Duquesne Light Company

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July 17, 1997

VIA FACSIMILE

R-00974104

Mr. James J. McNulty
Prothonotary's Office
Pennsylvania Public Utility Commission
P.O. Box 3265
North Office Building
Harrisburg, PA 17105-3265

Re: Duquesne Light Company Restructuring Filing

Dear Mr. McNulty:

Duquesne Light Company will be filing its Restructuring Plan on August 1, 1997. Would you please provide to me Duquesne's assigned docket number for this filing at your earliest convenience so that the Company can include the number on all the documents that will be filed and served on August 1. I can be contacted at the above telephone number.

Thank you.

Very truly yours,

RS Herskovitz

Richard S. Herskovitz

RSH/dlm

ORIGINAL

KJR

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August 1, 1997

Mr. James J. McNulty
Office of the Prothonotary
Pennsylvania Public Utility Commission
P.O. Box 3265
North Office Building
Harrisburg, PA 17105-3265

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PA.P.U.C.
PROTHONOTARY'S OFFICE

Re: Duquesne Light Company
Docket No. R-00974104
Restructuring Plan

Dear Mr. McNulty:

Enclosed for filing on behalf of Duquesne Light Company are eight copies of the Company's restructing plan pursuant to Section 2806 of the Pennsylvania Public Utility Code, the Commission's Order entered January 24, 1997 at Docket No. M-00960890F0005 (establishing a procedural schedule re restructuring filings) and the Commission's Order entered February 13, 1997 at Docket No. M-00960890F0003 (establishing data requirements for restructuring filings). A computer diskette of the restructuring plan filing is enclosed.

Also enclosed is a Certificate of Service providing a list of the parties which have been served with copies of this filing or notice thereof.

DOCKETED
AUG 06 1997

DOCUMENT
FOLDER

46

If you have any questions regarding this filing, please contact me.

Very truly yours,

Larry R. Crayne
Assistant General Counsel

LRC/dlm
Enclosure

cc: As per Certificate of Service (w/ encl.)

ORIGINAL

List of Complimentary Copies of Duquesne Filing:

1. James McNulty 9 sets
Acting Secretary
Pennsylvania Public Utility Commission

2. Chairman John M. Quain 1 set
Pennsylvania Public Utility Commission

3. Commissioner Nora Mead Brownell 1 set
Pennsylvania Public Utility Commission

4. Commissioner John Hanger 1 set
Pennsylvania Public Utility Commission

5. Commissioner David W. Rolka 1 set
Pennsylvania Public Utility Commission

6. Vice Chairman Robert K. Bloom 1 set
Pennsylvania Public Utility Commission

7. The Honorable Robert A. Christianson 1 set
Chief Administrative Law Judge
Pennsylvania Public Utility Commission

8. John F. Povilaitis, Esq. 1 set
Chief Counsel
Pennsylvania Public Utility Commission

9. Veronica Smith 1 set
Deputy Director

10. Otto Hofmann 1 set
Deputy Director

11. Irwin A. Popowsky, Esq. 6 sets
Consumer Advocate
Office of Consumer Advocate

12. Bernard A. Ryan, Jr. Esq. 2 sets
Small Business Advocate
Office of Small Business Advocate

13. Charles F. Hoffman, Esq. 7 sets
Office of Trial Staff
Pennsylvania Public Utility Commission

14. Cheryl Walker Davis 1 set
Office of Special Assistants

15. Mr. Glenn Bartron 1 set
Bureau of Audits
Pennsylvania Public Utility Commission

16. Mr. Donald Huth 3 sets
FUS
Pennsylvania Public Utility Commission

17. Dr. Z. Ahmed Kaloko 1 set
CEEP
Pennsylvania Public Utility Commission

18. Mr. Mitchell Miller 1 set
BCS
Pennsylvania Public Utility Commission

19. David Kleppinger 1 set
McNees, Wallace & Nurick

To Jim McNulty PUC

From Frank Nadolny 8-1-97

Re: DLC Restructuring Filing R-00974104

The following copies were delivered to the PUC today 8-1-97

No. of Copies	Location
8	PUC Prothonotary - Basement N. Off. Bldg
5	Commissioners
1	Chief ALJ
2	Deputy Dir
1	OSA
3	FUS
3	Law
1	Kevin Calder (Consumer Info.)
24	
7	OTS Picnic Bldg
1	Audits
1	CEEP Bartos Bldg
1	BCS

Others

~~6~~ → 4	OCA
2	SBA
1	Kleppinger (Industrials)

ORIGINAL

VOLUME I

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

DUQUESNE LIGHT COMPANY
DOCKET NO. R-00974104

APPLICATION FOR APPROVAL OF RESTRUCTURING PLAN UNDER SECTION 2806 OF THE PUBLIC UTILITY CODE

Direct Testimony of : **David D. Marshall**
Donald J. Clayton
Michael M. Schnitzer

VOLUME I

Duquesne Statement No. 1

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

DUQUESNE LIGHT COMPANY
DOCKET NO. R-00974104

Direct Testimony
of
David D. Marshall

Contents:

Overview of Duquesne Customer Choice Plan

DIRECT TESTIMONY OF DAVID D. MARSHALL

I. QUALIFICATIONS

Q. What is your name and position with Duquesne Light Company ("Duquesne")?

A. My name is David D. Marshall and I am President and Chief Executive Officer of Duquesne.

Q. What are your current responsibilities?

A. As President and Chief Executive Officer, I am responsible for the overall management and direction of Duquesne.

Q. Please describe your educational and professional experience.

A. I received my undergraduate degree in mathematics and economics from Colby College in Waterville, Maine in 1975. In June 1980, I earned an M.B.A. degree from the Amos Tuck School of Business Administration in Hanover, New Hampshire.

From the time of my graduation from the Tuck School until February of 1985, I was employed by Central Vermont Public Service Corporation (CVPS), an electric utility located in Rutland, Vermont. I held a number of positions at CVPS, including Manager of Rates and Economic Research, Director of Economic Analysis and my last position as Assistant Vice President of Finance.

In February 1985 I joined Duquesne as General Manager, Planning, Budgeting and Rates. Subsequently, I held the positions of Vice President, Corporate Development (1987), Assistant to the President (1990), Executive Vice President

(1992), and President and Chief Operating Officer (1993). I was appointed to my current position as Chief Executive Officer in 1996.

Q. Have you ever testified before this Commission or any other regulatory commission?

A. Yes. As General Manager, Planning, Budgeting and Rates at Duquesne, I submitted extensive testimony in Duquesne's last general rate cases in 1986 and 1987. Most recently, as President, I gave testimony before this Commission in January of 1996 as part of its Investigation into Electric Power Competition and before the Senate of Pennsylvania in August of 1996 in the hearings that led to the enactment of House Bill No. 1509.

II. SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide an overview of Duquesne's stand-alone restructuring plan ("Customer Choice Plan" or "Plan"). My testimony provides the summary of the Plan that is required by Appendix A to the Commission's February 13, 1997. I also discuss the additional benefits to customers that would result from Duquesne's proposed merger with the Allegheny Power System ("APS") and the joint restructuring plan associated with the merger. A joint restructuring plan by Duquesne and West Penn Power Company (the "Joint Plan") has been filed contemporaneously with this application in a separate docket.

Q. How is your testimony organized?

A. There are three main sections to my testimony. The first provides an overview of Duquesne's Customer Choice Plan. The second section provides a summary of the testimony of each witness appearing on behalf of Duquesne. The third section provides an overview of the additional benefits to Duquesne's customers that would result from the merger with APS.

Q. What relief does Duquesne seek in this proceeding?

A. Duquesne is requesting that the Commission approve its stand-alone restructuring plan without modification as an integrated, balanced program for the transition to competition that meets all the requirements of the restructuring legislation and is fair to both investors and consumers.

Q. You stated that Duquesne's Plan is a balanced program. Please summarize the benefits to customers.

A. The customer benefits of Duquesne's Customer Choice Plan include:

- access to alternative generation suppliers on fair and nondiscriminatory terms;
- a continued obligation to serve during the transition period;
- redesigned rates that encourage economically efficient consumption;
- accelerated amortization and depreciation of strandable assets without increasing rates above current levels;
- a new economic development rider applicable to commercial and industrial loads of 25 kW or greater;

- a total amortization and depreciation commitment of at least $1.7 billion over the transition period;
- a return on equity ("ROE") "spillover" provision to ensure that Duquesne does not earn in excess of a fair return during the transition period;
- a market-based process for setting competitive transition charges ("CTCs"); and
- customer-specific CTCs designed to prevent cost shifts between customers and customer classes.

The Customer Choice Plan builds on a history of innovation at Duquesne and contains a combination of innovative features that balance stakeholder interests. For example, the Plan uses a market-based valuation of generation to establish CTCs and to make a final determination of stranded costs. During each year of the transition period, Duquesne will conduct a competitive solicitation to sell a substantial block of generation, with the resulting market values used to determine the CTCs each year of the transition period. The CTCs paid by customers will therefore be known and measurable, as required by the restructuring legislation.

Duquesne also proposes a final valuation of the market value of Duquesne's generation assets in 2003 based on objective evidence of market value, not market price forecasts. This valuation will be provided by an unbiased arbitration panel. Duquesne will commit to be bound by the decision of the panel. There also is a mechanism by which this final valuation can be triggered before 2003 if market prices

rise to specified levels, or Duquesne completes its amortization commitment early, thereby ensuring that there will be no over-recovery of stranded costs.

The Customer Choice Plan also builds on the innovative approach to stranded cost mitigation that Duquesne first proposed in the Ft. Martin plan. Under that five-year plan, Duquesne used the proceeds from the sale of its interest in Ft. Martin to accelerate depreciation and amortization of strandable assets while maintaining rates at current levels. Section 2804(4)(v) of the restructuring legislation provides Duquesne the opportunity to build on this aggressive mitigation plan. In this case, Duquesne commits to a minimum of $1.7 billion in total amortization and depreciation of generation-related assets during the transition period while maintaining rates capped at current levels. Under Duquesne's proposal, shareholders will bear the risk that cost containment measures are not sufficient to generate the savings necessary to satisfy this commitment while maintaining earnings. If, to the contrary, revenues exceed expectations or additional cost savings are available, Duquesne has established an ROE "spillover" mechanism that will ensure that the related revenues are used to mitigate stranded costs, rather than to permit shareholders to earn higher than a fair return.

The Customer Choice Plan also uses innovation in the redesign of rates to encourage more efficient electricity consumption and to provide for additional stranded cost mitigation. Duquesne has been a leader in the past in encouraging economic development for certain classes of customers. Now, all customers will have the opportunity to benefit from a reduction in the cost of electricity for incremental

consumption. Equally important, Duquesne's innovative rate redesign proposal, which is described in detail by James A. Lahtinen (Statement No. 5), may increase the mitigation of stranded costs during the transition period by $15 million per year.

Q. Please summarize your conclusions with regard to Duquesne's proposal to merge with APS.

A. The Commission should go beyond approval of the Customer Choice Plan in this docket and approve the Merger Application and Joint Plan filed by Duquesne and APS. As explained in my direct testimony filed in that case:

- In addition to the customer benefits identified in Duquesne's stand-alone Customer Choice Plan, the merger will provide additional savings to Duquesne, on a nominal basis, of $365 million in generation-related costs, $173 million in distribution-related costs, and $9 million in transmission-related costs.
- Duquesne will flow through 100% of these cost reductions during the transition period to its ratepayers by (i) increasing the amortization of stranded costs by $160 million during the transition period, (ii) reducing distribution rates by $25 million in 2001, and (iii) freezing distribution rates at this reduced level until 2005.

III. OVERVIEW OF DUQUESNE'S CUSTOMER CHOICE PLAN

Q. Please explain how this part of your testimony is organized.

A. This part of the testimony is organized in four sections. The first discusses the implementation schedule for customer choice and the options customers will have. The second provides an overview of the unbundled rates filed by Duquesne. The third discusses the market-based valuation of stranded costs and the basis for Duquesne's request to recover stranded costs. The fourth discusses the effect of the restructuring legislation on utility planning and service obligations.

Implementation of Direct Access; Customer Options

Q. Please provide an overview of Duquesne's proposed schedule to implement customer choice.

A. Consistent with the restructuring legislation, Duquesne will phase-in customer choice over the 1999-2001 period, such that all retail customers will have the opportunity to choose their electric supplier by 2001. As explained in Mr. Frank Hoffmann's testimony (Statement No. 6), Duquesne has designed its phase-in plan for commercial and industrial customers to avoid, to the maximum practicable extent, creating competitive disadvantages for individual businesses or business segments.

Q. What options will direct access customers have?

A. Customers will have the option to purchase generation from alternate suppliers or continue taking all their requirements from Duquesne. If a customer chooses to remain with Duquesne, the customer will receive the same service at the same rates it does

today; however, pursuant to the unbundling requirements of the legislation, the customer will receive an unbundled bill. This unbundled bill will provide customers the information they need to determine whether they could realize savings by purchasing power on the open market.

Q. Will customers receiving direct access have the right to return to Duquesne at rates capped at current levels?

A. Yes. Consistent with the restructuring legislation, customers receiving direct access will have the option of returning to full requirements service from Duquesne at rates capped at current levels for the period specified in the restructuring legislation. To prevent the shifting of costs between customers and customer classes, a customer that returns to Duquesne will be required to remain with Duquesne for a twelve-month period. Otherwise, a customer could return to Duquesne in months when electricity prices are the highest, placing increased costs on Duquesne that limit its ability to mitigate stranded costs for the benefit of all customers. As explained by Mr. Lahtinen, Duquesne is willing, however, to consider other approaches to this issue.

Unbundling; Rate Caps; Rate Design

Q. Please summarize Duquesne's proposals regarding the rates to be charged customers beginning January 1, 1999.

A. The starting point for Duquesne's rate proposal is Section 2804(4)(v) of the restructuring legislation, which states:

> If an electric distribution utility rolls its energy cost rate into base rates at a combined level that does not exceed its combined

> level of such rates which have been approved by the commission as of the effective date of this chapter, the utility shall not be required to reduce its capped rates below the capped level upon the complaint of any party if the commission determines that any excess earnings achieved under the cap are being utilized to mitigate transition or stranded costs for the benefit of ratepayers or to offset other known and measurable cost increases that would be recoverable under traditional ratemaking but are not included within the capped rates.

Duquesne will comply with this provision by (i) rolling into current base rates an energy cost rate at the level approved by the Commission in the Ft. Martin rate plan, and (ii) committing to accelerate the amortization of stranded costs in an amount that, when added to test year revenue requirements, is equal to the revenues produced at current rate levels. As indicated, Duquesne's proposed amortization schedule of $1.7 billion is a minimum commitment. Duquesne's investors bear the risk that maintaining this commitment will depress earnings. Duquesne also will establish an ROE spillover to ensure that, if revenues exceed expected levels or costs are lower than expected, the resulting revenues are used to further mitigate stranded costs. These amortization and ROE spillover commitments are discussed in detail in the testimony of Donald J. Clayton (Statement No. 2).

