	91.1	10,570	HEAVY OIL	56,784	BBLS	6.40	363,418	848,821	2.47
8 BARTOW	3	208	3,864	38.2	98.4	80.8	10,817	HEAVY OIL	6,531	BBLS	6.40	41,797	97,635	2.53
9 BARTOW	3		55,264				11,207	GAS	619,344	MCF	1.00	619,344	1,424,480	2.58
10 CRYSTAL RIVER	1	369	251,302	91.5	92.9	98.7	9,801	COAL	97,739	TONS	25.20	2,463,011	4,129,453	1.64
11 CRYSTAL RIVER	1		0				0	LIGHT OIL	0	BBLS	5.80	0	0	0.00
12 CRYSTAL RIVER	2	464	301,322	87.3	89.1	99.4	9,802	COAL	117,205	TONS	25.20	2,953,558	4,951,888	1.64
13 CRYSTAL RIVER	2		0				0	LIGHT OIL	0	BBLS	5.80	0	0	0.00
14 CRYSTAL RIVER	4	697	479,701	92.5	95.2	98.6	9,351	COAL	178,713	TONS	25.10	4,485,684	8,983,878	1.87
15 CRYSTAL RIVER	4		0				0	LIGHT OIL	0	BBLS	5.80	0	0	0.00
16 CRYSTAL RIVER	5	697	505,983	97.6	98.3	98.9	9,345	COAL	188,375	TONS	25.10	4,728,224	9,469,835	1.87
17 CRYSTAL RIVER	5		0				0	LIGHT OIL	0	BBLS	5.80	0	0	0.00
18 SUWANNEE	1	33	1,269	5.3	100.0	98.1	13,987	HEAVY OIL	2,767	BBLS	6.40	17,708	52,874	4.18
19 SUWANNEE	1		44				14,491	GAS	638	MCF	1.00	638	1,468	3.33
20 SUWANNEE	2	32	762	1.9	100.0	96.8	13,696	HEAVY OIL	1,631	BBLS	6.40	10,438	31,167	4.09
21 SUWANNEE	2		632				14,192	GAS	8,969	MCF	1.00	8,969	20,629	3.26
22 SUWANNEE	3	80	5,844	9.8	99.9	87.7	12,181	HEAVY OIL	11,123	BBLS	6.40	71,188	212,5[illegible]	3.64
23 SUWANNEE	3		0				0	GAS	0	MCF	1.00	0	0	0.00
24 AVON PARK	1-2	58	1,222	2.8	99.8	97.3	16,635	LIGHT OIL	3,505	BBLS	5.80	20,328	94,905	7.76
25 BARTOW	1-4	187	183	10.1	99.8	97.8	12,413	LIGHT OIL	349	BBLS	5.80	2,023	9,415	5.78
26 BARTOW	1-4		13,888				12,880	GAS	178,317	MCF	1.00	178,317	410,129	2.96
27 BAYBORO	1-4	198	2,666	1.9	100.0	93.4	12,085	LIGHT OIL	5,555	BBLS	5.80	32,219	149,928	5.62
28 DEBARY	1-10	658	2,676	6.6	99.9	99.8	12,188	LIGHT OIL	5,622	BBLS	5.80	32,610	155,009	5.79
29 DEBARY	1-10		29,429				12,381	GAS	364,360	MCF	1.00	364,360	838,029	2.85
30 HIGGINS	1-4	128	1,870	7.0	99.4	99.2	14,356	LIGHT OIL	4,629	BBLS	5.80	26,848	121,983	6.52
31 HIGGINS	1-4		4,797				13,992	GAS	67,120	MCF	1.00	67,120	154,375	3.22
32 INT CITY	1-10	614	7,693	6.8	99.5	99.7	11,684	LIGHT OIL	15,497	BBLS	5.80	89,885	410,217	5.33
33 INT CITY	1-10		31,612				12,832	GAS	405,645	MCF	1.00	405,645	932,984	2.95
34 INT CITY	11	0	0	0.0	0.0	0.0	0	LIGHT OIL	0	BBLS	5.80	0	0	0.00
35 PORT ST. JOE	1	0	0	0.0	0.0	0.0	0	LIGHT OIL	0	BBLS	5.80	0	0	0.00
36 RIO PINAR	1	15	8	0.1	100.0	98.8	16,150	LIGHT OIL	22	BBLS	5.80	129	605	7.56
37 SUWANNEE	1-3	162	89	4.5	99.9	95.1	12,337	LIGHT OIL	189	BBLS	5.80	1,098	5,153	5.79
38 SUWANNEE	1-3		5,352				12,781	GAS	68,404	MCF	1.00	68,404	157,329	2.94
39 TURNER	1-4	160	111	0.1	99.9	77.1	15,772	LIGHT OIL	302	BBLS	5.80	1,751	8,271	7.45
40 UNIV OF FLA.	1	38	26,382	96.5	96.5	100.0	10,502	GAS	277,084	MCF	1.00	277,084	399,233	1.51
41 OTHER - START UP		-	0	-	-	-	-	LIGHT OIL	12,069	BBLS	5.80	70,000	328,466	0.00
42 OTHER - GAS TRANSP		-	0	-	-	-	-	GAS TRANSP	-		-	-	1,556,794	-
43 TOTAL		6,787	2,724,457				9,962					27,141,424	48,208,665	1.77

FLORIDA POWER CORPORATION
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Sep-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	745	499,551	93.1	93.1	100.0	10,531	NUCLEAR	5,260,772	MMBTU	1.00	5,260,772	1,738,055	0.35
2	ANCLOTE	1	503	189,717	52.4	96.9	81.5	9,775	HEAVY OIL	289,763	BBLS	6.40	1,854,484	4,520,304	2.38
