BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.	DOCKET NO. 030001-EI ORDER NO. PSC-03-1461-FOF-EI ISSUED: December 22, 2003

The following Commissioners participated in the disposition of this matter:

LILA A. JABER, Chairman
J. TERRY DEASON
BRAULIO L. BAEZ
RUDOLPH "RUDY" BRADLEY
CHARLES M. DAVIDSON

APPEARANCES:

JOHN T. BUTLER, ESQUIRE, Steel Hector & Davis LLP, 200 South Biscayne Boulevard, Suite 4000, Miami, Florida 33131-2939
On behalf of Florida Power & Light Company (FPL)

NORMAN H. HORTON, JR., ESQUIRE, Messer Caparello & Self, P.A., Post Office Box 1876, Tallahassee, Florida 32302-1876
On behalf of Florida Public Utilities Company (FPUC)

RUSSELL BADDERS, ESQUIRE, Beggs & Lane, 700 Blount Building, 3 West Garden Street, P. O. Box 12950, Pensacola, Florida 32576-2950
On behalf of Gulf Power Company (Gulf)

JAMES A. MCGEE, ESQUIRE, and BONNIE DAVIS, ESQUIRE, Progress Energy Florida, Inc., P. O. Box 14042, 3201 34th Street South, St. Petersburg, Florida 33733-4042
On behalf of Progress Energy Florida, Inc. (PEF)

JAMES D. BEASLEY, ESQUIRE, LEE L. WILLIS, ESQUIRE, and KENNETH R. HART, ESQUIRE, Ausley & McMullen, P. O. Box 391, Tallahassee, Florida 32302
On behalf of Tampa Electric Company (TECO)

RONALD C. LAFACE, ESQUIRE, Greenberg Traurig, P.A., 101 East College Avenue, Tallahassee, Florida 32301
On behalf of Florida Retail Federation (FRF)

MICHAEL B. TWOMEY, ESQUIRE, Post Office Box 5256, Tallahassee, Florida 32314-5256
On behalf of Catherine L. Claypool, Helen Fisher, William Page, Edward A. Wilson, Sue E. Strohm, Mary Jane Williamson, Betty J. Wise, Carlos Lissabet, and Lesly A. Diaz (TECO Residential Customers) and Sugarmill Woods Civic Association (Sugarmill Woods)

JOHN W. MCWHIRTER, Jr., ESQUIRE, McWhirter Reeves McGlothlin Davidson Kaufman & Arnold, P. A., 400 North Tampa Street, Suite 2450, Tampa, Florida 33601-3350
VICKI GORDON KAUFMAN, ESQUIRE, McWhirter Reeves McGlothlin Davidson Kaufman & Arnold, P. A., 117 South Gadsden Street, Tallahassee, Florida 32301
On behalf of Florida Industrial Power Users Group (FIPUG)

ROBERT D. VANDIVER, ESQUIRE, Associate Public Counsel, Office of Public Counsel, c/o The Florida Legislature, 111 West Madison Street, Room 812, Tallahassee, Florida 32399-1400
On behalf of the Citizens of the State of Florida (OPC).

WM. COCHRAN KEATING, IV, ESQUIRE, and JENNIFER A. RODAN, ESQUIRE, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850
On behalf of the Commission Staff (Staff).

ORDER APPROVING PROJECTED EXPENDITURES AND TRUE-UP AMOUNTS FOR FUEL ADJUSTMENT FACTORS; GPIF TARGETS, RANGES, AND REWARDS; AND PROJECTED EXPENDITURES AND TRUE-UP AMOUNTS FOR CAPACITY COST RECOVERY FACTORS

BY THE COMMISSION:

As part of this Commission's continuing fuel and purchased power cost recovery and generating performance incentive factor proceedings, a hearing was held on November 12-14, 2003, in this docket. The hearing addressed the issues set out in Order No. PSC-03-1264-PHO-EI, issued November 7, 2003, in this docket (Prehearing Order). Several of the positions on these issues were stipulated or not contested by the parties and presented to us for approval, but some contested issues remained for our consideration. As set forth fully below, we approve each of the stipulated and uncontested positions presented. Our rulings on the remaining contested issues are also discussed below.

We have jurisdiction over this subject matter pursuant to the provisions of Chapter 366, Florida Statutes, including Sections 366.04, 366.05, and 366.06, Florida Statutes.

I. GENERIC FUEL COST RECOVERY ISSUES

A. Shareholder Incentive Benchmarks

The parties stipulated that the actual benchmark levels for calendar year 2003 for gains on non-separated wholesale energy sales eligible for a shareholder incentive pursuant to Order No. PSC-00-1744-PAA-EI are as follows:

FPL: $21,657,720
Gulf: $1,405,575
PEF: $8,283,799
TECO: $1,546,058

Based on the evidence in the record, we approve these amounts as reasonable.

The parties also stipulated that the estimated benchmark levels for calendar year 2004 for gains on non-separated wholesale energy sales eligible for a shareholder incentive pursuant to Order No. PSC-00-1744-PAA-EI are as follows:

FPL:	$13,554,731
Gulf:	$2,016,185
PEF:	$8,239,266
TECO:	$1,261,681

Based on the evidence in the record, we approve these amounts as reasonable.

B. Base Level for Hedging-Related O&M Expenses

The parties did not contest that the appropriate base level for purposes of determining the incremental operation and maintenance expenses for each investor-owned electric utility's non-speculative financial and/or physical hedging program to mitigate fuel and purchased power price volatility are as follows:

FPL:	There is no one general base level that would be appropriate for the expanded hedging program. Each category of cost requested for recovery must be evaluated on a case by case, item by item basis to determine what portion, if any, of that category of cost was included in FPL's 2002 MFRs.
Gulf:	$0
PEF:	$0
TECO:	$169,153

Based on the evidence in the record, we approve these amounts as reasonable.

II. COMPANY-SPECIFIC FUEL COST RECOVERY ISSUES

A. Florida Power & Light Company

Prudence of Hedging-Related Actions

The parties stipulated that FPL's actions through December 31, 2002, to mitigate fuel and purchased power price volatility through implementation of its non-speculative financial and physical hedging programs were prudent. The parties further stipulated that FPL's hedging transactions are subject to staff audit and review and that such audit and review may be conducted to ascertain any relationship between utility and affiliate hedging activities to ensure that ratepayers are not assuming the risk of loss on hedging transactions without receiving a commensurate share of any hedging gain. Based on the evidence in the record, we approve these stipulations as reasonable.

Incremental Hedging Program O&M Expenses

The parties did not contest that FPL's actual and projected operation and maintenance expenses for 2002 through 2004 for its non-speculative financial and physical hedging programs are reasonable for cost recovery purposes. The evidence in the record indicates that since the inception of FPL's expanded hedging program in 2002, FPL has prudently managed the program to increase the sophistication of its market analysis, forecasting, trade monitoring, and risk management capabilities. The evidence further indicates that this increased sophistication facilitates the expansion of FPL's hedging activities on a well-informed and well-controlled basis. Based on the evidence in the record, we find that FPL's actual and projected operation and maintenance expenses for 2002 through 2004 for its non-speculative financial and physical hedging programs are reasonable for cost recovery purposes with the understanding that the expenses for 2003 and 2004 are subject to audit and true-up through the normal course of our fuel and purchased power cost recovery clause proceedings.

Recovery of Railcar Costs to Deliver Coal to Plant Scherer

The parties stipulated that FPL should be allowed to recover through the fuel clause the costs for 137 additional railcars to deliver coal to Plant Scherer. The evidence in the record indicates that these railcars are necessary to provide transportation of low-cost Powder River basin coal for use at Plant Scherer Unit 4. Accordingly, based on the evidence in the record, we approve recovery of these costs through the fuel clause.

B. Florida Public Utilities Company

Consolidation of Fuel Rates

The parties stipulated that this Commission, pursuant to separate petition, should address consolidation of the fuel rates for FPUC's Marianna and Fernandina Beach divisions concurrent with revisions to FPUC's base rates at the conclusion of Docket No. 030438-EI.

C. Gulf Power Company

Prudence of Hedging-Related Actions

The parties stipulated that Gulf's actions through December 31, 2002, to mitigate fuel and purchased power price volatility through implementation of its non-speculative financial and physical hedging programs were prudent. The parties further stipulated that Gulf's hedging transactions are subject to staff audit and review and that such audit and review may be conducted to ascertain any relationship between utility and affiliate hedging activities to ensure that ratepayers are not assuming the risk of loss on hedging transactions without receiving a commensurate share of any hedging gain. Based on the evidence in the record, we approve these stipulations as reasonable.