Q. Is this approach to mitigation new for Duquesne?

A. No. In December 1995, Duquesne filed a rate plan associated with the sale of its interest in Ft. Martin Unit 1. This rate plan included a commitment to (i) freeze base rates for five years (1996 through 2000), (ii) record a one-time write down of $130 million in nuclear plant investment, and (iii) increase amortization of nuclear

investments in the amount of $25 million for 1996-98. Pursuant to discussions with the Office of Consumer Advocate ("OCA") and the Office of Small Business Advocate ("OSBA"), Duquesne agreed to additional protections, including a cap on the ECR of 14.7 mills/kWh and the amortization and write-off of certain rate synchronization costs for Beaver Valley 2 and Perry 1. The Commission approved the modified plan without change, holding:

> The proposal of Duquesne is a unique opportunity to restructure a portion of the assets and expenses. The combination of elements in the amended petition strikes a reasonable balance through rate stabilization, expense recognition and cost reduction. For these reasons, Duquesne's proposal is in the public interest.

Petition of Duquesne Light Company for Declaratory Order, Docket No. P-00951001 et al. (June 20, 1996). Duquesne's restructuring plan provides the same "reasonable balance" of rate stabilization and stranded cost mitigation that the Commission approved in the Ft. Martin proceeding.

Q. You previously referred to the revenue requirement filed by Duquesne in this case. Has Duquesne functionally allocated this revenue requirement to generation, transmission and distribution?

A. Yes. This functional allocation is set forth in the exhibits to the testimony of Morgan K. O'Brien (Statement No. 4). The functionalized costs are then used to develop unbundled transmission and distribution rates, which are presented in the testimony of Mr. Lahtinen.

Q. You mentioned earlier that Duquesne is proposing to redesign its rates. Please explain.

A. Duquesne is redesigning its rates in a manner that will allow customers to make more efficient consumption decisions, while also providing additional revenues that can be applied to mitigate stranded costs. The rate redesign consists of moving a significant portion of generation-related costs into a fixed customer charge, which results in a lower variable (per kWh) charge than exists today. For example, a typical residential customer today pays approximately 11.4 cents/kWh under current tariffs, which is a rate far in excess of the short-run marginal cost of supplying the customer's incremental demands during most hours of the year. The Customer Choice Plan redesigns rates to lower the variable charge and thereby provides customers more efficient price signals. As explained in Mr. Lahtinen's testimony, these more efficient rates are set at a level that maximizes stranded cost mitigation. The redesigned rates thus both contribute to stranded cost mitigation and provide customers more efficient price signals.

Stranded Cost Recovery

Q. Please explain Duquesne's proposal with respect to stranded cost recovery.

A. I will summarize two of the principal components of Duquesne's proposal. The first is Duquesne's proposal to satisfy the statutory requirements of Section 2804(4)(v). As indicated, this provision permits Duquesne to charge rates up to current levels provided that "any excess earnings achieved under the cap are being utilized to mitigate transition or stranded costs for the benefit of ratepayers." In applying this provision, the question becomes how long Duquesne is entitled to charge rates up to the price cap? To answer that question, Duquesne must calculate the net present value of its

stranded costs over the life of its generating assets. This calculation is provided by Mr. Clayton.

The second component is the calculation of CTCs during the transition period. The objective here is to set CTCs at a level that accurately reflects the market choices facing (i) the customer, as it considers purchasing power from a variety of suppliers, and (ii) Duquesne, as it sells power in the market to mitigate stranded costs. Duquesne will meet this objective by calculating customer-specific CTCs on the basis of actual market prices. By using a customer-specific CTC formula, Duquesne will ensure that no customer pays more, assuming the same usage level, than it would have paid under bundled rates. By using a competitive solicitation to set market prices, Duquesne will ensure that CTCs reflect only known and measurable stranded costs, thereby protecting both the customer and Duquesne.

Before discussing each component in more detail, I note that they involve different considerations. The first requires Duquesne (i) to calculate a stranded cost amortization schedule that, coupled with the ROE spillover, ensures that available earnings are used to mitigate stranded costs, and (ii) to project the market value of Duquesne's stranded costs over the life of its generating assets. The latter calculation is important in determining how long Duquesne should be entitled to charge rates up to the price cap. The second does not require either of these analyses. Rather, the second requires Duquesne (i) to design a customer-specific CTC that ensures each customer will pay no more, assuming a constant usage level, than it did under current rates, and

(ii) to calculate market prices for use in setting the customer-specific CTCs. The latter calculation involves short-term, rather than long-term, market prices. This is because customers have the option to return to service from Duquesne at current rates throughout the transition period. Duquesne therefore cannot sell its generation on a long-term basis to establish CTCs, with the assurance that returning customers will be charged the market rate prevailing at the time of their return.

Q. Please provide more detail on Duquesne's proposal to meet the requirements of Section 2804(4)(v).

A. To determine whether Duquesne can meet the requirements of Section 2804(4)(v) throughout the transition period, Duquesne must compare the book value of its generation at the end of the transition period with the market value of that generation at that time. Duquesne must first calculate the stranded cost amortization that is possible at current rate levels, which Mr. Clayton testifies is $1.7 billion over the transition period. Duquesne then must compare the book value of generation-related assets (net of amortization) at the end of 2005 to the expected market prices of generation at the end of 2005. Using a range of market prices projected by Michael M. Schnitzer (Statement No. 3), Mr. Clayton concludes that book values will continue to exceed market values at the end of 2005. Duquesne therefore is entitled under Section 2804(4)(v) to charge rates up to current levels throughout the transition period.

Q. You mentioned that Mr. Clayton performs his analysis using a range of market price projections supplied by Mr. Schnitzer. Are such projections sufficient to satisfy the requirement that stranded costs be "known and measurable"?

A. No. As Mr. Schnitzer explains, his analysis is based on the best available market price information, including the results of Duquesne's recent solicitation to sell firm power for the period 1998-2005 and conservative assumptions concerning the post-2005 market price of power. However, as Mr. Schnitzer acknowledges, there is simply too much uncertainty today with respect to long-term market prices for an analyst to "forecast" known and measurable stranded costs. The experience from other restructuring cases in Pennsylvania supports this conclusion. In those cases, the testimony filed by competing experts contains stranded cost estimates, based on long-term market price forecasts, that differ by several billion dollars. Clearly, the uncertainty inherent in such projections poses significant risks for both investors and consumers and cannot be consistent with the known and measurable standard.

Q. What is Duquesne's proposal?

A. Duquesne is proposing that a final determination of its stranded costs not be made to-day. Instead, Duquesne proposes to initiate a final valuation of stranded costs, computed over the life of Duquesne's generating assets, in 2003. The valuation will be provided by an unbiased three-member arbitration panel. Duquesne will select one member, a consumer representative (such as the OCA and/or Commission Staff) will select the second member and these two will select a third member. The panel will

establish a market value based on objective evidence, not market price "forecasts." The objective market evidence may include consummated market transactions in the relevant market, such as forward contracts, futures contracts and/or comparable generating unit asset sales. The panel also can rely on the results of a competitive solicitation by Duquesne to sell firm power for a term coincident with the average remaining life of its generating assets.

Interested parties, including Duquesne, will have the opportunity to provide market price data to the panel and the panel's findings will be submitted to the Commission. Duquesne will commit to be bound by the panel's findings, subject only to one condition: if the Commission rejects the panel's findings and substitutes a market valuation that is adverse to Duquesne, the Commission will allow Duquesne to recalculate stranded costs by divesting some or all of its generating units, or spinning off its generating assets to a separate subsidiary and conducting an initial public offering for a portion of the stock of the new company.

Q: Assuming the panel's findings are accepted by the Commission, how will the findings affect stranded cost recovery?

A: If the panel's valuation demonstrates, contrary to expectations, that Duquesne will fully recover its stranded costs within the transition period, Duquesne will reduce the transition period accordingly. If, however, this valuation confirms that Duquesne cannot fully recover its stranded costs during the transition, the valuation will provide

the basis for any further relief that Duquesne is entitled to seek under the restructuring legislation.

Q. Is it possible that market prices will rise sufficiently prior to 2003 that this final market valuation will reveal that Duquesne has over-recovered its stranded costs?

A. It is theoretically possible, but highly unlikely given the low market prices revealed in Duquesne's recent solicitation. However, to ensure that there is no such over-recovery, Duquesne commits to accelerate the final valuation to 2001 or 2002 if market prices rise to the levels specified in Mr. Clayton's testimony.

Q. You have discussed in some detail the market valuation process to determine whether Duquesne's proposed amortization schedule will reduce book values to market levels at the end of the transition period. Is there anything further you wish to mention regarding Duquesne's amortization proposal?

A. Yes. Duquesne's amortization proposal provides customer benefits that go beyond the protections contained in Section 2808(f) of the legislation. Duquesne is proposing a minimum committed amortization schedule of $1.7 billion. This means that Duquesne's shareholders will bear the risk that this amortization is achieved at the cost of reduced earnings. For example, under Duquesne's proposal, if sales are above forecast levels, the associated revenues will be used for additional stranded cost mitigation; however, if sales are below forecast levels, Duquesne will not reduce its amortization of stranded costs below the minimum $1.7 billion commitment. Duquesne is proposing the same treatment for cost fluctuations. If the cost of service is below expected

levels, the resulting savings will be used for further mitigation; but if costs exceed expected levels, amortization will not be reduced below the minimum commitment.

Q. Please turn now to the second issue -- setting CTCs during the transition period.

A. Duquesne will calculate CTCs using a market-based determination of the value of Duquesne's generation. Each year during the transition period, Duquesne will conduct a public solicitation, or "request for proposals" ("RFP"), to sell a substantial block of power for a one-year term. Customer-specific CTCs will be set using the market prices established by the RFP, information about each customer's baseline consumption and information on class load shapes. The purpose of the customer-specific CTC methodology is to ensure that customers that are more expensive to serve (i.e., those taking a greater proportion of their requirements during peak hours) receive a higher credit and those that are less expensive to serve receive a lower credit. This is consistent with Section 2808(a) of the restructuring legislation, which states that CTCs should be set "in a manner that does not shift interclass or intraclass costs."

Q. Why is Duquesne using an RFP to set CTCs?

A. The RFP will provide reliable and objective evidence of the market prices prevailing in Duquesne's area. The RFP will protect both consumers and investors because it ensures, as the restructuring legislation requires, that CTCs are set to recover only known and measurable stranded costs.

Q. You have stated several times that Duquesne will use a market-based valuation of stranded costs, rather than a market price "forecast." Are other utilities using long-term market price forecasts to calculate stranded costs?

A. Yes, but as explained in the testimony of Mr. Schnitzer, market price forecasts have routinely proven inaccurate. This Commission's experience with "avoided cost" forecasts under PURPA should alone be sufficient to dissuade it from reliance on long-term forecasts. A market-based approach, by contrast, will protect both consumers and investors from the inaccuracy of forecasts. In Duquesne's opinion, a market-based approach is the best -- and perhaps only -- way to meet the requirement in the restructuring legislation that stranded costs be "known and measurable."

Q. You have discussed the role of market prices in computing stranded costs. Does the restructuring legislation also require that CTCs include the effects of cost of service mitigation?

A. Yes. Section 2808(c)(4) provides that the Commission may take into account past mitigation efforts and that utilities have a duty to pursue cost mitigation throughout the transition period. As explained in the testimony of Mr. Clayton, Duquesne is presenting a fully mitigated cost of service. This means that the revenue requirements on which Duquesne is proposing to set rates not only include the benefits of aggressive mitigation in the past, but also project a future cost of service that includes aggressive stranded cost mitigation, particularly the amortization of existing generating assets.

Q. Please describe Duquesne's past mitigation efforts.

A. I will provide only a summary of these efforts, given that Mr. Clayton provides a detailed recital of them. In the 1980s Duquesne faced the challenges of the shrinking steel industry in western Pennsylvania. By the end of the 1970s, the steel industry was predicting rapid expansion of its Pennsylvania production in the next decade. Not only did this growth not materialize, but by 1982 Duquesne had lost 50% of its existing industrial load and 30% of its total load.

The company took immediate steps in to deal with this loss of 700 MW of load. In 1980, the Erie nuclear units 1 and 2 and Davis Besse nuclear units 2 and 3 were canceled. The Phillips and Brunot Island units were later placed in cold reserve and removed from rate base. In addition, Perry 2 was declared de facto abandoned in Duquesne's 1986 rate case filing. Consequently, by the time of Duquesne's 1986 and 1987 base rate cases, Duquesne had mitigated the worst consequences of the steel decline. However, the Company was still faced with the cost and rate consequences associated with the capacity additions of Beaver Valley 2 and Perry 1. In the 1987 rate case, Duquesne therefore made a commitment to: stabilize rates and reduce costs; pursue marketing and economic development; reshape the company and reduce excess capacity; improve its financial condition; assist low income customers; and pursue shareholder initiatives to create value. Since that time, Duquesne has taken aggressive steps to meet the commitments it made. The specific mitigation measures undertaken by Duquesne in this period are detailed in Mr. Clayton's testimony.

Q. What were the tangible results of Duquesne's mitigation efforts?

A. Faced with an enormous challenge from the collapse of the steel industry load, Duquesne's innovative response has resulted in $340 million in stranded cost mitigation and $700 million in avoided rate increases to date. The continuing effects of this mitigation, calculated through 2005, total $1 billion in stranded cost mitigation and $700 million in avoided rate increases. Thus, the stranded cost problem facing Duquesne today is significantly smaller than it would have been had Duquesne not undertaken these mitigation measures.

Q. Has the Commission recognized these mitigation efforts?

A. Yes. In Duquesne's 1986 general rate case, the Commission recognized what it described as Duquesne's "self-imposed austerity" measures. Duquesne Light Company, Docket Nos. R-860378 et al. (Mar. 10, 1987). More recently, in the proceeding on the Ft. Martin sale, Commissioner Crutchfield observed that the sale was a "smart business decision made by Duquesne in response to the competitive pressures occurring the in the electric industry." Statement of Lisa Crutchfield, Docket No. P-00951001 (May 23, 1996). As indicated previously, the Commission found that the mitigation proposal contained in the Ft. Martin plan struck a "reasonable balance."

Q. You also stated that Duquesne's revenue requirements for the transition period include the benefits of aggressive mitigation in the future. Please explain.