3	ANCLOTE	1		0				0	LIGHT OIL	0	BBLS	5.80	0	0	0.00
4	ANCLOTE	2	503	183,129	50.6	96.5	78.1	9,785	HEAVY OIL	279,987	BBLS	6.40	1,791,917	• 4,367,798	2.39
5	ANCLOTE	2		0				0	LIGHT OIL	0	BBLS	5.80	0	0	0.00
6	BARTOW	1	115	22,481	27.2	98.7	88.3	10,757	HEAVY OIL	37,786	BBLS	6.40	241,828	564,895	2.51
7	BARTOW	2	117	25,888	30.7	98.1	85.5	10,737	HEAVY OIL	43,431	BBLS	6.40	277,959	649,298	2.51
8	BARTOW	3	208	3,920	32.9	96.8	73.5	11,058	HEAVY OIL	6,772	BBLS	6.40	43,340	101,238	2.58
9	BARTOW	3		45,297				11,454	GAS	518,832	MCF	1.00	518,832	1,193,313	2.63
10	CRYSTAL RIVER	1	369	243,803	91.8	92.9	98.9	9,801	COAL	94,822	TONS	25.20	2,389,513	3,999,180	1.64
11	CRYSTAL RIVER	1		0				0	LIGHT OIL	0	BBLS	5.80	0	0	0.00
12	CRYSTAL RIVER	2	464	291,601	87.3	89.1	99.4	9,804	COAL	113,447	TONS	25.20	2,858,856	4,772,702	1.64
13	CRYSTAL RIVER	2		0				0	LIGHT OIL	0	BBLS	5.80	0	0	0.00
14	CRYSTAL RIVER	4	697	438,711	87.6	95.2	91.5	9,395	COAL	164,585	TONS	25.10	4,131,085	8,127,210	1.85
15	CRYSTAL RIVER	4		0				0	LIGHT OIL	0	BBLS	5.80	0	0	0.00
16	CRYSTAL RIVER	5	697	488,191	97.3	98.3	98.8	9,346	COAL	181,778	TONS	25.10	4,562,833	8,976,208	1.84
17	CRYSTAL RIVER	5		0				0	LIGHT OIL	0	BBLS	5.80	0	0	0.00
18	SUWANNEE	1	33	513	2.2	100.0	94.5	13,988	HEAVY OIL	1,121	BBLS	6.40	7,176	21,427	4.18
19	SUWANNEE	1		14				14,057	GAS	197	MCF	1.00	197	453	3.23
20	SUWANNEE	2	32	310	2.5	100.0	95.8	13,520	HEAVY OIL	655	BBLS	6.40	4,191	12,515	4.04
21	SUWANNEE	2		257				14,008	GAS	3,600	MCF	1.00	3,600	8,279	3.22
22	SUWANNEE	3	8[illegible]	3,016	5.2	100.0	82.5	12,40[illegible]	HEAVY OIL	5,848	BBLS	6.40	37,428	111,750	3.71
23	SUWANNEE	3		0				0	GAS	0	MCF	1.00	0	0	0.00
24	AVON PARK	1-2	5[illegible]	487	1.2	99.9	96.3	16,882	LIGHT OIL	1,428	BBLS	5.80	8,281	38,621	7.77
25	BARTOW	1-4	197	28	6.4	99.8	96.8	12,431	LIGHT OIL	58	BBLS	5.80	323	1,504	5.78
26	BARTOW	1-4		8,640				12,879	GAS	111,275	MCF	1.00	111,275	255,931	2.96
27	BAYBORO	1-4	188	782	0.6	100.0	93.2	12,087	LIGHT OIL	1,588	BBLS	5.80	9,210	42,860	5.62
28	DEBARY	1-10	656	671	4.2	99.7	99.9	12,184	LIGHT OIL	1,411	BBLS	5.80	8,182	38,884	5.80
29	DEBARY	1-10		18,951				12,397	GAS	234,938	MCF	1.00	234,938	540,352	2.85
30	HIGGINS	1-4	128	1,010	4.1	99.8	99.2	14,387	LIGHT OIL	2,505	BBLS	5.80	14,531	66,015	6.54
31	HIGGINS	1-4		2,737				14,009	GAS	38,343	MCF	1.00	38,343	88,158	3.22
32	INT CITY	1-10	614	2,464	4.8	99.7	99.9	11,660	LIGHT OIL	4,953	BBLS	5.80	28,730	131,119	5.32
33	INT CITY	1-10		18,640				12,837	GAS	239,282	MCF	1.00	239,282	550,348	2.95
34	INT CITY	11	0	0	0.0	0.0	0.0	0	LIGHT OIL	0	BBLS	5.80	0	0	0.00
35	PORT ST. JOE	1	0	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	182	14	2.1	99.9	92.0	12,413	LIGHT OIL	30	BBLS	5.80	174	816	5.83
38	SUWANNEE	1-3		2,401				12,860	GAS	30,877	MCF	1.00	30,877	71,017	2.96
39	TURNER	1-4	180	14	0.0	100.0	58.3	15,809	LIGHT OIL	38	BBLS	5.80	221	1,046	7.47
40	UNIV OF FLA.	1	36	25,531	98.5	98.5	100.0	10,502	GAS	268,127	MCF	1.00	268,127	387,598	1.52
41	OTHER - START UP		-	0	-	-	-	-	LIGHT OIL	12,069	BBLS	5.80	70,000	326,466	0.00
42	OTHER - GAS TRANSP		-	0	-	-	-	-	GAS TRANSP	-		-	-	1,415,251	
43	TOTAL		6,767	2,519,757				9,940					25,046,298	43,108,626	1.71

