PROGRESS ENERGY FLORIDA

DOCKET NO. 030001-EI

Fuel and Capacity Cost Recovery
Final True-Up for the Period
January through December, 2002

DIRECT TESTIMONY OF
PAMELA R. MURPHY

Q. Please state your name and business address.

A. My name is Pamela R. Murphy. My business address is P. O. Box 1551, Raleigh, North Carolina 27602.

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

A. I am employed by Progress Energy Carolinas in the capacity of Director, Gas & Oil Trading.

Q. Have your duties and responsibilities remained the same since you last submitted testimony in this proceeding?

A. Yes, my responsibilities for the procurement and trading of natural gas and oil on behalf of Progress Energy Florida (Progress Energy or the Company) have remained the same.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present and address Progress Energy's Risk Management Plan for fuel procurement in 2004. In addition, I will address Staff's preliminary Issues 13F, regarding the Company's actions to mitigate price volatility through hedging programs, and 13G, regarding the Company's operation and maintenance expenses for its hedging programs.

Q. Has Progress Energy developed its Risk Management Plan for fuel procurement in 2004 in accordance with the Resolution of Issues proposed by Staff and approved by the Commission in Docket No. 011605-EI?

A. Yes. Progress Energy's Risk Management Plan was prepared in accordance with paragraph 2 of the Resolution of Issues and is attached to my prepared testimony as Exhibit No. ___ (PRM-1). Certain information in the exhibit has been redacted, consistent with the Company's request for confidential classification of this information.

Q. In what types of hedging activities does Progress Energy expect to engage during 2004?

A. Progress Energy has been conducting and will continue to conduct physical hedging while in the process of implementing Phase 1 and 2 of a new energy trading software system for both power and natural gas. Phase 2 of this new system will consist of the testing and implementation of specialized natural gas software (the Gas Management System) that will be used for physical and financial transactions, and is expected to be operational in mid-2004. Additionally, in August 2003, management approval was given to an expansion of the Company's hedging strategy under which its forecasted 2004 minimum monthly natural gas requirements will be hedged as a base level. The objective of this expanded hedging strategy is to provide greater fuel price stability to customers and thereby reduce the likelihood of future mid-course corrections, while attempting to capture savings if and when market opportunities present themselves. The newly approved strategy has already been implemented and, to date, Progress Energy has hedged a significant portion of its forecasted annual natural gas requirements for 2004.

Q. What are Progress Energy's plans for hedging residual oil in 2004?

A. Consistent with its hedging strategy for natural gas described above, Progress Energy is in the process of finalizing the adoption of a more active strategy for hedging residual (No. 6) oil. Under the revised strategy, the Company will physically hedge its forecasted 2004 minimum monthly No. 6 oil requirements as a base level, which represents nearly 70% of its forecasted annual requirements. This strategy has the same objective as the Company's natural gas hedging strategy described above.

Q. What is Progress Energy's time frame for hedging forward prices of natural gas and residual oil?

A. The Company's current hedging strategy extends for a two-year rolling period. For example, in the summer of 2003, Progress Energy will consider hedges forward through the summer of 2005 under a phased hedging approach.

Q. What is meant by the term "phased hedging approach"?

A. Progress Energy reviews its market view on forward pricing on a weekly basis. The Company's strategy is to enter into multiple transactions over time so that its hedging portfolio will be representative of the changing market dynamics, as opposed to hedging its requirements all at one time.

Q. Were Progress Energy's actions through July 2003 to mitigate fuel and purchased power price volatility through implementation of its non-speculative hedging programs prudent? (Staff Issue 13F)

A. Yes. For the seven-month period from January through July 2003, Progress Energy hedged approximately 29% of its natural gas purchases, which was the appropriate level for the period. Market conditions did not, in the Company's judgment, warrant hedging additional purchases, since natural gas prices during this period were already at high levels. This posed an unacceptable risk that additional hedges would have locked in above-market prices at the time delivery was to be taken.

Q. What were the results of Progress Energy's hedging activities during the January through July period?

A. The Company's hedging activities for the period produced customer savings of approximately $14 million. In addition, in May 2003, the Company renegotiated a long-term contract for residual (No. 6) oil that is expected to save its customers approximately $13.8 million through the end of 2007.

Q. Are Progress Energy's actual and projected operation and maintenance expenses for 2002 through 2004 for its non-speculative financial and/or physical hedging programs to mitigate fuel and purchased power price volatility reasonable for cost recovery purposes? (Staff Issue 13G)

A. Progress Energy will not incur any charges for the implementation of its new financial hedging program until Phase 2 of the program's software system becomes operational, which, as I described earlier, is expected to be mid-2004. At this time, the Company's allocated share of these charges has not been finalized. Therefore, the Company proposes to book the charges when they are incurred and address their reasonableness in subsequent true-up testimony.

Q. Does this conclude your testimony?

A. Yes, it does.

PROGRESS ENERGY FLORIDA

DOCKET NO. 030001-EI

Levelized Fuel and Capacity Cost Recovery Factors
January through December 2004

DIRECT TESTIMONY OF
JAVIER PORTUONDO

Q. Please state your name and business address.

A. My name is Javier Portuondo. 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 Progress Energy Service Company, LLC, in the capacity of Director, Regulatory Services - Florida.

Q. Have your duties and responsibilities remained the same since your testimony was last filed in this docket?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present for Commission approval the levelized fuel and capacity cost factors of Progress Energy Florida (Progress Energy or the Company) for the period of January through December 2004. In addition, I will address Staff preliminary Issue 13D regarding the Company's market price proxy for waterborne coal transportation, including a detailed discussion of the circumstances that led to the Commission's adoption of the market proxy mechanism. I will then address Staff Issues 13A, 13B and 13C regarding ongoing Commission practices for the treatment of certain costs related to Progress Fuels Corporation, Issue 13E regarding Progress Energy's purchase of synthetic coal in 2002, and a new matter of which Staff has recently advised the Company regarding the treatment of Progress Fuel's FOB Barge coal purchases in 2002. Finally, I will address an issue raised by the Company in an attempt to resolve any uncertainty that may exists regarding the appropriate baseline O&M expenses to be used in determining recoverable incremental costs in this proceeding.

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 F 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 the calculation of recoverable depreciation expense and return on capital associated with Progress Energy's new Hines Unit 2 in accordance with the rate case stipulation and settlement approved by the Commission in April 2002, and

Part F contains a graphic depiction of the Company's incremental cost evaluation process.

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 3.453 ¢/kWh (before metering voltage adjustments). The basic factor consists of a fuel cost for the projection period of 2.90246 ¢/kWh (adjusted for jurisdictional losses), a GPIF reward of 0.00714 ¢/kWh, and an estimated prior period true-up of 0.54052 ¢/kWh.