A. This mitigation plan is described in more detail in the testimony of Duquesne's other witnesses, but I will summarize some of the key elements here:

- a minimum of $1.7 billion in total amortization and depreciation of regulatory assets and stranded generation costs during the transition period, with additional amortization and depreciation possible through the ROE spillover mechanism;
- additional revenues through the redesign of rates to encourage additional consumption at more efficient levels, which may yield approximately $15 million per year in additional stranded cost mitigation;
- reductions in operation and maintenance expenses and capital expenditures below historic levels at both fossil and nuclear plants, totalling more than $25 million per year;
- the continuing benefit of past mitigation, including the financial mitigation discussed by Mr. Clayton (nearly $700 million during the transition period); and
- approximately $550 million in additional mitigation due to the cost savings associated with the proposed merger with APS.

All the foregoing mitigation will be passed on to Duquesne's ratepayers through the Customer Choice Plan or, as to the last point, the Joint Plan.

Q. You have discussed Duquesne's methodology for calculating CTCs and its mitigation plan, but you have not discussed the appropriate standard for stranded cost recovery. Please turn to that subject.

A. The Commission should apply the following standard: rates should be set at a level that gives Duquesne a fair opportunity to recover a return on and of all prudent investments that may become stranded in the transition to competition.

Q. Does this standard guarantee Duquesne recovery of all its stranded costs?

A. No. Duquesne could fail to fully recover its stranded costs for several reasons. Full recovery would be impaired if Duquesne was unable to keep operation and maintenance costs below the levels approved by the Commission in setting rates. Full recovery also would be impaired if sales to retail customers were lower than the level assumed by the Commission in setting rates. Finally, Duquesne is entitled to rates designed to recover only prudently incurred costs.

Q. Does Duquesne's Customer Choice Plan fairly balance investor and consumer interests?

A. Yes. The Customer Choice Plan balances investor and consumer interests. The following are examples of the benefits and protections for consumers:

- access to alternative generation suppliers on fair and nondiscriminatory terms;
- a continued obligation to serve at current rate levels, which provides customers the benefits of a competitive market and the protections of the traditional regulatory compact;
- unbundled and redesigned rates that reduce rates for incremental consumption an average of 25% and contribute to stranded cost mitigation; and

- a new economic development rider that will reduce rates an average of 20-25% for a typical commercial or industrial customer over a five-year period;
- rate levels that include a guaranteed level of stranded cost amortization and an ROE spillover that ensures that investors do not earn more than a fair return;
- a CTC based on "known and measurable" market values set by an RFP and a final market valuation in 2003 by an unbiased arbitration panel.

Investors also will be treated fairly under the Customer Choice Plan. The Plan is designed to provide investors with a fair opportunity, consistent with the customer protections above, to earn a fair return on and recovery of Duquesne's prudent investments.

Q. Some have argued that investors have no reasonable expectation of earning a fair return on investments that cannot be recovered in a deregulated market. Please comment.

A. I do not agree. Duquesne's investments were made under a regulatory system that provided investors a reasonable expectation that they would earn a fair return on and recovery of prudent investments by the utility.

Q. Please explain your point.

A. The regulatory system to which I refer, sometimes called the "regulatory contract," is typified by the utility's obligation to serve the demands of all customers within its franchised territory. To meet this obligation, Duquesne forecast the expected demands of its customers over a planning horizon of 20 years and planned to have in place the generation needed reliably to serve these demands. Each of Duquesne's investment

decisions in generation was based on this obligation to serve and each investment decision over the last twenty years was scrutinized by the Commission. With minor exceptions, all the associated costs were found to have been prudently incurred.

The fact that the remaining book value of these investments may not be recoverable in a deregulated market does not mean that recovery of these investments in a CTC is not appropriate. The *quid pro quo* for Duquesne accepting the foregoing obligation to serve was the grant of an exclusive franchise to serve these customers. Duquesne therefore could reasonably expect that the loads forecasted for its customers would be served by Duquesne, not by other utilities in the region, and thus that Duquesne could reasonably recover its investment in rates over the life of those investments. While there was some risk of self-generation in recent years, there was no obligation to deliver energy produced by others over Duquesne's transmission and distribution wires, as there is under the restructuring legislation. Moreover, any revenue impacts associated with the loss of load were, consistent with traditional regulation, spread across all customer classes, not borne by shareholders. In short, prior to the change in policy reflected in the legislation, Duquesne's rates were sufficient to permit it to earn a fair return on and of its investments; it is the change in regulatory policy that creates the potential of stranded costs at issue in this case.

Q. Some have argued that, since the government does not insulate other industrial companies from changes in economic conditions or government policies, utilities should receive no such protections. Please comment.

A. There is a material difference between a regulated electric utility and other industrial companies. Take, for example, a large supplier of aircraft. A supplier of aircraft builds fleets of planes and invests large amounts of capital in doing so. The supplier is subject to intense competition from other aircraft manufacturers and is aware that the airlines will have the option of purchasing their aircraft from a number of suppliers. To compete as a manufacturer, the supplier has the choice of investing capital to build aircraft on the assumption that the airlines will purchase their requirements from that supplier (and not others), or of executing contracts under which the airlines make certain quantity and price commitments in return for the supplier making the required investments. In addition, the supplier has the choice not to construct additional aircraft or to limit its production -- for example, because of the unwillingness of airlines to make the necessary contractual commitments.

This is in contrast to the contractual opportunities and investment decisions faced by electric utilities. Consider the example of Duquesne when it began its nuclear construction program to meet the expected growth in demand from the steel sector. Duquesne had the legal obligation to plan for and serve that demand growth. Duquesne did not have the option to decline to make the required investments unless the steel companies signed long-term contracts to pay for such investments. Rather, Duquesne was required to make prudent investment decisions to serve all its load based on the information available at that time, with the expectation that the Commission would permit Duquesne to roll such investments into the rates of customers. Now that

this regulatory system has been modified it would be unfair to permit customers to avoid responsibility for such investments and to shift such responsibility to Duquesne's investors.

To do so would result in an arbitrary and one-sided switch in policies. Traditional regulation does not allow a utility to earn more than a fair return during "good times," such as when growth in customer demand exceeds expectations, the cost of service is lower than expected, or investments have a positive market-to-book value. The sale of Ft. Martin is a good example. Duquesne sold its interest in Ft. Martin for $130 million (pre-tax) in excess of the remaining book value of the plant. Duquesne was not, however, permitted to return this value to shareholders through excess earnings. Rather, Duquesne returned this value to ratepayers through the accelerated amortization of assets. Another example was Duquesne's proposed sale of 500 MW of firm power to General Public Utilities in 1990 through reactivation of the Phillips and Brunot Island plants. The Commission determined that the net revenues from the proposed sale, estimated at over $300 million, would be fully credited to ratepayers. This was the case even though Duquesne's investors had been incurring the "caretaker" costs of maintaining those units in a condition that would permit their reactivation. While the sale ultimately fell through due to a lack of regulatory approval in New Jersey, the point is that the Commission determined that ratepayers, not investors, should benefit from market values in excess of the book value on which Duquesne is permitted to earn a fair return.

I comment on the Ft. Martin and proposed GPU sales not to criticize the Commission orders issued in those cases. Rather, those orders were entirely consistent with the regulatory contract. I discuss the orders simply as a point of comparison to the arguments of some that the Commission should now, when book values exceed market values, change policy and require Duquesne's investors to absorb the difference. Clearly, this would an arbitrary and unfair switch in policy and would produce a result for which shareholders have not been compensated. I fully expect and trust that the Commission will not be influenced by such arguments and will set rates that provide Duquesne a fair opportunity to fully recover a return on and of all prudent investments.

The Restructured Business

Q. Please summarize the nature of the changes in the organization and operation of Duquesne Light as the result of the Customer Choice Plan.

A. I will discuss two aspects of this topic. The first is the change in the nature of Duquesne's generation planning function and its obligation to serve customers within its service territory. The second is the functional unbundling of Duquesne's business into those units that will continue to provide services that are regulated on a cost of service basis and those that are not regulated.

Q. Please turn to Duquesne's generation planning function and the nature of the obligation to serve during and after the transition to competition.

A. As I discussed earlier in my testimony, electric utilities have operated under a regulatory system that required them to plan to serve all customers within their territory

on a reliable basis. The amount of generation constructed to meet these demands was a function of the expected peak customer demand plus a "reserve margin." This reserve margin allowed the utility to continue serving load reliably during periods when demand exceeded forecasts or when a portion of the utility's generation was unavailable due to forced or planned outages. The reserve margin was calculated using a "loss of load probability" model that generally used as its solution a one-day-in-ten-years standard of interruption.

This planning process will change in a number of important respects, two of which I will mention here. First, following the transition to competition, utilities in Pennsylvania will no longer be obligated to serve all the energy requirements of the customers in their service territory. Utilities such as Duquesne thus will no longer be obligated as a matter of law to have available sufficient generation to serve these customers. Rather, the regulatory-based obligation to serve will be replaced by contractual obligations between customers and generation suppliers.

The second major change will be in the nature of "reliable" service. Today, reliable service means service without interruption -- regardless of the cost to supply customers in a given hour. In the future, as utilities install real-time meters and as hourly spot energy prices become public, customers and suppliers will have the information necessary to determine whether it is economic to increase or decrease consumption at peak periods when the marginal cost of service is very high. Conversely, customers and suppliers will have similar price signals available in off-

peak periods when the cost of service is very low. Using this information, I expect many customers will choose to be interrupted or to reduce their consumption in peak hours instead of paying the high cost of energy in those hours.

Q. Do you expect these changes to occur immediately?

A. No. The restructuring legislation continues to impose on Duquesne an obligation to serve throughout the transition period. Duquesne will choose the most economic means of meeting this obligation, such as making short-term capacity purchases in the wholesale market. The testimony of Mark Karl (Statement No. 9) discusses this continuing obligation to serve in more detail.

Q. You have stated that the obligation to serve will be replaced by competition among a variety of suppliers. Do you expect that the introduction of competition to supply retail customers will benefit those customers by reducing rate levels?

A. Introducing retail competition will benefit customers by securing for them the efficiencies of a competitive generation sector. This does not necessarily mean, however, that rates will be lower immediately. In the long-run, I am confident that competition will produce lower rates than will continued reliance on comprehensive regulation of the generation sector. However, the Commission should bear in mind that this does not necessarily mean that rates will be "lower" than they are today at all times in the future; rather, the point is that they will be lower than they otherwise would have been under traditional regulation. Competition encourages the efficient utilization of societal resources; it does not guarantee "low" rates or any rate in

particular. Rather, the benefits to consumers will consist of more efficient risk bearing by suppliers; increased operational efficiencies of power producers; a greater range of customer choices, products and services; improvements in technological innovation; and better use and expansion of the transmission system.

Q. Please turn to the functional unbundling of regulated and unregulated services and business units.

A. Duquesne began the unbundling of services and business units in mid-1996 with the implementation of FERC Order Nos. 888 and 889. In these orders, the FERC required that the wholesale merchant function be separated from the transmission function to ensure that the utility's power sales would not receive preferential access to transmission system information.

Q. What is Duquesne's position on independent system operators ("ISOs")?

A. Duquesne has been a long-standing advocate of ISOs. In 1996, I testified before this Commission that a regional ISO that administers an efficient location-based transmission pricing regime was the best way to achieve transmission comparability and efficiency. Duquesne has taken the same position in all its pleadings and testimony filed with the FERC.

Q. Has Duquesne been involved in the efforts to form an ISO in its region?

A. Yes. Duquesne has been active in the PJM restructuring proceeding. In fact, Duquesne's Section 211 request submitted to PJM in 1994 included many of the

principles adopted by PJM in its ISO proposal, including a single-system transmission rate and comparability for all transmission users.

Q. Commissioner Hanger has expressed concern that non-PJM utilities in Pennsylvania have not yet joined an ISO. How can Duquesne effect reform in this area?

A. Duquesne is a small utility that simply does not have sufficient influence to lead a reform effort in this area. That is one of the advantages of the proposed merger with APS. The merged company will be well situated to be a leader with respect to the trend toward greater separation of the generation and transmission functions. My testimony in the merger proceeding addresses the joint proposals of Duquesne and APS in this area.

Q. Do additional functional separation and unbundling issues arise as the result of the transition to retail competition?

A. As explained in Mr. Hoffman's testimony, the transition to competition at the retail level will require that Duquesne functionally separate regulated retail functions from those that will not be regulated. Duquesne is taking the first step in this area by proposing a code of conduct that will govern the interaction of the regulated and unregulated units of Duquesne.

IV. INTRODUCTION OF COMPANY WITNESSES

Q. Please identify the other witnesses providing direct testimony on behalf of Duquesne in this proceeding.

A. In addition to myself, the following witnesses will be responsible for presenting the Company's case-in-chief:

Donald J. Clayton is Treasurer of Duquesne. Mr. Clayton describes how Duquesne has aggressively mitigated stranded costs and moderated rates in the past. He also describes how these efforts will continue throughout the transition period, resulting in total mitigation of $1.0 billion. Mr. Clayton also describes how Duquesne proposes to recover its stranded costs under a rate cap through 2005 and demonstrates why the Company meets the requirements of Section 2804(4)(v). To make this showing, Mr. Clayton calculates a range of stranded costs that are likely to remain in 2006, despite a minimum commitment of $1.7 billion of depreciation and amortization during the transition period. He also describes the equity return spillover mechanism that ensures the committed level of amortization is a floor, and that prospective earnings in excess of the allowed return would be applied to increase this amortization level. Mr. Clayton also describes the events that might trigger an early termination of the transition period.

Michael M. Schnitzer is President and a Director of The Northbridge Group, an economic and management consulting firm based in Waltham, Massachusetts. Mr. Schnitzer provides independent support for Duquesne's compliance with the known and measurable standard under the Act. He supports use of a market-based approach rather than an administrative determination of stranded costs. Mr. Schnitzer supports Duquesne's proposal to meet the requirements of Section 2804(4)(v) of the

restructuring legislation to establish a price cap through 2005. Mr. Schnitzer also supports Mr. Clayton's market valuation as of 2005 with a market price ceiling estimate based on a gas-fired combined cycle unit. In addition, Mr. Schnitzer supports Mr. Lahtinen's use of a market-based approach to CTC calculation. Mr. Schnitzer also provides independent support for the final market valuation mechanism in 2003 used to calculate a residual value for Duquesne's generation assets at the end of the transition period. Finally, Mr. Schnitzer supports the customer safeguards built into the Customer Choice Plan.

Morgan O'Brien is Controller of Duquesne. Mr. O'Brien supports the Company's claim for recovery of regulatory assets, unfunded nuclear decommissioning expenses and fossil decommissioning expenses under the Act. Mr. O'Brien also presents the 1996 cost of service and the pro forma financial data and the Company's responses to the Commission's restructuring plan filing requirements in Appendix A of the Restructuring Order. The results of Mr. O'Brien's study are used by Mr. Lahtinen to unbundle Duquesne's rates.