FLORIDA POWER CORPORATION
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD OF: Apr-98 THROUGH Sep-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	751	3,089,633	93.1	93.1	100.0	10,482	NUCLEAR	32,175,158 MMBTU	1.00	32,175,158	10,817,802	0.35
2 ANCLOTE	1	505	1,137,877	51.3	98.8	78.0	9,758	HEAVY OIL	1,734,541 BBLS	6.40	11,101,062	27,058,839	2.38
3 ANCLOTE	1		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
4 ANCLOTE	2	505	1,061,998	47.9	98.4	70.3	9,792	HEAVY OIL	1,624,933 BBLS	6.40	10,399,571	• 25,348,954	2.39
5 ANCLOTE	2		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
6 BARTOW	1	115	126,787	25.0	98.8	89.2	10,697	HEAVY OIL	211,916 BBLS	6.40	1,356,260	3,168,138	2.50
7 BARTOW	2	117	141,314	27.4	98.4	89.7	10,654	HEAVY OIL	235,252 BBLS	6.40	1,505,613	3,517,019	2.49
8 BARTOW	3	209	22,178	28.5	98.6	83.2	11,656	HEAVY OIL	40,393 BBLS	6.40	258,517	603,879	2.72
9 BARTOW	3		239,322				11,701	GAS	2,800,346 MCF	1.00	2,800,346	6,469,020	2.70
10 CRYSTAL RIVER	1	370	1,165,608	71.7	74.6	96.2	9,812	COAL	453,833 TONS	25.20	11,436,602	19,079,719	1.64
11 CRYSTAL RIVER	1		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
12 CRYSTAL RIVER	2	466	1,732,269	84.7	87.1	98.6	9,781	COAL	672,336 TONS	25.20	16,942,880	28,251,983	1.63
13 CRYSTAL RIVER	2		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
14 CRYSTAL RIVER	4	700	2,263,372	73.6	82.0	89.0	9,402	COAL	847,860 TONS	25.10	21,281,286	42,166,888	1.86
15 CRYSTAL RIVER	4		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
16 CRYSTAL RIVER	5	700	2,975,702	96.7	98.3	98.1	9,306	COAL	1,103,251 TONS	25.10	27,691,582	54,947,147	1.85
17 CRYSTAL RIVER	5		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
18 SUWANNEE	1	33	3,422	2.5	100.0	94.1	14,022	HEAVY OIL	7,497 BBLS	6.40	47,982	143,272	4.19
19 SUWANNEE	1		221				14,395	GAS	3,181 MCF	1.00	3,181	7,377	3.34
20 SUWANNEE	2	32	2,074	2.8	100.0	94.5	13,657	HEAVY OIL	4,426 BBLS	6.40	28,324	84,575	4.08
21 SUWANNEE	2		1,930				14,130	GAS	27,270 MCF	1.00	27,270	62,797	3.25
22 SUWANNEE	3	80	18,429	5.2	99.9	84.7	12,269	HEAVY OIL	35,330 BBLS	6.40	226,114	675,182	3.66
23 SUWANNEE	3		0				0	GAS	0 MCF	1.00	0	0	0.00
24 AVON PARK	1-2	59	3,480	1.3	99.9	95.1	16,649	LIGHT OIL	9,990 BBLS	5.80	57,940	270,220	7.76
25 BARTOW	1-4	192	269	6.3	99.8	95.1	12,413	LIGHT OIL	576 BBLS	5.80	3,339	15,539	5.78
26 BARTOW	1-4		52,471				12,861	GAS	674,804 MCF	1.00	674,804	1,555,515	2.96
27 BAYBORO	1-4	195	6,090	0.7	83.3	89.4	12,066	LIGHT OIL	12,690 BBLS	5.80	73,603	342,508	5.62
28 DEBARY	1-10	678	5,561	4.0	99.8	97.0	12,189	LIGHT OIL	11,686 BBLS	5.80	67,782	322,196	5.79
29 DEBARY	1-10		113,492				12,390	GAS	1,406,164 MCF	1.00	1,406,164	3,242,138	2.86
30 HIGGINS	1-4	133	5,948	3.8	99.7	96.0	14,380	LIGHT OIL	14,747 BBLS	5.80	85,531	388,577	6.53
31 HIGGINS	1-4		16,364				13,994	GAS	228,996 MCF	1.00	228,996	527,358	3.22
32 INT CITY	1-10	636	19,008	4.7	99.7	96.6	11,670	LIGHT OIL	38,245 BBLS	5.80	221,821	1,012,347	5.33
33 INT CITY	1-10		112,785				12,839	GAS	1,448,093 MCF	1.00	1,448,093	3,335,485	2.96
34 INT CITY	11	52	165	0.1	33.3	62.2	11,965	LIGHT OIL	340 BBLS	5.80	1,974	9,010	5.46
35 PORT ST. JOE	1	0	0	0.0	0.0	0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
