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Florida Power
CORPORATION

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 970096-EQ

Petition for Expedited Approval of an Agreement to Purchase the Tiger Bay Cogeneration Facility and Terminate Related Purchase Power Contracts

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DIRECT TESTIMONY AND EXHIBITS OF

ROBERT D. DOLAN

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For Filing January 29, 1997

FLORIDA POWER CORPORATION
DOCKET NO. 970096-EQ

DIRECT TESTIMONY OF
ROBERT D. DOLAN

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Robert D. Dolan. My business address is Post Office Box 14042, St. Petersburg, Florida 33733.

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

A. I am employed by Florida Power Corporation ("Florida Power" or "the Company") and I am currently the Manager of Cogeneration Contracts and Administration.

Q. Please describe your duties and responsibilities in that position.

A. I have responsibility for implementing Florida Power's cogeneration and small power production ("QF") policies, which include contract negotiation and administration. I have been involved in the Company's QF matters since 1986, except for the period of time between approximately December 31, 1990 and February 18, 1991, when I was working on behalf of another subsidiary of Florida Progress. I have been responsible for the administration of Florida Power's QF contracts since June 1991. In addition, I am familiar with the measures taken by the Company to administer, clarify or renegotiate its various QF contracts.

Q. Please describe your educational and business background.

A. I have a Bachelor of Science Degree in Electrical Engineering from Christian Brothers University. In June, 1977, I was employed by Allen & Hoshall Consulting Engineers where I conducted numerous studies for municipal and REA electric utilities.

In 1980, I was employed by Dashiel. My duties there included turn-key substation and transmission line design and construction for industries, industrial cogenerators and utilities.

In 1982, I was employed by Turner, Collie & Braden. My duties included high voltage substation design including structures, equipment selection, configuration, relaying and specifications; process and building electrical design; and site design including electrical distribution, medium voltage substations and lighting.

In 1983, I was employed by Florida Power as an Industrial Services Engineer in the Northern Division located in Monticello. In that capacity, I was responsible for cogeneration and large industrial/commercial customers. My duties included oversight of cogeneration interconnections and participation in the contracting process for various cogeneration projects located in North Florida. In 1986, I assumed the position of Senior Cogeneration Engineer. My responsibilities in that position were to provide project management for QF interconnections. I also performed technical and economic analyses of a wide range of cogeneration projects, negotiated contracts for firm capacity and energy from QFs, and developed the Company's guidelines for Interconnection Standards.

In 1990, I was appointed Project Manager, Cogeneration Projects. My responsibilities included continued exploration of cogeneration opportunities for Florida Power Corporation. In 1991, I was appointed to my current position as Manager, Cogeneration Contracts and Administration.

Q. Are you a member of any professional organizations?

A. Yes. For the past several years I was a member of the Edison Electric Institute Cogeneration Task Force. In addition, I am a member of the Institute of Electrical and Electronic Engineers and the Association of Energy Engineers.

Q. Do you hold any professional certifications or licenses?

A. I am a registered Professional Engineer in the State of Florida. I became registered in 1978.

Q. Have you ever testified before the Florida Public Service Commission?

A. Yes. I have testified several times before this Commission concerning QF matters, including proceedings requesting the approval or interpretation of several QF contracts, a proceeding to authorize installation of new Company-owned generating units, a proceeding relating to the Company's minimum load curtailment plan, annual planning hearings, bidding and rulemaking hearings.

II. PURPOSES AND ORGANIZATION OF TESTIMONY

Q. What are the purposes of your testimony?

A. I am testifying in support of Florida Power's recent agreement with the Tiger Bay Limited Partnership under which the Company plans to purchase the 220 megawatt Tiger Bay cogeneration facility located in Polk County, Florida. Florida Power has determined that this purchase arrangement is a unique and timely opportunity that will result in substantial customer savings. The Company is seeking approval in this proceeding to recover the purchase price and associated financing costs from its customers over a period not to exceed five years under the capacity cost recovery portion of its fuel and purchased power cost recovery clause. In addition, the Company is asking for approval to recover purchased gas costs associated with the Tiger Bay facility under the fuel cost recovery portion of that clause.

My testimony provides an overview of the purchase arrangement. I will describe the Tiger Bay project, explain the context in which the Company decided to acquire the facility, outline the principal terms of the purchase agreement and identify the expected benefits of the purchase. Mr. John Scardino's testimony describes Florida Power's proposed accounting and ratemaking treatment of the purchase in greater detail.

Q. How is your testimony organized?

A. My testimony covers four general areas. First, I will outline the basic characteristics of the Tiger Bay project. The Commission should be generally familiar with this facility because it has been in operation since January 1995, under five purchase power agreements which were approved by the Commission between 1989 and 1991 in Dockets 890094-EQ, 890915-EQ, 891005-EQ and 910549-EQ. Second, I will summarize the Company's reasons for investigating ways to mitigate the customer impacts of uneconomic purchased power contracts, and I will explain why Tiger Bay represented an ideal acquisition candidate. Third, I will summarize the terms of the purchase agreement. Finally, I will provide a cost-benefit comparison which establishes that the purchase has the potential to save customers as much as $2.4 billion in cumulative payment obligation and has a benefit-to-cost ratio of between 8.9 and 10.4.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring Exhibit Nos. ___ (RDD-1) through ___ (RDD-6). The Tiger Bay purchase agreement, the fuel transportation contracts, and the steam sales and lease agreements are reproduced in Exhibit Nos. _____(RDD-6) for ease of reference.

III. DESCRIPTION OF THE TIGER BAY PROJECT

Q. Where is the Tiger Bay facility located?

A. The Tiger Bay facility is located near Fort Meade in Polk County, Florida. It is a cogeneration facility which supplies electricity to Florida Power and thermal energy in the form of steam to US Agri-Chemicals Corporation ("US Ag") for use in producing fertilizer products.

Q. When did the Tiger Bay plant become commercially operational?

A. The plant began delivering test energy to Florida Power in August 1994, and had a commercial in-service date of January 1, 1995.

Q. Is Tiger Bay a large supplier of electricity to Florida Power?

A. Yes. In fact, Tiger Bay is Florida Power's largest qualifying facility ("QF") supplier. The facility delivers 217.75 megawatts of committed capacity to the Company under five purchased power agreements ("PPAs"). Three PPAs -- totaling 171.6 MW -- have terms extending through December 2024 and energy pricing provisions based on Tampa Electric Company's ("TECO") Big Bend 4 avoided coal unit. The fourth PPA -- covering 40.15 MW -- runs through December 2025 and the energy is priced on the basis of Florida Power's Crystal River 1 and 2 coal units. The last PPA is for 6 MW, extends through 2004 and the energy is priced by reference to the TECO Big Bend 4 avoided coal unit.

Q. Please describe the equipment configuration at Tiger Bay.

A. The combined cycle facility consists of a GE Frame 7001FA gas turbine generator with a Deltak heat recovery steam generator and a condensing GE 74.9 MW steam turbine. Tiger Bay's facilities also include 230 kV step-up transformers and circuit breakers which, technically, are treated as transmission equipment.

Q. How is the Tiger Bay project currently owned and managed?

A. Tiger Bay is currently owned by a partnership called the Tiger Bay Limited Partnership, which is comprised of three general partners -- Destec Energy, Inc. (50.79%), Energy Investors Fund (25.61%) and General Peat Resources, L.P. (18.67%); a limited partner -- International Power Systems, Inc. (2.43%); and an economic interest -- Peat Development Partners, Inc. (2.5%). Destec Operating Company currently operates the facility. The operating cost in 1996 was approximately $5,500,000. The existing staff at the facility includes a plant manager, plant engineer, maintenance supervisor, operations supervisor, clerk, two purchasing and stores agents, three maintenance technicians and ten operators.

Q. Please outline the current gas supply and transportation arrangements for the Tiger Bay facility.

A. Natural gas is supplied to the facility by Vastar Resources, Inc. (formerly ARCO Natural Gas Marketing, Inc.) under a long-term contract. The contract provides for deliveries in volumes adequate for the Tiger Bay Facility. The natural gas contract with Vastar requires confidential treatment of the terms and conditions. Transportation is provided on the Florida Gas Transmission system -- 10,600 mmBtu's/day on the FTS-1 system through 2011, and 22,400 mmBtu's/day on the FTS-2 system through February 2015.

Q. What lease and steam sale arrangements are currently in place for the Tiger Bay project?

A. The project has a land lease with US Ag which extends through 2025 and contains an annual lease payment of approximately $530,000. The steam sales agreement also is with US Ag and also runs through 2025. It provides for payments of $1.50/thousand pounds of steam for the first 40,000 pounds/hour (average steam take is about 35,000 pounds/hour). The steam sale revenues are about $500,000 per year.

IV. THE CLIMATE FOR CONSIDERING CONTRACT BUYOUTS

Q. Why does the Company believe that mitigation today of these purchased power costs is in the best interest of its customers?