Incremental Hedging Program O&M Expenses

The parties stipulated that Gulf's actual and projected operation and maintenance expenses for 2002 through 2004 for its non-speculative financial and physical hedging programs are reasonable for cost recovery purposes. Based on the evidence in the record, we find that Gulf's actual and projected operation and maintenance expenses for 2002 through 2004 for its non-speculative financial and physical hedging programs are reasonable for cost recovery purposes with the understanding that the expenses for 2003 and 2004 are subject to audit and true-up through the normal course of our fuel and purchased power cost recovery clause proceedings.

D. Progress Energy Florida, Inc.

Methodology to Determine Equity Component of PFC's Capital Structure

The parties stipulated that PEF has confirmed the appropriateness of the "short-cut" methodology used to determine the equity component of Progress Fuels Corporation's (PFC) capital structure for calendar year 2002. We approve this stipulation as reasonable.

Calculation of Market Price True-Up for Powell Mountain Coal

The parties stipulated that PEF properly calculated the market price true-up for coal purchases from Powell Mountain in accordance with the market pricing methodology approved by this Commission in Docket No. 860001-EI-G. We approve this stipulation as reasonable.

Price for Waterborne Transportation Service from PFC

The parties stipulated that this Commission should retain jurisdiction to make adjustments, if necessary, to PEF's calculation of its 2002 price for waterborne coal transportation services (WCTS) provided by PFC pursuant to the market pricing methodology (market price proxy) approved by this Commission in Order No. PSC-93-1331-FOF-EI, issued September 13, 2003, in Docket No. 030001-EI. To avoid double recovery of upriver transportation costs (i.e., costs to transport coal from mine to barge) through both its market price proxy and commodity costs for purchases made FOB Barge, PEF indicates that it makes adjustments that reflect the ratio of FOB Barge purchases made at the time of the market price proxy's inception. Our staff's auditor found that PFC's contract for purchase of synfuel from KRT/Massey was FOB Barge by the terms of that contract. Based on this finding, our staff believes that an adjustment may be necessary. The parties stipulated that this Commission should allow the parties further time to review this matter to determine whether and to what extent an adjustment should be made to the costs incurred under that contract. We approve these stipulations as reasonable.

Prudence of Hedging-Related Actions

The parties stipulated that PEF's actions through December 31, 2002, to mitigate fuel and purchased power price volatility through implementation of its non-speculative financial and/or physical hedging programs were prudent. The parties further stipulated that PEF's hedging transactions are subject to staff audit and review and that such audit and review may be conducted to ascertain any relationship between utility and affiliate hedging activities to ensure that ratepayers are not assuming the risk of loss on hedging transactions without receiving a commensurate share of any hedging gain. Based on the evidence in the record, we approve these stipulations as reasonable.

Incremental Hedging Program O&M Expenses

The parties stipulated that PEF's actual and projected operation and maintenance expenses for 2002 through 2004 for its non-speculative financial and/or physical hedging programs are reasonable for cost recovery purposes. We approve this stipulation as reasonable with the understanding that the expenses for 2003 and 2004 are subject to audit and true-up through the normal course of our fuel and purchased power cost recovery clause proceedings.

Elimination of Market Price Proxy for Waterborne Transportation Service Provided by PFC

By Order No. PSC-93-1331-FOF-EI, issued September 13, 1993, in Docket No. 930001-E1, this Commission approved a stipulation establishing a market price proxy for domestic waterborne coal transportation service (WCTS) provided to PEF through its affiliate, PFC. This market price proxy is adjusted annually and establishes the price PEF pays PFC for waterborne transportation of coal from multiple points on the Mississippi/Ohio River System to PEF's Crystal River plant site. This market price proxy also represents the amount PEF recovers from its ratepayers for this service. This market price proxy was based on the amounts that PFC (formerly known as Electric Fuels Corporation, or EFC) paid its transportation suppliers, or vendors, for waterborne coal transportation services in 1992. This base cost ($23.00) was approved as the rate for 1993 and has been adjusted annually by the weighted average of a set of five cost indices: CPI-U (the Consumer

Price Index-Urban); PPI (the Producer Price Index); No. 2 Diesel Fuel Index; AHE (Average Hourly Earnings); and RCAF-U (Rail Cost Adjustment Factor-Unadjusted). Any governmental impositions placed on vendors of EFC after 1992 which the vendors choose to pass on to PFC are then added to the index-adjusted price.

By Order No. PSC-94-0390-FOF-EI, issued April 4, 1994, in Docket No. 940001-EI, this Commission approved a counterpart to the domestic market price proxy for foreign coal transportation for all shipments of coal received "freight on board" (F.O.B.) at the International Marine Terminal (IMT) in New Orleans. The foreign market price proxy was determined to be a price equal to 50.2% of the domestic market price proxy. It was established on the basis of the proportion of EFC's transloading and Gulf transport barging costs to EFC's total 1992 waterborne transportation costs. Arithmetically, the resulting market proxy price is the same as simply multiplying the combination of the 1992 transloading and Gulf transport barging costs ($11.56) times the same composite index used to escalate the domestic market price proxy each year.

Witness William B. McNulty, on behalf of the Commission's staff, testified that both the existing domestic and foreign market price proxies should be eliminated for all components of waterborne coal transportation[1] on a going-forward basis except for any component for which the utility is unable to obtain competitive bids. Witness McNulty asserted that for any such component, the Commission should establish a new market price proxy based on carefully determined base price, escalators, and weightings. Witness McNulty also proposed an administrative process whereby the

[1]Mr. McNulty identified the components of WCTS provided to PEF through PFC as follows: (1) upriver transport (moving coal from mine to river); (2) upriver terminalling (transloading coal to river barges); (3) river transport (moving coal by barge down the Ohio/Mississippi River system from the upriver terminal to a terminal near New Orleans); (4) Gulf terminalling (transloading coal for storage and blending at a terminal near New Orleans); and (5) Gulf transport (moving coal by ocean tug/barge across the Gulf of Mexico from a terminal near New Orleans to PEF's Crystal River plant).

Commission could make a transition from the use of the existing market price proxies to his proposed mechanism.

In his testimony, Mr. McNulty presented an analysis of both the domestic and foreign market price proxies in comparison to PFC's actual cost of providing WCTS to PEF for 2002. Mr. McNulty also addressed the profits that PFC should be allowed to receive in return for the additional risk it assumed when the market proxy mechanism was implemented. Based on his analysis, Mr. McNulty concluded that, due to adjustment of the 1993 base price by application of the escalators approved as part of the market price proxy mechanisms, both market price proxies exceeded the costs of providing service in 2002 and allowed PFC to achieve significantly more profit than it would have in the absence of the proxy. (It is important to note that PFC also carried the risk that market prices would exceed the proxy price.) Further, Mr. McNulty testified that the growth rate of the domestic market price proxy has not reflected the growth rate of the waterborne coal transportation market, and that the application of the proxy escalators and their respective weightings yield inaccurate estimates of market price because they do not reflect the prevailing cost changes in the industry. Mr. McNulty also testified that the foreign market price proxy is now obsolete because it is based on a ratio of Gulf transport costs to total costs that existed ten years ago but has changed since that time. Mr. McNulty stated that it is particularly important that the foreign market price proxy be eliminated or modified because PEF's foreign coal purchases are expected to increase significantly in 2004 and 2005.

To remedy this situation, Mr. McNulty proposed that this Commission eliminate both market price proxies effective at the end of 2004 and require PFC to use competitive bidding for each component of WCTS that it provides for PEF as its current contracts expire. Mr. McNulty testified that competitive markets exist for most of the components of WCTS included in the market price proxies, but that it is unclear whether a market exists for the Gulf transport component required by PEF. Mr. McNulty proposed that for any component of WCTS for which PFC is unable to obtain competitive bids, the Commission should establish a new market price proxy based on carefully determined base price, escalators, and weightings.

Mr. McNulty proposed that no action should be taken regarding the current market price proxy mechanism as it applies to 2002, 2003, and 2004. Mr. McNulty asserted that it would be inappropriate for the Commission to apply a new WCTS cost recovery method on a retroactive basis to 2002. Mr. McNulty also asserted that it would be inappropriate to use a new WCTS cost recovery method for 2003 and 2004 because PFC and PEF have relied upon such regulatory treatment in contracting for services in the near term. Mr. McNulty noted that PFC's existing contracts are scheduled to expire in late 2004 or early 2005.

PEF did not offer testimony to rebut Mr. McNulty's testimony. Witness Javier Portuondo, on behalf of PEF, testified that while he may not completely agree with the cost data that Mr. McNulty used as the basis for his testimony, he does agree with the methodology outlined by Mr. McNulty under which the existing market price proxies would terminate at the end of 2004 followed by competitive bidding and the establishment, where necessary, of new market price proxies.