36 RIO PINAR	1	16	11	0.0	33.3	95.9	16,158	LIGHT OIL	31 BBLS	5.80	178	832	7.57
37 SUWANNEE	1-3	169	145	2.1	100.0	90.4	12,348	LIGHT OIL	309 BBLS	5.80	1,790	8,403	5.79
38 SUWANNEE	1-3		15,722				12,798	GAS	201,182 MCF	1.00	201,182	462,978	2.94
39 TURNER	1-4	167	174	0.0	66.7	97.1	15,774	LIGHT OIL	473 BBLS	5.80	2,745	12,966	7.45
40 UNIV OF FLA	1	37	149,215	91.8	92.1	99.8	10,487	GAS	1,561,764 MCF	1.00	1,561,764	2,340,923	1.57
41 OTHER - START UP		-	0	-	-	-	-	LIGHT OIL	72,414 BBLS	5.80	420,000	1,958,783	0.00
42 OTHER - GAS TRANSP		-	0	-	-	-	-	GAS TRANSP	-	-	-	8,452,821	-
43 TOTAL		6,917	14,463,054				9,936				143,739,465	246,463,156	1.70

FLORIDA POWER CORPORATION
INVENTORY ANALYSIS
ESTIMATED FOR THE PERIOD OF: APR-98 THROUGH SEP-98

			Apr-98	May-98	Jun-98	Jul-98	Aug-98	Sep-98	TOTAL
	HEAVY OIL								
1	PURCHASES:								
2	UNITS	BBL	513,501	555,994	586,004	822,116	751,260	665,363	3,894,238
3	UNIT COST	$/BBL	15.60	15.60	15.60	15.60	15.60	15.60	15.60
4	AMOUNT	$	8,011,402	8,673,503	9,141,658	12,825,017	11,719,657	10,379,657	60,750,893
5	BURNED:								
6	UNITS	BBL	513,501	555,994	586,004	822,116	751,260	665,363	3,894,238
7	UNIT COST	$/BBL	15.56	15.55	15.56	15.56	15.57	15.55	15.56
8	AMOUNT	$	7,991,540	8,644,101	9,118,131	12,794,653	11,700,789	10,349,224	60,598,837
9	ENDING INVENTORY:								
10	UNITS	BBL	470,001	470,000	470,000	470,000	470,000	470,000	
11	UNIT COST	$/BBL	15.56	15.58	15.59	15.60	15.60	15.60	
12	AMOUNT	$	7,314,187	7,323,840	7,328,368	7,330,679	7,331,492	7,331,790	
13	DAYS SUPPLY:		27	26	24	18	19	21	
	LIGHT OIL								
14	PURCHASES:								
15	UNITS	BBL	12,372	13,512	23,609	40,190	47,739	24,079	161,501
16	UNIT COST	$/BBL	27.08	27.08	27.08	27.08	27.08	27.08	27.08
17	AMOUNT	$	335,040	365,898	639,340	1,088,336	1,292,782	652,038	4,373,436
18	BURNED:								
19	UNITS	BBL	12,372	13,512	23,609	40,190	47,739	24,079	161,501
20	UNIT COST	$/BBL	27.04	27.00	26.89	26.83	26.86	26.88	26.88
21	AMOUNT	$	334,511	364,769	634,798	1,078,143	1,281,831	647,339	4,341,390
22	ENDING INVENTORY:								
23	UNITS	BBL	275,000	275,000	275,000	275,000	275,000	275,000	
24	UNIT COST	$/BBL	27.04	27.04	27.04	27.05	27.05	27.06	
25	AMOUNT	$	7,436,000	7,436,515	7,437,344	7,438,575	7,439,822	7,440,399	
26	DAYS SUPPLY:		667	631	349	212	179	343	
	COAL								
27	PURCHASES:								
28	UNITS	TON	487,000	511,000	493,000	492,000	468,000	491,000	2,942,000
29	UNIT COST	$/TON	47.19	46.42	46.95	46.77	47.38	46.73	46.90
30	AMOUNT	$	22,981,530	23,720,620	23,146,350	23,010,840	22,173,840	22,944,430	137,977,610
31	BURNED:								
32	UNITS	TON	329,574	490,858	544,002	576,184	582,031	554,632	3,077,281
33	UNIT COST	$/TON	47.12	46.93	47.05	46.70	47.31	46.64	46.95
34	AMOUNT	$	15,530,583	23,034,576	25,597,350	26,906,005	27,534,864	25,868,279	144,467,715
35	ENDING INVENTORY:								
36	UNITS	TON	475,000	495,142	444,140	359,957	245,926	182,294	
37	UNIT COST	$/TON	47.12	46.76	46.85	46.81	47.13	46.96	
38	AMOUNT	$	22,383,530	23,152,345	20,809,836	16,849,553	11,591,004	8,543,049	
39	DAYS SUPPLY:		29	30	27	23	16	11	
	GAS								
40	BURNED:								
41	UNITS	MCF	578,029	804,056	1,273,738	2,259,791	1,989,860	1,445,468	8,351,902
42	UNIT COST	$/MCF	4.12	3.65	3.22	2.93	2.96	3.12	3.17