A. The cost associated with QF purchased power agreements will be recovered from the Company's customers dollar for dollar over the life of these contracts, since this Commission's orders have authorized the recovery of these costs. Furthermore, in states where customers will receive future choice of their generation supplier, the cost of QF purchaser power agreements are guaranteed future recovery from the utility customers through a surcharge to the distribution and transmission price. This concept is also being considered at the congressional level as shown in proposed House Bill #338 "Ratepayer Protection Act." A copy is included as Exhibit No. _______(RDD-1). Reducing these ongoing customer costs using sound mitigation strategies is good for the Company's customers.

Q. Why did Florida Power decide to evaluate the possibility of renegotiating or buying out purchased power contracts or purchasing QF facilities?

A. Long-term purchased power agreements represent one of the most significant types of sunk costs in excess of current estimated avoided generation cost for our customers. Today, operating QFs account for about 1050 megawatts of firm purchase power commitments for Florida Power. These firm contracts represent roughly 11% of all the Company's capacity resources and provide approximately 22% of the total annual energy supplied by the Company to its customers. With hindsight, we now know that the prices required to be paid to QF suppliers over contract terms as long as 30 years will be well above Florida Power's estimated avoided cost as measured against the Company's future generation located at its Polk County site.

Due to the payout structure of these purchase power agreements (value of deferral pricing) and the project structure of the QFs (project financing), the sooner within the project life a buyout of these contracts or a purchase of these facilities occurs, the greater the benefit derived.

Given the adverse effect of these purchase power agreements on its customers, Florida Power formulated a strategy aimed at identifying QF suppliers that might be willing to renegotiate the terms of their purchase power agreements in ways that would mitigate these uneconomic obligations. Florida Power's more particular objectives have included reducing the Company's purchase obligation by shortening the terms of uneconomic purchase power agreements or purchasing the facility outright, and by negotiating greater dispatch rights. Under this strategy, Florida Power has been able to reduce the cost of purchase power obligations under several agreements, establish greater dispatch rights, and buyout or buydown several QF purchase power agreements. So far, we estimate that Florida Power has entered into arrangements that are estimated to save retail customers approximately $1.9 billion over the lives of these purchase power agreements. The current proposal to purchase the Tiger Bay project is a continuation of these efforts.

Q. Are you aware of any precedent for buying out of QF contracts?

A. Yes. The Edison Electric Institute ("EEI") reported in March of 1996 that 20 utilities had successfully negotiated nearly 100 QF buyouts, accounting for approximately 3,514 megawatts of capacity. Development phase projects accounted for about 75% of the reported buyouts. EEI emphasized that its figures represented a lower bound of buyout activity because some buyouts had been unreported and some were underway at the time of the survey.

Q. Where have the QF buyouts and buydowns occurred?

A. They have occurred throughout the country. In Florida, for example, Florida Power & Light Company bought out the Cypress Energy project, and Florida Power has bought down or negotiated early terminations of five contracts. This Commission has authorized some of these arrangements. Its actions suggest a willingness to consider restructuring transactions where the Commission is satisfied that sufficient customer benefits have been demonstrated.

This openness to the idea of mitigating uneconomic purchased power costs is consistent with the sentiments expressed in other jurisdictions. For example, in a 1995 West Penn Power Company case, the Federal Energy Regulatory Commission ("FERC") actively encouraged utilities to buy out of uneconomic QF contracts, and explained that it would allow utilities to recover prudently incurred buyout costs in their wholesale rates. FERC repeated the same encouragement in a later Jersey Central Power Company case. Relevant portions of these decisions are reproduced for the Commission's convenience in my Exhibit No. ____(RDD-2).

Other state commissions also have promoted negotiated buyouts of uneconomic QF deals. For example, the California CPUC has authorized several buyout arrangements and even issued rules early in 1996 allowing a utility's shareholders to keep 10% of any buyout savings in order to ensure that there would be adequate incentive for buyout initiatives. The Pennsylvania PUC likewise has encouraged its jurisdictional utilities to "vigorously seek to renegotiate or to voluntarily buy out uneconomic NUG contracts... ." See Exhibit No. ____(RDD-2).

Q. What made Florida Power decide that Tiger Bay was a good acquisition candidate?

A. The Company began looking into the possibility of purchasing the Tiger Bay facility and terminating the PPAs during the second quarter of 1996. It was not just a good candidate. It was the <u>best</u> purchase candidate for several reasons. First, it is Florida Power's most expensive QF that is not owned by a municipality. The capacity payments under the Tiger Bay PPAs increase at a composite escalation rate of more than 6%. The cost of power under the PPAs currently is over $50/MWH and is projected to be $188/MWH, which will be $131/MWH above Florida Power's avoided cost of power by 2025 when the last PPAs terminate. The cost of the Tiger Bay PPAs to Florida Power's customers is estimated to be $2.5 billion above current estimated avoided cost.

Second, Tiger Bay is by far the largest of Florida Power's QF suppliers. Early termination of this one uneconomic project will eliminate approximately 27% of the costs in excess of avoided cost after 2001. <u>See</u> Exhibit No. _____(RDD-3).

Third, the Tiger Bay PPAs have the longest duration of any of Florida Power's QF purchase power agreements. Therefore, <u>without</u> the acquisition, the project's uneconomic impacts would continue longer than for other QFs. <u>With</u> the acquisition, the cost savings will be realized through 2025.

Q. Were there more reasons why Tiger Bay was a good acquisition candidate?

A. Yes. The combination of cost factors meant that the Company could get more "bang for its buck" (i.e., achieve the greatest overall customer savings) by purchasing this project than by restructuring any other purchased power arrangement. But there were still more reasons why this particular purchase made sense. The Tiger Bay facility has a number of desirable characteristics. It uses an advanced gas-fired combined cycle configuration with "F" technology that is well engineered and in good condition. It will be the most efficient generating unit on Florida Power's system. The facility is located in close proximity to Florida Power's Polk County generation site and offers the potential for savings from consolidated operations. The Company's Energy Supply staff visited the facility regularly during construction and after commercial operation; Energy Supply therefore is very familiar with the facility, its existing personnel and its operating requirements. The Energy Supply staff has reported to Florida Power's management that the Tiger Bay facility would fit well into the Company's fleet of generating units. In addition, Florida Power believes that it may be able to increase the output of the Tiger Bay facility by about 10 MW and to improve the facility's heat rate with minimal additional cost. The plant is very attractive already, but these enhancements may bring even more benefits in the future.

Perhaps the most important consideration in pursuing this particular acquisition was that the timing was right from Tiger Bay's perspective as well as from Florida Power's. Tiger Bay responded quickly and with great interest to the suggestion that a purchase might be mutually beneficial.

In hindsight, this opportunity appears to have been possible only because Florida Power had finished its assessment of this facility and made a purchase offer to Tiger Bay just prior to the time that Destec Energy, its majority partner, was planning to solicit buyers for all of its assets. If Florida Power had not made a purchase proposal prior to the announcement of the sale of Destec Energy, Florida Power most likely would not have been able to carve the Tiger Bay facility out of the larger Destec Energy sale. This was a one-of-a-kind timing opportunity for Florida Power's customers that may never repeat itself.

Q. Why was the timing of this acquisition "right" from Florida Power's perspective?

A. In my opinion, there couldn't have been a better time (except maybe before the plant was constructed). The sooner we can get this uneconomic obligation behind us, the better. While already operational, this project is in the very early stages of its contract life. By terminating the PPAs at an early point and avoiding the uneconomic obligations soon as possible, Florida Power will be able to expedite the customers' benefits. In addition, because the project owners will realize their return on investment much earlier than anticipated, Florida Power was able to negotiate a favorable price on behalf of our customers.

Q. What conclusions has the Company drawn about the viability of the Tiger Bay facility?

A. The Company is continuing its extensive due diligence reviews and must be satisfied with the results of its due diligence as a precondition to the purchase. However, the analysis that has already been completed indicates that the Tiger Bay facility is a profitable and viable project that should be capable of operating efficiently and satisfying the terms of the PPAs.

The viability of this facility is of utmost importance in the context of purchasing the project and terminating the PPAs. It would make no sense to buy out of a contract if the facility was not viable and capable of remaining operational for all or most of the contract life. In other words, if Florida Power could walk away from a contract because the seller was in default, or could be expected to default, there would be no reason to pay money to purchase the project and terminate that contract.

V. <u>THE TERMS OF THE TIGER BAY ACQUISITION</u>

Q. Please describe the assets to be acquired by Florida Power under the Tiger Bay purchase agreement.

A. Tiger Bay and Florida Power have agreed that Florida Power will purchase the Tiger Bay facility in its entirety. The assets to be acquired by Florida Power include Tiger Bay's generating facility (with all spare parts and permits), the Florida Power PPAs, the lease with US Ag of the property on which the facility is located, the gas supply and transportation contracts to fuel the facility, the steam sale agreement with US Ag, the amended

O&M agreement with Destec Operating Company and miscellaneous other contracts relating to the operation of the facility.

Q. Will all of these agreements survive after the purchase and sale is completed?

A. No. Immediately after closing, the PPAs will be terminated. In addition, Florida Power and Destec Operating Company each have the unilateral option to terminate the O&M agreement nine months after closing, or earlier by mutual agreement.

Q. Which of the major agreements will survive the closing?

A. The land lease and the steam sale agreement with US Ag will continue in effect after closing. The steam sale agreement will provide about $500,000 in annual revenues which will flow through to Florida Power's customers. Leasing the land, rather than owning it, is also advantageous because US Ag will remain responsible for any adverse environmental conditions that may have existed in the past.