Based on the evidence in the record, we find that the domestic and foreign market price proxies established in Order No. PSC-93-1331-FOF-EI and Order No. PSC-94-0390-FOF-EI, respectively, should be eliminated and cease to operate beginning January 1, 2004. We further find that the proxies, as trued-up through the established practice in this docket, shall serve as the basis for cost recovery for 2002 and 2003 waterborne coal transportation service provided to PEF through PFC. Mr. McNulty has recommended that we allow the existing market price proxies to continue in effect through the end of 2004. However, based on Mr. McNulty's conclusion that the proxies we have approved may nonetheless allow PFC to earn an unreasonably high profit on the services it provides for PEF, we believe the proxies should cease operation sooner, on January 1, 2004. Because PEF was not previously on notice that the proxies may cease to serve as the basis for cost recovery for either 2002 or 2003, we decline to adjust PEF's recoverable amounts under the proxies for those years as a matter of fundamental fairness. Until our vote in this proceeding to terminate the proxies, the proxies have provided regulatory certainty to PEF, its customers, and its investors by serving as the basis for determining the recoverable price for the services provided to PEF through PFC.

We elect not to adopt any particular methodology for determining PEF's recoverable waterborne coal transportation service costs at this time. We believe that additional input from PEF and intervenors on this subject will allow us to make a more fully informed decision. Therefore, we direct our staff to open a new docket for the purpose of establishing a new system for determining the just, reasonable, and compensatory rate for PEF's waterborne coal transportation service for 2004 and beyond.

E. Tampa Electric Company

Benchmark Price for Waterborne Coal Transportation Services Provided by TECO Affiliates

The parties stipulated that the appropriate 2002 waterborne coal transportation benchmark price for transportation services provided by TECO affiliates is $23.87 per ton. Further, the parties stipulated that TECO's actual costs associated with transportation service provided by TECO affiliates are below the 2002 waterborne transportation benchmark price. We approve these stipulations as reasonable.

Prudence of Hedging-Related Actions

The parties stipulated that TECO's actions through December 31, 2002, to mitigate fuel and purchased power price volatility through implementation of its non-speculative financial and physical hedging programs were prudent. Based on the evidence in the record, we approve this stipulation as reasonable.

Incremental Hedging Program O&M Expenses

The parties stipulated that TECO's actual and projected operation and maintenance expenses for 2002 through 2004 for its non-speculative financial and physical hedging programs are reasonable for cost recovery purposes. Based on the evidence in the record, we find that TECO's actual and projected operation and maintenance expenses for 2002 through 2004 for its non-speculative financial and physical hedging programs are reasonable for cost recovery purposes with the understanding that the expenses for 2003 and 2004 are subject to audit and true-up through the normal course of our fuel and purchased power cost recovery clause proceedings.

<u>Replacement Fuel Costs Associated with Ceasing Operations at Gannon Units 1-4</u>

Pursuant to a Consent Final Judgment (CFJ) entered into with the Florida Department of Environmental Protection, signed December 6, 1999, and a Consent Decree (CD) entered into with the United States Environmental Protection Agency and Department of Justice, signed February 29, 2000, TECO must cease operating coal-fired generation at its Gannon Station[2] by December 31, 2004. Specifically, the CD requires TECO to repower coal-fired generating capacity at Gannon of no less than 200 megawatts (MW) by May 1, 2003. As a result, according to TECO witness William T. Whale, Gannon Units 5 and 6 are being repowered from coal to natural gas and are being renamed as Bayside Units 1 and 2, respectively.[3] Mr. Whale stated that the shutdown schedules for Gannon Units 5 and 6 are driven by the in-service dates of Bayside Units 1 and 2.

Mr. Whale testified that to achieve the required May 1, 2003, in-service date for Bayside Unit 1, Gannon Unit 5 was shut down on January 30, 2003, to convert its steam turbine generator to the Bayside Unit 1 combined cycle configuration. He further testified that due to the planned January 15, 2004, in-service date for Bayside Unit 2, the shutdown date for Gannon Unit 6 would occur around September 30, 2003. Mr. Whale stated that Gannon Units 3

---

[2]Mr. Whale described the Gannon Station Units as follows: Gannon Unit 1 was commissioned in 1957 and, prior to being shut down and placed on long-term reserve standby, had a net capacity rating of 94 MW; Gannon Unit 2 was commissioned in 1958 and, prior to being shut down and placed on long-term reserve standby, had a net capacity rating of 100 MW; Gannon Unit 3 was commissioned in 1960 and has a net capacity rating of 155 MW; Gannon Unit 4 was commissioned in 1963 and has a net capacity rating of 100 MW. Each of the Gannon units has one boiler supplying steam to one steam turbine generator.

[3]Mr. Whale described the Bayside Units as follows: Bayside Unit 1 went into commercial operation on April 24, 2003, with a net capacity of 690 MW in the summer and 779 MW in the winter; Bayside Unit 2 is expected to be in service January 15, 2004, with a net capacity of 908 MW in the summer and 1,022 MW in the winter.

and 4 would be shut down around October 15, 2003, so that Bayside Unit 2 could utilize the transmission facilities currently used for the operation of Gannon Unit 4. He testified that the existing transmission facilities cannot accommodate the operation of both Bayside Unit 2 and Gannon Unit 4, making it necessary for Gannon Unit 4 to cease operations to allow for the tie-in and testing of Bayside Unit 2 prior to its commercial operation.

Mr. Whale testified that TECO never anticipated or planned for the shutdown of Gannon Units 1 through 4 to occur exactly on December 31, 2004. He testified that TECO made a determination that it would attempt to keep the units running as long as reliably possible without incurring significant expenditures given the age of the units, the short remaining life, and the associated outage time necessary for any planned maintenance work. Mr. Whale stated that in light of TECO's obligations to cease coal-fired generation at the station and the age of the units, the company determined that the most prudent approach to maintenance was to use a "patch and go" approach which required limited investment with minimal planned outage time.

Mr. Whale testified that by the summer of 2002, TECO began to perform detailed evaluations, considering numerous options, for possible shutdown dates for Gannon Units 1 through 4. Mr. Whale stated that the company ran multiple scenarios to evaluate ratepayer impacts (including fuel and purchased power costs), operation and maintenance (O&M) impacts, and wholesale sales opportunities for off-system sales. Mr. Whale testified that by late 2002, it became apparent that the units needed to be shut down in 2003. Mr. Whale asserted that this realization was driven primarily by four factors: the declining availability and reliability of the units; the significant expenditures that would need to be incurred in an effort to keep the units running reliably; the potential for safety incidents; and the short window of time until the units would be required to shut down under the CFJ and CD, regardless of how much the company might invest in an effort to keep them operating. Mr. Whale stated that, based on these considerations, a plan was formalized to shut down Gannon Units 1 and 2 on March 15, 2003, and Gannon Units 3 and 4 in September 2003. Mr. Whale indicated that these plans were communicated to the Florida Department of Environmental Protection, the Environmental Protection Agency, and the Department of Justice on February 7, 2003.

Mr. Whale testified that given the current condition of Gannon Units 1 through 4, TECO estimated that it would need to incur additional O&M expense of approximately $57 million to keep the units operating somewhat reliably beyond the actual and currently planned shutdown dates and through 2004. Mr. Whale asserted that to the extent the performance of the units continues to decline despite investment in repairs and maintenance, there could be additional costs incurred to replace power during forced unplanned outages.

TECO witness Benjamin F. Smith testified that in TECO's February, 2003, and most recent analysis, TECO did not project the need to purchase replacement firm capacity as a result of the shutdown of the Gannon Units to meet its summer 2003 reserve margin requirements, due to the April 2003 in-service date of Bayside Unit 1. Mr. Smith stated that the company did anticipate purchasing supplemental energy as needed in 2003. Mr. Smith asserted that TECO projects it will purchase 50 MW of firm capacity for its summer 2004 reserve margin requirement and anticipates purchasing supplemental energy as needed in 2004. Mr. Smith testified that although TECO projects its system capacity and energy needs, it is neither feasible nor appropriate to isolate and then attribute costs to a single variable, such as the shutdown of the Gannon units, on an actual basis due to system dynamics. Mr. Smith identified these system dynamics as including unit forced outages, operating restrictions, weather, customer demand, and statewide transmission and stability issues.