James A. Lahtinen is General Manager, Regulatory and Economic Analysis Unit of Duquesne. Mr. Lahtinen sponsors Duquesne's unbundled allocated cost of service study and unbundled tariffs designed to recover such costs. He supports the approach the Company has taken in unbundling transmission, distribution, ancillary service and generation costs by customer class. Mr. Lahtinen explains Duquesne's approach to calculating Customer Generation Credits and CTCs based on actual market

price data. He also describes the rationale underlying Duquesne's proposed rate redesign and how these rates were calculated to comply with the restructuring legislation and to mitigate stranded costs. Finally, he provides public data on market prices that corroborate the prices received by Duquesne in its recent request for proposals.

Frank A. Hoffmann is General Manager, Marketing and Sales Unit of Duquesne. Mr. Hoffmann outlines Duquesne's method for phasing-in customers for direct access during the three-year phase-in period. Mr. Hoffmann also summarizes Duquesne's proposals on universal service and energy conservation. Duquesne will maintain all existing programs for assisting low income customers. He also describes the Company's proposed consumer education program. This program is multi-faceted and is designed to reach all segments of our diverse customer base. Mr. Hoffmann also presents the proposed Code of Conduct for ensuring that all alternative suppliers are treated fairly and that confidential information is not released without authorization. Finally, Mr. Hoffmann describes the Company's economic development rates and how those rates will change or continue in the future.

Robert Irvin is General Manager, System Operations Unit of Duquesne. Mr. Irvin describes the current market prices for power delivered in Duquesne's service territory. Mr. Irvin also describes Duquesne's recent RFP. He also discusses the procedures and systems that Duquesne will implement to promote competition and

provide unbundled access to electric generation during the transition period. Finally, he describes how Duquesne differentiated between distribution and transmission assets.

Fred Allison is Assistant Controller of Duquesne. Mr. Allison addresses the implementation of metering, meter reading, billing, payment processing, collections and supplier settlement for purposes of direct access. Mr. Allison describes a new metering technology that Duquesne has begun installing. This new technology will enhance service reliability, allow greater flexibility in meter reading and billing and allow the Company to receive real-time information on customer usage. Mr. Allison also addresses the arguments of some stakeholders that, in addition to unbundling generation, transmission and distribution, all "revenue cycle services" should be unbundled. Finally, Mr. Allison describes the Company's proposed procedures for addressing supplier settlements.

Mark Karl is a Senior Consultant, responsible for Duquesne's Integrated Resource Planning Department. Mr. Karl supports the forecast of generation output for Duquesne's units used in Mr. Clayton's analysis. Mr. Karl also supports the price duration curve analysis that is used to derive hourly market prices from the annual market data obtained from the Duquesne RFP.

Ralph L. Nelson is Manager of Operations Services in Duquesne's Fossil Generation Unit. Mr. Nelson provides the calculation of Duquesne's operation and maintenance expense and capital expenditures during the transition period for

Duquesne's fossil generation. Mr. Nelson also describes the cost mitigation that has allowed Duquesne to reduce the cost of operating its fossil units.

Ralph E. Duckworth is Controller of Duquesne's Nuclear Unit. Mr. Duckworth provides the calculation of Duquesne's operation and maintenance expense and capital expenditures during the transition period for Duquesne's nuclear generation. Mr. Duckworth also describes Duquesne's mitigation of nuclear O&M costs.

Jeffrey D. Makholm is a Senior Vice President of National Economic Research Associates, Inc., an economic consulting firm based in Cambridge, Massachusetts. Dr. Makholm supports the equity cost of capital used by Duquesne to calculate its revenue requirements and by Mr. Clayton to derive present value calculations. Mr. Makholm also explains why utilities should be permitted to recover stranded costs and shareholders have not already been compensated for the risk of stranded costs.

Thomas P. LaGuardia is President of TLG Services, Inc. Mr. LaGuardia presents the results of his analysis of the nuclear decommissioning costs for Beaver Valley Units 1 & 2 and Perry Unit 1. He also presents fossil decommissioning studies for the Company's fossil-fired generating stations.

V. THE MERGER WITH APS

Q. Please discuss why the Commission should go further and approve the Merger Application and the Joint Plan.

A. The rationale for Commission approval of the Merger Application and the Joint Plan is fully set out in the Company's joint application with West Penn. As documented therein, additional synergy benefits will be created by the merger and shared by the customers of Duquesne, West Penn and the other non-jurisdictional subsidiaries of Allegheny Power. In summary, the evidence shows that:

- In addition to the customer benefits identified in Duquesne's stand-alone Customer Choice Plan, the merger will provide additional savings to Duquesne, on a nominal basis, of $365 million in generation-related costs, $173 million in distribution-related costs and $9 million in transmission-related costs.
- Duquesne will flow through 100% of these cost reductions during the transition period to its ratepayers by (i) increasing the amortization of stranded costs by $160 million during the transition period, (ii) reducing distribution rates by $25 million in 2001, and (iii) freezing distribution rates at this reduced level until 2005.

Q. Does that conclude your testimony?

A. Yes it does.

VOLUME I

Duquesne Statement No. 2

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

DUQUESNE LIGHT COMPANY
DOCKET NO. R-00974104

Direct Testimony
of
Donald J. Clayton

Contents:

Regarding Cost Mitigation Efforts, Stranded Cost Calculations and Recovery, Cost of Capital and Capital Structure.

DIRECT TESTIMONY OF D. J. CLAYTON

I. QUALIFICATIONS

Q. Please state your name and business address for the record.

A. My name is Donald J. Clayton. My business address is 411 Seventh Avenue, Pittsburgh, Pennsylvania 15230-1930.

Q. By whom are you employed?

A. I am employed by Duquesne Light Company ("Duquesne," "Duquesne Light" or "the Company").

Q. What is your position with Duquesne?

A. I am the Treasurer.

Q. How long have you been employed by the Company?

A. I have been employed by Duquesne since August of 1985.

Q Please describe your responsibilities as Treasurer of the Company.

A. My areas of responsibility include corporate finance, cash management, financial planning, corporate budgeting, electronic commerce and shareholder relations.

Q. Please describe your professional and educational background?

A. A copy of my curriculum vitae which describes my professional and educational background is provided as Exhibit DJC-1.

Q. Have you previously testified before this Commission?

A. Yes. I have testified before the Commission in the Company's last two base rate proceedings at Docket Nos. R-860378 and R-870651. I have also supported the

Company's filings at P-00951001, related to the sale of the Ft. Martin Plant; P-900485, related to the proposed power sale to GPU and affiliated interest filings at G-00940376 (Woods Run) and G-00940392 (Headquarters' Building).

II. PURPOSE AND CONCLUSIONS

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to explain the efforts that the Company has undertaken to mitigate its stranded costs and to minimize its costs generally, to describe and provide support for the Company's stranded cost calculations and stranded cost recovery plan, and to support the Company's overall cost of capital (excluding return on equity) and capital structure. I am also sponsoring several of the required data items identified in Appendix A to the Commission's Order dated February 13, 1997 at Docket No. M-00960890.

Q. Please summarize your conclusions.

A. My conclusions correspond to the purposes of my testimony. First, Duquesne has already implemented the most aggressive mitigation strategy of any utility in Pennsylvania. These past efforts have resulted in over $1 billion of mitigation which has enabled the Company to avoid $700 million in rate increases and to reduce its potentially stranded costs as of January 1, 1999 by $340 million. The results of this past mitigation will continue after January 1, 1999 through December 31, 2005 (the "Transition Period") and over this period will result in further reductions in potentially stranded costs of $690 million. Witnesses Marshall, Lahtinen and Karl describe the Company's ongoing mitigation efforts.

Second, Duquesne has proposed a restructuring plan that relies on a true market-based determination of stranded costs as of the end of the Transition Period. The plan provides

for a generation price cap and a minimum commitment of $1.7 billion of depreciation and amortization of generation and regulatory assets by December 31, 2005. All of the generating plant and regulatory assets that will be recovered under the accelerated depreciation and amortization for which the Company is now seeking approval were either approved in prior rate and regulatory proceedings or recognized for recovery in future proceedings. Hence, the prudence of these investments has already been determined by the Commission.

Third, the appropriate overall cost of capital for the Company is 9.61% and the appropriate after-tax discount rate for use in the present value calculations is 7.83%. This cost of capital is based on a cost of common equity of 11.50% and a year end 1996 capital structure of 40.08% common equity, 9.69% preferred equity and 50.23% long-term debt. The cost of common equity is independently supported by the testimony of Dr. Jeffrey D. Makholm.

III. DUQUESNE HAS AGGRESSIVELY MITIGATED STRANDED COSTS AND MODERATED RATES

Q. Why are Duquesne's historic and planned mitigation efforts important to the Company's claim for stranded cost recovery?

A. In Section 2808(C)(4) of the Customer Choice Act it states that:

> "the Commission shall consider the extent to which the electric utility has undertaken efforts to mitigate generation-related transition or stranded costs by appropriate means in a manner that is reasonable under all of the circumstances, including consideration of whether mitigation has been commensurate with the magnitude of the electric utility's generation-related transition or stranded costs."

Therefore, Duquesne's aggressive historic mitigation efforts should be recognized by the Commission as a proactive solution which reduces the Company's stranded cost to the absolute minimum level possible before the phase in to competition begins in 1999.

Q. In your summary of the Company's position with respect to stranded cost recovery you state that Duquesne has implemented the most aggressive mitigation strategy of any company in Pennsylvania. Will you identify the components of this strategy?

A. Yes. Duquesne's historic mitigation efforts fall into six major areas, as follows: (1) cost containment; (2) financial restructuring; (3) maximization of market revenues; (4) acceleration of depreciation and amortization; (5) asset sales; and (6) tax planning.

Q. Are Duquesne's historic mitigation strategies consistent with the mitigation strategies described in the Customer Choice Act?

A. Yes. In Section 2808(c)(4) the act states that:

> "during the transition period, electric utilities shall have the duty to mitigate generation-related transition or stranded costs to the extent practicable. Efforts may include the following:
> (I) Acceleration of depreciation and amortization of existing rate base generation assets.
> (II) Minimization of new capital spending for existing rate base generation assets.
> (III) Reallocation of depreciation reserves to existing rate base generation assets.
> (IV) Reduction of book assets by application of new proceeds of any sale of idle or under-utilized existing rate base generation assets.
> (V) Maximization of market revenues from existing rate base generation assets.
> (VI) Issuance of securitized debt pursuant to the provisions of Section 2812 (relating to approval of transition bonds)."

Duquesne's depreciation, cost containment, asset sales and maximization of market revenue strategies are specifically identified in the Act. Duquesne's historic mitigation

efforts have, however, gone well beyond the strategies specifically identified in the act. With respect to cost containment Duquesne has not only reduced generation related capital spending but has reduced operating and maintenance expenses throughout the Company as well as capital spending related to transmission and distribution. Duquesne's financial restructuring efforts have significantly reduced its overall cost of capital and these efforts are consistent with the benefits other companies may be able to derive from asset securitization. Duquesne's tax planning strategies are unique and have significantly contributed to the Company's mitigation efforts.

Loss of Steel Load Placed Duquesne in Financial Distress

Q. Please describe the historical context for Duquesne's past mitigation efforts.

A. Throughout the 1970s, various steel companies had informed Duquesne that they intended to add significant high load factor load over the next several years. With these and other additions, it was expected that the Company's total load would approach 3300 MW. All indications were that the Company was deficient in base load capacity and would have to make significant capacity additions in order to fulfill its public service obligation to meet this demand. Consequently, Duquesne had approximately 3,600 MW of capacity in service or under construction and another 400 MW on the drawing board. (Perry Units No. 1 and No. 2 and Beaver Valley Unit No. 2 were under construction and Erie Nuclear Units No. 1 and No. 2 and Davis Besse Units No. 2 and No. 3 were in the planning and design stages).

Q. Did this load growth actually occur?

A. No. Quite the contrary. The steel making industry in Pittsburgh virtually collapsed. This factor, and its consequent ripple effect through the Pittsburgh economy, was devastating.

In fact, by 1982, the Company had lost 50% of its then existing industrial load (700 MW) and 30% of its total load. At the same time, Duquesne was left with expensive new nuclear generating units to serve the base load that had just evaporated. The resulting upward pressure on rates began to manifest itself immediately, with revenue declining and rate base expanding.

Q. What steps did the Company take to address this situation?

A. Duquesne acted to reduce its planned and existing capacity. In 1980, the Company canceled the four nuclear plants, Erie Unit Nos. 1 and 2, and Davis Besse Units No. 2 and No. 3 which were in the design phase. In 1986, the Company declared a de facto abandonment of Unit No. 2 at the Perry Nuclear Plant. At about the same time, the Company placed its Phillips Generating Station (an older coal-fired unit) and a portion of its Brunot Island Units in "cold reserve" and removed them from its rate base. These actions had the effect of reducing the Company's capacity to approximately 2,800 MW. At the same time, the Company attempted to address its revenue losses by aggressively selling power at wholesale.

Q. Was there a point at which this situation became critical for the Company?

A. Yes, the lowest point was reached in 1986. In that year both Beaver Valley Unit No. 2 and Perry Unit No. 1 were nearing completion but not producing any revenue. As one can imagine, the associated drain on the Company's financial resources was devastating. Duquesne's bond rating was reduced to "BBB-", the last notch above a junk bond. In order to begin to restore the Company's financial health, the Company reduced its dividend by 41%. (The Company's dividend level has not yet reached the pre-1986 level). The drain on our human resources was also severe. We were forced to lay off 100

employees and implement salary reductions and freezes. Throughout these trying times, the Company managed to maintain its standards of customer service and environmental protection. Nevertheless, 1986 was truly a watershed year despite the hardships endured by the Company and its customers. In 1986 the Company formulated and adopted the "Duquesne Plan," which ultimately restored the Company to financial health and led to its ability to contain costs and obviate the need for rate relief. I will discuss the Duquesne Plan in detail after I discuss the Company's 1987 rate case, which was decided in March 1988 in Docket R-870651.

Q. What were some of the significant results of the rate case that was decided in 1988?

A. In that case, the Commission found that the Company required a revenue increase of approximately $232 million, to be phased-in over a three year period. The phase-in was to be followed by a three-year rate freeze and then a rate decrease of approximately 8% in 1994. Although the Commission deemed that 95% of the costs associated with Beaver Valley Unit No. 2 were prudent, the Company was denied any equity return of the investment associated with that plant through December 31, 1991. The Commission also required as a *quid pro quo* for the inclusion in rate base of the investment in Perry Unit No. 1, that an equivalent amount of capacity of the Company's Elrama units be denied an equity return on rate base. Duquesne was also prohibited from continuing to amortize the costs associated with the canceled nuclear units, (Erie Units No. 1 and No. 2 and Davis Besse Units No. 2 and No. 3) which had been authorized in earlier orders. Duquesne was also required to maintain its equity ratio at a level of 40% to 42%.

Q. You stated that you wanted to expand upon your description of the Duquesne Plan. What were the central elements of the Duquesne Plan?