At least initially, the gas supply and transportation contracts will continue in effect. However, the Company will investigate a restructuring or buyout of the gas supply contract. Preliminary efforts toward such a renegotiation are already underway, but Vastar has been reluctant to negotiate with a non-party to the contract. If these efforts are successful, the customer savings associated with the purchase will be even greater than we have estimated in this docket. If a buyout cannot be accomplished, the Company expects the costs under the Vastar gas supply contract to be high relative to Florida Power's current forecast of gas supply costs until the contract terminates.

Q. How much will Florida Power pay Tiger Bay under the purchase agreement?

A. The agreed-upon purchase price is $445 million plus an additional amount to reimburse Tiger Bay for certain commitments incurred for spare parts and equipment required to perform a scheduled repair of the gas turbine in March and April 1998. The purchase price will be increased or decreased to reflect any difference between the project's accounts receivable and accounts payable at the time of the closing. The purchase price is payable in cash and Tiger Bay will pay off its obligations at closing and cause all liens and mortgages to be immediately released.

Q. What is the price Florida Power Corporation's customers are effectively paying for the Tiger Bay purchase?

A. While Florida Power will recover the retail portion of the purchase price and associated financing charges ($488 million), customers effectively will pay only $256 million on a cumulative basis and $215 million on a net present value basis. This is because the customers no longer will pay the costs associated with the Tiger Bay PPAs but still will receive the committed capacity from the Tiger Bay facility (i.e., the difference between the original contract cost and the purchase cost). <u>See</u> Exhibit No. ____ (RDD-4)

Q. What was the Company's basis for concluding that $445 million was a reasonable purchase price?

A. The $445 million figure represents a negotiated price to purchase a going concern which, as I explained previously, is a profitable and viable business that was expected to continue in operation through the lives of the PPAs. Florida Power's analysis showed that Tiger Bay's pre-tax cash flow, or profit discounted at 12%, would yield a net present value of approximately $445 million. The Company, based on its experience in dealings with QF investors, considered this to be the minimum amount that Tiger Bay would accept under the purchase agreement. After two months of intense negotiations over the purchase price, we reached, as described above, Tiger Bay's lower limit. Florida Power felt that if we continued to push for a price below $445 million, negotiations would have fallen apart, and Destec would have rolled this asset into its total asset sale. In that case, this one of a kind opportunity would have been lost. In addition, at a purchase price of $445 million, Florida Power was able to secure a net customer savings of between $2.0 billion and $2.4 billion in cumulative purchased power payments. <u>See</u> Exhibit No. ___ (RDD-4), pages 2 and 3 of 4. That was considered to be an outstanding deal for the customer.

Q. How will the purchase and sale transaction be consummated?

A. Based on the seller's tax considerations with respect to the project, Florida Power was required to set up a special, single purpose subsidiary (FPC Acquisition Limited Liability Company) through which the assets will be transferred from Tiger Bay to the Company. Immediately following the closing (in fact, the same day), the assets will be transferred to Florida Power, the PPAs will be terminated and the subsidiary will hold no utility assets. The subsidiary then may be dissolved at Florida Power's discretion.

Q. What are the major conditions to closing the sale?

A. The transaction is conditioned upon timely receipt of any required regulatory consents and approvals, including: (1) expiration of the required waiting period following a filing with the United States Department of Justice under the Hart-Scott-Rodino Antitrust Improvements Act of 1996; (2) authorization of any FERC-jurisdictional asset transfers (i.e., transmission facilities) under the Federal Power Act; and (3) this Commission's final approval of the contemplated transactions, including recovery of the purchase price over a period not to exceed five years. The agreement already has been approved by the Boards of Directors of Florida Power, Destec Energy and Tiger Bay. The transaction, however, remains conditioned on the closing of Destec Energy's currently planned sale to a third party. In addition, the Tiger Bay partnership will need to obtain lender consent to the transaction.

Q. What other provisions does the purchase agreement include to protect Florida Power's interests?

A. The agreement also contains a series of covenants, representations and warranties which provide Florida Power assurances concerning the condition of the Tiger Bay facility, the project's compliance with applicable regulatory and environmental regulations and the owners' legal authority to proceed with the transaction. In lieu of indemnity rights for breach of Tiger Bay's representations and warranties, Florida Power has certain rights to terminate the Agreement without closing, including without limitation: (1) prior to February 1, 1997, if Florida Power is unsatisfied with the results of its due diligence investigation of the Tiger Bay facility (other than the gas turbine compressor); (2) on or before April 30, 1997, if in the opinion of Florida Power's professional engineer after investigation of the gas turbine compressor during the March 15, 1997 scheduled outage of the facility, the mechanical integrity of the compressor is compromised and/or a material loss of performance has resulted or will result in excess of normal aging; (3) if this Commission has not, by July 1, 1997, issued a final, non appealable order approving the rate recovery of the purchase price over no more than five years; or (4) if Tiger Bay is in default of the agreement because (a) any of Tiger Bay's representations and warranties is false or misleading in any material respect, (b) Tiger Bay fails to perform any of its covenants under the agreement, or (c) Tiger Bay fails to timely perform or satisfy any of its material obligations under the agreement.

Q. Please explain generally the nature of Florida Power's due diligence activities.

A. Florida Power must be satisfied that the equipment at the Tiger Bay facility currently is in sound operating condition and that it is likely to continue to operate efficiently in the future. The purchase agreement requires Tiger Bay to keep the facility in good condition up to the time of closing. If Florida Power is not satisfied with its due diligence reviews, the purchase agreement can be terminated prior to closing.

Florida Power's due diligence activities fall into three major categories: (1) analysis of the physical plant condition; (2) analysis of environmental/regulatory issues; and (3) analysis of contract issues. The physical plant review focuses primarily on the condition of the gas turbine, the steam turbine, the heat recovery steam generator and the balance of plant. Florida Power has carved out special rights to investigate the status of the gas turbine during its scheduled maintenance in March 1997. The environmental/regulatory review is necessary to ensure that there are no unknown adverse environmental conditions at the Tiger Bay site and that the necessary permits and licenses are all in order. Finally, it is necessary to evaluate the various project contracts so that the Company can identify any unanticipated cost or liability exposure.

To date, the Company's due diligence efforts have not disclosed any cost or risk which is expected to interfere with a timely closing.

Q. When do the parties plan to go to closing under the purchase agreement?

A. Subject to the required conditions, consents and regulatory approvals, and subject to successful completion of Florida Power's due diligence reviews, the parties currently plan to close the transaction on or about July 1, 1997.

VI. IMPACTS OF THE TIGER BAY ACQUISITION

Q. Before addressing Tiger Bay, can you provide a simple example of a contract buyout and how it can produce overall net benefits?

A. Yes. The best analogy I can think of is a home mortgage under which the homeowner can prepay some of its principle obligations and thereby shorten the total payment period. In doing so, the total payments are dramatically reduced.

Q. Why do many individuals pay off their home mortgage early?

A. An individual pays off his home mortgage early to receive assured savings with zero risk.

Q. What are the similarities of this example and the purchase of Tiger Bay?

A. Both have savings which are virtually guaranteed because the future benefits will materialize in both cases. In fact, Tiger Bay has a much greater return on investment for the customer than prepaying a home mortgage. The purchase of Tiger Bay, at a minimum, will produce a compounded return on investment of over 15%, significantly higher than the mortgage prepayment would provide.

Q. Please explain Florida Power's quantification of the cost savings associated with the purchase in light of the $445 million initial cost.

A. Exhibit No. ____ (RDD-4) supports the conclusion that the Tiger Bay purchase will produce net savings for Florida Power's customers between $2.0 billion and $2.4 billion in cumulative payments. This represents a direct net present value savings of between $280 million and $388 million. Exhibit No. _____(RDD-5) illustrates the customer savings by comparing the costs of the Tiger Bay purchase alternative to the future cost obligations of the Tiger Bay PPAs. The Tiger Bay PPAs are estimated to be about $2.3 billion above the Tiger Bay purchase alternative after 2001. As I have already said, because there are immediate savings, the cumulative cost of the transaction to be recovered from customers is about $256 million. By avoiding these purchased power costs, Florida Power, therefore, will achieve a benefit-to-cost ratio for its customers of between 8.9 and 10.4. See Exhibit No. _____(RDD-4).

Q. Why have you referred to the customers' savings in terms of ranges rather than specific values?

A. As explained in Mr. Scardino's testimony, Florida Power is not seeking immediate recovery of non-fuel costs associated with the Tiger Bay facility. Initially, these costs, which are expected to average about $10 million annually, will be supported by the Company's existing base rates. Exhibit No. _____(RDD-4) includes several scenarios showing customer costs and savings. The scenarios differ only in terms of when, if at all, Florida Power will increase its base rates, and, therefore, begin to include the Tiger Bay non-fuel costs in such rates. Scenario 1 on page 2 of Exhibit No. ____(RDD-4) may be the most representative prediction of the customer cost impacts because it assumes no base rate increase for several years, which we currently consider to be a reasonable expectation.