43	AMOUNT	$	2,383,675	2,937,223	4,106,190	6,623,136	5,890,408	4,510,730	26,456,411
	NUCLEAR								
44	BURNED:								
45	UNITS	MMBTU	5,346,673	5,434,674	5,260,772	5,436,134	5,436,134	5,260,772	32,175,159
46	UNIT COST	$/MMBTU	0.33	0.33	0.33	0.33	0.33	0.33	0.33
47	AMOUNT	$	1,764,403	1,793,442	1,736,055	1,793,924	1,793,924	1,736,055	10,617,803

FLORIDA POWER CORPORATION
FUEL COST OF POWER SOLD
ESTIMATED FOR THE PERIOD OF: APR-98 THROUGH SEP-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 $
Apr-98	ECONSALE	C	20,000,000		20,000,000	1.568	2.136	313,600	427,200	90,880
	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	–	48,764,000		48,764,000	1.786	1.786	871,000	871,000	0
	TOTAL		68,764,000		68,764,000	1.723	1.888	1,184,600	1,298,200	90,880
May-98	ECONSALE	C	40,000,000		40,000,000	1.515	2.083	606,000	833,200	181,760
	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	–	25,011,000		25,011,000	1.767	1.767	442,063	442,063	0
	TOTAL		65,011,000		65,011,000	1.612	1.962	1,048,063	1,275,263	181,760
Jun-98	ECONSALE	C	40,000,000		40,000,000	1.528	2.096	611,200	838,400	181,760
	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	–	20,852,000		20,852,000	2.141	2.141	446,394	446,394	0
	TOTAL		60,852,000		60,852,000	1.738	2.111	1,057,594	1,284,794	181,760
Jul-98	ECONSALE	C	80,000,000		80,000,000	1.758	2.326	1,406,400	1,860,800	363,520
	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	–	87,869,000		87,869,000	2.047	2.047	1,798,578	1,798,578	0
	TOTAL		167,869,000		167,869,000	1.909	2.180	3,204,978	3,659,378	363,520
Aug-98	ECONSALE	C	60,000,000		60,000,000	1.814	2.382	1,088,400	1,429,200	272,640
	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	–	136,981,000		136,981,000	1.987	1.987	2,721,827	2,721,827	0
	TOTAL		196,981,000		196,981,000	1.934	2.107	3,810,227	4,151,027	272,640
Sep-98	ECONSALE	C	60,000,000		60,000,000	1.670	2.238	1,002,000	1,342,800	272,640
	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	–	171,734,000		171,734,000	2.098	2.098	3,603,202	3,603,202	0
	TOTAL		231,734,000		231,734,000	1.987	2.134	4,605,202	4,946,002	272,640
Apr-98	ECONSALE	C	300,000,000		300,000,000	1.676	2.244	5,027,600	6,731,600	1,363,200
THRU	SALE D	D	0		0	0.000	0.000	0	0	0
Sep-98	SALE F	F	0		0	0.000	0.000	0	0	0
	SALE OTHER	–	0		0	0.000	0.000	0	0	0
	STRATIFIED	–	491,211,000		491,211,000	2.012	2.012	9,883,064	9,883,064	0
	TOTAL		791,211,000		791,211,000	1.885	2.100	14,910,664	16,614,664	1,363,200

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH	NAME OF PURCHASE	TYPE & SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	C/KWH (A) FUEL COST	C/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJ (7) x (8)(B)
Apr-98	EMERGENCY	A&B	0			0	0.000	0.000	0
	TECO	--	245,000			245,000	2.878	2.878	7,050
	UPS PURCHASE	UPS	81,138,000			81,138,000	1.740	1.740	1,411,800
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		81,383,000	0	0	81,383,000	1.743	1.743	1,418,850
May-98	EMERGENCY	A&B	3,000			3,000	6.300	9.000	270
	TECO	--	1,388,000			1,388,000	2.883	2.883	40,010
	UPS PURCHASE	UPS	191,952,000			191,952,000	1.740	1.740	3,339,970
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		193,343,000	0	0	193,343,000	1.748	1.748	3,380,250
Jun-98	EMERGENCY	A&B	227,000			227,000	7.114	10.163	23,070