Utilizing this basic factor, Schedule E1-D shows the calculation and supporting data for the Company's final levelized fuel cost factors for service received at secondary, primary, and transmission metering voltage levels. To perform this calculation, effective jurisdictional sales at the secondary level are calculated by applying 1% and 2% metering reduction factors to primary and transmission sales, respectively (forecasted at meter level). This is consistent with the methodology used in the development of the capacity cost recovery factors. The final fuel cost factor for residential service is 3.458 ¢/kWh.

Schedule E1-E develops the Time Of Use (TOU) multipliers of 1.310 On-peak and 0.865 Off-peak. The multipliers are then applied to the levelized fuel cost factors for each metering voltage level, which results in the final TOU fuel factors for application to customer bills during the projection period.

Q. What is the change in the fuel factor for the projection period from the fuel factor currently in effect?

A. The projected average fuel factor for 2004 of 3.453 ¢/kWh is an increase of 0.717 ¢/kWh, or 26.2%, from the 2003 midcourse fuel factor of 2.736 ¢/kWh.

Q. Please explain the reasons for the increase.

A. The increase is primarily driven by the recovery of the projected 2003 true-up balance of $210.4 million. Also contributing to the higher fuel factor is an increase in the projected fuel cost of oil and natural gas, as well as a slight increase due to recovery of actual energy costs, since the regulatory asset associated with the 1997 buyout of the Tiger Bay purchase power agreements (PPAs) has been fully amortized. In 2004, Tiger Bay will be treated as a company owned generating facility rather than a contractual cogenerator. Partially offsetting this increase is a reduction in coal prices and higher nuclear generation due to no refueling outage scheduled for 2004.

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 combustion turbine units to burn natural gas instead of distillate oil ($124,000), the annual payment to the Department of Energy for the decommissioning and decontamination of their enrichment facilities ($1,743,831), and the recovery of the depreciation and return associated with Hines Unit 2 ($42,589,716). These fuel cost adjustments total $44,457,547.

Q. Is the cost of purchasing emission allowances still included in Schedule E1, line 4, "Adjustments to Fuel Cost"?

A. No. Beginning in 2004, the cost of emission allowances will be recovered through the Environmental Cost Recovery Clause (ECRC). Order No. PSC-95-0450-FOF-EI in Docket No. 950001-EI allowed emission allowances to be recovered through the Fuel and Purchased Power Cost Recovery Clause if a utility was not participating in an ECRC. Progress Energy began utilizing the ECRC on January 1, 2003 and received Commission approval to move emission allowances to that clause in 2004.

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

A. Line 6 includes energy costs for the purchase of 60 MWs from Tampa Electric Company and the purchase of 414 MWs under a Unit Power Sales (UPS) agreement with the Southern Company. The capacity payments associated with the UPS contract are based on the original contract of 400 MWs. The additional 14 MWs are the result of revised SERC ratings for the five units involved in the unit power purchase, providing a benefit to Progress Energy in the form of reduced costs per kW. Both of these contracts have been approved for cost recovery by the Commission. The capacity costs associated with these purchases are included in the capacity cost recovery factor.

Q. What is included in Schedule E1, line 8, "Energy Cost of Economy Purchases"?

A. Line 8 consists primarily of economy purchases from within or outside the state. Line 8 also includes energy costs for purchases from Seminole Electric Cooperative, Inc. (SECI) for load following, and off-peak hydroelectric purchases from the Southeast Electric Power Agency (SEPA). 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 clause. Such non-fuel charges, if any, are reported on line 10.

Q. How was the Gain on Other Power Sales, shown on Schedule E-1, Line 15a, developed?

A. Progress Energy estimates the total gain on non-separated sales during 2004 to be $4,584,880, which is below the three-year rolling average for such sales of $8,239,266 by $3,654,386. Based on the sharing mechanism approved by the Commission in Docket No. 991779-EI, the total gain will be distributed to customers.

Q. How was Progress Energy's three-year rolling average gain on economy sales determined?

A. The three-year rolling average of $8,239,266 is based on calendar years 2001 through 2003, and was calculated in accordance with Order No. PSC-00-1744-PAA-EI, issued September 26, 2000 in Docket 991779-EI.

Q. Why has the depreciation expense and return on capital associated with Hines Unit 2 been included in the Adjustments to Fuel Cost entry you described earlier?

A. The stipulation approved by the Commission in April 2002 for Progress Energy's base rate review proceeding (Docket No. 000824-EI) provides that the Company will be allowed the opportunity to recover the depreciation expenses and return on capital for its new Hines Unit 2 through the fuel clause beginning with the unit's commercial operation through the end of 2005, subject to the limitation that the costs of Hines Unit 2 recovered over this period may not exceed the cumulative fuel savings provided by the unit over the same period. Because Hines Unit 2 is scheduled to begin commercial operation in December 2003, these two cost components of the unit for 2004 have been included in the projection period for recovery in accordance with the stipulation. Part E of my exhibit shows the calculation of the depreciation expense and return on capital associated with Hines Unit 2.

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

A. Progress Energy has several wholesale contracts with Seminole, some of which represent Seminole's own firm resources, and others that provide for the sale of supplemental energy to supply the portion of their load in excess of Seminole's own resources, 1528 MW in 2004. The fuel costs charged to Seminole for 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. New contracts for fixed amounts of intermediate and peaking capacity began in January of 2000. While those sales are not necessarily priced at average cost, Progress Energy is crediting average fuel cost of the appropriate stratification (intermediate or peaking) in accordance with Order No. PSC-97-0262-FOF-EI. 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 system 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 system cost basis in this proceeding, while actually recovering the costs from these customers on a higher, stratified cost basis.

Line 17 also includes the fuel cost of sales made to the City of Tallahassee in accordance with Order No. PSC-99-1741-PAA-EI. The stratified sales shown on Schedule E6 include 100,140 MWh, of which 93% is priced at average nuclear fuel cost, the balance at an estimated incremental cost of $25 per MWh. Other transactions included on Line 17 are the 50 MW sale to Florida Power & Light and a 15 MW sale to the City of Homestead.

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 (Cycle 14) was developed from the unamortized investment cost of the fuel in the reactor. Cycle 14 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 14 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 cost of Cycle 14 is $.35 per million BTU.

Q. Please 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. The process begins with the fuel price forecast and the system sales forecast. These forecasts are input into the Company's production cost model, PROSYM, along with purchased power information, generating unit operating characteristics, maintenance schedules, and other pertinent data. PROSYM then computes system fuel consumption, replacement fuel costs, and energy purchases and 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 Financial Planning & Regulatory Services Department using the most recent data available. The forecast used for this projection period was prepared in June 2003.