Q. Are generation replacement cost sensitivity analyses required to evaluate the Tiger Bay acquisition?

A. No. Florida Power is acquiring the Tiger Bay facility and, therefore, is not dependant on estimates of generation replacement costs to determine the savings associated with this transaction.

Q. Are fuel cost sensitivity analyses required to evaluate the Tiger Bay acquisition?

A. The fuel costs contained in the forecasted costs of the Tiger Bay PPAs is based on an estimate of future coal prices. Historically, coal prices have not demonstrated the volatility of other fuel types. Since the estimate of future coal prices used in this forecast is relatively flat, any sensitivity analyses that increases these prices only adds to the value of the Tiger Bay acquisition. Because of the low forecasted escalation of coal prices, a reduction in coal prices below the level in the current forecast is highly unlikely.

In addition, the natural gas costs associated with this transaction are known because of the existing long-term gas supply contract. The only sensitivity analyses that could be performed on the price of natural gas are for the time period after the expiration of this supply contract. Reasonable sensitivity analyses of that future period will not materially affect the net present value savings of the Tiger Bay acquisition.

Q. How does the Company plan to finance the costs of this transaction?

A. As explained in Mr. Scardino's testimony, Florida Power is still evaluating the most economical method of debt financing for this transaction. For illustrative purposes, the exhibaits assume that the retail portion of the transaction price will be financed with a set of five medium-term notes maturing in years one through five of the transaction's closing.

Q. How does the Company plan to recover these purchase costs from its customers?

A. As also explained by Mr. Scardino, Florida Power is requesting authorization to recover the retail portion of the purchase price and associated financing costs from customers over a period not to exceed five years. For the reasons explained by Mr. Scardino, the Company considers it necessary and appropriate to recover 100% of this purchase amount through the capacity cost recovery ("CCR") portion of the Company's fuel and purchased power cost recovery clause. Florida Power is also asking for approval to recover the ongoing gas supply and transportation costs associated with the Tiger Bay facility in the same manner as any other fuel expense under the fuel recovery portion of the fuel and purchased power cost recovery clause. These are prudently incurred fuel costs because it is necessary to acquire the Vastar contract in order to achieve the overall customer savings that I quantified earlier. In other words, Florida Power's customers cannot have one without the other. Therefore, the Vastar fuel costs should not be treated differently than any other prudent gas purchase costs.

Q. Have you prepared an exhibit which charts the costs over time of the Tiger Bay project with a five-year recovery of the purchase costs?

A. Yes I have. Exhibit No. ____ (RDD-5) compares (1) the Tiger Bay contract costs from 1997 through 2025, with (2) the post-acquisition costs over the same time period. The exhibit shows graphically the impacts of the initial purchase cost as well as the long-term cost savings that will result from the purchase, based on Scenario 1 in RDD-4, page 2 of 4. The conclusion to be drawn from this graph is that there will be a short-term (i.e., five-year) customer cost to the transaction, but that the Tiger Bay costs will drop dramatically after year five and remain well under the original contract cost for the next 23 years. This graph more clearly illustrates the overwhelming magnitude of customer savings compared to the costs required to achieve them.

Q. When do customers start receiving net annual benefits from the Tiger Bay acquisition?

A. Customers start receiving net annual benefits or savings in the near term (sixth year). This purchase discontinues much higher cost PPAs and immediately replaces them with a lower cost generation supply.

Q. Please summarize your conclusions about the Tiger Bay acquisition.

A. This is probably a one-time-only opportunity to substantially reduce our customers' costs while acquiring advanced gas turbine combined cycle technology for future low cost energy generation. We know of no comparable opportunity. The cost to customers will be dwarfed in comparison to their savings.

Q. Does this conclude your testimony, Mr. Dolan?

A. Yes, it does.

EXHIBITS TO THE TESTIMONY OF
ROBERT D. DOLAN

EXHIBIT NO. ___ (RDD-1)
HOUSE BILL NO. 338 "RATEPAYER PROTECTION ACT"

Ratepayer Protection Act (Introduced in the House)

HR 338 IH

105th CONGRESS

1st Session

H. R. 338

To prospectively repeal section 210 of the Public Utility Regulatory Policies Act of 1978.

IN THE HOUSE OF REPRESENTATIVES

January 7, 1997

Mr. STEARNS (for himself, Mr. TOWNS, Mr. SOLOMON, Mr. MCHALE, Mr. MANTON, Mr. MURTHA, Mr. HOUGHTON, and Mr. BOEHLERT) introduced the following bill; which was referred to the Committee on Commerce

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A BILL

To prospectively repeal section 210 of the Public Utility Regulatory Policies Act of 1978.

Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled,

SECTION 1. SHORT TITLE.

This Act may be cited as the 'Ratepayer Protection Act'.

SEC. 2. FINDINGS.

The Congress finds that--

(1) implementation of section 210 of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 824a-3) resulted in many consumers paying excessive rates for electricity;

(2) the Energy Policy Act of 1992 gives nonregulated producers of electricity additional access to the wholesale electric market through transmission access and exemption from the Public Utility Holding Company Act of 1935; and

(3) in light of the competitive wholesale electric marketplace brought about by the Energy Policy Act of 1992, section 210 of the Public Utility Regulatory Policies Act of 1978 need no longer exist.

SEC. 3. PROSPECTIVE REPEAL.

(a) NEW CONTRACTS- After January 7, 1997, no electric utility shall be required to enter into a new contract or obligation to purchase or to sell electric energy or capacity pursuant to section 210 of the Public Utility Regulatory Policies Act of 1978.

(b) EXISTING RIGHTS AND REMEDIES NOT AFFECTED- Nothing in this section affects the rights or remedies of any party with respect to the purchase or sale of electric energy or capacity from or to a facility determined to be a qualifying small power production facility or a qualifying cogeneration facility under section 210 of the Public Utility Regulatory Policies Act of 1978 pursuant to any contract or obligation to purchase or to sell electric energy or capacity in effect on January 7, 1997, including the right to recover the costs of purchasing such electric energy or capacity.

(c) INTERPRETATIONS AND ACTIONS TAKEN- Nothing in this Act may be deemed or construed as implying congressional ratification of any interpretation of, or any action taken pursuant to, the Public Utility Regulatory Policies Act of 1978.

SEC. 4. RECOVERY OF COSTS.

In order to assure recovery by electric utilities purchasing electric energy or capacity from a qualifying facility pursuant to any legally enforceable obligation entered into or imposed pursuant to section 210 of the Public Utility Regulatory Policies Act of 1978 prior to January 7, 1997, of all costs associated with such purchases, the Commission shall promulgate and enforce such regulations as may be required to assure that no utility shall be required directly or indirectly to absorb the costs associated with such purchases from a qualifying facility. Such regulations shall be treated as a rule enforceable under the Federal Power Act (16 U.S.C. 791a-825r).

SEC. 5. DEFINITIONS.

For purposes of this Act--

(1) the term 'Commission' means the Federal Energy Regulatory Commission;

(2) the term 'electric utility' means any person, State agency, or Federal agency, which sells electric energy;

(3) the term 'qualifying small power production facility' has the same meaning as provided in section 3(17)(C) of the Federal Power Act;

(4) the term 'qualifying cogeneration facility' has the same meaning as provided in section 3(18)(A) of the Federal Power Act; and

(5) the term 'qualifying facility' means either a small power production facility or a qualifying cogeneration facility.

EXHIBITS TO THE TESTIMONY OF
ROBERT D. DOLAN

EXHIBIT NO. ___ (RDD-2)
EXCERPTS FROM RELAVENT FERC DECISIONS

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approval of or precedent regarding any principle or issue in the proceeding.[1]

On February 16, 1995, Clifton Power Corporation (Clifton) filed a motion to intervene in the proceeding and a second motion to stay the order pending full disclosure by the Commission of all information, decisions, negotiations and other information regarding all aspects of the proceeding.

The Commission will not entertain interventions in a post-license proceeding unless the proceeding involves a material change in the development plan of the project or the terms of the license, or unless the proceeding affects the rights of property-holders in a manner not contemplated in the license.[2] The Agreement does not involve such changes or effects. Accordingly, Clifton's motion to intervene is denied. As Clifton is not a party to the proceeding, its motion for stay must be rejected.[3]

This notice constitutes final agency action. Requests for rehearing by the Commission of this notice may be filed within 30 days of the issuance of this notice, pursuant to 18 C.F.R. § 385.713.

[¶ 61,153]

West Penn Power Company, Docket No. EL95-30-000

Order Denying Petition for Declaratory Order

(Issued May 8, 1995)

Before Commissioners: Elizabeth Anne Moler, Chair; Vicky A. Bailey, James J. Hoecker, William L. Massey, and Donald F. Santa, Jr.

On March 10, 1995, West Penn Power Company (West Penn) filed a Petition for Issuance of a Declaratory Order (West Penn Petition). West Penn seeks a declaration by the Commission that certain actions by the Pennsylvania Public Utility Commission (Pennsylvania Commission) and Washington Power Company, L.P. (Washington Power) violate section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA)[1] and this Commission's implementing regulations. Specifically, West Penn argues that under federal law: (a) an electric utility cannot be required to purchase capacity from a qualifying facility (QF)[2] at rates that exceed the utility's current avoided costs; (b) a State regulatory authority may not modify a power purchase agreement privately negotiated between an electric utility and a QF or, alternatively, avoided costs must be recalculated as of the time of such modification; and (c) avoided costs must be recalculated if a QF seeks certification of a new project design. Finally, West Penn requests a determination that it has no current obligation to purchase capacity and energy from Washington Power's QF.