A. The Duquesne Plan is, perhaps, best expressed in the following quote from the Company's 1986 Annual Report:

> "To become more efficient, more competitive, more market-driven, more customer-oriented and more profitable, we are determined to evolve and change."

Clearly, long before electric competition became the law in this State, Duquesne recognized that it needed to become a nimble, active competitor if it was to survive and prosper.

Duquesne Aggressively Pursued Cost Containment

Q. What cost containment measures did you undertake?

A. The Company began an aggressive fuel cost reduction effort. For example, in 1988 our average fuel component in base rates was 16.45 mills per kwh. Today our fuel cost is capped at 14.70 mills per kwh[1]. We established cost containment and reduction programs for both capital expenditures and O&M. Since 1988, the Company's capital expenditures have averaged just $101 million annually or approximately two thirds of the Company's normal depreciation level. The Company's O&M costs have been reduced in nominal terms from $342 million in 1988 to $331 million in 1996. Also, since the implementation of the Duquesne Plan, the Company's workforce has been reduced from 4,500 to today's level of 3,500 with most of this reduction being accomplished through attrition and hiring freezes.

Duquesne Completed an Aggressive Financial Restructuring

Q. What other efforts were undertaken?

[1] Under the Fort Martin Agreement, the fuel component is permitted to be no higher than 14.7 mills per kWh and is currently being charged at a much lower rate (12.8 mills per kWh).

A. Duquesne embarked upon an aggressive financial restructuring program to reduce our capital costs through the sale and leaseback of Beaver Valley No. 2, debt refinancing and a buy-back of equity. Since 1988, the Company has reduced its outstanding debt by $216 million, reduced its outstanding preferred and preference stock by $25 million and has repurchased $270 million of its common stock. Also, in 1996, the Company declared a one time dividend of $150 million to DQE which further reduced the Company's equity capitalization. As a result of these programs, the Company's interest cost has been reduced by approximately $60 million and the Company's overall cost of capital has dropped from 10.94% in 1988 to just 9.61% which compares favorably with the other electric utilities in Pennsylvania. At the same time as we were reducing the cost of capital through financial restructuring, we were adding flexibility to our financing ability by replacing our 1947 mortgage indenture. The Company's new mortgage indenture will make it much easier for the Company to truly "unbundle" its assets and to continue to downsize its capital structure.

Duquesne Aggressively Pursued New Sources of Market Revenues

Q. What has Duquesne done to maximize market revenues?

A. Earlier, I mentioned the Company's off system sales. We aggressively pursued this source of revenue and flowed through the benefits to our customers. Off-system sales prior to the sale of Ft. Martin have averaged 3,000 gwh per year making the Company a major seller of power in the wholesale market. This has produced significant gross margins ($10 to $12 million per year) that lessened the rate burden on our customers through a credit to the Company's fuel clause. We also vigorously pursued economic

development activities in our service territory in an effort to increase revenues in a manner that would reduce the need for rate increases for all customers. Duquesne pursued numerous economic development activities, such as: the adoption of economic development riders to our tariff (which offer reduced rates to new customers for up to five years); the adoption of "Rule 4" (which allows the company to negotiate confidential rates with large customers); a loan program for developers who agree to use electric equipment; maintenance of a database of potential development sites; and active participation in the business community. As a result of these programs and others, Duquesne's industrial and commercial sales growth in recent years has been strong and recently our peak load has once again reached its 1981 level.

Accelerated Depreciation and Asset Sales Have Mitigated Stranded Costs

Q. When did the Company first accelerate depreciation related to its nuclear facilities?

A. The Company increased the depreciation expense related to Perry by $25 million in 1995. Duquesne was the first company in Pennsylvania to request such an increase in depreciation without a corresponding request for a rate increase. This was made possible because of the previously discussed mitigation strategies.

Q. Please describe the Ft. Martin sale and rate agreement.

A. In continued pursuit of its mitigation strategies, the Company negotiated the sale to AYP Capital, Inc. (an unregulated subsidiary of Allegheny Power Systems, Inc. ("APS") of its 50% interest (267 MW) in Unit 1 of the Ft. Martin Power Station, which is located on the Monongahela River between Morgantown, West Virginia and Point Marion, Pennsylvania. The sale of the Company's interest in this plant enabled it to sell, at a price of $169 million, an asset that because of the West Virginia Export Tax, was

relatively expensive for the Company to operate. Moreover, the Company's sale of this asset enabled it to propose to the Commission the Ft. Martin Agreement which produced very substantial benefits for customers.

Q. Please discuss the Ft. Martin Agreement and its attendant benefits.

A. The principal elements of the Ft. Martin Agreement, contained in the Company's amended petition to the Commission for its approval of the sale of the Ft. Martin plan to AYP Capital, Inc. are, as follows:

1. Duquesne shall cap its rates through December 31, 2000.

2. Duquesne will use its net proceeds from the sale to record a one time reduction of $130 million (pre-tax) in the value of its nuclear plant investment;

3. The Company will restore to service its generating units located at its Brunot Island Power Station;

4. Duquesne will increase its annual depreciation and amortization by $25 million for the years 1996, 1997 and 1998 for its nuclear units;

5. The Company will increase its annual contribution to its nuclear decommissioning trust fund by $5 million;

6. Duquesne will cap its energy costs in its Energy Cost Rate at 14.7 mills per kwh, including a $5 million credit to offset the loss of potential off-system sales from the Ft. Martin Plant;

7. Duquesne will begin to amortize its $51.1 million in rate synchronization costs for Beaver Valley Unit No. 2 and Perry Unit No. 1 with an initial $9 million charge off followed by a ten year amortization of the remaining balance of $42 million; and

8. The Company will contribute $500,000 annually to assist low income customers.

The Office of Consumer Advocate ("OCA") concurred in the Company's proposal, and the Commission, by order entered June 20, 1996, approved it as being in the public interest.

Duquesne Has Used Innovative Tax Planning Strategies to Mitigate Stranded Costs

Q. Please explain how Duquesne has and will continue to mitigate its stranded costs through innovative tax planning.

A. The Company is providing in its cost of service a tax allocation factor which lowers its effective tax rate from 41% to 24%. This lower tax rate reflects the tax benefits of certain investments made at subsidiaries of Duquesne. Previously flowed through tax benefits have now reversed and are causing taxable income for both federal and state income tax purposes to be higher than regulatory book net income. The tax benefits mitigate the taxes that would otherwise be payable by customers in rates. Going forward, the Company is reflecting the future tax benefits of certain investments made at Duquesne and its subsidiaries to mitigate nearly $300 million of the Company's potential stranded costs.

The Internal Revenue Code was amended in 1982 to encourage companies to invest capital in fixed assets within the U.S. and allowed for accelerated depreciation of those investments under a system known as the ACRS depreciation system. Under the ACRS system nuclear power plants were depreciated over a ten year period using a 150% declining balance methodology. Thus, Duquesne's investment in Perry Unit No. 1 and

Beaver Valley Unit No. 2 were depreciated for tax purposes over 10 years. For ratemaking purposes these investments would be depreciated over their expected operating period of 40 years. In both of its most recent base rate cases, R-860378 and R-870651, Duquesne was required to flow through to customers the state income tax benefit of the ACRS tax depreciation exceeding the ratemaking depreciation, as well as certain federal income tax benefits for deducting certain costs currently for income tax purposes (as opposed to capitalizing for regulatory accounting purposes). This regulatory treatment causes significant income tax liability to be recognized commencing with the year the regulatory depreciation exceeds the income tax depreciation and continuing through the regulatory accounting life of the plant. Duquesne recognized early on that, absent any mitigation, these future tax burdens caused by the reversal of the accelerated depreciation would have to be borne by its customers through higher rates.

Beginning in 1995, Duquesne and its subsidiaries invested in a series of investments whose returns were centered around the income tax benefits which the Company could use to mitigate its growing tax burden. These investments included investments in affordable housing projects, investments in Internal Revenue Code ("IRC") Section 29 alternative fuels projects, as well as, leasehold interest investments. The affordable housing projects are all located within the state of Pennsylvania and the majority of the investments are actually located within the service territory of the Company. These projects provide affordable housing to low-income families and supplement the investors' return with income tax credits. The Section 29 alternative fuels projects are

investments in gas projects which economically would not warrant development but for the income tax credits which the U.S. Congress created to enhance energy exploration and development by investors. These projects are also all within the state of Pennsylvania. Finally, Duquesne invested through a subsidiary in a series of leasehold interests which were structured to pass on the tax benefits of lease arrangements from lessees who would not otherwise have been able to realize these tax benefits for a variety of circumstances. In total, through these tax advantaged vehicles, Duquesne is providing a reduction in its effective tax rate from 41% (a rate which reflects the reversal of the previously flowed through benefits) to only 24%.

DQE Passed On Tax Planning Expertise to Benefit Customers

Q. How did Duquesne acquire the expertise to enter into tax advantaged investments?

A. In 1989, DQE was formed as a holding company, both to help meet competition and to strengthen the Company's financial position. Due to the initial inherent riskiness, an unregulated subsidiary of DQE was used as the vehicle for DQE's first tax advantaged transactions involving leveraged leases. In 1993, DQE entered the field of affordable housing through an unregulated subsidiary. Essentially, the federal government subsidizes affordable housing transactions by providing tax benefits. Prior to DQE's involvement, most of the affordable housing credits in Pennsylvania went to Philadelphia, almost none went to Pittsburgh. Having developed the expertise in this area (and, more importantly, having absorbed the initial risk) DQE then shared that expertise with Duquesne, which allowed the Company to develop its own affordable housing projects in Pittsburgh. These projects provide multiple benefits. They not only help the local economy (by injecting capital) and low income residents (who are given

access to good quality, affordable housing), but they also reduce Duquesne's federal income tax rate and, hence, its overall cost of service. These projects also demonstrate the feasibility of "all electric" energy for such developments.

Q. Was the expertise in Section 29 transactions and tax advantaged lease transactions similarly transferred from DQE to Duquesne?

A. Yes. For the transactions known as alternative fuels transactions which qualify for tax credits under IRC Section 29, as with the affordable housing projects, the expertise was developed by DQE's unregulated subsidiary which took the initial risks associated with the transaction. When it became clear that the risks were manageable, the expertise was then shared with Duquesne so that it could benefit from this tax planning strategy. These transactions were especially valuable because they permitted Duquesne to obtain an entry into the natural gas business and to take advantage of the convergence in the energy market. The expertise for the other type of transactions known as Leasehold Interest transactions were similarly transferred. Again, DQE first entered into these transactions in 1994. When it became clear that they were viable and the risk was manageable, the expertise was shared with Duquesne. In 1995, the Diemen-Flevo transaction became available in the Netherlands and Duquesne was able to take advantage of it due to the expertise developed by DQE, thereby reducing the Company's Federal Income tax rate and, hence, its cost of service.

As a direct consequence of all of these tax planning strategies, Duquesne has been able to lower its effective Federal Income Tax rate to just 24%. In most cases, utilities are seeking to transfer expertise developed at the regulated level to unregulated affiliates or

subsidiaries and keep all of the benefits for the shareholders. Here, in stark contrast, DQE developed tax mitigation expertise at the unregulated level and, rather than keeping all of the benefits for shareholders, allowed the regulated subsidiary, Duquesne, to participate in the tax planning strategies. This participation has produced direct benefits to the form of lower costs that have enabled the Company to forego rate increases until 2001 and aggressively mitigate its stranded costs.

Duquesne Has Pursued Other Sources of Mitigation

Q. Are there other major areas where the Company has successful mitigated its stranded costs?

A. Yes. We have successfully mitigated our stranded costs by reducing the unfunded portion of nuclear decommissioning costs and by writing off part of our "early window" costs.

Q. Explain how the Company reduced the unfunded portion of Nuclear Decommissioning.

A. Without additional rate relief from the Commission, Duquesne has increased its annual funding of nuclear decommissioning expense from $1,345,467 to $8,762,097. This amount is more than six times higher than the amount authorized by the Commission and included in the Company's rates. In Duquesne's most recent base rate case (R-870651), the Commission allowed annual recovery through then current rates of $1,345,467. The Company was limited to funding that amount of its estimated decommissioning liability in a "qualified trust" by Internal Revenue Code § 468A. In 1994, the Company sought and obtained a landmark ruling from the National office of the IRS, which for the first time allowed funding for nuclear decommissioning to be placed into a "qualified trust" based on an accounting order of the Commission, rather than a base rate increase, as had been previously required. At the same time, the Company received an order, in Docket P-

00940843, which recognized an increase in annual funding of nuclear decommissioning expense to $3,624,486 without a concomitant base rate increase. In a public meeting held October 17, 1996, the Commission issued an order in Docket P-0091110, which further increased the Company's funding of decommissioning (consistent with the Ft. Martin rate agreement) of the BV Unit Nos. 1 and 2 and Perry Unit 1 to $8,762,097, again without increasing base rates to customers.

Q. Explain how the Company has mitigated its regulatory assets through its treatment of Deferred Rate Synchronization or "Early Window" Costs.

A. In Duquesne's petition in Docket P-870222, the PUC granted the Company's request for "early window" rate treatment for Beaver Valley Unit No. 2 and Perry Unit No. 1. As part of the settlement agreement related to the sale of the Ft. Martin plant, Duquesne agreed to write-off $9.0 million of these deferred, early window costs. Moreover, the company agreed to amortize the remaining $42 million of these early window costs over a ten year period without any increase in rates to customers.

Duquesne Has Moderated Rates

A. Section 2808(c)(5) of the Customer Choice Act states:

> "of equal importance to the mitigation efforts under paragraph (4)(I) through (VI), the Commission shall consider efforts undertaken over time, prior to the enactment of this chapter to reduce or moderate customer rate levels while maintaining safe and efficient operations."

Q. How has Duquesne complied with the Act to moderate rate levels?

A. Duquesne has not requested a base rate increase since 1988. Since 1992 (the last year of the Company's rate phase-in from the 1988 rate order) both the nominal and real cost of electricity in Duquesne's service territory has fallen and the decline in real terms is

expected to continue throughout the transition. This could not have been accomplished without extraordinary even heroic efforts by Duquesne's employees and the sacrifices made by both employees and the Company's shareholders. Indeed, when one considers the situation with which the Company was faced in 1982, it is nothing short of a miracle that Duquesne has managed to contain its costs and reduce its rates.

Q. How do Duquesne's rates compare to other utilities?

A. Duquesne's charges to its residential customers are often mischaracterized as being high because they are expressed in terms of cents per kilowatt hour. This ignores the fact that Duquesne has one of the lowest average usage levels (i.e., 500 kwh/month) for residential customers of any Company in the country. When Duquesne's charges to customers are expressed as an average monthly bill the Company finds itself in the middle of the pack when compared to other U.S. utilities and actually lower than the Pennsylvania average. Duquesne's commercial rates compare favorably to the ECAR and MAAC averages and its industrial rates are below average in the ECAR and MAAC regions.