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. Yes. 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 Regulated Commercial Operations Department based on forecast assumptions for residual (#6) oil, distillate (#2) 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.

CAPACITY COST RECOVERY

Q. How was the Capacity Cost Recovery factor developed?

A. The calculation of the capacity cost recovery (CCR) factor 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 is calculated using separation factors from

the Company's most recent Jurisdictional Separation Study available at the time this filing was prepared.

Sheet 2: Estimated/Actual True-Up. This schedule presents the actual ending true-up balance as of July, 2003 and re-forecasts the over/(under) recovery balances for the next five months to obtain an ending balance for the current period. This estimated/actual balance of $3,309,148 is then carried forward to Sheet 1, to be refunded during the January through December, 2004 period.

Sheet 3: Development of Jurisdictional Loss Multipliers. 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 2003 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 CCR factor 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 CCR factor for primary and transmission rate classes reflects the application of metering reduction factors of 1% and 2% from the secondary CCR factor.

Q. Please explain the decrease in the CCR factor for the projection period compared to the CCR factor currently in effect.

A. The projected average retail CCR factor of 0.77482 ¢/kWh is 13.6% lower than the 2003 mid-course factor of 0.89702 ¢/kWh. The decrease is primarily due to the elimination of the capacity payments associated with the buyout of the Tiger Bay PPAs, since the regulatory asset has been fully amortized. Partially offsetting this decrease is the annual contractual escalation in capacity payments.

Q. Has Progress Energy included incremental security charges in the 2004 projected capacity amount?

A. Yes. The Company has included $4,644,108 related to incremental security charges for 2004.

Q. What additional internal and/or external security initiatives have taken place or are anticipated to take place that will impact Progress Energy's request for recovery through the Capacity Cost Recovery Clause in 2004?

A. On April 29, 2003, the U.S. Nuclear Regulatory Commission (NRC) issued three orders intended to strengthen protection requirements for nuclear reactors (Design Basis Threat or DBT), limit working hours for security personnel, and improve training for guards. Licensees must submit revised DBT plans to the Commission for review and approval by April 29, 2004 and implement by October 29, 2004. Progress Energy is currently assessing this risk. The Company is also assessing the impact of limiting guard working hours and enhancing training. Licensees must start implementation immediately and must complete by October 29, 2004. The estimated cost of these NRC requirements is included in the total recoverable amount above. The NRC has also increased its annual license fee partly to cover the costs of making plants safe from terror attacks.

In addition to the NRC orders, the Coast Guard, Department of Homeland Security (DHS) issued on July 1, 2003 a series of interim rules to promulgate maritime security requirements mandated by the Maritime Transportation Security Act of 2002. The six interim rules consist of: Implementation of National Maritime Security Initiatives, Area Maritime Security, Vessel Security, Facility Security, Outer Continental Shelf Facility Security, and Automatic Identification System. The final rule is expected to be issued before November 25, 2003. The rule is expected to impact the following sites: Bartow Plant, Anclote Plant, Crystal River Complex, Higgins Plant, and Bayboro Station. These sites are expected to require such things as additional security officers, additional gates, and closed circuit television (CCTV) systems. The timing of this rule's issuance has not allowed Progress Energy enough time to thoroughly quantify the financial impact of its implementation. Therefore we have not included an estimate of the implementation cost but rather will include the actual cost incurred as part of the Company's Actual True-up filing. The costs will be accounted for in accordance with Order PSC-02-1761-FOF-EI, which states on page 10 that:

> "(B)ecause of the extraordinary nature of the costs in question and the unique circumstances under which they arose, we find that these costs do not clearly fall within the classification of 'items which traditionally and historically would be recovered through base rates'."

. . . Because these costs are extraordinary, these costs shall be treated as current year expenses. Further, we require that these expenses be separately accounted to enhance our staff's ability to audit them."

WATERBORNE COAL TRANSPORTATION

Q. Before addressing Staff Issue 13D regarding Progress Energy's market price proxy, please describe the background of waterborne coal transportation to the Company's Crystal River plant site and its regulation by the Commission?

A. The origin of the current arrangement for waterborne transportation of coal to the Crystal River plant site took place in 1976. At that time the Company, then Florida Power Corporation (FPC), had two units at the Crystal River site that had been previously converted from coal to oil and were then in the process of being converted back to coal. These units, Crystal River 1 and 2, had a combined capacity of approximately 750 MW and would require about 2 million tons of coal annually. At the same time, FPC was in the design and pre-construction stages of two new coal-fired units, Crystal River 4 and 5, with a combined capacity of approximately 1,450 MW and annual coal requirements of nearly 4 million tons per year.

Faced with the need to arrange for the procurement and delivery of up to 6 million tons of coal a year starting almost from scratch, the Company elected a strategy aimed at securing a greater degree of control over the costs and reliability of its long-term coal supply and transportation needs than it could obtain as simply a purchaser of these services subject to the vagaries of an uncertain market. Under this strategy, the Company would acquire business expertise and ownership leverage through capital investment in partnerships with organizations experienced in the various segments of the coal supply and transportation business, particularly those segments lacking a competitive market. However, it would have been problematic for FPC to engage in such a business venture itself due to serious legal and tax impediments associated with multi-state operations and asset ownership and other key aspects of the strategy's business plan.

As a result, Electric Fuels Corporation (EFC), the predecessor of Progress Fuels Corporation (PFC), was formed in March 1976 as a wholly-owned subsidiary of FPC to carry out this long-term strategy for supplying the coal requirements of the Crystal River plant site.

Q. How did EFC implement this strategy with respect to waterborne coal transportation?

A. The most critical implementation issues were the absence of competitive markets in two key segments of the waterborne transportation route; (1) the storage and transloading of coal from river barges to Gulf barges at the mouth of the Mississippi River, and (2) the trans-Gulf transportation of coal to the Crystal River plant site. Neither segment had facilities with sufficient capacity to handle the approximately 2 million tons of waterborne coal annually that EFC needed to deliver to the Crystal River site (the requirements of the site remaining after maximum rail deliveries). This meant that a long-term commitment would have to be made for the construction of additional facilities to increase tonnage capacity in both segments. EFC chose to make that commitment through an ownership interest in the facilities, rather than entering into long-term contracts with third-party owners of the new facilities.