As described below, we deny West Penn's petition for declaratory order. The Pennsylvania Commission, and the courts, have determined that a valid, legally binding contract exists in this case. We will not disturb that contract. However, we would encourage the parties to the contract to consider settling their differences at this stage particularly if, as may be the case, the facility has not been constructed.

I. Background

A. *Statutory and Regulatory Background*

We have had occasion in several recent cases to summarize the basic components of section 210 of PURPA and our implementing regula-

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[1] *Trafalgar Power, Inc.*, 70 FERC ¶ 61,027 (1995).

[2] *See, e.g., Sayles Hydro Associates*, 48 FERC ¶ 61,049 (1989); *Joseph M. Keating*, 41 FERC ¶ 61,073 (1987); and *Kings River Conservation District*, 36 FERC ¶ 61,365 (1986).

[3] Pursuant to rule 212 of the Commission's Rules of Practice and Procedure, 18 C.F.R. 385.212(a)(2) (1994), motions may be filed only by a participant or a person who has filed a timely motion to intervene which has not been denied. A participant is defined in rule 102 as any party or any employee of the Commission assigned to present the position of the Commission staff in a proceeding before the Commission. 18 C.F.R. § 385.102(b) (1994).

Although Clifton's motions do not specifically request rehearing of the order, that request, too, would be denied because Clifton is not a party to the proceeding.

[1] 16 U.S.C.A. § 824a-3 (West 1985 & Supp. 1995).

[2] A QF is a cogeneration or small power production facility that meets certain specified criteria, primarily relating to technical aspects and ownership, under PURPA and our implementing regulations. *See* 16 U.S.C.A. §§ 796(17)-(18) (West 1985 & Supp. 1995); 18 C.F.R. Part 292 (1994). If all of the relevant statutory and regulatory criteria are satisfied, a QF may be both a qualifying cogeneration facility and a qualifying small power production facility. *See id.*

…cy of the facts change.[51] In no sense does a QF certification or recertification ratify or impose modifications on any power sales contract to which the QF is party.

West Penn's invocation of the legislative history of the Solar, Wind, Waste, and Geothermal Power Production Incentives Act of 1990 is equally unavailing.[52] West Penn correctly points out that that legislation, which by increasing the permissible size limits under certain circumstances for small power production facilities under PURPA enabled Washington Power to obtain additional certification as a qualifying small power production facility, expressly did not intend to have the effect of requiring the purchase of additional capacity or energy under existing contracts. No such effect, however, resulted in this case. The obligations of West Penn to purchase capacity and energy from the Facility were established by the Purchase Agreement, which continued to govern those obligations after Washington Power's additional certification. Moreover, we note that West Penn incorrectly alleges that after the passage of that legislation, Washington Power converted from a cogeneration facility to a small power production facility.[53] That simply is not true. As our certification orders indicate, the Facility's certification as a qualifying small power production facility was in addition to, not in replacement of, its certification as a qualifying cogeneration facility.[54]

As noted above, the Pennsylvania Commission, and the courts, have determined that a valid, legally binding contract exists. Our decision not to disturb the contract has not turned on the factual issue of whether the contract rate required by the Pennsylvania Commission will in fact exceed West Penn's avoided cost over the term of the contract. However, if West Penn believes that this is the case, it should make every attempt to buy-out (or buy-down) the contract. We would encourage the parties to the contract to consider settling their differences particularly if the facility has not been constructed. Moreover, if this is the case, we believe that both the Commission and the Pennsylvania Commission should encourage such an effort.

We do not believe that there is any significant difference between this situation and that faced by utilities when they find that previously negotiated fuel contracts are no longer competitive due to changes in fuel markets. In the latter situation, we have encouraged utilities to buy-out (or buy-down) higher-priced fuel contracts in order to substitute lower-priced fuel currently available and we have allowed the recovery of prudently-incurred buy-out/buy-down costs. *See Kentucky Utilities Company*, 45 FERC ¶ 61,409 (1988).

The Commission is aware today, as it was in 1980 when it adopted its PURPA regulations, that some QF contracts may result in rates above avoided cost over the term of the agreement, just as some may result in rates below avoided cost. However, as we explained in *Connecticut Power*, *NYSEG* and in this order, we do not believe the remedy is to invalidate such contracts, except in narrow circumstances.[55] Rather, we believe the appropriate action is to buy-out or buy-down such contracts. To facilitate such action, we clarify that if utilities are prudent in buying out or buying down existing power purchase agreements, whether or not with QFs, this Commission will permit the recovery in wholesale rates of a pro rata share of the buy-out or buy-down costs.

The Commission orders:

The relief requested in the West Penn Petition is hereby denied as discussed in the body of this order.

[¶ 61,154]

Colorado Interstate Gas Company, Docket No. RP95-233-000

Order Accepting Tariff Sheets Subject to Condition

[51] *See, e.g., Newbay*, 56 FERC at pp. 62,532-33; *Midland*, 56 FERC at p. 62,393.

[52] *See id.* at pp. 35-36.

[53] *Id.* at p. 35.

[54] *See Cogeneration Recertification*, 70 FERC at p. 64,386 n.1; *Small Power Production Certification*, 69 FERC 64,296 n.1. We note that West Penn did not intervene in or protest any of Washington Power's QF certification proceedings. *See Cogeneration Recertification*, 70 FERC at p. 64,386; *Small Power Production Certification*, 69 FERC at p. 64,296; *Cogeneration Certification*, 42 FERC at p. 63,443.

We note that West Penn claims that Washington Power's proposed small power production facility is "substantially different" from the proposed cogeneration facility that formed the basis of the Purchase Agreement. West Penn Petition at p. 33. West Penn similarly alleges that Washington Power made a "substantial redesign of its proposed QF." West Penn Answer at p. 19. West Penn fails to specify any differences, however, and our QF certification orders reflect no such differences.

[55] *See Connecticut Power*, 70 FERC at pp. 61,029-30; *NYSEG*, slip op. at pp. 23-24.

Initial Comments

Citizens Utilities Company
Conoco Inc.
Pacific Gas and Electric Company
Southern California Gas Company
Transwestern Pipeline Company
Yates Petroleum Corporation

Reply Comments

Amoco Production Company and Amoco Energy Trading Corporation
Conoco Inc.
Pacific Gas and Electric Company
Southern California Gas Company
Transwestern Pipeline Company
Yates Petroleum Corporation

[¶ 61,092]

Jersey Central Power & Light Company, Docket No. EL95-36-000

Order Denying Petition for Declaratory Order

(Issued October 17, 1995)

Before Commissioners: Elizabeth Anne Moler, Chair; Vicky A. Bailey, James J. Hoecker, William L. Massey, and Donald F. Santa, Jr.

On March 23, 1995, Jersey Central Power & Light Company (Jersey Central) filed in this proceeding a petition for a declaratory order. The petition requests that the Commission declare invalid the procedures of the New Jersey Board of Public Utilities (New Jersey Board) implementing the Public Utility Regulatory Policies Act of 1978 (PURPA), 16 U.S.C. § 824a-3 (1994). Specifically, Jersey Central claims that under the state procedures it was required to enter into a purchase agreement with Freehold Cogeneration Associates, L.P. (Freehold), a qualifying facility (QF) under PURPA, for 100 megawatts of power at rates that, at the time of contract execution and approval, exceeded Jersey Central's avoided cost. Jersey Central asserts that such a state direction is in violation of the avoided cost cap on utility purchases under PURPA, as construed by the Commission.

As described more fully below, consistent with our recent decisions on this subject, we will deny Jersey Central's petition.

Background

The Freehold Facility

Freehold is a partnership engaged in the development, ownership and (when built) operation of a qualifying cogeneration facility to be located in Freehold Township, New Jersey. The Freehold facility was certified as a QF by order of the Commission, acting pursuant to delegated authority, issued October 1, 1993. *See Freehold Cogeneration Associates, L.P.*, 65 FERC ¶ 62,004 (1993). Steam recovered from the Freehold facility will be used by the Nestle Beverage Company (Nestle) for space heating and the manufacture of coffee and tea beverages.

Relevant Events

On September 28, 1988, the New Jersey Board adopted a competitive bidding process, in place of negotiations, under which Jersey Central would obtain capacity using price caps or ceilings based on the utility's current avoided cost estimate. However, the New Jersey Board also exempted certain QF projects from this newly-established bidding process. Although the Freehold project was not included on the New Jersey Board's list of projects exempt from competitive bidding, because the price terms in the contract between Freehold and Jersey Central were not yet complete, Freehold petitioned the New Jersey Board for that status.