TECO witness Joann T. Wehle testified that the replacement fuel costs associated with the shutdown of Gannon Units 1 through 4 are reasonable. Ms. Wehle stated that TECO's units are operated to provide safe, reliable electric service to ratepayers, and the company procures the fuel to operate all units based on their economic dispatch. Ms. Wehle further stated that TECO follows its Commission-reviewed fuel procurement policies and procedures. Referring to Mr. Whale's testimony, Ms. Wehle stated that TECO's decision to shut down Gannon Units 1 through 4 in 2003 was arrived at only after careful and deliberate evaluation of many dynamic, competing and complex factors. Therefore, Ms. Wehle concluded, costs for replacement fuel due to the shutdown of Gannon Units 1 through 4 in 2003 are reasonable and prudently incurred and should be approved for recovery through the fuel clause.

Witness Michael J. Majoros, testifying on behalf of OPC, asserted that as a result of the early closure of Gannon Units 1 through 4, TECO's stockholders would receive benefits in the form of lower operating expenses, while TECO's ratepayers would be charged higher rates for replacement fuel costs associated with the early closure. Mr. Majoros contended that this Commission should offset TECO's requested fuel cost recovery amounts by the incremental O&M savings associated with the closure of the Gannon units, so that TECO's stockholders are neither better nor worse off as a result of the early closure while ratepayers receive some offset to the higher fuel costs. Mr. Majoros asserted that the O&M savings are $9.1 million for 2003 and $16.0 million for 2004.

Mr. Majoros testified that TECO, as part of its 2002 Ten Year Site Plan, stated it would operate Gannon Units 1 through 4 until the December 31, 2004, deadline set forth in the CD and CFJ and would repower Gannon Units 5 and 6 by May, 2003, and May, 2004, respectively. Mr. Majoros further testified that the 2002 TECO budget process contemplated closure of Gannon's coal units in September, 2004, in compliance with the CFJ and CD agreements. Mr. Majoros noted that on February 6, 2003, TECO announced its decision to shut down the Gannon plant early, anticipating that Gannon Units 1 and 2 would cease operations in mid-March 2003, and Gannon Units 3 and 4 would cease operations by October, 2003. Mr. Majoros asserted that although TECO claimed it made this decision in late January and early February, 2003, he believes that TECO made a corporate decision as early as October 2002 to shut down the units in 2003. As support, the witness referenced a document dated October 3, 2002, showing TECO's "base case" as assuming Gannon Units 1 and 2 would shut down on March 15, 2003, Units 3 and 4 would run until September 1, 2003 (or until the budgeted O&M dollars were gone), and Units 5 and 6 would shut down in February and September, 2003, respectively.

In his testimony, Mr. Majoros contended that TECO's decision to shut down Gannon Units 1 through 4 on this schedule was an economic decision designed to allow the company to meet its internal earnings goals more so than a decision based on safety and reliability concerns. Mr. Majoros also questioned the basis for TECO witness Whale's estimate of $57 million to keep the Gannon Units running reliably through 2004. Mr. Majoros asserted that this estimate was based on achieving an 80% to 85% availability factor for the units as opposed to a 60% availability factor that more realistically reflects the typical availability of the units and which would require less cost to achieve.

In support of Mr. Majoros' testimony, OPC witness William M. Zaetz testified that safety and reliability were not factors in TECO's decision to shut down Gannon Units 1 through 4 and that any perceived safety or reliability concerns were a result of TECO's failure to conduct adequate preventative maintenance. Mr. Zaetz asserted that he had never seen a plant shut down for safety reasons and that if the decision to close the Gannon units was based on safety concerns, the unit should have been shut down immediately rather than be allowed to continue to run. Mr. Zaetz testified that the Gannon units were running as would be expected given the maintenance conducted on those units. Mr. Zaetz concluded that TECO made a conscious decision to run the Gannon units as long as it could without spending any dollars to increase reliability or to make them safer, and that Gannon's performance was predictable, while any side effects that resulted were dealt with by spending the least amount of money possible.

Witness Sheree L. Brown, on behalf of FIPUG and FRF, testified that the Commission should require TECO to offset its replacement power costs associated with the closure of the Gannon units by her calculation of the O&M savings associated with the units' closure. Ms. Brown asserted that this would be a fair and equitable result due to the following: the decision to shut down the units early was a voluntary decision by TECO within its control; the requirement to shut down the units by the end of 2004 was a direct result of claimed violations by the United States Environmental Protection Agency; the ratepayers will suffer continued harm through additional replacement power costs from 2005 through 2007; and the ratepayers have also paid TECO for the environmental modifications which were challenged by the EPA.

On rebuttal, TECO witness J. Denise Jordan, disputed Ms. Brown's calculation of an adjustment to offset replacement power costs with O&M savings associated with the closure of the Gannon units. Ms. Jordan indicates that Ms. Brown's calculation was not based in fact, and, given the proper facts, should have yielded a much smaller amount. In any event, Ms. Jordan disagreed that any adjustment was necessary and responded to each of the points raised by Ms. Brown as a basis for making an adjustment. First, Ms. Jordan responded that Tampa Electric makes "voluntary" company decisions after careful and complete analysis, as was the scheduling decision for shutting down Gannon Units 1 through 4. She asserted that is no reason to mix or offset base rate revenue or expenses with fuel adjustment revenue or expenses. Second, Ms. Jordan responded that Tampa Electric did not admit violations of environmental requirements but settled litigation initiated by the EPA and DEP because settlement appeared to be the most prudent and cost-effective alternative in light of the litigation and the risks inherent in such litigation. Third, Ms. Jordan responded that Ms. Brown's assertion that ratepayers will suffer continued harm through additional replacement power costs from 2005 through 2007 is misplaced because any such additional costs stem directly from the fact that the coal units at Gannon Station are required to cease operation after December 31, 2004. Fourth, Ms. Jordan responded that Ms. Brown's assertion that the ratepayers' have paid TECO for the environmental modifications that were challenged by the EPA is cumulative and ignores the fact that those modifications were in the economic interest of Tampa Electric's customers.

Ms. Jordan also responded to OPC witness Majoros' calculation of O&M savings associated with closure of the Gannon units, stating that it is fundamentally flawed because it is based on information gathered through discovery but taken out of context. In addition, Ms. Jordan responded to Mr. Majoros' assertion that O&M amounts not spent at Gannon Station represent a savings to TECO that will result in increased earnings to benefit shareholders, and that an offset to recoverable fuel costs is appropriate. First, referring to witness Whale's rebuttal testimony, discussed below, Ms. Jordan stated that TECO did not simply cut O&M spending at its Gannon units, but focused its investment strategies to obtain a better value from its O&M expenditures. Second, Ms. Jordan stated that Mr. Majoros provided no support for his allegation that the company's O&M spending decisions resulted in savings for shareholders but only made a statement that, as a general proposition, increased earnings benefit shareholders. Third, Ms. Jordan stated that Mr. Majoros ignored the structure of cost-based ratemaking in Florida. Ms. Jordan stated that investor-owned utilities collect base rates and operate within an allowable earnings range, and that TECO should not be penalized based only on an assertion that shareholders might benefit from increased earnings without a demonstration of such earnings.

On rebuttal, TECO witness Whale responded to the testimony of Mr. Zaetz and Mr. Majoros. Mr. Whale first challenged Mr. Zaetz's qualifications to make a determination as to the safe operational capability of the Gannon units, asserting that Mr. Zaetz has never been a plant manager, maintenance manager, or operations manager; that there is no indication that he has experience in the decision-making process of determining when a unit would need to be shut down, whether for safety or any other reason; and that his testimony does not indicate that he is a Certified Safety Professional or has obtained any industry-recognized safety credentials. Mr. Whale also asserted that Mr. Zaetz has no basic knowledge of the operations of the Gannon units.

Mr. Whale disagreed with Mr. Zaetz' testimony that neither safety nor reliability was a factor in TECO's decision to shut down Gannon Units 1 through 4 in 2003, stating that TECO arrived at the decision to shut down the Gannon units in 2003 after consideration of many complex factors including safety, reliability, and other issues. Mr. Whale also responded to Mr. Zaetz' assertions that any plant can be repaired, regardless of its safety level, and that TECO's failure to repair the aging Gannon facilities demonstrated that the company's concern about continuing to operate the units was solely budgetary. Mr. Whale asserted that the fact that a unit or plant may be repaired does not indicate that making the repairs is a good business decision. Mr. Whale stated that TECO implemented its "patch and go" maintenance strategy to maximize the benefits of its maintenance spending given that Gannon Station would have to be shut down in the near term, regardless of the amounts of time and dollars spent repairing and maintaining it. Mr. Whale asserted that the company's maintenance spending was re-focused on the activities that would keep the Gannon units running safely for limited investment, and improve the operations of the company's other plants, which were not subject to shutdown on or before December 31, 2004. Further, Mr. Whale asserted that in addition to the repair costs to improve the safety and reliability of the Gannon units, TECO would have had to spend significant time and dollars planning outages to repair and replace components, procuring replacement equipment, installing the new equipment, and replacing capacity of the affected units while they were off-line for the planned outages.