With respect to the river-to-Gulf transloading segment, EFC acquired a one-third ownership interest with two other experienced partners in International Marine Terminals (IMT), which began the construction of a new transloading and storage terminal on the Mississippi River approximately 60 miles south of New Orleans. In a similar vein, EFC acquired a 65% ownership interest in a partnership with Dixie Carriers, an experienced operator of ocean-going carrier vessels, for the transportation of coal to the Crystal River plant site. Since no carrier vessels capable of navigating the site's shallow, narrow channel were available, specially designed ocean-going tug-barge units had to be constructed by the partnership, Dixie Fuels Limited (DFL).

In addition to its investment in these two major undertakings, EFC also acquired ownership interests in several smaller upriver terminals, where coal delivered from the mines is loaded onto river barges. Due to the limited availability of upriver terminal capacity, these investments allowed EFC to obtain priority at existing terminals and to develop additional capacity by constructing new terminals. Since sufficient capacity existed at the time in the upriver mine-to-river (or "short-haul") transportation segment and the river barge transportation segment, EFC contracted with third-party suppliers of those services.

Q. What was the regulatory response of the Commission to the coal procurement and transportation responsibilities the Company placed with EFC?

A. As I indicated earlier, but for the legal and tax consequences it faced in 1976 (and still faces), the Company could have implemented its coal procurement and transportation strategy itself, through an internal operating division or department. Functionally, however, EFC served in much the same capacity and was indirectly regulated by the Commission in a similar manner. I use the term "indirectly regulated" because even though the Commission had no regulatory authority over EFC itself, the Commission had more than ample authority over the coal procurement and transportation costs the Company was allowed to recover through its fuel clause. And since FPC chose to pursue its strategy through an affiliate solely for business considerations, it supported the Commission's treatment of EFC in a utility-like manner.

Under this regulatory treatment, FPC was allowed to recover EFC's prudently incurred costs to procure and deliver coal to the Company, including a utility rate of return on its capital investment IMT and DFL. In return, any profits EFC earned from these investments would be returned to the Company and credited to the cost of coal charged to its customers. For example, because of its ownership interest in DFL, EFC receives 65% of DFL's profits. However, under the Commission's regulatory treatment, EFC would also earn a rate of return on its capital investment in DFL. Therefore, EFC would credit its DFL profits dollar-for-dollar against the cost of coal charged to the Company and, ultimately, its customers.

Q. How did this regulatory treatment of EFC work over time?

A. Initially, quite well. By 1986, however, several concerns about the continued use of this regulatory treatment, then referred to as "cost-plus" pricing, led the Commission to initiate an investigation into the matter (Docket No. 860001-EI-G). The investigation continued for nearly three years and included several hearings covering various aspects of EFC's operation. The following quotation from the Commission's final order concluding the investigation, although somewhat lengthy, best summarizes its findings and policy determinations, and also sets the stage for the currently pending issue regarding PFC's waterborne transportation market proxy mechanism:

> "[W]e believe and find that a change from cost-plus pricing is warranted. While we believe that the current system has been generally successful in allowing only reasonable and prudent cost to be passed through the utilities' fuel adjustment clauses, we believe that it has been administratively costly, caused unnecessary regulatory tension, and left the lingering suspicion that it has resulted in higher costs to the utility's customers. Implicit in cost-plus pricing is the requirement that one is capable of conducting a cost-of-service analysis of a business to determine that its expenses are both necessary and reasonable. This is a methodology that is demanded for monopoly utility services, and which usually proves to be complex, expensive and time consuming. It is a methodology which requires a high degree of familiarity with the capital requirements and expenses necessitated by the operation of the business being reviewed. Cost-

of-service analysis of affiliated operations places additional demands upon the regulatory agency in terms of time, expense and acquiring additional expertise. All come at some additional cost that must eventually be borne by the ratepayer, either in his role as customer or as a taxpayer. Furthermore, there seems to be no end to the types of affiliate business that we are expected to become sufficiently familiar with so that we might judge that reasonableness of their cost on a cost-of-services basis.

"Considering the many advantages offered by a market pricing system, we, as a policy matter, shall require its adoption for all affiliate fuel transactions for which a comparable market price may be found or constructed.

"In concluding, we note the following: (1) from the record in this case, we are convinced that market prices can be established for the affiliate coal; (2) market prices for the transportation-related services should be established if possible, but if not, methodologies for reasonably allocating the cost should be suggested; [and] (3) cost-of-service methodologies should be avoided, if possible; ... ." (Order No. 20604, issued January 13, 1989 in Docket No. 860001-EI-G.)

Q. With respect to the Commission's finding that "market prices for the transportation-related services should be established if possible," was a market price for EFC's waterborne transportation service eventually established pursuant to this finding?

A. In a strict sense, no. Unlike the situation with coal purchased by EFC from an affiliated supplier for which a market pricing mechanism was approved, the Commission recognized that comparable prices could not be found for some of the waterborne transportation services purchased by EFC from affiliates. In fact, this is the very reason EFC purchased these services from affiliates. As I described earlier, a market for river-to-Gulf transloading services and trans-Gulf transportation services to the Crystal River plant site did not exist at the time EFC was formed. That remained the situation when Order No. 20604 was issued, as it does today. This is particularly problematic with respect to the trans-Gulf transportation services provided by DFL's tug-barge units, which had to be custom made because of the unique and hazardous channel to the Crystal River plant site. There simply are no other vessels with the capacity to meet the waterborne coal requirements of the site that are capable of safely traversing the site's shallow, narrow channel.

Nonetheless, it was clear to the Company that the Commission expected an alternative to cost-plus pricing for EFC's waterborne transportation, even if a true market pricing mechanism could not be established. To this end, the Company began a series of negotiations with Staff, Public Counsel and FIPUG which ultimately led to the development of a pricing mechanism that the parties considered to be a reasonable alternative, or proxy, for a true market pricing mechanism. This alternative, referred to as a "market price proxy", was presented to the Commission at the August 1993 fuel adjustment hearing as a stipulated issue and was approved by Order No. PSC-93-1331-FOF-EI, issued September 13, 1993 in Docket No. 930001-EI.

Q. Please describe the market price proxy approved by the Commission?

The market price proxy became effective as of January 1993, and consists of a base price and a composite index used to escalate or de-escalate the base price annually. The base price of $23.00 per ton was derived from EFC's actual 1992 costs incurred for waterborne transportation services in delivering coal to the Crystal River plant site. The base price would then be adjusted as of January 1st each subsequent year using a composite index that consists of five individually weighted indices commonly used to adjust contract prices in the transportation services business. The total weighting of these indices is set at 90%, with 10% of the base price remaining fixed. In addition, the market proxy price may be adjusted for increases or decreases in EFC's waterborne transportation costs which result from governmental impositions on its transportation suppliers not in effect as of December 31, 1992.