On July 31, 1989, the New Jersey Board reversed itself and exempted the Freehold project from the competitive bidding requirement. In making this decision, the New Jersey Board stated that any pricing arrangement that resulted from further negotiations between Freehold and Jersey Central would be assessed against Jersey Central's most recent (1988) forecast of its avoided cost, and encouraged the parties to negotiate a reasonable settlement on the issue of pricing. After more than two years of negotiations the parties, on March 26, 1992, executed a Purchase Power Agreement (Agreement). Jersey Central subsequently submitted the Agreement to the New Jersey Board recommending that it be approved, and on July 8, 1992, the New Jersey Board issued an order approving the Agreement stating that the price was equal to 100% of the applicable avoided cost.

After it approved the Agreement, the New Jersey Board issued a decision directing all New Jersey electric utilities to reexamine power purchase contracts with non-utility generators to determine whether they are economic and whether there are any candidates the parties' arguments. As we stated in *West Penn*, "we would encourage the parties to the contract to consider settling their differences particularly if the facility has not been constructed." 71 FERC at p. 61,497. We continue to believe that it is appropriate to buy-out or buy-down QF contracts that can be demonstrated to result in rates above avoided cost over the term of the contracts. Accordingly, as we stated in *West Penn*:

> To facilitate such action, we clarify that if utilities are prudent in buying out or buying down existing power purchase agreements, whether or not with QFs, this Commission will permit the recovery in wholesale rates of a pro rata share of the buy-out or buy-down costs.

Id.

The Commission orders:

Jersey Central's petition for declaratory order is hereby denied.

[¶ 61,093]

Consumers Power Company, Project Nos. 2436-019, 2447-018, 2448-025, 2449-017, 2450-016, 2453-014 and 2580-029

Order Denying Rehearing

(Issued October 18, 1995)

Before Commissioners: Elizabeth Anne Moler, Chair; Vicky A. Bailey, James J. Hoecker, William L. Massey, and Donald F. Santa, Jr.

On November 28, 1994, the Commission's Office of the Executive Director and Chief Financial Officer sent Consumers Power Company (Consumers) annual charges bills for the use by the above-listed seven projects of federal lands for fiscal year 1995. The projects are located on the AuSable and Manistee Rivers in Oscoda, Alcona, Iosco, Mecosta, Manistee, and Wexford Counties, Michigan. The federal lands are within the Huron-Manistee National Forest, which is administered by the U.S. Forest Service. The statements for the seven projects totaled $245,682.53.

On December 28, 1994, Consumers requested correction or rehearing of the billing,[1] contending that it should not be assessed for the acres for which it holds a flowage easement, which is asserts is all it needs for project purposes. For the reasons discussed below, we deny rehearing.

Background

On July 15, 1994, the Commission issued new licenses for eleven Consumers hydroelectric projects.[2] Pursuant to section 10(e) of the Federal Power Act,[3] Article 201 of each license for the nine projects located within the Huron-Manistee National Forest provided that the licensee would be assessed an annual charge for the project's use of specified acres of federal land.

The license orders' specification of the acreage of United States lands within a project boundary, and of the acreage subject to annual charges, was based on maps filed by Consumers in conjunction with a comprehensive settlement agreement submitted on March 3, 1993, in all eleven relicense proceedings.[4] When the Commission approved the settlement and issued eleven new licenses, the seven projects at issue increased their occupancy of National Forest lands from a total of 2.99 acres to a total of 5,347.9 acres.

On rehearing, Consumers points out that the maps submitted on March 3, 1993, were offered only for the purpose of illustrating lands and boundaries, and not as formal revisions to

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[1] Consumers has paid the full assessment, but under protest with respect to the seven projects addressed herein.

[2] *See* 68 FERC ¶¶ 61,082, 61,081, 61,072, 61,075, 61,071, 61,073, 61,080, 61,083, 61,074, 61,076, and 61,079.

[3] 16 U.S.C. § 803(e). Section 10(e)(1) provides in pertinent part:

> That the licensee shall pay to the United States reasonable annual charges in an amount to be fixed by the Commission for ... recompensing [the United States] for the use, occupancy, and enjoyment of its lands or other property ....

The Commission's regulations governing federal land use charges are at p. 18 C.F.R. § 11.2 (1995).

[4] *See* Offer of Settlement, Cross-Reference appendix. In an April 12, 1993 filing entitled Explanatory and Support Statements, Consumers explained that, whereas its relicense applications had originally proposed that on Forest system lands the project boundary be set at a reservoir's edge, the offer of settlement proposed that the project boundary be set 200 feet from a reservoir's normal maximum surface elevation.

EXECUTIVE SUMMARY

The Pennsylvania Public Utility Commission (Commission) submits this Report and Recommendation to the Governor and General Assembly in response to the nationwide interest in restructuring of the electric industry. As a result of its Investigation concerning electric competition, the Commission recommends that it is in the public interest for Pennsylvania to begin a careful transition that will provide all retail customers the opportunity to choose their electric generation provider, and that will end the regulation of electric generation as a retail monopoly.

It is evident that electric power generation is not a natural monopoly and thus should not be regulated as such. Conversely, it is evident that electric power transmission and distribution continue to be natural monopolies and should be regulated. However, the need to resolve key issues prevents an immediate move to full retail electric generation competition. Thus, a transition period is recommended which fully prepares all stakeholders to achieve the maximum benefits possible when retail electric generation competition commences.

Milestone reviews during the transition period are essential to ensure that the transition to retail electric generation competition is conducted in a careful and appropriate manner while resolving associated issues. The milestone reviews are an opportunity for the Commission to make modifications that future circumstances require. Following a reasonable transition period, a phase-in of full retail electric generation competition should begin, provided that the milestone reviews confirm that necessary preparations have been completed. During the phase-in period, milestone reviews should continue to verify that the introduction of retail electric generation competition is appropriate.

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potential stranded costs problem for electric utilities because the price they pay for the power produced by these facilities may be higher than the expected market price of electricity.

These contracts became an obligation of the utilities because of a requirement by the federal government that utilities purchase power made available by qualifying facilities (QF). In 1978, Congress passed the National Energy Act (NEA) to reduce the country's dependence on foreign oil. PURPA also implements the policies of the NEA and requires electric utilities to purchase electricity from a QF based upon the utilities' avoided cost. Avoided cost is defined as the price the utility would otherwise have incurred for its power rather than purchasing it from the QF. The problem of NUG stranded costs exists because the utilities' avoided cost at the time the contracts were negotiated was based on projected substantial increases in fuel prices. However, energy prices decreased during the 1980s. The average price paid for NUG contracts is 6.10 cents per kwh. Consequently, electric utilities must purchase power at a higher price than is currently available in the market or at prices higher than the current cost of a newly-constructed generator plant.

As a result of this Investigation, the Commission recommends that utilities be authorized to collect the costs of currently effective and approved NUG contracts as they are incurred. Utilities should vigorously seek to renegotiate or to voluntarily buy-out uneconomic NUG contracts, especially contracts for facilities which have not yet been built. Since NUG contracts were required by law, utilities will have the opportunity to request recovery of the unmitigated prudent costs of such contracts within the cost recovery mechanism.

iii. Electric Utility Generation. The third element of identified stranded costs for electric utilities is uneconomic generation assets, primarily nuclear power plants. The seven major investor-owned electric utilities in Pennsylvania had an original cost in nuclear generation power plants of $15.6 billion. Pennsylvania's current net plant investment in nuclear power plants is $12.3 billion.

Electric utilities have invested heavily in their generation assets based on the existing system of rate base/rate of return regulation. That is to say, a utility receives a certificated service territory in which it is the supplier of power. In return it commits to build its system as necessary to serve the current and future needs of all customers in the service area. The utility is then allowed to recover the cost of prudent investment it makes to provide such service, plus the opportunity to earn a regulated return on investment.

There can be no doubt that the existing ratemaking system itself has significantly contributed to stranded utility investments. Current regulated rates are the result of the existing ratemaking rules and procedures under the Code. The wide disparity in existing rates also demonstrates that utilities made substantially

EXHIBITS TO THE TESTIMONY OF
ROBERT D. DOLAN

EXHIBIT NO. ___ (RDD-3)

CUSTOMERS' QF COSTS VS.
CURRENT ESTIMATED AVOIDED COSTS

Exhibit _____ (RDD-3) - Customers' PPA Cost versus Current Estimated Avoided Cost ($ millions)