In response to Mr. Majoros' testimony, Mr. Whale asserted that TECO never had a plan to operate the units until December 31, 2004, but instead recognized that the units' shutdown would require flexibility to respond to dynamic conditions as the deadline approached. Mr. Whale further testified that TECO's estimates of the O&M investments needed to keep Gannon Units 1 through 4 until December 31, 2004, show a range of costs from $37 million to $57 million to achieve an approximate 60% and 85% availability, respectively. Mr. Whale stated that under either scenario, keeping the units running through 2004 would be a very expensive proposition after which TECO would have nothing to show for the expenditures because the units would no longer be permitted to burn coal.

Based on the evidence in the record, we are persuaded that TECO's decision to shut down Gannon Units 1 through 4 when it did was a prudent decision. The evidence indicates that TECO estimated expenditures of $37 million to maintain those units at 60% availability until December 31, 2004, the last date that the units could be operated pursuant to the CFJ and CD. The evidence further indicates that Gannon Units 1 through 4 were not needed for reliability purposes in 2004 due to the addition of Bayside Units 1 and 2. We find that, given TECO's obligations to cease coal-fired generation at the station and the age of the units, the company was prudent in implementing the "patch and go" maintenance approach it chose which required limited investment with minimal planned outage time. Based on our finding that TECO's decision to shut down Gannon Units 1 through 4 was a prudent decision and on Ms. Wehle's testimony supporting the reasonableness of the replacement fuel costs, we find that the replacement fuel costs associated with the early shut down of Gannon Units 1 through 4 were prudently incurred.

We also recognize that TECO's decision to shut down the Gannon units when it did yielded savings to the company in O&M expenses. The record indicates that in 2002, TECO conducted an analysis to determine the cost impacts associated with potential closure dates for Gannon Units 1 through 4. That analysis, set forth in Exhibit MJM-5 to OPC witness Majoros' testimony, showed, among other things, TECO's estimates of O&M savings and replacement fuel costs for 2003 associated with five different closure scenarios. On cross-examination, TECO witness Jordan identified one of the scenarios as best reflecting actual events. Under that scenario, TECO estimated O&M savings of $10,521,000.

But for TECO's decision to cease operations at Gannon Units 1 through 4 when it did, the company would not have incurred the replacement fuel costs that we have determined to be reasonable. Further, but for that same decision, the company would not have achieved O&M savings estimated at $10,521,000 for 2003. Because these O&M savings derive from the same finite decision that resulted in replacement fuel costs, we believe that, under the unique circumstances presented, the replacement fuel costs to be borne by customers should be offset to some extent by the amount of savings. We are confronted with testimony from witnesses Majoros, Zaetz, and Brown that make a fair case for offsetting replacement fuel costs by the entire $10,521,000. We are also confronted with our finding that TECO's decision to shut down the units when it did was prudent and based on sound economic, reliability, and safety concerns, which tends to support TECO's argument that no offsetting should occur. Taking into account all of the competing evidence in the record on this point and the unique circumstances presented, we believe that a fair and reasonable sharing of the O&M savings associated with the units' closure will be achieved by providing 80% of the estimated O&M savings, or $8,416,800, to ratepayers as an offset to TECO's recoverable fuel costs, and providing TECO the benefit of the remaining 20% of the O&M savings.

Gains or Losses on Resale of Surplus Coal Associated with Ceasing Operations at Gannon Units 1-4

Based on our finding that TECO's decision to shut down Gannon Units 1 through 4 when it did was prudent, we find that TECO should record any gain or loss on the resale of surplus coal associated with closure of those units as a credit or charge to the fuel clause.

Dead Freight Coal Transportation Costs Associated with Ceasing Operations at Gannon Units 1-4

The evidence in the record indicates that TECO will not incur dead freight costs for coal transportation related to the shutdown of Gannon Units 1 through 4, and the company's projected 2004 fuel and purchased power costs did not include any dead freight costs. Therefore, the question of the appropriate regulatory treatment for such costs is moot.

Review of Amounts Paid to HPP

We decline to review the amounts paid by TECO under its contract with Hardee Power Partners (HPP) simply because HPP was sold. This Commission has previously approved the contract for cost recovery purposes and reviewed it as recently as 2001. The evidence in the record indicates that the rates, terms, and conditions of the contract have not changed as a result of the sale of HPP, and that the contract will not be amended, changed, or assigned as a result of the sale. No evidence to the contrary has been offered by any party to indicate that any specific problem concerning this contractual arrangement should be addressed.

III. APPROPRIATE PROJECTED EXPENDITURES AND TRUE-UP AMOUNTS FOR FUEL COST RECOVERY FACTORS

Based on the evidence in the record, we approve the following as the appropriate final fuel adjustment true-up amounts for the period January 2002 through December 2002:

FPL:	$72,467,176	over-recovery
FPUC-Fernandina Beach:	$1,167,570	over-recovery
FPUC-Marianna:	$78,631	under-recovery
Gulf:	$1,056,921	over-recovery
PEF:	$66,271,472	under-recovery
TECO:	$28,662,327	under-recovery

Based on the evidence in the record, we approve the following as the appropriate estimated/actual fuel adjustment true-up amounts for the period of January 2003 through December 2003:

FPL:	$344,729,859	under-recovery
FPUC-Fernandina Beach:	$135,130	over-recovery
FPUC-Marianna:	$265,146	under-recovery
Gulf:	$23,923,505	under-recovery
PEF:	$144,154,788	under-recovery
TECO:	$88,345,118	under-recovery

Based on the evidence in the record, we approve the following as the appropriate total fuel adjustment true-up amounts to be collected/refunded from January 2004 through December 2004:

FPL:	$344,729,859	under-recovery
FPUC-Fernandina Beach:	$1,302,700	over-recovery
FPUC-Marianna:	$343,777	under-recovery
Gulf:	$22,866,584	under-recovery
PEF:	$210,426,260	under-recovery
TECO:	$91,007,445	under-recovery

Based on the evidence in the record, we approve the following as the appropriate projected net fuel and purchased power cost recovery amounts to be included in the fuel cost recovery factors for the period January 2004 through December 2004:

FPL:	$3,380,102,249
FPUC-Fernandina Beach:	$13,835,447
FPUC-Marianna:	$11,706,084
Gulf:	$259,212,752
PEF:	$1,344,114,962
TECO:	$736,077,577

We note that the amount approved above for PEF includes PEF's 2004 projected costs for waterborne coal transportation service provided by its affiliate, PFC, based on a market price proxy that, pursuant to this Order, will cease to operate as a means for determining cost recovery as of January 1, 2004. As previously stated in this Order, we have directed our staff to open a new docket for the purpose of establishing a new system for determining the just, reasonable, and compensatory rate for PEF's waterborne coal transportation service for 2004 and beyond. Through the true-up process in this docket, the amount approved above for PEF will be adjusted to reflect the rate for 2004 that is established through the new docket.

Based on the evidence in the record and stipulation of the parties we approve the following as the appropriate revenue tax factors to be applied in calculating each investor-owned electric utility's levelized fuel factor for the projection period January 2004 through December 2004:

FPL:	1.01597
FPUC-Fernandina Beach:	1.01597
FPUC-Marianna:	1.00072
Gulf:	1.00072
PEF:	1.00072
TECO:	1.00072

Based on the evidence in the record and the resolution of the generic and company-specific fuel cost recovery issues discussed above, we approve the following as the appropriate levelized fuel cost recovery factors for the period January 2004 through December 2004:

FPL:	3.742¢/kWh
FPUC-Fernandina Beach:	1.569¢/kWh
FPUC-Marianna:	2.430¢/kWh
Gulf:	2.459¢/kWh
PEF:	3.453¢/kWh
TECO:	3.922¢/kWh

Based on the evidence in the record and stipulation of the parties, we approve the following as the appropriate fuel recovery line loss multipliers to be used in calculating the fuel cost recovery factors charged to each rate class/delivery voltage level class:

FPL:

GROUP	RATE SCHEDULE	MULTIPLIER
A	RS-1, GS-1, SL2	1.00206
A-1*	SL-1, OL-1, PL-1	1.00206
B	GSD-1	1.00199
C	GSLD-1 & CS-1	1.00093
D	GSLD-2, CS-2, OS-2 & MET	.99366
E	GSLD-3 & CS-3	.95529