Established and adjusted in this manner, the market proxy price is then paid to EFC in lieu of any payment for the costs it incurs to obtain waterborne transportation services in any of the five waterborne transportation segments; *i.e.*, short haul transportation to the upriver terminal, upriver storage and loading onto river barges, river barge transportation, storage and transloading from river barges to Gulf barges, and trans-Gulf transportation to the Crystal River plant site. In addition, EFC will no longer receive a return on its investment in IMT or DFL. In other words, compared to the price it will be paid under the market proxy mechanism, EFC will receive the benefit of any cost reductions it can achieve in providing waterborne transportation services to the Company, and it will incur the risk of any cost increases beyond its control, including the risk of catastrophic loss such as the loss of a DFL vessel at sea.

Q. With that background, please address Staff Issue 13D: Should the Commission modify or eliminate the method for calculating Progress Energy Florida's market price proxy for waterborne coal transportation that was established in Order No. PSC-93-1331-FOF-EI, issued September 13, 1993, in Docket No. 930001-EI?

A. I am not aware of any reason put forward by Staff or a party regarding a flaw or deficiency in the market proxy mechanism or a change of circumstances since the mechanism was approved by the Commission that would suggest it should be modified or eliminated. Nor am I aware of any reason to believe the mechanism has not performed reasonably in approximating the market price of waterborne coal transportation to the Crystal River plant site. To the contrary, when the market price proxy is measured against the benefits and objectives of market pricing articulated by the Commission in Order No. 20604 and quoted earlier in my testimony, I believe this consensus proposal developed jointly by the Company, Staff and other parties has served its intended purpose well. Moreover, the basis for the market price proxy remains conceptually sound. According to the Bureau of Labor Statistics (BLS), indices of the kind used in the market proxy mechanism are typically the basis for contract escalation. The indices used to escalate the market proxy base price are focused on the economic conditions that would reasonably and logically result in increases to the base price over time; and therefore result in an escalated price that fairly tracks these economic conditions, which the BLS quantified in the development of these indices.

In short, absent compelling reasons for change that have not yet been provided, the market price proxy developed to comply with the policy requirements of Order No. 20604, and which met the satisfaction of the Commission, Staff, the parties, and the Company, should remain in effect.

OTHER ISSUES

Q. Has Progress Energy confirmed the validity of the methodology used to determine the equity component of Progress Fuels Corporation's capital structure for calendar year 2002? (Staff Issue 13A)

A. Yes. Progress Energy's Audit Services department has reviewed the analysis performed by PFC. The revenue requirements under a full utility-type regulatory treatment methodology using the actual average cost of debt and equity required to support the Company's regulated business was compared to revenues billed using an equity component based on 55% of net long-term assets (the "short cut method"). The analysis showed that for 2002, the short cut method resulted in revenue requirements which were $47,749, or 0.01%, higher than revenue requirements under the full utility-type regulatory treatment methodology. Progress Energy submits that this analysis confirms again the appropriateness and continued validity of the short cut method.

Q. Has Progress Energy properly calculated the market price true-up for coal purchases from Powell Mountain? (Staff Issue 13B)

A. Yes. The calculation has been made in accordance with the market pricing methodology approved by the Commission in Docket No. 860001-EI-G.

Q. Has Progress Energy properly calculated the 2002 price for waterborne transportation services provided by Progress Fuels Corporation? (Staff Issue 13C)

A. Yes. Progress Energy has performed its calculation of the 2002 waterborne transportation price under the same methodology as the previous calculations that have been approved by the Commission.

Q. Were Progress Energy Florida's purchases of synthetic coal during 2002 cost effective? (Staff Issue 13E)

A. Yes. Progress Energy's purchases of synthetic coal (synfuel) in 2002 were made under an arrangement that allowed these purchases to substitute for purchases that would have been required under a contract for regular compliance coal at a price $2.00 per ton higher than was paid for the synfuel purchases. This resulted in fuel savings of over $1.3 million.

Q. In consideration of Order No. PSC-93-1331-FOF-EI, in Docket No. 930001-EI, issued September 13, 1993, should the Commission make an adjustment to Progress Energy Florida's 2002 waterborne coal transportation costs to account for upriver costs from mine to barge

for coal commodity contracts which are quoted FOB Barge? (New Staff Issue)

A. No adjustment is needed, since the Company and PFC have scrupulously followed the letter and spirit of the waterborne market proxy with respect to FOB Barge coal purchases. The market proxy's base price was determined from the waterborne transportation costs of PFC (then Electric Fuels Corporation, or EFC) in 1992. In that year, 27.8% of EFC's upriver waterborne coal was purchased at an FOB Barge price. This means that for these purchases the upriver "short-haul" transportation costs were included in the commodity purchase price, and were not included in the market proxy's waterborne transportations costs.

To avoid any significant over or under-recovery of these short-haul costs under the market proxy, PFC has attempted to maintain approximately the same ratio of purchases at an FOB Barge price since the inception of the market proxy in 1993. Over the ten-year period through 2002, PFC's purchases at the FOB Barge price have averaged 24.5%, meaning PFC has under-recovered the short-haul costs reflected in the market proxy through 2002. In 2002 itself, PFC's upriver waterborne coal purchases were 1,774,617 tons, of which 504,288 tons were purchased at an FOB Barge price, or 28.4% of its total upriver purchases. This slight imprecision in the 2002 ratio compared to the 27.8% base year guideline is not only small compared to the 24.5% 10-year average or the 2001 ratio of 19.0%, but is particularly small considering the complexities of optimizing individual purchase quantities, scheduling constraints, and periodic adjustments to the Company's coal requirements that PFC must take into account throughout the course of any given year.

Q. At the outset of your testimony you indicated a desire on Progress Energy's part to resolve any uncertainty that currently exists regarding the appropriate baseline expenses to be used in determining recoverable incremental costs. Please explain what you mean by the term "baseline expenses" as it is used in the determination of incremental costs.

A. The need to determine incremental costs in this proceeding arises because from time to time the Commission, under long-established policy, authorizes the recovery of certain O&M expenses through the fuel adjustment clause rather than base rates. Typically, this occurs when O&M expenses for an activity related to the adjustment clause are in excess of those that existed when the utility's base rates were last set. A recent example of this is the Commission's decision to authorize recovery of post-9/11 power plant security costs. Before actual recovery can begin, however, the Commission must assure itself that any portion of these expenses which may be included in base rates is not recovered twice – once through base rates and again through the clause. Therefore, to determine the level of incremental O&M expenses recoverable through the clause, the necessary first step is to establish the amount, if any, of these expenses included in the utility's base rates. This amount is sometimes referred to as the utility's "baseline expenses."