	TECO	--	6,187,000			6,187,000	2.883	2.883	178,380
	UPS PURCHASE	UPS	193,632,000			193,632,000	1.740	1.740	3,369,200
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		200,046,000	0	0	200,046,000	1.781	1.785	3,570,650
Jul-98	EMERGENCY	A&B	655,000			655,000	7.100	10.144	66,440
	TECO	--	13,016,000			13,016,000	2.883	2.883	375,260
	UPS PURCHASE	UPS	242,009,000			242,009,000	1.740	1.740	4,210,950
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		255,680,000	0	0	255,680,000	1.812	1.820	4,652,650
Aug-98	EMERGENCY	A&B	1,339,000			1,339,000	7.113	10.161	136,060
	TECO	--	10,639,000			10,639,000	2.883	2.883	306,710
	UPS PURCHASE	UPS	234,865,000			234,865,000	1.740	1.740	4,086,650
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		246,843,000	0	0	246,843,000	1.818	1.835	4,529,420
Sep-98	EMERGENCY	A&B	247,000			247,000	7.133	10.190	25,170
	TECO	--	7,265,000			7,265,000	2.883	2.883	209,460
	UPS PURCHASE	UPS	212,543,000			212,543,000	1.740	1.740	3,698,240
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		220,055,000	0	0	220,055,000	1.784	1.787	3,932,870
Apr-98 THRU Sep-98	EMERGENCY	A&B	2,471,000			2,471,000	7.111	10.158	251,010
	TECO	--	38,740,000			38,740,000	2.883	2.883	1,116,870
	UPS PURCHASE	UPS	1,156,139,000			1,156,139,000	1.740	1.740	20,116,810
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		1,197,350,000	0	0	1,197,350,000	1.788	1.794	21,484,690

FLORIDA POWER CORPORATION
ENERGY PAYMENT TO QUALIFYING FACILITIES
ESTIMATED FOR THE PERIOD OF: APR-98 THROUGH SEP-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) ENERGY COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ (7) x (8)(A)
Apr-98	QUALIFYING								
	FACILITIES	COGEN	583,669,000			583,669,000	2.017	5.663	11,772,951
	TOTAL		583,669,000	0	0	583,669,000	2.017	5.663	11,772,951
May-98	QUALIFYING								
	FACILITIES	COGEN	654,280,000			654,280,000	1.990	5.242	13,019,107
	TOTAL		654,280,000	0	0	654,280,000	1.990	5.242	13,019,107
Jun-98	QUALIFYING								
	FACILITIES	COGEN	682,294,000			682,294,000	2.053	5.172	14,004,499
	TOTAL		682,294,000	0	0	682,294,000	2.053	5.172	14,004,499
Jul-98	QUALIFYING								
	FACILITIES	COGEN	708,082,000			708,082,000	2.137	5.143	15,133,658
	TOTAL		708,082,000	0	0	708,082,000	2.137	5.143	15,133,658
Aug-98	QUALIFYING								
	FACILITIES	COGEN	708,540,000			708,540,000	2.127	5.130	15,068,248
	TOTAL		708,540,000	0	0	708,540,000	2.127	5.130	15,068,248
Sep-98	QUALIFYING								
	FACILITIES	COGEN	684,278,000			684,278,000	2.083	5.193	14,254,216
	TOTAL		684,278,000	0	0	684,278,000	2.083	5.193	14,254,216
Apr-98	QUALIFYING								
THRU	FACILITIES	COGEN	4,021,143,000			4,021,143,000	2.070	5.246	83,252,679
Sep-98	TOTAL		4,021,143,000	0	0	4,021,143,000	2.070	5.246	83,252,679

FLORIDA POWER CORPORATION
ECONOMY ENERGY PURCHASES
ESTIMATED FOR THE PERIOD OF: APR-98 THROUGH SEP-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)
Apr-98	ECON PURCH	C	90,000,000	1.526	1.526	1,373,400	3.643	3,278,700	1,905,300
	OUC PURCH	J	0	0.000	0.000	0	0.000	0	0
	OTHER	–	3,930,000	2.529	2.529	99,390	2.529	99,390	(0)
	TOTAL		93,930,000	1.568	1.568	1,472,790	3.596	3,378,090	1,905,300
May-98	ECON PURCH	C	90,000,000	2.410	2.410	2,169,010	3.643	3,278,700	1,109,690