A	RST-1, GST-1	
	ON-PEAK	1.00206
	OFF-PEAK	1.00206
B	GSDT-1, CILC-1(G)	
	ON-PEAK	1.00199
	OFF-PEAK	1.00199
C	GSLDT-1 & CST-1	
	ON-PEAK	1.00093
	OFF-PEAK	1.00093
D	GSLDT-2 & CST-2	
	ON-PEAK	.99497
	OFF-PEAK	.99497
E	GSLDT-3, CST-3, CILC-1(T) & ISST-1(T)	
	ON-PEAK	.95529
	OFF-PEAK	.95529
F	CILC-1(D) & ISST-1(D)	
	ON-PEAK	.99317
	OFF-PEAK	.99317

FPUC:

Fernandina Beach	Multiplier
All Rate Schedules	1.0000

Marianna	Multiplier
All Rate Schedules	1.0000

GULF:

GROUP	RATE SCHEDULE	MULTIPLIER
A	RS, GS, GSD, GSDT, SBS, OSIII, OSIV	1.00526
B	LP, LPT, SBS	0.98890
C	PX, PXT, SBS, RTP	0.98063
D	OSI, OSII	1.00529

*The multiplier applicable to customers taking service under Rate Schedule SBS is determined as follows: customers with a Contract Demand in the range of 100 to 499 KW will use the recovery factor applicable to Rate Schedule GSD; customers with a Contract Demand in the range of 500 to 7,499 KW will use the recovery factor applicable to Rate

Schedule LP; and customers with a Contract Demand over 7,499 KW will use the recovery factor applicable to Rate Schedule PX.

PEF:

GROUP	DELIVERY VOLTAGE LEVEL	MULTIPLIER
A	Transmission	0.9800
B	Distribution Primary	0.9900
C	Distribution Secondary	1.0000
D	Lighting Service	1.0000

TECO:

GROUP	MULTIPLIER
A	1.0043
A1	n/a*
B	1.0005
C	0.9745

*Group A1 is based on Group A, 15% of On-Peak and 85% of Off-Peak.

Based on the evidence in the record and the resolution of the generic and company-specific fuel cost recovery issues discussed above, we approve the following as the appropriate fuel recovery factors for each rate class/delivery voltage level class adjusted for line losses:

FPL:

GROUP	RATE SCHEDULE	FUEL RECOVERY FACTOR (¢/kWh)
A	RS-1, GS-1, SL2	3.750
A-1*	SL-1, OL-1, PL-1	3.678
B	GSD-1	3.749
C	GSLD-1 & CS-1	3.745
D	GSLD-2, CS-2, OS-2 & MET	3.718
E	GSLD-3 & CS-3	3.575

A	RST-1, GST-1	
	ON-PEAK	4.090
	OFF-PEAK	3.599
B	GSDT-1, CILC-1(G)	
	ON-PEAK	4.090
	OFF-PEAK	3.598
C	GSLDT-1 & CST-1	
	ON-PEAK	4.085
	OFF-PEAK	3.595
D	GSLDT-2 & CST-2	
	ON-PEAK	4.061
	OFF-PEAK	3.573
E	GSLDT-3, CST-3, CILC-1(T) & ISST-1(T)	
	ON-PEAK	3.899
	OFF-PEAK	3.431
F	CILC-1(D) & ISST-1(D)	
	ON-PEAK	4.054
	OFF-PEAK	3.567

*WEIGHTED AVERAGE 16% ON-PEAK AND 85% OFF-PEAK

FPUC-Marianna:

Rate Schedule	Fuel Recovery Factor (per kWh)
RS	$.04056
GS	$.04005
GSD	$.03738
GSLD	$.03536
OL	$.02912
SL	$.02903

FPUC-Fernandina Beach:

Rate Schedule	Fuel Recovery Factor (per kWh)
RS	$.02968
GS	$.02941
GSD	$.02765
CSL	$.01956
OL	$.01956
SL	$.01956

GULF:

		FUEL RECOVERY FACTOR (¢/kWH)		
		STANDARD	TIME OF USE	
GROUP	RATE SCHEDULE		ON-PEAK	OFF-PEAK
A	RS, GS, GSD, SBS, OSIII, OSIV	2.472	2.866	2.304
B	LP, LPT, SBS	2.432	2.820	2.267
C	PX, PXT, RTP, SBS	2.411	2.796	2.248
D	OSI, OSII	2.449	N/A	N/A

*The recovery factor applicable to customers taking service under Rate Schedule SBS is determined as follows: customers with a Contract Demand in the range of 100 to 499 KW will use the recovery factor applicable to Rate Schedule GSD; customers with a Contract Demand in the range of 500 to 7,499 KW will use the recovery factor applicable to Rate Schedule LP; and customers with a Contract Demand over 7,499 KW will use the recovery factor applicable to Rate Schedule PX.

PEF:

		FUEL RECOVERY FACTOR (¢/kWH)		
	DELIVERY	STANDARD	TIME OF USE	
GROUP	VOLTAGE LEVEL		ON-PEAK	OFF-PEAK
A	Transmission	3.389	4.440	2.931
B	Distribution Primary	3.423	4.484	2.961
C	Distribution Secondary	3.458	4.530	2.991
D	Lighting Service	3.279		

TECO:

RATE SCHEDULE	FUEL RECOVERY FACTOR (¢/kWh)
RS, GS, TS	3.939
RST and GST	4.943 (on peak)
	3.421 (off peak)
SL-2, OL-1, and OL-3	3.649
GSD, GSLD, and SBF	3.924
GSDT, GSLDT, EV-X, and SBFT	4.924 (on peak)
	3.408 (off peak)
IS-1, IS-3, SBI-1, and SBI-3	3.822

IST-1, IST-3, SBIT-1, and SBIT-3	4.796 (on peak) 3.319 (off peak)

IV. GENERIC CAPACITY COST RECOVERY ISSUES

Methodology for Determining Incremental Costs of Post-9/11 Security Measures

By Order No. PSC-01-2516-FOF-EI, issued December 26, 2001, in Docket No. 010001-EI, and Order No. PSC-02-1761-FOF-EI, issued December 13, 2002, in Docket No. 020001-EI, this Commission authorized recovery through the capacity cost recovery clause of certain incremental power plant security expenses incurred as a result of measures taken in response to the terrorist attacks of September 11, 2001. In this docket, we are asked to determine the appropriate methodology for determining which of these costs are incremental to costs already being recovered in a utility's base rates. On this issue, we heard testimony from FPL witness Korel M. Dubin, PEF witness Javier Portuondo, TECO witness J. Denise Jordan, and staff witness Matthew Brinkley.

Having reviewed the evidence in the record, we find that the appropriate methodology consists of the evaluation process proposed by PEF witness Portuondo, set forth below, together with a base amount adjustment method proposed by witness Brinkley. This methodology is based on the principle that costs already reflected in base rates should be removed from the costs to be recovered through a cost recovery clause to ensure that costs are not recovered twice, once through base rates and once through the clause. The evaluation process that we approve, as proposed by witness Portuondo, is as follows:

1. First, the utility shall remove any O&M expenses associated with a project that were included in the MFRs from the rate proceeding that established the utility's current base rates. If none are found, all project costs are eligible for further evaluation. Any costs that are found to have been included in the MFRs are excluded from the project's recoverable costs at that point.

2. After this initial review, the utility shall identify any specific project costs that, although not associated directly with the project in the MFRs, are reflected elsewhere in base rates. This step is performed by determining whether the cost would be incurred regardless of the new project.

3. Finally, the utility shall determine whether the new project will create any offsetting O&M savings associated with related activities, in which case the savings are credited to the project or task to reduce its total cost.

We agree with staff witness Brinkley that base amounts used for calculating incremental security costs for recovery through the capacity cost recovery clauses should be adjusted for growth or decline in energy sales in kilowatt-hours from the base year to the current year. By adjusting the base year amounts for growth in energy sales, we believe utilities will collect through the capacity clause only those expenses that are truly incremental to the level of costs being recovered through base rates. For those utilities currently operating under a revenue sharing plan approved by this Commission, current year revenues shall be reduced by the amount of revenues refunded through the utility's sharing plan prior to application of this growth adjustment.

Finally, we find that utilities seeking recovery of incremental security costs through the capacity clause shall provide a breakdown of those costs by project groups and identify any base rate items that were removed. This requirement is intended to enhance our staff's ability to review and audit these costs.

V. COMPANY-SPECIFIC CAPACITY COST RECOVERY ISSUES

A. <u>Florida Power & Light Company</u>

Based on the evidence in the record, we find that FPL's incremental security expenses for 2002 through 2004 associated with the measures taken in response to post-September 11, 2001, security requirements are reasonable for cost recovery purposes, with the understanding that the expenses for 2003 and 2004 are subject to audit and true-up through the normal course of our fuel and purchased power cost recovery clause proceedings. Included in FPL's 2004 cost projections is 62% of a Nuclear Regulatory Commission (NRC) fee increase attributable to Homeland Security costs. We find this projection reasonable.