Q. Why has Progress Energy raised an issue regarding the appropriate baseline expenses to be used in determining recoverable incremental costs?

A. In each instance where the recovery of incremental costs has been requested by the Company and approved by the Commission since the 2002 rate case settlement went into effect, the baseline O&M expenses used to determine the recoverable amount of the incremental costs have been derived from the MFRs in that proceeding. Progress Energy believes that using the 2002 MFRs for that purpose is entirely appropriate. However, the continued use of these MFRs to establish the Company's baseline expenses has surfaced as a potential issue in pending matters.

To the extent any uncertainty exists as to the appropriateness of using the 2002 MFRs as source of baseline expenses, Progress Energy desires to have it resolved, since the need to establish baseline expenses is an ongoing one. Dealing with this issue on a case-by-case basis each time the recovery of incremental costs is sought appears unwise and inefficient. This is particularly so when the underlying question is the same in each instance: What baseline expenses best reflect the level of O&M expenses included in base rates? If the Company's base rates are unchanged, the answer to this question should be the same each time it arises.

For this reason, I believe that all concerned would benefit from the establishment of a uniform approach for setting the baseline level of O&M expenses when determining recoverable incremental costs. Doing so will allow everyone to know in advance how incremental costs are to be treated, and thus avoid the need to continually deal with this question on a case-by-case basis.

Q. Does Progress Energy seek to recover any incremental costs in this proceeding today that have been calculated using baseline O&M expenses from the Company's 2002 MFRs?

A. Yes. Based on the Commissions decision authorizing recovery of post-9/11 power plant security costs, these costs have been included in Progress Energy's true-up balance and in its projections for 2004 submitted for Commission approval in this proceeding. The Company has calculated the amount of its recoverable incremental power plant security costs using baseline expenses derived from the 2002 MFRs, as I will explain in greater detail latter in my testimony.

Q. Why is the use of baseline expenses derived from the Company's 2002 rate case MFRs the appropriate way to determine recoverable incremental costs?

A. The 2002 MFRs have been and should continue to be used by Progress Energy to establish baseline O&M expenses when determining recoverable incremental costs because they most accurately reflect the level of expenses included in the Company's current base rates. Based on long standing practice, I think it is clear that the MFRs would have been used for this purposes had the 2002 rate case been resolved in the traditional manner, *i.e.*, by a Commission decision based on the evidentiary record from a lengthy adversarial hearing. However, the fact that the 2002 rate case was resolved through settlement – a resolution that all agree is far superior to contentious, inefficient and costly litigation – provides no basis for a different conclusion about the appropriateness of using fully developed, rate case quality expense data in subsequent incremental cost determinations.

The 2002 MFRs were extensively reviewed and evaluated through discovery and testimony by Staff and the parties to the settlement negotiations. As has been previously noted, the Commission conducted a full rate case in every sense, except for the final hearing that was superceded by a negotiated settlement. The MFRs were a product of that fully developed rate case process and, as such, they and the related discovery and testimony served as a foundation for negotiations that led to the settlement and for Staff and Commission review and approval of the settlement. The use of the MFRs for incremental cost purpose is not only appropriate for this reason, but also because there simply is no other credible alternative for establishing baseline O&M expenses that reflects the level of expenses in current rates.

To summarize, by establishing a uniform treatment for the way in which baseline O&M expenses are determined, the Commission will resolve any uncertainty that now exist, avoid the need to address the issue on an inefficient and potentially inconsistent case-by-case basis, and allow all concerned to know the rules of the game in advance. By establishing the use of the Company's 2002 MFRs as that uniform treatment, the Commission will have selected the best, if not only, source of baseline O&M expenses that reflects the level included in the Company's currently approved base rates, as it must to ensure against double recovery of these expenses.

Q. Please describe the evaluation process used by Progress Energy to determine the incremental costs it submits for recovery through the adjustment clauses.

A. The evaluation process used by Progress Energy incorporates the Commission's long standing practice for determining recoverable incremental costs by removing any O&M expenses associated with the project that were included in the MFRs from the rate proceeding that established the Company's current base rates. Therefore, from the time Progress Energy's current rates were approved at the conclusion of its 2002 rate proceeding, the Company has evaluated the incremental costs associated with all projects submitted for adjustment clause recovery, including the incremental costs currently before the Commission, by first examining the 2002 rate case MFRs to determine whether any of the project's costs have been included. 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.

After this initial review, the second step is to 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. The following list provides an example of how several project cost component are broken down for analysis in this step.

- Labor from positions that were part of the last set of MFRs:
  - Regular labor is not considered incremental since is would be incurred regardless of the new project or task.
  - Overtime labor is considered incremental as it results only from the need to complete this new project or task.
  - Regular and Overtime labor for net new positions are considered incremental if it results only from the need to complete this new project or task.
- Outside Contract Labor is considered incremental since the expenditure would not have been incurred were it not for the new project or task.
- Outside Professional Services are considered incremental since the expenditure would not have been incurred were it not for the new project or task.
- Materials and Supplies are considered incremental since the expenditure would not have been incurred were it not for the new project or task.
- Travel is considered incremental since the expenditure would not have been incurred were it not for the new project or task.

The third step is to 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. Part F of my exhibit is a decision tree that graphically depicts the Company's incremental cost evaluation process using its post-9/11 power plant security project as an example.

Q. Does this conclude your testimony?

A. Yes, it does.

Exhibit No. ____ (PRM-1)

Confidential Document (confidential information redacted)

Progress Energy Florida, Inc.
Risk Management Plan
Fuel Procurement and Wholesale Power Purchases

I. Objective

The objective of Progress Energy Florida, Inc.'s, (PEF) Risk Management plan is to provide the mechanisms to manage PEF's overall fuel costs and wholesale power purchases to provide reliable service to PEF's customers. As a result, this should ultimately reduce the number of mid-course corrections to the fuel factor portion of the customer's bill. The risk management plan allows for the use of various tools to reduce price volatility of natural gas and oil using approved products to hedge either financially and/or physically.

Progress Energy Carolinas, Inc., acts as agent for PEF. PEF has adopted Progress Ventures' risk management policies and practices.