	OUC PURCH	J	0	0.000	0.000	0	0.000	0	0
	OTHER	–	5,730,000	3.245	3.245	185,913	3.245	185,913	0
	TOTAL		95,730,000	2.460	2.460	2,354,923	3.619	3,464,613	1,109,690
Jun-98	ECON PURCH	C	110,000,000	2.719	2.719	2,990,900	3.643	4,007,300	1,016,400
	OUC PURCH	J	0	0.000	0.000	0	0.000	0	0
	OTHER	–	8,490,000	3.391	3.391	287,874	3.391	287,874	(0)
	TOTAL		118,490,000	2.767	2.767	3,278,774	3.625	4,295,174	1,016,400
Jul-98	ECON PURCH	C	120,000,000	3.334	3.334	4,000,800	3.643	4,371,600	370,800
	OUC PURCH	J	0	0.000	0.000	0	0.000	0	0
	OTHER	–	9,510,000	3.613	3.613	343,568	3.613	343,568	0
	TOTAL		129,510,000	3.354	3.354	4,344,368	3.641	4,715,168	370,800
Aug-98	ECON PURCH	C	110,000,000	3.231	3.231	3,554,100	3.643	4,007,300	453,200
	OUC PURCH	J	0	0.000	0.000	0	0.000	0	0
	OTHER	–	9,510,000	3.673	3.673	349,307	3.673	349,307	0
	TOTAL		119,510,000	3.266	3.266	3,903,407	3.645	4,356,607	453,200
Sep-98	ECON PURCH	C	90,000,000	2.913	2.913	2,621,700	3.643	3,278,700	657,000
	OUC PURCH	J	0	0.000	0.000	0	0.000	0	0
	OTHER	–	6,630,000	3.315	3.315	219,802	3.315	219,802	0
	TOTAL		96,630,000	2.941	2.941	2,841,502	3.621	3,498,502	657,000
Apr-98 THRU Sep-98	ECON PURCH	C	610,000,000	2.739	2.739	16,709,910	3.643	22,222,300	5,512,390
	OUC PURCH	J	0	0.000	0.000	0	0.000	0	0
	OTHER	–	43,800,000	3.392	3.392	1,485,854	3.392	1,485,854	0
	TOTAL		653,800,000	2.783	2.783	18,195,764	3.626	23,708,154	5,512,390

SCHEDULE E10

FLORIDA POWER CORPORATION
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE
ESTIMATED FOR THE PERIOD OF: APRIL 1998 THROUGH SEPTEMBER 1998

	DESCRIPTION		Apr-98	May-98	Jun-98	Jul-98	Aug-98	Sep-98	Period Average	Prior Residèntial Bill *	Apr-98 vs. Prior
1	Base Rate Revenues	($)	49.05	49.05	49.05	49.05	49.05	49.05	49.05	49.05	0.00
2	Fuel Recovery Factor	(c/kwh)	2.015	2.015	2.015	2.015	2.015	2.015	2.015	1.825	
3	Fuel Cost Recovery Revenues	($)	20.18	20.18	20.18	20.18	20.18	20.18	20.18	18.25	1.93
4	Capacity Cost Recovery Revenues	($)	10.04	10.04	10.04	10.04	10.04	10.04	10.04	12.61	-2.57
5	Energy Conservation Cost Revenues	($)	3.23	3.23	3.23	3.23	3.23	3.23	3.23	2.80	0.43
6	Gross Receipt Taxes	($)	2.12	2.12	2.12	2.12	2.12	2.12	2.12	2.12	0.00
7	Total Revenues	($)	84.62	84.62	84.62	84.62	84.62	84.62	84.62	84.83	-0.21

* Actual Residential Billing for Mar-98

FLORIDA POWER CORPORATION
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE

			Apr-95 thru Sep-95	Apr-96 thru Sep-96	Apr-97 thru Sep-97	Apr-98 thru Sep-98	1996 vs. 1995	1997 vs. 1996	1998 vs. 1997
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL		66,708,153	89,064,213	88,319,791	60,699,837	33.6%	-0.2%	-31.4%
2	LIGHT OIL		14,496,443	15,465,036	19,832,214	2,382,687	6.8%	28.1%	-88.0%
3	COAL		135,989,600	131,309,383	152,089,938	144,487,718	-3.4%	15.8%	-5.0%
4	GAS		19,963,775	19,448,167	42,997,620	26,466,411	-2.6%	121.1%	-38.6%
5	NUCLEAR		12,983,536	6,072,617	0	10,617,802	-53.2%	-100.0%	0.0%
6	OTHER		1,613,331	1,196,108	868,247	1,998,793	-25.9%	-28.2%	129.2%
7	TOTAL	$	251,764,920	262,874,424	304,087,710	246,453,156	4.3%	15.8%	-18.9%
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL		2,596,487	3,305,807	3,539,118	2,514,079	27.3%	7.1%	-29.0%
9	LIGHT OIL		249,760	255,718	321,699	40,861	2.4%	25.8%	-87.3%