B. Progress Energy Florida, Inc.

Based on the evidence in the record, we find that PEF's incremental security expenses for 2002 through 2004 associated with the measures taken in response to post-September 11, 2001, security requirements are reasonable for cost recovery purposes, with the understanding that the expenses for 2003 and 2004 are subject to audit and true-up through the normal course of our fuel and purchased power cost recovery clause proceedings. Included in PEF's 2004 cost projections is approximately 88% of an NRC fee increase attributable to Homeland Security costs. PEF has agreed that the appropriate percentage of this fee increase to include for cost recovery is 62%. Because the difference in these amounts has a negligible effect on the capacity cost recovery factors, we find that an adjustment for this difference may be made through the true-up process in the next annual fuel and purchased power cost recovery hearing.

C. Tampa Electric Company

Based on the evidence in the record, we find that TECO's incremental security expenses for 2002 through 2004 associated with the measures taken in response to post-September 11, 2001, security requirements are reasonable for cost recovery purposes, with the understanding that the expenses for 2003 and 2004 are subject to audit and true-up through the normal course of our fuel and purchased power cost recovery clause proceedings.

VI. APPROPRIATE PROJECTED EXPENDITURES AND TRUE-UP AMOUNTS FOR CAPACITY COST RECOVERY FACTORS

Based on the evidence in the record and the resolution of the company-specific capacity cost recovery issues discussed above, we approve the following final capacity cost recovery true-up amounts for the period January 2002 through December 2002:

FPL:	$12,676,723	over-recovery
GULF:	$193,696	over-recovery
PEF:	$4,497,883	over-recovery
TECO:	$314,462	under-recovery

Based on the evidence in the record and the resolution of the company-specific capacity cost recovery issues discussed above, we approve the following estimated/actual capacity cost recovery true-up amounts for the period January 2003 through December 2003:

FPL:	$16,048,425	over-recovery
GULF:	$1,058,876	over-recovery
PEF:	$1,188,735	under-recovery
TECO:	$1,847,047	under-recovery

Based on the evidence in the record and the resolution of the company-specific capacity cost recovery issues discussed above, we approve the following total capacity cost recovery true-up amounts to be collected/refunded during the period January 2004 through December 2004:

FPL:	$28,725,148	over-recovery
GULF:	$1,252,572	over-recovery
PEF:	$3,309,148	over-recovery
TECO:	$2,161,509	under-recovery

Based on the evidence in the record and the resolution of the generic and company-specific capacity cost recovery issues discussed above, we approve the following projected net purchased power capacity cost recovery amounts to be included in the recovery factor for the period January 2004 through December 2004:

FPL:	$580,834,356
GULF:	$17,619,376
PEF:	$301,641,556
TECO:	$40,590,196

At our next annual fuel and purchased power cost recovery hearing, as part of the final true-up process for 2003 capacity costs, FPL, PEF, and TECO should demonstrate that no double-recovery of security costs has occurred after applying the base year growth adjustment approved in this Order, above.

Based on the evidence in the record and stipulation of the parties, we approve the following jurisdictional separation factors to be applied to determine the capacity costs to be recovered during the period January 2004 through December 2004:

FPL:	98.84301%
GULF:	96.50187%
PEF:	Base - 95.957%, Intermediate - 86.574%, Peaking - 74.562%
TECO:	95.43611%

Based on the evidence in the record and the resolution of the generic and company-specific capacity cost recovery issues discussed above, we approve the following projected capacity cost recovery factors for each rate class/delivery class for the period January 2004 through December 2004:

FPL:

Rate Class	Capacity Recovery Factor ($/kW)	Capacity Recovery Factor ($/kWh)
RS1	-	.00625
GS1	-	.00613
GSD1	2.35	-
OS2	-	.00603
GSLD1/CS1	2.39	-
GSLD2/CS2	2.30	-
GSLD3/CS3	2.25	-
CILCD/CILCG	2.37	-
CILCT	2.33	-
MET	2.38	-
OL1/SL1/PL-1	-	.00170
SL2	-	.00410

Rate Class	Capacity Recovery Factor (Reservation Demand Charge) ($/kW)	Capacity Recovery Factor (Sum of Daily Demand Charge) ($/kW)
ISST1D	.29	.14
SST1T	.27	.13
SST1D	.28	.13

GULF:

Rate Class	Capacity Recovery Factor (cents/kWh)
RS, RSVP	.194
GS	.188
GSD, GSDT, GSTOU	.157
LP, LPT	.135
PX, PXT, RTP, SBS	.118
OS-I, OS-II	.057
OS-III	.122
OS-IV	.056

FPC:

Rate Class	Capacity Recovery Factor (cents/kWh)
Residential	0.877
General Service Non-demand - Secondary	0.795
@Primary Voltage	0.787
@Transmission Voltage	0.779
General Service 100% Load Factor	0.506
General Service Demand - Secondary	0.698
@Primary Voltage	0.691
@Transmission Voltage	0.684
Curtailable - Secondary	0.628
@Primary Voltage	0.621
@Transmission Voltage	0.615
Interruptible - Secondary	0.529
@Primary Voltage	0.524
@Transmission Voltage	0.518
Lighting	0.157

TECO:

Rate Class	Capacity Recovery Factor (cents/kWh)
RS	.267
GS, TS	.244
GSD, EV-X	.210
GSLD, SBF	.185
IS-1, IS-3, SBI-1, SBI-3	.016
SL/OL	.105

VII. GENERATING PERFORMANCE INCENTIVE FACTOR (GPIF) ISSUES

The parties stipulated that the appropriate Generation Performance Incentive Factor (GPIF) rewards/penalties for performance achieved during the period January 2002 through December 2002 are those set forth in Attachment A to this Order, which is incorporated by reference herein. We approve these stipulations as reasonable.

The parties stipulated that the appropriate GPIF targets/ranges for the period January 2004 through December 2004 are those set forth in Attachment A to this Order, which is incorporated by reference herein. We approve these stipulations as reasonable.

VIII. OTHER MATTERS

The parties stipulated that the new fuel adjustment charges and capacity cost recovery factors approved in this Order should be effective beginning with the first billing cycle for January 2004 and thereafter through the last billing cycle for December 2004. The parties also stipulated that the first billing cycle may start before January 1, 2004, and the last billing cycle may end after December 31, 2004, so long as each customer is billed for twelve months regardless of when the factors became effective. We approve these stipulations as reasonable.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that the stipulations and findings set forth in the body of this Order are hereby approved. It is further

ORDERED that Florida Power & Light Company, Progress Energy Florida, Inc., Tampa Electric Company, Gulf Power Company, and Florida Public Utilities Company are hereby authorized to apply the fuel cost recovery factors set forth herein during the period January 2004 through December 2004. It is further

ORDERED that the estimated true-up amounts contained in the fuel cost recovery factors approved herein are hereby authorized subject to final true-up, and further subject to proof of the reasonableness and prudence of the expenditures upon which the amounts are based. It is further

ORDERED that Florida Power & Light Company, Progress Energy Florida, Inc., Gulf Power Company, and Tampa Electric Company are hereby authorized to apply the capacity cost recovery factors as set forth herein during the period January 2004 through December 2004. It is further

ORDERED that the estimated true-up amounts contained in the capacity cost recovery factors approved herein are hereby authorized subject to final true-up, and further subject to proof of the reasonableness and prudence of the expenditures upon which the amounts are based.

By ORDER of the Florida Public Service Commission this 22nd day of December, 2003.

BLANCA S. BAYÓ, Director
Division of the Commission Clerk
and Administrative Services

By: Kay Flynn
Kay Flynn, Chief
Bureau of Records and Hearing
Services

(S E A L)

WCK

DISSENT:

CHAIRMAN LILA A. JABER dissents from the Commission's decision, in part, with the following opinion:

On the issue of modifying or eliminating the method for calculating Progress Energy Florida's (PEF) market price proxy for waterborne coal transportation service that was established by Order No. PSC-93-1331-FOF-EI, Chairman Jaber concurs in part and dissents in part as follows.

I commend and agree with the majority's decision to initiate a separate proceeding to establish a mechanism to replace the current proxy mechanism outlined in Order No. PSC-93-1331-FOF-EI. I, too, believe that a separate proceeding will provide stakeholders the opportunity to present and the Commission the opportunity to hear additional, detailed evidence on whether a competitive bidding (RFP) process, or some other process, will result in a more suitable mechanism.

Moreover, I commend and agree with the majority's opinion that we must provide regulatory certainty for both customers and the businesses we regulate. In fact, it is our obligation to provide such certainty. Certainty creates a business environment that promotes investment and good, reliable service. In that regard, my dissent is limited to the following.