II. Fossil Fuel and Purchased Power Future Needs

A. Fossil Fuel

1. Coal
    - PEF plans to burn approximately 6 million tons of coal per year in 2004 and in 2005

2. Residual Oil
    - PEF plans to burn approximately 9.5 million bbls. of #6 fuel oil per year in 2004 and 9.8 million bbls. in 2005

3. Distillate Oil
    - PEF plans to burn approximately 600,000 bbls. of #2 fuel oil per year in 2004 and 700,000 bbls. In 2005

4. Natural Gas
    - PEF plans to burn approximately 55,000,000 MMBtu in 2004 and approximately 58,500,000 MMBtu in 2005

B. Purchased Power - PEF plans to purchase approximately 0.6 million MWH/year and sell approximately 1.1 million MWH/year on the wholesale market in 2004 and 2005.

III. Risk Management Profile

A. Risk Identification * The primary risks PEF has identified with procurement of fossil fuels and purchased power are:

1. Coal

- Plant availability due to unscheduled outages
- Supply or transport problems due to labor disputes, weather, or other unforeseen delays
- Coal quality errors
- Financial strength of suppliers
- Changes in laws regulating mining, transportation or burning of coal
- Price volatility

2. Oil (Residual and Distillate)

- Differences between forecasted/scheduled requirements and actual requirements due to economic changes, overall power demand, weather changes, change in price relationships between competing fuels, plant availability (maintenance/unexpected shutdowns or startups), out-of-economic plant dispatch (e.g., due to transmission system constraints), power market changes, etc.
- Differences between forecasted/scheduled deliveries and actual deliveries due to supply or transport problems, loading and unloading delays, etc.
- Fuel quality problems such as blending errors, off-spec deliveries, changes in SO2 values, changes in plant fuel handling capability, etc.
- Changes in laws, regulations, plant permits, etc. that affect the amount, cost, testing requirements or quality of oil required
- Impact of regulatory, management, internal and external audit reviews
- General industry changes that impact overall availability/cost/quality of fuel oil
- Price volatility and fuel oil market related factors

3. Natural Gas

- Imbalance penalties with interstate pipelines as a result of over/under burns based on differences between forecasted /scheduled gas and actual requirements due to, but not limited to, changes in weather, plant availability, and alert day tolerances
- Deliveries by interstate pipelines and suppliers impacted by force majeure events, such as pipeline disruptions, production outages, hurricanes, etc.

- Natural gas storage level deviation from expected norms
- Crude oil prices
- Degree day deviations from expected monthly norms
- Defaults by suppliers (for example, bankruptcy)
- Price risk based on volatility in the natural gas industry caused by commodity funds (technical trading)
- Contractual disputes regarding payment and deliveries

4. Purchased Power

- Default risk – inability of the supplier to obtain adequate resources to deliver the power per contract or agreement
- Directional price risk – e.g., purchased power contracts in which the price of the purchased power is tied to an index
- Physical risk – inability of electrical grid to reliably support power transfer
- Credit risk – inability of contract counterparty to deliver per contract resulting in purchase of higher cost purchased power
- Basis risk – e.g., supplier(s) can experience adverse weather as compared with PEF's service territory

*Acts of terrorism are considered beyond PEF's control

B. Risk Quantification

- Quantification of various risks, including stop-loss limits and Value-at-Risk (VaR) calculations, are included in Progress Ventures Risk Management Guidelines Appendix 13.

C. Risk Management (Daily Management Activities)

1. Coal

- Review actual conditions and adjust delivery schedules as needed
- Maintain contacts with plants and suppliers
- Monitor market prices and spot market options
- Monitor suppliers financial strength
- Build flexibility on volume terms etc., into agreements
- Develop alternative supply sources whenever possible

2. Oil

- Monitor actual conditions and consumption levels vs. forecasted levels and update forecasts frequently as conditions change. Adjust delivery schedules as needed
- Monitor actual delivery status and maintain frequent contact with suppliers and receiving plants to anticipate problems and take corrective action
- Keep current on market prices and activity. Utilize contract price options, inventory, and spot market options as appropriate. PEF has used, and continues to use, negotiated fixed prices as a method of stabilizing prices. This is usually accomplished by fixing prices on all or part of individual ships or a series of shipments to be delivered over a period of time of one to three months.
- Continue to scrutinize a supplier's financial strength in order to assess ongoing creditworthiness.

3. Natural Gas

- Monitor plant gas burns vs. forecasted gas burns. If gas burn is projected to be out of tolerance on the pipeline, reschedule gas and re-allocate gas to different plants, or switching to alternative fuels, like oil
- Use fuel oil, where applicable, to maintain load
- Build additional optionality into seasonal/term contracts by specifying the use of a daily or a monthly market index (with the right to select either one), include take or release triggers on volumes to allow added flexibility, as well as the right to mutually agree to a fixed price
- Implement term contracts that allow swing volumes
- Evaluate fixing a percentage of the monthly natural gas requirements, in order to offset volatility for the ratepayers
- Evaluate zero cost collars for physical natural gas requirements in lieu of, or in conjunction with, fixed-price natural gas
- Evaluate the premium cost of purchasing a call option for a percentage of the utility's monthly natural gas requirements
- Use physical fuel oil inventory, where applicable, to dispatch at lowest fuel price. Logistics of physical fuel oil inventory levels must also be managed with this alternative
- Monitor natural gas trends to determine the direction of long-term market swings
- Re-market any excess gas supplies/capacity, separately or bundled, on a daily basis
- Continue to scrutinize a supplier's financial strength in order to assess ongoing creditworthiness

4. Purchased Power

   - PEF assesses each supplier's ability to deliver power based on historical reliability as a supplier (default risk) and credit ratings
   - PEF utilizes both fixed price contracts (next day purchases) and variable price contracts tied to a specific counterparty's incremental cost
   - PEF utilizes firm transmission paths where available for reliable purchased power

5. Portfolio Management

   - PEF will manage its risks associated with meeting its forecasted load requirements by maintaining a generation fleet with the capability of fuel switching, contracting for a diverse fuel supply and transportation portfolio, and the use of sales and purchases of energy to and from outside sources.

D. Acceptable Level of Risk

1. Oil and Coal - The amount of risk considered acceptable is based on past experiences with what has been successful and evaluating the risk profile of any problems or opportunities based on this experience.

2. Natural Gas - Decisions regarding acceptable risk are based on the circumstances at the time natural gas is purchased. The circumstances at the time may include scenarios involving all or a part of the following: force majeure events, fuel oil inventories, competitive fuel pricing, supply constraints, forward pricing trends etc. For example, if the utility views a strong directional market trend for natural gas based on industry reports, events in the marketplace, demand, national storage levels, etc., the utility would consider implementing the risk management tools identified for managing natural gas risk.