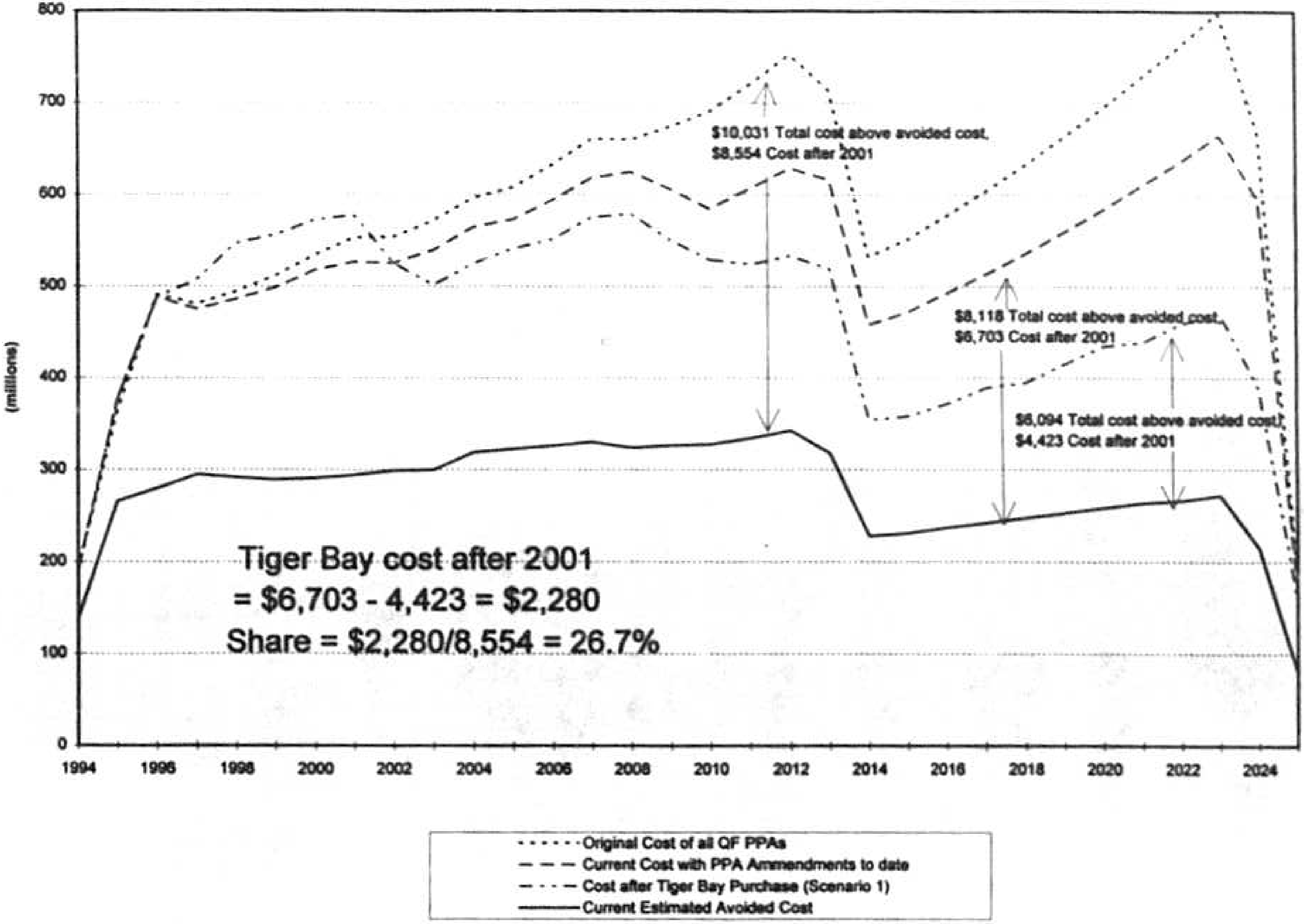

Exhibit ___ (RDD-3)

EXHIBITS TO THE TESTIMONY OF
ROBERT D. DOLAN

EXHIBIT NO. __ (RDD-4)

SAVINGS DUE TO PURCHASE OF TIGER BAY

Savings Due to the Purchase of Tiger Bay
Economic Evaluation of Purchase
($000)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
		Tiger Bay Transaction						
Year	Existing Contract Total	Fuel Cost	Base Rate Cost	Purchase Cost	Total	(1)-(5) Net Savings	Cost	Savings
1997	37,944	20,947	5,776	48,811	75,534	(37,590)	(37,590)	0
1998	76,473	41,486	21,506	97,622	160,614	(82,141)	(82,141)	0
1999	82,219	42,099	15,414	97,622	155,134	(72,915)	(72,915)	0
2000	87,830	44,580	16,859	97,622	159,061	(71,230)	(71,230)	0
2001	91,022	44,529	20,770	97,622	162,922	(71,900)	(71,900)	0
2002	95,081	45,903	16,431	48,811	111,145	(16,064)	(16,064)	0
2003	99,835	47,225	15,070	0	62,296	37,539	0	37,539
2004	105,254	48,703	16,780	0	65,483	39,771	0	39,771
2005	103,113	50,235	21,199	0	71,434	31,678	0	31,678
2006	108,386	51,723	13,769	0	65,492	42,894	0	42,894
2007	113,523	53,361	17,362	0	70,724	42,799	0	42,799
2008	119,336	55,064	18,868	0	73,932	45,404	0	45,404
2009	124,670	56,833	12,525	0	69,358	55,312	0	55,312
2010	131,228	58,670	17,157	0	75,827	55,401	0	55,401
2011	136,914	37,397	16,651	0	54,048	82,867	0	82,867
2012	144,557	37,975	11,566	0	49,541	95,016	0	95,016
2013	151,542	38,566	16,127	0	54,692	96,849	0	96,849
2014	159,419	39,168	15,408	0	54,576	104,844	0	104,844
2015	167,581	39,782	14,087	0	53,869	113,712	0	113,712
2016	176,286	40,409	15,281	0	55,689	120,597	0	120,597
2017	185,528	41,048	20,239	0	61,287	124,241	0	124,241
2018	195,302	41,699	12,789	0	54,488	140,813	0	140,813
2019	205,642	42,364	19,021	0	61,385	144,257	0	144,257
2020	216,603	43,042	24,622	0	67,664	148,939	0	148,939
2021	228,225	43,734	14,066	0	57,800	170,425	0	170,425
2022	240,527	44,439	20,154	0	64,593	175,934	0	175,934
2023	253,568	45,159	14,739	0	59,898	193,671	0	193,671
2024	267,396	45,893	15,478	0	61,371	206,025	0	206,025
2025	80,958	46,642	23,641	0	70,283	10,676	0	10,676
Total =	$4,187,964	$1,288,674	$483,356	$488,110	$2,260,139	$1,927,826	($351,839)	$2,279,664
NPV at 6/97	$1,285,460	$497,966	$184,663	$399,592	$1,082,211	$203,250	($292,584)	$495,834

Benefit/Cost Ratio (nominal dollars) = 6.5

Savings Due to the Purchase of Tiger Bay
Scenario #1 - Base Rate Cost Recovery after 2002
($000)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
		Tiger Bay Transaction				(1)-(5)		
	Existing					Net		
	Contract	Fuel	Base Rate	Purchase		Customer	Customer	Customer
Year	Total	Cost	Cost	Cost	Total	Savings	Cost	Savings
1997	37,944	20,947	0	48,811	69,758	(31,814)	(31,814)	0
1998	78,473	41,486	0	97,622	139,108	(60,635)	(60,635)	0
1999	82,219	42,099	0	97,622	139,721	(57,501)	(57,501)	0
2000	87,830	44,580	0	97,622	142,202	(54,371)	(54,371)	0
2001	91,022	44,529	0	97,622	142,151	(51,129)	(51,129)	0
2002	95,081	45,903	0	48,811	94,714	367	0	367
2003	99,835	47,225	15,070	0	62,296	37,539	0	37,539
2004	105,254	48,703	16,780	0	65,483	39,771	0	39,771
2005	103,113	50,235	21,199	0	71,434	31,678	0	31,678
2006	108,386	51,723	13,769	0	65,492	42,894	0	42,894
2007	113,523	53,361	17,362	0	70,724	42,799	0	42,799
2008	119,336	55,064	18,868	0	73,932	45,404	0	45,404
2009	124,670	56,833	12,525	0	69,358	55,312	0	55,312
2010	131,228	58,670	17,157	0	75,827	55,401	0	55,401
2011	136,914	37,397	16,651	0	54,048	82,867	0	82,867
2012	144,557	37,975	11,566	0	49,541	95,016	0	95,016
2013	151,542	38,566	16,127	0	54,692	96,849	0	96,849
2014	159,419	39,168	15,408	0	54,576	104,844	0	104,844
2015	167,581	39,782	14,087	0	53,869	113,712	0	113,712
2016	176,286	40,409	15,281	0	55,689	120,597	0	120,597
2017	185,528	41,048	20,239	0	61,287	124,241	0	124,241
2018	195,302	41,699	12,789	0	54,488	140,813	0	140,813
2019	205,642	42,364	19,021	0	61,385	144,257	0	144,257
2020	216,603	43,042	24,622	0	67,664	148,939	0	148,939
2021	228,225	43,734	14,066	0	57,800	170,425	0	170,425
2022	240,527	44,439	20,154	0	64,593	175,934	0	175,934
2023	253,568	45,159	14,739	0	59,898	193,671	0	193,671
2024	267,396	45,893	15,478	0	61,371	206,025	0	206,025
2025	80,958	46,642	23,641	0	70,283	10,676	0	10,676
Total =	$4,187,964	$1,288,674	$386,600	$488,110	$2,163,384	$2,024,581	($256,450)	$2,280,031
NPV at 6/97	$1,285,460	$497,955	$107,172	$399,592	$1,004,719	$280,741	($215,334)	$496,076