Q. Has Duquesne maintained safe and efficient operations?

A. Yes. The Company has maintained its commitment to safe and efficient service. Perhaps this is best evidenced by the fact that we are the only electric company in the state to guarantee service by offering a $25 bill credit if we are not on time for appointments, do not connect a new customer within 24 hours, do not provide an accurate bill or do not act professionally and courteously in our dealings with our customers. While the Company has reduced overall capital spending it has made significant investments in the customer service area. In 1992 the Company completed a new $24 million customer information system (DISCUS). Our field representatives use laptop computers to enhance their service

capabilities and were singled out by Lotus for the development of this unique application of their Notes™ software. Currently the Company is working with ITRON to install the Customer Advanced Reliability System (CARS) which will enable two-way wireless communication between the Company and a customer's meter. Historically Duquesne's reliability and safety records have been above average, and the Company is committed to maintaining its high standards.

Q. You spoke earlier about the Ft. Martin Agreement having imposed a rate cap. For how long have Duquesne's rates remained essentially frozen?

A. The Company has not sought a base rate increase since 1987. That case produced a rate increase in March 1988. The Ft. Martin Agreement caps the Company's base rates and fuel clause until October of 2001. Therefore, prior to the passage of the Act, Duquesne had already taken actions that resulted in a rate cap through 2001. In effect, the Company was operating under a self-imposed regime of price cap regulation significantly before the Legislature even took action to restructure Pennsylvania's electric industry. While the Act specifically permits the Commission to prospectively employ performance based rates and alternative regulation in Section 2806(I), in fact Duquesne has been operating under the discipline of incentive regulation since 1988.

Duquesne Has Achieved Efficiencies Through Price Cap Regulation

Q. Are you equating price cap regulation with performance based regulation?

A. Yes, absolutely. In the "old world" of cost plus regulation, cost increases were passed on to customers in the form of higher rates. With our last rate increase in 1988, we concluded that our rates had reached levels that could impede our ability to compete. We therefore

determined to completely change our corporate philosophy to stress competition and cost reduction. We were determined to "live within our means," directing all of our efforts to reducing our costs and operating more efficiently, rather than to rate cases and increased prices, to earn appropriate returns for our shareholders.

Q. Have these efforts been successful?

A. Our record of being able to avoid base rate increases for almost 14 years (March of 1988 to October of 2001) speaks for itself. Moreover, we have reduced our rates in nominal terms and the effect of inflation over that period has made our product increasingly less expensive in real terms than it was in 1988.

Q. What was the average base rate allowed in the last rate case in 1988?

A. In 1988 the average rate level allowed was 9.9 cents/kwh.

Q. How does that compare to the average base rate level today?

A. Today's average rate level is 8.8 cents/kwh.

Q. What percentage decrease does this represent?

A. In nominal terms, this is a 12.5% decrease in rates.

Q. Is this a representative figure?

A. Not particularly, because during the period from 1988 to today, inflation has continued. Therefore, in real terms rates had actually decreased 24% by 1996; and are expected to decrease a total of 40% by 2000.

Q. Earlier in your testimony you alluded to the fact that Duquesne's unit cost rates were higher than the average electricity rates in Pennsylvania. Is that a particularly relevant statistic?

A. I do not believe it to be. As I have previously pointed out, usage is an important factor. As well, because Duquesne operates primarily in a major urban area with the high cost of an underground system in the downtown area, it is more relevant to compare our rates to those charged by utilities serving other large metropolitan areas. Viewed in that perspective, Duquesne's rates are certainly in line with other companies. Duquesne's average residential rate was approximately 11.7 cents per kwh in 1995. In contrast, PECO's average residential rate was nearly 13 cents in 1995, Boston Edison's rate was 12.5 cents and Consolidated Edison's rate was over 16 cents. Additionally, Southern California Edison's and PG&E's residential rate were both over 12 cents. It should be noted, however, that none of those companies suffered load losses comparable to the devastating load losses suffered by Duquesne in the early 1980's and all of these companies have significantly higher average residential usage levels than Duquesne.

Company Shareholders Have Borne Costs of Mitigation

Q. How have the Company's shareholders been affected by the Company's mitigation strategies.

A. The Company's shareholders have borne a significant portion of the burden of Duquesne's mitigation strategies. Since the Company's last base rate case the Company's shareholders have never achieved the 12.87% return on equity authorized by the Commission and, to date, the DQE dividend level has not returned to the level set for Duquesne at the end of 1985.

Duquesne Has Balanced Other Stakeholder Interests While Mitigating Stranded Costs

Q. How have the interests of the Company's other stakeholders been balanced?

A. I have previously discussed some of the effects of the Company's mitigation strategies on employees and the burdens employees have borne as a result. On the positive side, however, the Company received the EEI Diversity Award in 1994 and 1995 and the EEI Minority Business Development Award in 1996. The Company has extended the current contract with its bargaining unit employees to 2001. Throughout this period the Company has instituted several innovative programs including pay for knowledge at power stations, a performance based 401K matching program, cafeteria style benefit plans, part-time work in certain areas, cost effective health care plans, and other pro-employee benefits. The Company has created a motivated workforce that is expected to perform at high standards and has done this while reducing the size of the total workforce and its costs.

At the same time, the Company has consistently been an environmental leader. This is most recently evidenced by receipt of the 1996 Governor's Award for Environmental Excellence which recognized the Company's efforts in the air pollution area. The Company has a long record of environmental achievement ranging from being the first company in the country to install a full plant scrubber system, to the creation of the natural habitat on Brunot Island. The Company's generation system met all of the requirements of Phase I of the Clean Air Act long before the deadline for compliance.

In addition to its environmental leadership, the Company has been an outstanding corporate citizen. Duquesne Light contributes approximately $2,000,000 (grants and in-kind donations) to educational, health, civic and human service organizations annually. The Company and its customers contribute over $800,000 to the Dollar Energy Fund

annually. This is a matching program in which customer contributions are matched dollar for dollar by Duquesne Light. Duquesne and its employees contribute approximately $1,000,000 annually to the United Way of Southwestern Pennsylvania, making it the area's 6th largest corporate contributor. Each year, Duquesne Light loans seven employees to the United Way Loaned Representative program, making it the most generous corporate supporter of this program in our region.

In the area of education, our 12-year-old Partners In Education program operates under the philosophy that, by enhancing the physical and human resources in area schools, we can help students increase their level of achievement. Under this special relationship with five area school districts in Allegheny and Beaver counties, Duquesne Light provides grants, job-shadowing experiences with company employees, field trips to company facilities, supplies and equipment, cultural experiences, and teacher development.

Employee volunteerism is an equal partner with corporate giving in the company's total community outreach program. An internal organization called the Employee Community Advisory Committee (ECAC) coordinates volunteer activities, offering employees a variety of ways to contribute their time and talents. Among the annual projects ECAC sponsors are: Scouting for Food, Juvenile Diabetes Race for the Cure, and United Way Day of Caring. Some 40 employees also volunteer their time, expertise and enthusiasm as members of the Duquesne Light Speakers Team. Each year, they make nearly 200 presentations to schools, community, senior citizen, and professional groups on topics related to electric safety, usage, efficiency, and reliability; and the environment.

The Company has also provided a significant amount of assistance to its low income customers. The Company contributes $500,000 annually to its Pilot Customer Assistance program which gives low income customers a chance to zero-out arrearages in their electric bills and reduce consumption to affordable levels. $700,000 is contributed to "Smart Comfort" a program for low income customers to make more efficient use of electricity. The "Smart Comfort" program received the Governor's Energy Award in both 1992 and 1993. The "Smart Comfort" program received the Governor's Energy Award in both 1992 and 1993. Our "CARES" program helps payment troubled customers with special needs to obtain the necessary social support and assistance. The Company's hardship fund is a partnership with the Dollar Energy Fund in which the Company's stockholders match contributions up to $325,000 annually while the Company provides administrative support. The Company also has a "Gatekeeper" program to identify situations where social support is needed and offers consumer credit counciling services.

Overall the Company has done an admirable job of balancing the diverse interests of all of its stakeholders.

Duquesne Will Mitigate $1.0 Billion of Potentially Stranded Costs And Has Avoided $700 Million of Rate Increases

Q. Could you summarize Duquesne's mitigation efforts?

A. Yes. A quantification of the various mitigation strategies previously discussed is presented in Exhibit DJC-2. The exhibit shows that by December 31, 1998 Duquesne will have mitigated $340 million of potentially stranded costs and that by December 31, 2005

the Company will have reduced its potentially stranded costs by approximately $1,030 million. The exhibit also shows that the Company has avoided some $700 million of rate increases which would have been required had the Company not pursued its aggressive mitigation strategies. Duquesne has actively engaged in mitigation efforts for more than ten years. Even though the Company was dealt crushing blow by the loss of steel load in the early 1980s it has rebounded while balancing the interests of it customers, shareholders, employees and other stakeholders. Duquesne pursued aggressive cost containment for fuel, O&M and capital additions. Duquesne was the only company in Pennsylvania to use the proceeds of a sale and leaseback transaction to financially restructure itself and significantly reduce its cost of capital. Duquesne has been a significant seller of power in the wholesale market and has passed all of the benefits of these sales to ratepayers through its fuel clause. The Company was the first Company in the state to voluntarily accelerate depreciation related to nuclear plants and has increased its depreciation and amortization rate by more than any other utility in the state. Duquesne is the only Company who has voluntarily increased its nuclear decommissioning funding level to over six times the amount originally included in rates. Duquesne is the only company in the state to sell a power plant and use the gain to offset a portion of its stranded cost. Duquesne is the only Company to use innovative tax planning strategies to mitigate stranded costs. Duquesne has reduced its base rates since 1992 while other companies in Pennsylvania have received rate increases. Duquesne's mitigation plan has complied with both the letter and intent of the Act and should be recognized by the Commission in determining that Duquesne is indeed entitled to an opportunity to fully recover its stranded costs. In addition to our stand alone proposals, a critical mitigation

strategy to be employed by the Company is the proposed merger with Allegheny Power Systems[2] Approval of the merger will permit the Company to commit to an additional $160 million of depreciation and amortization, a $25 million reduction in our distribution rates beginning July 1, 2001, and a rate freeze for distribution through 2005. In addition, it is likely that our stranded costs as of December 31, 2005 will be $200 million less than they would be without the merger and that the merger synergies will enable the Company to shorten its stranded cost recovery period.

IV. DUQUESNE PROPOSES A MARKET-BASED RESTRUCTURING PLAN FOR CALCULATION AND RECOVERY OF STRANDED COSTS

Q. You have described the mitigation efforts of the Company in the first part of your testimony. *How does the Company propose to recover its "Transition or Stranded Costs"* during the Transition Period?

A. Section 2803 of the Customer Choice Act defines "Transition or Stranded Costs" as:

> "An electric utility's known and measurable net electric generation-related costs, determined on a net present value basis over the life of the asset or liability as part of its restructuring plan, which traditionally would be recoverable under a regulated environment but which may not be recoverable in a competitive electric generation market and which the Commission determines will remain following mitigation by the electric utility."

In my testimony, I have used the term "stranded costs" to refer broadly to these costs. Most of the Company's stranded costs fall into two categories; generation related stranded costs (including future decommissioning expense) and regulatory assets. A third category, transition costs, are smaller in magnitude and include such items as the cost of our restructuring filing, the cost of customer choice education programs, and the cost of

[2] The details of the Company's merger application and combined restructuring proposals are set forth in the joint restructuring plan filing.

implementing the pilot program. Generation related stranded costs arise because it is expected that the market price of power will not support both a return on and return of the historic investments made by companies in generating assets when all future cash flows, including fuel cost, operating and maintenance expenses, future capital expenditures, and taxes are considered. Regulatory assets are assets which have been created because there has been either an explicit or implicit regulatory promise that such amounts will be recoverable and provided for in future revenues. In other words, regulatory assets are created (or impaired) by the actions of regulators. Mr. O'Brien in his testimony (Duquesne Statement No. 4) further explains how investors have relied upon these regulatory promises.

Duquesne Proposes to Recover its Stranded Costs Under a Rate Cap

Q. Please describe Duquesne's approach to stranded cost recovery.

A. The starting point for Duquesne's approach is section 2804 (4)(v) of the Customer Choice Act, which states:

> "If an electric distribution utility rolls its energy cost rate into base rates at a combined level that does not exceed its combined level of such rates which have been approved by the Commission as of the Effective Date of this chapter, the utility shall not be required to reduce its capped rates below the capped level upon the compliant of any party if the Commission determines that any excess earnings achieved under the cap are being utilized to mitigate transition or stranded costs for the benefit of ratepayers or to offset other known and measurable cost increases that would be recoverable under traditional ratemaking but are not included within the capped rates."

Pursuant to this provision, Duquesne is rolling into current base rates an energy cost rate that is cost-justified and equal to the ECR cap approved by the Commission as part of the Ft. Martin Agreement. In addition, Duquesne is committing to accelerate the depreciation and amortization of stranded costs in an amount that (when added to test

year revenue requirements) will result in a total revenue requirement equal to the revenues produced by current rate levels. As I will discuss below, this depreciation and amortization level is a minimum commitment and Duquesne's investors bear the risk that maintaining this commitment will depress earnings. In the event, however, that revenues exceed expected levels, or the cost of service is lower than expected, Duquesne is proposing an ROE spillover mechanism that will, as contemplated by the statute, ensure that the associated revenues are used to further mitigate stranded costs.

Q. Section 2804 (4)(v) refers to the mitigation of stranded costs, but does not refer to a specific stranded cost calculation. Why is this?

A. Section 2804 (4)(v) contemplates an approach under which a utility can continue to charge rates at current levels if it can support such rate levels with its test year revenue requirement calculation plus an annual depreciation and amortization of stranded costs. Thus, whatever "total" stranded costs may be, the utility can continue to charge rates each year at current levels so long as it uses any potentially excess revenues to accelerate the depreciation and amortization of stranded costs.

Q. Will Duquesne do a specific calculation of stranded costs at some time in the future?

A. Yes. As discussed in the testimony of Mr. Schnitzer (Duquesne Statement No. 3), Duquesne is proposing a final market-based valuation in mid-2003. This will determine stranded costs after netting out the accelerated depreciation and amortization under the rate cap.

Duquesne is Entitled to a Rate Cap Under Section 2804(4)(V)

Q. To show you are entitled to a rate cap, doesn't Duquesne need to calculate the stranded costs that would be amortized?

A. Yes, but in a narrow respect. As detailed in Mr. Schnitzer's testimony, Duquesne must make a *prima facie* showing that:

- Excess earnings achieved under the cap will be utilized to mitigate transition or stranded costs for the benefit of ratepayers under the proposed minimum amortization commitments and ROE spillover mechanism
- The market value of generation beginning in 2006 is below the book value of generation and generation-related regulatory assets net of the committed minimum level of depreciation and amortization.