3. Purchased Power- Considerations for purchasing power on a long term and mid-term basis include, but are not limited to the following:
   - Price curves – directional price risk associated with fuel and power
   - Generator outages
   - Load forecast
   - Physical risk associated with transfer capability of transmission system
   - Credit worthiness of potential supplier(s)
   - Default risk of potential supplier(s)
   - Basis risk – e.g., supplier(s) can experience adverse weather as compared with PEF's service territory

E. Constraints to Implementing Financial Hedging Tools

1. Energy Trading and Risk Management Software System
   - Progress Ventures (Ventures) is in Phase 1 timeline of transitioning to the Zainet electronic software system. Anticipated completion of Phase 1 should occur by October 1st for PEF. Phase 2 of the software system will begin after the completion of Phase 1. Phase 2 contains the natural gas software system (Gas Management System) that will be used for financial and physical transactions to capture and report risk. Anticipated completion of Phase 2 is June 1, 2004.

2. Financial Trading Expertise
   - This process has been delayed until PEF is closer to implementing Phase 2 of the Zainet system. At that time, PEF will evaluate the skill set and staffing requirements in the front, middle, and back office to, (i) transact in the financial markets, and (ii) to monitor, control, bill and report financial transactions.

IV. Fuel Procurement and Wholesale Purchased Power Plans for 2004

1. Coal
   [redacted]

2. Oil
   - [redacted]

3. Natural Gas
   - [redacted]

4. Purchased Power
   - [redacted]
   - [redacted]

V. Guidelines

1. The Board of Directors has established a Risk Management Policy which directs the Risk Management Committee (RMC) to oversee Progress Energy's management of financial risks. The Risk Management Policy states the RMC shall regularly report on activities related to and carried out under the Policy to the Chief Executive Officer (CEO), the Board of Directors and the Finance Committee. The CEO is ultimately responsible for the company's management of risk.

2. The Risk Management Committee Guidelines identify the roles, responsibilities and decision making process of the RMC and its agents.

3. Progress Ventures Risk Management Guidelines provide a methodology to assess, report, and mitigate risk associated with trading and marketing activities and procurement. In addition, there is a product approval process to provide a structure to validate that all significant product risks have been identified and integrated into the risk control structure.

4. Progress Ventures Credit Risk Management Guidelines provide a methodology to evaluate, measure, mitigate, and report credit risk associated with Ventures trading, marketing, and procurement activities.

VI. Processes (Front Office)

PEF's Oil Process Analysis, PEF's Natural Gas Process Analysis, and Progress Fuels' Coal Purchasing Procedures provide the procedures utilized to implement PEF's risk management plan. To date, "Nucleus" is PEF's natural gas transaction software system utilized to track and verify natural gas transactions. Zainet (Phase 1) will become the system of record (anticipated to be October 1, 2003) to track and verify natural gas transactions. "FMS" (Fuel Management System) is the system used to track and verify coal and oil transactions.

VII. Risk Reporting (Middle Office)

Risk control generates reports and distributes to both trading and senior management on a daily basis. This is the primary mechanism to communicate group performance to management, the RMC, and the Board of Directors. The reports include all current positions and updates according to the markets. Market changes include pricing, correlation, volatility, et cetera. In addition, as conditions differ from day-to-day, gas scheduling updates deals with best-available information to correctly reflect how much gas is received and delivered at their respective delivery and receipt points.

A. Risk control manages all of the following activities:

1. Forward Curves - Forward curves provide prices for delivery of products at future dates. Forward curves provide the critical data necessary to calculate mark-to-market, value-at-risk, and stress testing. These curves are generated daily.

2. Market Pricing – Daily prices received from index providers are updated on a daily basis to settle or to mark all positions to the correct market price as of close of business.

3. Mark-to-Market (MTM) - MTM is a methodology utilized to value all physical and financial instruments, including those associated with assets. MTM measures unrealized gains and losses (forward positions) prior to contract settlement by calculating the difference between the transaction price and the forward curve.

4. Stress Testing - Stress testing is used to simulate extreme market conditions (e.g., hurricane), and the results are delivered in the daily reports.

VIII. Controls and Oversight

1. The Risk Management Committee (RMC) – The RMC oversees Progress Energy's management of financial risks.

   Committee Members
   - Chief Executive Officer - Progress Energy, Inc. (Optional)
   - Chief Financial Officer - Progress Energy, Inc. (Chair)
   - President – Progress Energy Service Company, LLC
   - President – Energy Supply business unit
   - President – Progress Ventures
   - Executive Vice President – General Counsel – Progress Energy, Inc.
   - Senior Vice President – Finance and Information Technology (*non-voting*) – Progress Energy, Inc.

   Committee Members Responsibilities
   - Identifies, assesses, and monitors corporate financial risks
   - Approves:
     (i) Risk guidelines for various company activities
     (ii) New and existing trading, marketing, procurements and hedging products
     (iii) Analytical methodologies, models and assumptions
     (iv) Organization structure to ensure adequate segregation of duties

   - Reviews:

(i) Aggregate market and credit capital for approval by the BOD
(ii) Summary positions and financial reports
(iii) Broad trading, marketing, hedging, and procurement strategies
(iv) General business conditions, market and credit risk exposures

- Presents to the CEO, BOD and Finance Committee:
  (i) Recommended aggregate market and credit limits and modifications for approval
  (ii) Summary positions and financial reports
  (iii) Summary of valuation methods, key controls, limit exceptions and violations
  (iv) Special studies as requested
- Creates sub-committees to provide greater attention to risk issues in various company activities

2. Trading, Marketing and Fuels Sub-Committee - The Trading, Marketing and Fuels Subcommittee's objective is to review market and credit risk exposure and business development and proposal opportunities associated with trading, marketing and procurement activities.

   Sub-Committee Members
   - President – Ventures
   - VP – Regulated Commercial Operations
   - VP – Ventures Finance
   - Manager – Middle Office
   - Manager - Risk Management
   - Manager – Credit
   - Trading and Marketing Managers

   Sub-Committee Responsibilities - Reviews, at a minimum:
   - Commodity market trends
   - Trading, hedging, procurement and marketing strategies
   - Aggregate commodity risk exposures
   - Market and credit exposure versus defined limits
   - New products and services for RMC approval
   - Model and model assumptions
   - Key operational controls
   - Credit exposure versus defined limits
   - Pricing methodologies
   - Summary exception reports
   - Conducts special studies requested by the RMC
   - Approves liquidity limits

3. Auditing Department – Audit Services provides independent assurance and consulting services that ensure regulatory compliance, effective corporate governance, operational excellence, and appropriate risk management for all major activities including fuel procurement. Activities are audited based on relative priority rather than a fixed cycle. Within that framework, Audit Services' oversight of fuel procurement risk management activities is addressed from the following perspectives:
    - Compliance
    - Trading and procurement
    - Operational