I believe that staff witness McNulty's testimony was extremely compelling. Repeatedly, witness McNulty stated that the proxy mechanism established by Order No. PSC-93-1331-FOF-EI has resulted in Progress Fuels Corporation achieving excessive margins in previous years for the waterborne coal transportation service it provides to PEF. Therefore, I would have gone further than the majority by retaining our jurisdiction to determine, at a minimum, the recoverable amount of PEF's 2003 waterborne coal transportation costs, until the separate proceeding could be completed and the appropriate audit for that year performed. I believe this regulatory approach would keep both the customers and the utility whole. Using this approach, I do not find it necessary at this time to determine that Order No. PSC-93-1331-FOF-EI should be modified such that the proxy mechanism would cease January 1, 2004. By making that determination, I believe the majority eliminated the option of establishing a transition period. My preferred approach would be to decide the fate of the current proxy mechanism concurrently with our decision on what a new mechanism, if any, should be. I do not believe that the parties had an adequate opportunity to suggest a more sufficient mechanism in this proceeding.

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Any party adversely affected by the Commission's final action in this matter may request: 1) reconsideration of the decision by filing a motion for reconsideration with the Director, Division of the Commission Clerk and Administrative Services, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, within fifteen (15) days of the issuance of this order in the form prescribed by Rule 25-22.060, Florida Administrative Code; or 2) judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or the First District Court of Appeal in the case of a water and/or wastewater utility by filing a notice of appeal with the Director, Division of the Commission Clerk and Administrative Services and filing a copy of the notice of appeal and the filing fee with the appropriate court. This filing must be completed within thirty (30) days after the issuance of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure.

GPIF REWARDS/PENALTIES

January 2002 to December 2002

Utility	Amount	Reward/Penalty
Florida Power and Light Company	$ 7,449,429	Reward
Gulf Power Company	$ 431,920	Reward
Progress Energy Florida	$ 2,781,223	Reward
Tampa Electric Company	$ 2,496,021	Penalty

Utility/ Plant/Unit	EAF		Heat Rate	
FPL	Target	Adjusted Actual	Target	Adjusted Actual
Cape Canaveral 1	90.3	90.8	9,727	9,207
Cape Canaveral 2	88.2	85.6	9,661	9,115
Fort Lauderdale 4	91.8	94.4	7,618	7,528
Fort Lauderdale 5	91.9	93.4	7,535	7,401
Manatee 1	81.5	89.8	10,415	9,865
Manatee 2	85.4	90.1	10,335	10,088
Martin 1	89.2	80.2	9,990	9,040
Martin 2	90.8	89.5	10,012	8,914
Martin 3	94.9	96.3	6,958	6,954
Martin 4	87.9	94.2	7,028	7,004
Port Everglades 3	94.3	92.3	9,929	9,388
Port Everglades 4	86.0	90.7	9,933	9,162
Putnam 1	84.7	86.9	9,261	8,836
Riviera 3	84.4	96.3	10,327	9,797
Riviera 4	93.1	96.5	9,762	9,366
Turkey Point 1	85.4	89.2	9,783	9,083
Turkey Point 2	94.3	98.7	9,645	9,332
Turkey Point 3	93.6	100.0	10,994	11,193
Turkey Point 4	86.0	91.6	11,069	11,117
St. Lucie 1	86.0	91.7	10,795	10,811
St. Lucie 2	93.6	100.0	10,836	10,850
Scherer 4	84.4	83.2	10,225	10,097

Gulf	Target	Adjusted Actual	Target	Adjusted Actual
Crist 4	90.9	93.1	10,499	10,979
Crist 6	77.3	78.3	10,546	10,649
Crist 7	79.7	85.8	10,196	10,255
Smith 1	90.7	92.0	10,054	10,206
Smith 2	86.6	58.2	10,050	10,309
Daniel 1	88.0	92.4	10,191	9,991
Daniel 2	70.7	73.9	9,906	9,850

Attachment A

GPIF REWARDS/PENALTIES

January 2002 to December 2002

Utility/ Plant/Unit	EAF		Heat Rate	
PEF	Target	Adjusted Actual	Target	Adjusted Actual
Anclote 1	91.7	96.4	10,183	10,386
Anclote 2	81.7	84.3	10,090	10,124
Crystal River 1	86.8	92.9	9,750	9,725
Crystal River 2	65.1	66.4	9,619	9,656
Crystal River 3	96.2	98.6	10,283	10,288
Crystal River 4	76.5	76.3	9,413	9,441
Crystal River 5	94.5	98.5	9,376	9,463
Bartow 3	80.1	82.7	10,053	10,008
Tiger Bay	80.3	82.1	8,267	8,313
TECO	Target	Adjusted Actual	Target	Adjusted Actual
Big Bend 1	77.3	71.1	10,111	10,519
Big Bend 2	66.7	52.4	9,815	10,398
Big Bend 3	67.5	53.8	10,036	10,275
Big Bend 4	82.6	84.3	10,089	10,488
Gannon 5	56.7	65.2	10,716	11,202
Gannon 6	63.9	61.6	10,704	11,192
Polk 1	78.0	84.6	10,087	10,565

GPIF TARGETS

January 2004 to December 2004

Utility/ Plant/Unit	EAF				Heat Rate	
	Company			Staff	Company	Staff
FPL	EAF	POF	EUOF			
Cape Canaveral 2	89.8	0.0	10.2	Agree	9,528	Agree
Lauderdale 4	79.6	15.3	5.1	Agree	7,473	Agree
Lauderdale 5	89.5	4.6	5.9	Agree	7,467	Agree
Manatee 1	93.7	0.0	6.3	Agree	10,427	Agree
Manatee 2	75.2	20.5	4.3	Agree	10,384	Agree
Martin 1	91.5	0.0	8.5	Agree	10,130	Agree
Martin 2	92.1	0.0	7.9	Agree	10,086	Agree
Martin 3	94.6	1.4	4.0	Agree	6,885	Agree
Martin 4	92.0	4.0	4.0	Agree	6,844	Agree
Port Everglades 3	92.7	0.0	7.3	Agree	9,819	Agree
Port Everglades 4	89.7	3.8	6.5	Agree	9,859	Agree
Scherer 4	84.0	12.0	4.0	Agree	10,189	Agree
St Lucie 1	86.8	6.8	6.4	Agree	10,860	Agree
St Lucie 2	85.4	8.2	6.4	Agree	10,900	Agree
Turkey Point 3	75.8	17.8	6.4	Agree	11,140	Agree
Turkey Point 4	93.6	0.0	6.4	Agree	11,134	Agree
Gulf	EAF	POF	EUOF			
Crist 4	97.9	0.0	2.1	Agree	10,388	Agree
Crist 5	96.8	0.0	3.2	Agree	10,232	Agree
Crist 6	86.7	6.3	7.0	Agree	10,501	Agree
Crist 7	70.1	21.6	8.3	Agree	10,223	Agree
Smith 1	90.1	8.2	1.7	Agree	10,114	Agree
Smith 2	82.8	8.2	9.0	Agree	10,024	Agree
Daniel 1	69.6	24.9	5.5	Agree	9,994	Agree
Daniel 2	81.1	12.0	6.9	Agree	9,828	Agree

Attachment A

Page 4 of 4

GPIF TARGETS

January 2004 to December 2004

Utility/ Plant/Unit	EAF				Heat Rate	
	Company			Staff	Company	Staff
PEF	EAF	POF	EUOF			
Anclote 1	94.4	0.0	5.6	Agree	10,407	Agree
Anclote 2	91.1	3.8	5.0	Agree	10,174	Agree
Crystal River 1	81.1	11.5	7.4	Agree	9,731	Agree
Crystal River 2	81.3	0.0	18.7	Agree	9,685	Agree
Crystal River 3	97.1	0.0	2.9	Agree	10,310	Agree
Crystal River 4	85.2	9.6	5.2	Agree	9,322	Agree
Crystal River 5	93.4	0.0	6.6	Agree	9,389	Agree
Hines 1	88.3	9.6	2.2	Agree	7,530	Agree
Tiger Bay	88.0	7.7	4.4	Agree	7,964	Agree
TECO	EAF	POF	EUOF			
Big Bend 1	67.2	5.7	27.1	Agree	10,708	Agree
Big Bend 2	66.7	5.7	27.6	Agree	10,384	Agree
Big Bend 3	67.6	5.7	26.7	Agree	10,278	Agree
Big Bend 4	78.2	5.7	16.0	Agree	10,272	Agree
Polk 1	85.6	4.4	10.0	Agree	10,569	Agree