Benefit/Cost Ratio (nominal dollars) = 8.9

Savings Due to the Purchase of Tiger Bay
Scenario #2 - No Base Rate Cost Recovery
($000)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
		Tiger Bay Transaction				(1)-(5)		
Year	Existing Contract Total	Fuel Cost	Base Rate Cost	Purchase Cost	Total	Net Customer Savings	Customer Cost	Customer Savings
1997	37,944	20,947	0	48,811	69,758	(31,814)	(31,814)	0
1998	78,473	41,486	0	97,622	139,108	(60,635)	(60,635)	0
1999	82,219	42,099	0	97,622	139,721	(57,501)	(57,501)	0
2000	87,830	44,580	0	97,622	142,202	(54,371)	(54,371)	0
2001	91,022	44,529	0	97,622	142,151	(51,129)	(51,129)	0
2002	95,081	45,903	0	48,811	94,714	367	0	367
2003	99,835	47,225	0	0	47,225	52,609	0	52,609
2004	105,254	48,703	0	0	48,703	56,551	0	56,551
2005	103,113	50,235	0	0	50,235	52,878	0	52,878
2006	108,386	51,723	0	0	51,723	56,663	0	56,663
2007	113,523	53,361	0	0	53,361	60,161	0	60,161
2008	119,336	55,064	0	0	55,064	64,272	0	64,272
2009	124,670	56,833	0	0	56,833	67,837	0	67,837
2010	131,228	58,670	0	0	58,670	72,558	0	72,558
2011	136,914	37,397	0	0	37,397	99,518	0	99,518
2012	144,557	37,976	0	0	37,976	106,581	0	106,581
2013	151,542	38,566	0	0	38,566	112,976	0	112,976
2014	159,419	39,168	0	0	39,168	120,252	0	120,252
2015	167,581	39,782	0	0	39,782	127,799	0	127,799
2016	176,286	40,409	0	0	40,409	135,878	0	135,878
2017	185,528	41,048	0	0	41,048	144,480	0	144,480
2018	195,302	41,699	0	0	41,699	153,602	0	153,602
2019	205,642	42,364	0	0	42,364	163,278	0	163,278
2020	216,603	43,042	0	0	43,042	173,561	0	173,561
2021	228,225	43,734	0	0	43,734	184,491	0	184,491
2022	240,527	44,439	0	0	44,439	196,088	0	196,088
2023	253,568	45,159	0	0	45,159	208,409	0	208,409
2024	267,396	45,893	0	0	45,893	221,503	0	221,503
2025	80,958	46,642	0	0	46,642	34,317	0	34,317
Total =	$4,187,964	$1,288,674	$0	$488,110	$1,776,784	$2,411,181	($255,450)	$2,666,631
NPV at 6/97	$1,285,460	$497,955	$0	$399,592	$897,547	$387,913	($215,334)	$603,248

Benefit/Cost Ratio (nominal dollars) = 10.4

Cost of the Tiger Bay Contract
($000)

	(1)	(2)	(3)	(4)	(5)	(6)
			(1)+(2)			(3)-(4)-(5)
	Contract Capacity Cost	Contract Energy Cost	Total Contract Cost	FPC Lease Payments	FPC Royalty Payments	Contract Case Total
1997	24,753	13,787	38,539	400	195	37,944
1998	52,504	27,282	79,785	800	512	78,473
1999	55,686	27,977	83,663	800	644	82,219
2000	59,073	30,335	89,408	800	778	87,830
2001	62,651	30,093	92,744	800	922	91,022
2002	66,438	30,497	96,935	800	1,055	95,081
2003	70,495	31,368	101,863	800	1,228	99,835
2004	74,778	32,698	107,476	800	1,422	105,254
2005	77,200	28,010	105,210	800	1,297	103,113
2006	81,890	28,778	110,668	800	1,482	108,386
2007	86,877	29,305	116,182	1,000	1,659	113,523
2008	92,155	30,251	122,406	1,200	1,870	119,336
2009	97,787	30,148	127,934	1,200	2,065	124,670
2010	103,751	30,990	134,741	1,200	2,312	131,228
2011	110,078	31,489	141,568	1,200	3,453	136,914
2012	116,790	32,694	149,484	1,200	3,727	144,557
2013	123,921	32,794	156,715	1,200	3,973	151,542
2014	131,497	33,377	164,874	1,200	4,254	159,419
2015	139,539	33,789	173,328	1,200	4,547	167,581
2016	148,072	34,274	182,347	1,200	4,860	176,286
2017	157,158	34,764	191,923	1,200	5,195	185,528
2018	166,792	35,260	202,052	1,200	5,550	195,302
2019	177,010	35,760	212,770	1,200	5,928	205,642
2020	187,868	36,267	224,134	1,200	6,331	216,603
2021	199,406	36,778	236,184	1,200	6,759	228,225
2022	211,646	37,295	248,942	1,200	7,214	240,527
2023	224,649	37,818	262,467	1,200	7,699	253,568
2024	238,464	38,347	276,811	1,200	8,215	267,396
2025	43,662	38,881	82,543	1,200	384	80,958
Total 1997-2025 =	$3,382,689	$931,106	$4,313,695	$30,200	$95,530	$4,187,964
NPV at 6/97	$982,517	$336,126	$1,318,644	$10,374	$22,810	$1,285,460

Exhibit ______ (RDD-5)

Impact of Tiger Bay Purchase on Customers

Based on Scenario #1 (Exhibit RDD-4, page 2 of 4)

(Assumes no recovery of base rate costs prior to 2003)

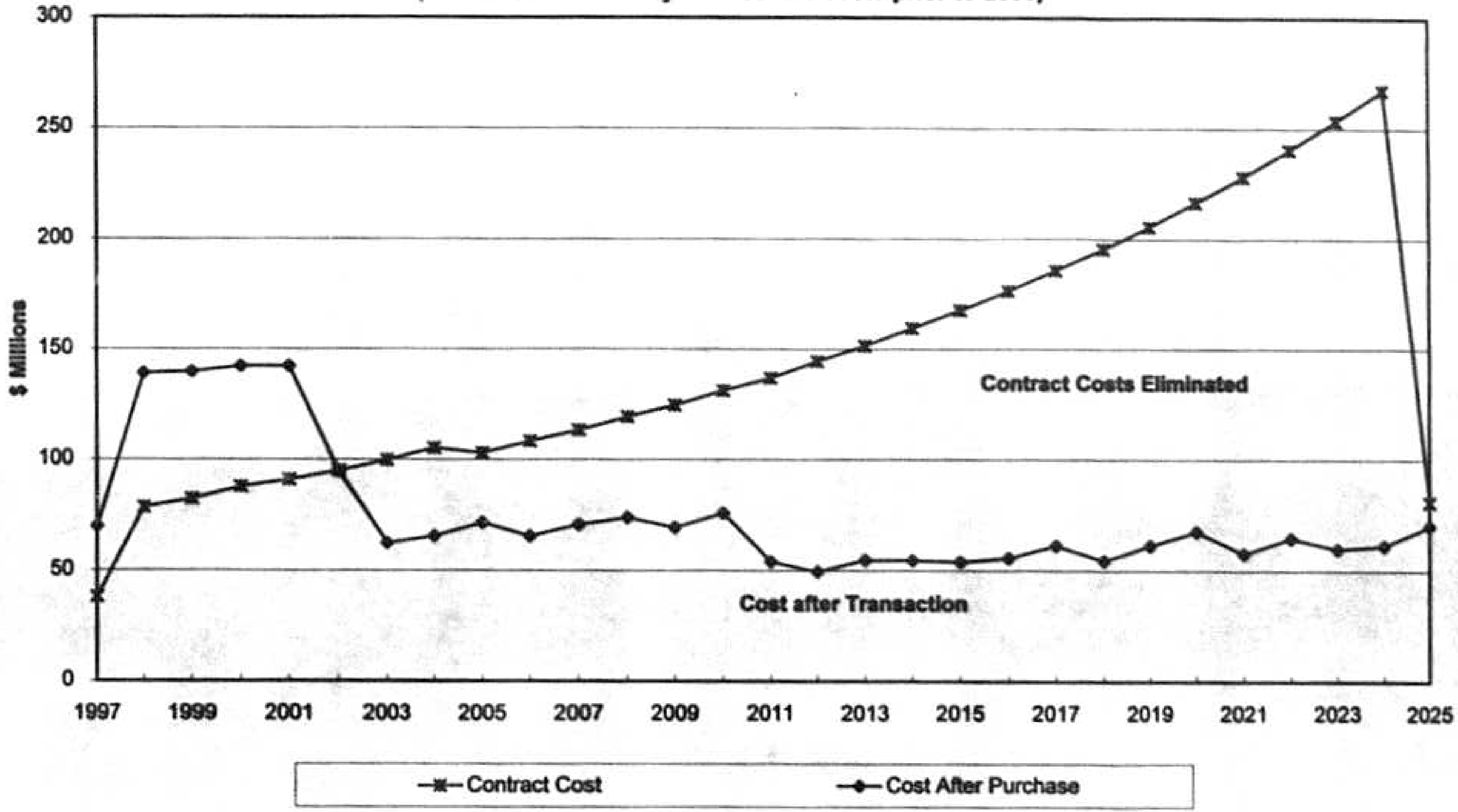

Exhibit ___ (RDD-5)

EXHIBITS TO THE TESTIMONY OF
ROBERT D. DOLAN

EXHIBIT NO. __ (RDD-5)

IMPACT OF TIGER BAY PURCHASE ON CUSTOMERS