Q. How will you make the first showing? .

A. My analysis quantifies the level of generation related depreciation and amortization that can be achieved between 1999 and 2005 under a generation price freeze, while still providing the Company with an opportunity to earn a fair return on invested capital. As shown in Exhibit DJC-3, this analysis indicates that the net book value of the Company's generation related assets can be reduced by approximately $1.7 billion under the price cap leaving a net book value of approximately $535 million.

Q. How will you make the second showing?

A. My analysis compared the estimated range of market value of the Company's generatory stations as of December 31, 2005, with the projected net book value of its generating assets and regulatory assets with depreciation and amortization of no less than $1.7 billion. This analysis demonstrates that the Company will likely have remaining stranded costs of $8 to $582 million at the end of 2005, depending on the level of market prices in 2006 and beyond.

Q. Please describe the results for each station as shown on Exhibit DJC-3.

A. Exhibit DJC-3 shows the gross plant value, accumulated depreciation, accumulated deferred income tax and accumulated investment tax credit balances for each station as of December 31, 1996 and the bring down of these balances to December 31, 2005. These net plant balances are then used as the basis for determining the Company's range of stranded generation cost remaining as of December 31, 2005.

Q. How did you estimate the market value of the Company's generating assets as of year end 2005 for purposes of showing that Duquesne will still have stranded costs?

A. The market value of the Company's generating assets as of year end 2005 was estimated using a margin analysis approach. The future cash flows or "to go" costs were assembled for each of the Company's generating stations through the end of its book life. These amounts were then deducted from a forecast of market revenues for each of the Company's generating stations using a range of market prices as forecasted by Mr. Schnitzer (Duquesne Statement No. 3). As described in Mr. Schnitzer's testimony, the range of prices is a market price ceiling based on the cost of entry of new gas-fired combined cycle capacity. The margin contribution of generation was tax affected and then discounted at the Company's after-tax cost of capital to arrive at the market value of the generating portfolio as of December 31, 2005. These results are summarized in Exhibit DJC-3.

Q. I notice that other Duquesne witnesses have criticized the use of market price "forecasts." Why are you using one to estimate stranded costs?

A. I am doing so for the narrow purpose of making the *prima facie* showing that Duquesne is entitled to continue its rate cap through 2005. The process of setting a "known and measurable" CTC for individual customers, and of making a final determination of any

generation values beyond 2005, is a distinct undertaking and one that uses the market-based valuations described in the testimony of Mr. Schnitzer.

Q. What do you conclude based on your comparison of estimated book and market values in 2005?

A. Given a range of $(47) million to $527 million of market value based on Mr. Schnitzer's estimate of the market price ceiling, the results of this analysis show that as of December 31, 2005 the Company will likely have from $582 million of stranded costs under the low market value to $8 million of stranded costs under the high market value. Thus, it is likely that Duquesne will have stranded costs remaining in 2006 over a wide range of potential market prices.

Q. What do you conclude about Duquesne's showing for purposes of Section 2804(4)(v)?

A. Duquesne has made a *prima facie* showing of both of the propositions required under Section 2804(4)(v) and is therefore entitled to a price cap during the Transition Period.

Stranded Costs Are Likely to Remain in 2005

Q. Please elaborate on the estimate of stranded costs you made as of 2005. What do the unit by unit margin calculations show?

A. Pages 44 to 67 of Exhibit DJC-3 shows the margin calculation for each of the Company's stations. The schedule shows the market revenues to be derived from each station. The market revenue for each station was determined based on Mr. Schnitzer's range of market prices. For purposes of the analysis Duquesne's equivalent availability factor were assumed to be maintained at historic levels. Once the market revenues by plant were

determined the "to go" costs were deducted to arrive at the contribution margin from each plant.

In addition to direct cost at each station an allocation of administrative and general expenses was made based on the overhead allocation methodology described in detail in Mr. O'Brien's testimony (Duquesne Statement No. 4). Once the margin calculations were complete the margin contributions were tax affected and then discounted at the Company's after-tax cost of capital. The sums of these amounts by plant were then compared to the Company's net book value amounts by plant at December 31, 2005. Duquesne's range of generation related stranded costs of $8 to $582 million was then computed by deducting the estimated market values from the Company's net book values. The results show that Duquesne's generating plants will have unamortized stranded costs, as follows: Beaver Valley 1 - $36 to ($92) million (benefit), Beaver Valley 2 - $28 to ($34) million (benefit), Perry - $34 million, Cheswick - $20 to $179 million, Elrama - $35 million, Mansfield - $129 to ($11) million (benefit), Sammis - $11 million to $46 million, Eastlake - $27 to $53 million, Brunot Island - $8 to $32 million and Phillips - $10 million.

Supporting Data Confirms Stranded Cost Analysis

Q. What other supporting data are provided for the "to go" costs and market based revenue forecasts?

A. The fixed and variable production costs, load forecasts and plant availability data are consistent with the revised Integrated Resource Plan which has been provided in response to Appendix A, Item G-7 and is being supported by Mr. Mark Karl (Duquesne Statement No.

9). The capital expenditure forecast by generating station is being supported by Messrs. Nelson and Duckworth (Duquesne Statement Nos. 10 and 11). As previously stated, the range of market price ceilings forecast beyond 2005 is supported by the testimony of Mr. Michael Schnitzer (Duquesne Statement No. 3).

Q. How were the Beaver Valley Unit No. 2 lease payments included in your analysis of generation related stranded costs?

A. The Beaver Valley Unit No. 2 lease payments beyond 2005 were discounted at the after tax cost of capital and the accelerated amortization applied to the lease (including earnings) through 2005 were netted. This amount was then added to the Company's net book values at December 31, 2005 before the comparisons to market values were made.

Q. Has the Company included "cold reserved" units in its stranded cost determination?

A. Yes. The company has included the Phillips Power Station and the cold reserved portion of the Brunot Island Power station in its determination of stranded costs.

Q. Given stranded cost recovery for your cold reserved units, how would the Company treat any proceeds from sales of these assets?

A. There is no market for the Company's cold reserved units at this time. However, should these assets prove to be valuable, the proceeds of any sale of these assets would be used to directly reduce the Company's stranded costs. The procedure for crediting the proceeds of any future sales are described in Mr. Schnitzer's testimony.

Q. How were possible life extensions of generating plants treated in your analysis of stranded costs?

A. No life extensions beyond the currently estimated book lives were assumed in the stranded cost analysis. The purpose for which stranded costs are being calculated as of December

31, 2005 is to demonstrate that Duquesne is entitled to continuation of a rate cap throughout the Transition Period under Section 2804(4)(v) of the Customer Choice Act. A final market-based valuation of the plants as of December 31, 2005 will take place in mid-2003 under Duquesne's proposal. As part of the final valuation, life extension analyses for Duquesne's fossil generating stations would be completed to assess whether such extensions were economic based on the market price data available in 2003. The analysis would consider the cost of life extension based on more certain information about environmental compliance costs. Any incremental market value from such life extensions would be reflected in the final market valuation.

Q. Why were decommissioning costs excluded from the margin analysis?

A. Decommissioning costs are truly "sunk costs." That is, the obligation to decommission power plants has already been assumed by the Company. The present value of Duquesne's unfunded decommissioning liability was deducted directly from the Company's market value estimates rather than including the periodic funding as a "to go" cost in the margin analysis. Mathematically the Company's stranded cost claim would be unchanged given this alternative treatment. It should be noted that with the nuclear decommissioning funding proposed, it is estimated that there will be only a small unfunded nuclear liability in 2005 (i.e. $2 million). However, the actual level of required funding would be determined as part of the final market-based valuation in mid-2003.

Q. How were the decommissioning costs for fossil and nuclear generation stations determined?

A. The estimated decommissioning costs for each of the Company's generation stations were prepared by Mr. Thomas LaGuardia and are supported in his direct testimony (Duquesne Statement No. 13). The decommissioning cost estimates prepared by Mr. LaGuardia were

made in current dollars. These estimates were escalated to the end of each of the generating stations' useful lives. A 2.5% escalation rate was used for fossil stations and a 4.0% escalation rate was used for nuclear stations. The inflated amounts were then discounted at the Company's after-tax cost of capital for fossil stations and at 7.5% for nuclear stations (i.e. the expected after-tax earnings rate on the Company's external funds for nuclear decommissioning) to December 31, 2005. The unfunded portion was then deducted from the present value of the margin analysis for each station before the comparison to the Company's net book value at December 31, 2005 was made. A summary of the decommissioning cost estimates and the related calculations are shown in Exhibit DJC-7.

Q. You stated previously that Duquesne is proposing to roll into base rates an ECR of $14.7 mills/kWh. Is this the same rate level as the currently effective ECR?

A. No.

Q. Please explain the basis for this adjustment?

A. Section 2804(4) (v) permits Duquesne to roll the ECR into base rates at a combined level that does not exceed that previously approved by the Commission. Duquesne's proposal is consistent with this requirement because the Commission has previously approved, as part of the Ft. Martin rate plan, an ECR of up to 14.7 mills/kWh. As indicated in the fuel cost projections contained in Exhibit DJC-3, Duquesne's fuel costs throughout the transition period will exceed 14.7 mills/kWh.

Q. Does the increase in the ECR mean that customers will pay higher rates that they would have in the absence of restructuring?

A. No. Even in the absence of the restructuring legislation, Duquesne had the right to propose a cost-justified ECR of 14.7 mills/kWh and indeed Duquesne did so earlier this year. The Commission did not approve the proposed increase, however, stating that the matter should be considered in the restructuring case. I also would note that, if, contrary to the projections in Exhibit DJC-3, Duquesne's energy costs fall below 14.7 mills/kWh in the future, the associated excess earnings will be used for further stranded cost mitigation under the ROE spillover. Finally, it is important to remember that, as Mr. Lahtinen testifies, Duquesne's customers will receive a significant rate reduction -- 50% for residential customers -- for incremental usage under Duquesne's proposed rate redesign.

Regulatory Assets are Fully Amortized By the End of 2005

Q. How was the $758 million of generation related regulatory assets as of December 31, 1998 shown in Exhibit DJC-4 determined and amortized?

A. The $758 million of generation related regulatory assets as of January 1, 1998 shown in Exhibit DJC-4 was developed from the Company's balance sheet as of December 31, 1996 and a bring down of each of the regulatory asset balances using known and estimated amortization amounts for 1997 and 1998. The December 31, 1998 balance was then amortized on a straight line basis through 2005. Mr. O'Brien in his direct testimony (Duquesne Statement No. 4) details each of the Company's regulatory assets and describes the basis for recovery of each regulatory asset class.

Q. Is the Company claiming a return on all of its regulatory assets?

A. No. For certain regulatory assets only the present value of amortization (or recovery) is claimed. These assets include deferred rate synchronization or "early window" costs,

deferred Employee Costs, DOE Decontamination and decommissioning costs, pre-accrual of nuclear outage costs, deferred pilot program costs. A return as well as recovery is claimed for all of the Company's other regulatory assets.

Q. Is it appropriate for the Company to earn a return on the regulatory asset related to FAS 109?

A. Yes. For purposes of estimating stranded costs as of 2005, the Company has reduced the book value of its generation assets by the full amount of its accumulated deferred tax and accumulated ITC balances. The Company proposes that the final market-based valuation should similarly account for deferred taxes and ITCs. Thus, customers will be credited with the full value of these balances against the book value of generation. Accordingly, it is appropriate for the Company to claim a return on the tax related asset. Since the Company is amortizing its tax related regulatory asset more rapidly than it is reversing its deferred tax balance (i.e., the regulatory asset is being amortized over the Transition Period while the deferred tax balance is being reversed over the remaining life of the Company's plants), Duquesne's customers will actually incur a lower total revenue requirement than they would under traditional ratemaking. Of course, both methods produce the same present value of revenue requirements. If a return were to be denied on the tax related assets, then an offsetting adjustment should be made to the generation related deferred tax balance.

Q. How were debt discounts and premiums included in your stranded cost claim?

A. Duquesne's cost of capital assumes that debt discounts and premiums will be amortized (and earn a return equal to the Company's cost of capital) over the average remaining life of its outstanding debt and preferred securities. Since the Transition Period is shorter than the remaining average life of the Company's securities, a shortfall would be experienced. As

such, the Company has included an amount equal to the amount of debt discounts and premiums above what would normally be amortized through the cost of capital and amortized this amount between 1999 and 2005.

Q. How was the Beaver Valley Unit No. 2 sale/leaseback premium handled?

A. The sale leaseback premium was handled similarly to the debt premiums and discounts. The portion of the debt premium which would normally be amortized prior to 2006 through the lease payment expense was so amortized. The amount which would have been amortized between 2006 and 2016 (i.e., the end of the lease period) was included in regulatory assets and amortized between 1999 and 2005.

Q. Are there any other items which are unusual in Duquesne's stranded cost claim?

A. Most of Duquesne's other regulatory assets are normal course of business items. However, the deferred fuel amount has been adjusted to reflect the deferral required as a result of our most recent ECR filing and a new item has been added related to our pilot program participation incentive. Neither of these items was on our 1996 balance sheet but have subsequently been created by the Commission's Orders at (M-00970917) and (P-00971175).

Q. How were the $18.2 million of transition costs determined?

A. The transition cost estimates shown in Exhibit DJC-5 are based on the best available information to date. The pilot program implementation expense and restructuring implementation expense were prepared by Mr. Allison. The customer education expenses were estimated by Mr. Hoffmann. The deferred pilot program costs are based on the Company's settlement proposal at Docket No. P-00971175. Restructuring filing expense has been estimated by the Company's legal department.

Q. Does the Company have any significant stranded costs related to Non-Utility Generator (NUG) contracts?

A. No. The Company has no significant stranded costs related to NUG contracts. The small contracts (56 MW) to which the Company is committed are however included in the Company's generating cost forecasts.

Q. Have all of the Company's stranded cost claims been made on a net present value basis and netted against any benefits which would be normally recognized under current Pennsylvania regulatory practice?

A. Yes. All of the Company's stranded cost claims are made on a net present value basis and have been reduced by any potential benefits which could have been expected to accrue to the Company under current Pennsylvania regulatory practice.

Q. Are all of the Company's claimed stranded costs currently recoverable under current regulatory practice?

A. Yes. As further described by Mr. O'Brien, all of the Company's claimed stranded costs have been either specifically approved for recovery by the Commission or have been typically recoverable under current Pennsylvania regulatory practice.

Duquesne Commits to Generation Related Depreciation and Amortization of $1.7 Billion

Q. You have previously indicated that there will be unamortized stranded costs of between $8 million and $582 million at the end of 2005. Is the Company committing to a certain level of generation related depreciation and amortization by year end 2005?