10	COAL		7,481,874	7,388,270	8,420,115	8,136,969	-1.2%	14.0%	-3.4%
11	GAS		889,969	641,698	1,394,379	701,622	-27.9%	117.3%	-49.7%
12	NUCLEAR		3,257,691	1,686,232	0	3,069,633	-48.3%	-100.0%	0.0%
13	OTHER		0	0	0	0	0.0%	0.0%	0.0%
14	TOTAL	MWH	14,475,389	13,276,726	13,675,311	14,463,064	-8.3%	3.0%	5.8%
	UNITS OF FUEL BURNED								
15	HEAVY OIL	BBL	4,1[illegible]8	5,171,041	5,514,793	3,894,288	24.6%	6.6%	-29.4%
16	LIGHT OIL	BBL	606,338	635,364	730,410	89,067	4.8%	15.0%	-87.8%
17	COAL	TON	2,837,768	2,797,018	3,216,640	3,077,281	-1.4%	15.0%	-4.3%
18	GAS	MCF	9,661,630	7,296,232	14,901,760	8,381,802	-24.0%	106.4%	-43.8%
19	NUCLEAR	MMBTU	34,084,080	17,810,678	0	32,176,168	-47.7%	-100.0%	0.0%
20	OTHER	BBL	70,069	45,372	31,148	72,414	-35.2%	-31.3%	132.6%
	BTUS BURNED (MMBTU)								
21	HEAVY OIL		26,812,616	33,439,264	36,123,288	24,923,443	24.9%	8.0%	-31.0%
22	LIGHT OIL		3,499,912	3,433,364	4,210,228	616,703	-1.9%	22.6%	-87.7%
23	COAL		71,129,660	70,906,906	80,633,939	77,362,368	-0.3%	13.6%	-4.0%
24	GAS		9,848,218	7,627,216	15,679,039	8,361,802	-23.6%	107.0%	-46.4%
25	NUCLEAR		34,084,080	17,810,678	0	32,176,168	-47.7%	-100.0%	0.0%
26	OTHER		410,210	263,812	180,979	420,000	-36.7%	-31.4%	132.1%
27	TOTAL	MMBTU	145,684,793	133,381,136	136,628,247	143,739,446	-8.6%	2.4%	5.2%
	GENERATION MIX (% MWH)								
28	HEAVY OIL		17.94%	24.90%	25.88%	17.38%	38.0%	4.0%	-32.8%
29	LIGHT OIL		1.73%	1.93%	2.35%	0.28%	11.6%	20.8%	-88.3%
30	COAL		51.69%	55.65%	61.57%	56.26%	7.7%	10.6%	-8.6%
31	GAS		6.15%	4.83%	10.20%	4.85%	-21.1%	111.7%	-52.0%
32	NUCLEAR		22.50%	12.69%	0.00%	21.22%	-43.6%	-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	16.07	17.22	16.02	15.56	7.2%	-7.0%	-2.8%
36	LIGHT OIL	$/BBL	23.91	24.37	27.16	26.74	1.9%	11.4%	-1.5%
37	COAL	$/TON	47.92	46.96	47.28	46.55	-2.0%	0.7%	-0.7%
38	GAS	$/MCF	2.08	2.66	2.89	3.16	28.3%	7.6%	9.4%
39	NUCLEAR	$/MMBTU	0.38	0.34	0.00	0.33	-10.6%	-100.0%	0.0%
40	OTHER	$/BBL	23.03	26.34	27.88	27.06	14.4%	4.6%	-1.8%
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL		2.48	2.66	2.45	2.43	7.4%	-8.2%	-0.8%
42	LIGHT OIL		4.14	4.51	4.71	4.61	8.9%	4.4%	-2.1%
43	COAL		1.91	1.86	1.89	1.87	-3.1%	2.0%	-1.1%
44	GAS		2.03	2.58	2.76	3.17	27.6%	6.8%	14.8%
45	NUCLEAR		0.38	0.34	0.00	0.33	-10.6%	-100.0%	0.0%
46	OTHER		3.93	4.53	4.74	4.66	15.2%	4.7%	-1.6%
47	TOTAL	$/MMBTU	1.73	1.97	2.23	1.72	14.1%	13.1%	-23.0%
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL		10,366	10,116	10,207	9,914	-2.4%	0.9%	-2.9%
49	LIGHT OIL		14,013	13,426	13,087	12,848	-4.2%	-2.6%	-3.4%
50	COAL		9,507	9,597	9,564	9,506	0.9%	-0.3%	-0.6%
51	GAS		11,066	11,730	11,173	11,906	6.0%	-4.7%	6.6%
52	NUCLEAR		10,463	10,569	0	10,482	1.0%	-100.0%	0.0%
53	OTHER		0	0	0	0	0.0%	0.0%	0.0%
54	TOTAL	BTU/KWH	10,078	10,046	9,991	9,938	-0.3%	-0.6%	-0.5%
	GENERATED FUEL COST PER KWH (C/KWH)								
55	HEAVY OIL		2.57	2.69	2.50	2.41	4.9%	-7.4%	-3.4%
56	LIGHT OIL		5.80	6.05	6.16	5.83	4.3%	1.8%	-5.4%
57	COAL		1.82	1.78	1.81	1.78	-2.2%	1.6%	-1.7%
58	GAS		2.24	3.03	3.08	3.77	35.1%	1.7%	22.3%
59	NUCLEAR		0.40	0.36	0.00	0.35	-9.6%	-99.9%	0.0%
60	OTHER		0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
61	TOTAL	C/KWH	1.74	1.98	2.22	1.70	13.7%	12.4%	-23.3%