A. Yes. The Company proposes to use the generation related depreciation and amortization schedule shown in Exhibit DJC-6. This schedule is the minimum level of amortization to

which the Company is committed. As explained below, the Company will further accelerate depreciation and amortization if it is able to do so while maintaining an 11.5% ROE.

Q. How are customers protected by the guarantee of a minimum level of depreciation and amortization?

A. Duquesne's minimum depreciation and amortization commitment ensures that the net book value of generation to be used for purposes of finally determining stranded costs will be at the level shown in Exhibit DJC-3 (except for possible deviations in future capital spending or changes in the tax law). Of course, future capital expenditures would have to be cost justified and prudent or the Company would not be able to recover these amounts in any case. Tax law changes are outside of the Company's control and would be addressed as such changes (if any) occur.

Q. Please explain the Company's proposed "final market-based valuation"?

A. The Company has proposed a final market-based valuation to ensure that residual credit is given to its customers that properly reflects the market value of the Company's generating stations beyond 2005. The Company believes that the range of preliminary estimates of the market value of its generating plant as of December 31, 2005 spans the most likely range of values. However, the actual market value could be higher than the high end of the range or lower than the low end of the range. It is generally accepted that the markets for electricity will be more fully developed in the future than they are today. Given a more fully developed market for electricity in the future, the residual value of the Company's generating plants will then be able to be determined based on market evidence. Mr.

Schnitzer's testimony (Duquesne Statement No. 3) provides additional detail on the Company's proposed final market-based valuation.

Q. How does the Company propose to recover stranded costs which remain at the end of 2005?

A. The Company proposes to extend the rate cap beyond 2005 to recover any stranded cost which will remain after 2005 based on the final market-based determination of stranded costs in mid-2003..

Triggers Protect Ratepayers from Excess Amortization

Q. Are there any conditions which would trigger an early determination of the final market-based value of the Company's plants.

A. Yes, there are two triggers. First if the long term market price of power rises significantly prior to 2003, then it is possible that the residual market value at the end of 2005 will exceed the unamortized book value of generation. The proposed solution is to trigger an early final market valuation based on established price triggers for the years 2001 and 2002. I have calculated the market prices for generation for each of these years based on an adjusted percentage of the high market price ceiling as forecasted by Mr. Schnitzer. I deflated Mr. Schnitzer's 2006 price to 2001 and 2002 using a 2.5% discount rate. I then applied a 75% discount factor to this price to calculate the trigger prices of $28.5/mwh for 2001 and $29.2/mwh for 2002. The early trigger price is that market price which would be likely to establish a high enough residual value to allow an early end to the rate cap and further collection of CTC. Duquesne will commit to accelerate the final market valuation to 2001 or 2002 if the trigger is exceeded. The market evidence to be used for the trigger mechanism is the annual solicitation for sale of firm power held in 2000 and 2001 to establish the customer specific CTCs for 2001 and 2002. If the market price determined in

those solicitations exceeds the values set forth above, the final market-based valuation will be accelerated.

Q. What is the second trigger?

A. Under the ROE spillover proposal described below if the accumulated revenue credit when netted with the net book value of the Company's generating and regulatory assets was equal to (or less than) the Company's net book value estimated in 2005 as shown in Exhibit DJC-3 at any time before mid 2003 an early valuation would be triggered. That is, if the Company were able to complete its minimum committed schedule of amortization and depreciation ahead of schedule then it would be appropriate to trigger an early valuation.

Q. How does this second trigger relate to the Company's ROE spillover proposal?

A. The Company's proposed "ROE spill over" adjustment will ensure that the Company does not have excessive earnings during the Transition Period and that customers are given the proper credit through a shortening of the rate cap period if the Company's actual results are better than expected. The Company proposes to establish a collar on its earnings of + or - ½% around its claimed ROE of 11.5%. If the Company's earnings exceed 12%, it would establish a deferred revenue credit account which would ultimately be used to fund accelerated depreciation and amortization. If earnings fall below 11% an adjustment to the deferred revenue account will be made to increase the Company's earning to the 11% ROE level or to eliminate the credit and balance in the account, which ever is smaller. If at any time during the transition period, the balance in the deferred revenue credit account (including income tax provisions) when netted against the Company's net book value of generating and regulatory assets was equal to the estimated net book value as of December 31, 2005 as shown in Exhibit DJC-3, the final market-based valuation would be triggered.

Q. What circumstances would cause the ROE spillover to be used?

A. Probably the most important positive factor would be the effect of increased "tail block" sales on the Company's revenue forecast. Under the Company's proposed rate design it is likely that sales levels will increase as marginal consumption increases due to lower rates for consumption above historic levels. Since the magnitude of these sales is unknown they have not been included in the Company's base forecast. These sales could be significant and would be credited through the ROE spillover proposal to reduce the Company's book value below committed levels. Of course, any decreases in the Company's costs could also trigger the ROE spillover mechanism.

Q. How would the Company's final market-based valuation and ROE spillover proposal change if the Commission makes different determinations with respect to stranded cost, and CTCs for the Company?

A. The Company's final market-based valuation and ROE spillover proposals are part of a comprehensive restructuring plan. The Company believes that it is important to let the market determine the market price of power and that a reasonable opportunity to fully recover its stranded costs must be afforded to the Company. If unfavorable determinations are made then the Company would have to re-evaluate its final market-based valuation and ROE spillover proposals. We believe that our proposals ensure that the Company's customers will never pay more than the minimum amount required to write the company's generation assets down to market value and that the burdens of stranded cost recovery have and will continue to be borne by all of the Company's stakeholders in a balanced manner. If, however, the Commission made a significant disallowance of our stranded cost recovery or if there was no opportunity to let the market make the final determination of stranded

costs for the Company, the Company would not be able to implement its restructuring plan. Under these conditions the ROE spillover would be moot because the Company would have little hope of earning a fair return. Similarly, if an artificially determined high market price is used to deny recovery under the rate cap, the Company will have little hope of earning a fair return on its assets.

Q. Is the Company proposing to unconditionally cap its rates during the transition period?

A. No. Although the Company believes that it will be able to operate under the rate cap, the Company is reserving the right to raise rates as permitted under Section 2804(4) of the Act.

V. COST OF CAPITAL

Q. In preparing your overall rate of return recommendations, what underlying principle has served as your guide in establishing the evidence you will present?

A. The criterion for establishing a fair rate of return for a public utility has been long established and was a result of landmark decisions of the United States Supreme Court. In 1923, in the Bluefield Water Works and Improvement Co. vs. Public Services Commission (262 U.S. 679, 1923) case, the Court said:

> "A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but has no constitutional rights to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures."

And, in 1944, in the Federal Power Commission vs. Hope Natural Gas Company (320 U.S. 591, 1944) case, the Court said:

> "From the investor or company point of view, it is important that there be enough revenue not only for operating expenses, but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investment in other enterprises having corresponding risks. That return, moreover,

should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital."

Thus, the Supreme Court has made it clear that a fair rate of return should result in an overall rate of return sufficient to insure investor confidence in the financial soundness of the utility.

Q. Please explain briefly how you have determined the fair rate of return.

A. I have followed what is commonly known as the "cost of capital" method. This approach first identifies the various components of the capital structure and their corresponding percentages of the capitalization total. Next, the cost of each type of capital item is determined, and with these two sets of data in hand, the weighted cost of capital is calculated. Thus, the overall cost of capital equals the sum of the weighted costs.

Q. What is the overall rate of cost of capital you are recommending?

A. Appendix A, Item H-1 shows the development of the Company's overall cost of capital of 9.61%. Appendix A, Item L-8 shows the after-tax discount rate of 7.83% used in the present value calculations which is also based on the Company's overall cost of capital. The data shows the consolidated capitalization at the end of the test period and it shows the annual cost of each of the capitalization components at that time.

Q. How did you develop the capital structure used to generate the overall rate of return recommendations?

A. The capital structure used to determine the overall rate of return and after-tax discount rate was the capital structure at year end 1996. As part of the company's mitigation plan, approved in conjunction with the sale of the Ft. Martin Power Station, the company agreed to target the components of its capital structure to be similar to the levels approved in its last

base rate case or 40.2% common equity, 9.96% preferred and preference equity and 49.84% long-term debt. As of year end 1996, the company's capital structure had the following percentages; 40.08% equity, 9.69% preferred equity and 50.23% long-term debt. Since the year end 1996 capital structure is very close to the company's target capital structure I have used the year 1996 capital structure throughout the filing. As previously noted, the detailed capital structure is set forth in Appendix A, Item H-1.

Q. Please describe the capital costs you applied to your recommended capital structure.

A. The annual cost applied to the consolidated capitalization components is shown under the columns entitled "average rate" on Appendix A, Item H-1. The long-term debt component is shown with a cost of 8.51 percent and is developed in detail in Appendix A, Item H-2. The preferred and preference stock component is shown with a cost rate of 7.45 percent and is developed in detail in Appendix A, Item H-7.

Q. Please describe how you developed the cost of long-term debt and preferred and preference stock.

A. I developed the Company's long-term debt cost and the cost of preferred and preference stock at the end of the test year using all known interest and dividend rates and applicable terms on the Company's outstanding long-term debt and preferred and preference stock issues. I did not assume that any additional long-term debt or preferred or preference stock would be issued. The Company's claimed costs of both long-term debt and preferred and preference stock are based solely on the Company's embedded cost rates.

Q. How did you determine the 11.5% cost of common equity claimed in this proceeding?

A. An 11.65% cost of common equity for Duquesne has been identified by Dr. Jeffrey D. Makholm in his direct testimony. To be conservative, I have reduced this amount to 11.5% as the Company's claimed cost of common equity.

Q. How does the Company plan to keep its capital structure in line with the test year capital structure throughout the transition period?

A. The Company's scheduled debt maturities and the call provisions of its long-term debt will allow it to continue to reduce its outstanding debt throughout the transition period. Common equity can be maintained at the 40% level by paying dividends to DQE (the Company's sole shareholder) which is equivalent to repurchases of common stock for publicly traded companies. The Company can repurchase preferred through open market purchases or tender offers. A sample financing plan which demonstrates the feasibility of maintaining the Company's capital structure is shown on Exhibit DJC-8. Of course the actual financing plan may differ from the sample plan but the sample plan produces a reasonable result given the Company's current forecast and proposed restructuring plan.

Q. You have stated elsewhere in your testimony that Duquesne's overall cost of capital compares favorably to the other utilities in the state. Is that correct?

A. Yes. Exhibit DJC-9 shows a comparison of Duquesne's claimed cost of capital with the claimed cost of capital for the other Pennsylvania electric utilities as claimed in their respective restructuring filings.

Q. Will the company securitize its stranded costs?

A. At this time, the Company is not requesting to securitize any of its stranded cost. However, the Company reserves the right to request securitization in a future proceeding.

Q. Is securitization beneficial to the Company at this time?

A. No. At this time there are no economic benefits to be derived from asset securitization for Duquesne. There is no economic basis to securitize because the Company has already restructured its finances to the point where its current debt costs are lower than the cost of issuing securitized debt, and the Company is already employing a high degree of debt leverage in its capital structure. In fact, Duquesne's debt leverage is higher than any other Pennsylvania electric company as shown in Exhibit DJC-9. Since 1986 the Company has repurchased 30% of its common stock, has refinanced all of its debt and has refinanced several of its preferred and preference issues. At this point securitization could place Duquesne's current investors at greater risk because the cash flow related to securitized debt would have a higher priority of payment than the payment to Duquesne's other security holders. Since the Company's total revenues will be unchanged, the cash flows to current investors will be more uncertain than they are today and hence more risky than they are without securitization. Since there are no economic benefits to help offset this increased risk, securitization is not appropriate at this time for Duquesne.

Q. When would securitization be appropriate?

A. Securitization would be appropriate if there were a true economic benefit to be derived from issuing such securities.

V. APPENDIX A ITEMS

Q. Will you please identify the Appendix A items you are sponsoring?

A. I am sponsoring the following Appendix A items:

G-1 Corporate History

G-2 System Map

G-3 Base Budget

G-4 O&M/capital Budget Projection

G-5 Financial Schedules

G-6 Property Description

H-1 Claimed Capitalization

H-2 Embedded Cost of Long Term Debt

H-3 Economic Cost of Debt

H-4 Short Term Debt - Lines of Credit

H-5 Other Short Term Debt

H-6 Long Term Debt Reacquisitions

H-7 Embedded Cost of Preferred Stock

H-8 Common Stock Issuances

H-9 Common Stock Offering Information

H-10 Parent Company Capitalization

H-11 Parent Company Financial Statements

H-12 Corporate Organizational Structure

H-13 Quarterly and Annual Financial Reports for Company and Parent

H-14 Projected Capital Requirements

H-15 Restrictive Financial Covenants

H-16 Comparative Financial Data

L-1 Competitive Transition Charge

L-2 Stranded Cost Summary

L-3 Stranded Cost Methodology

L-4 Securitization Amounts

L-5 Generating Station Data

L-6 Return to Revenue Factor

L-7 Generation Station Costs per Kilowatt Hour

L-8 Discount Rate

L-9 Market Price Forecast and Generation Station Information

L-10 Operating and Maintenance Expense Efficiency Factor

L-11 Inflation Rate Assumptions

L-17 Stranded Cost Graph

O-1 Securitization Filing

O-2 Description of Merger Consolidation, Acquisition or Disclosures

O-3 New Business Entities

Q. Does this conclude your testimony?

A. Yes. It does.

Duquesne Light Company
Summary of
Net Book and Range of
Market Values at
12/31/2005

Net Book Value of Generating Plant Assets	$535 million
Market Value of Generation Portfolio	
Low	($47) million
High	$527 million
Stranded Cost	
Low - Market Value	$582 million
High - Market Value	$8 million

Revenue Requirements Forecast

Year	1997	1998	1999	2000	2001	2002	2003	2004	2005
Total Duquesne Light									
Revenue from Customers	1081.7	1107.4	1,125.2	1,141.8	1,159.7	1,178.2	1,197.4	1,217.7	1,238.6
Deferred Revenue	0.0	0.0	38.9	(25.8)	(13.1)	0.0	0.0	0.0	0.0
Off-system Sales	16.9	18.9	42.5	45.0	48.7	47.9	45.2	45.6	13.7
Other Revenues	34.3	32.8	35.9	36.0	36.1	36.2	36.3	36.3	32.2
Total Revenue	1132.9	1159.0	1,242.5	1,197.1	1,231.4	1,262.3	1,278.9	1,299.6	1,284.4
Operating Expenses									
Fuel & Purchased Power	201.5	214.5	246.0	223.5	235.5	247.1	256.2	263.9	295.8
Non Fuel O&M (production)	122.0	113.6	138.2	122.1	119.4	135.1	134.6	139.4	128.6
Outage Accounting	3.1	1.8	(6.9)	(1.8)	7.8	(0.6)	(2.4)	1.6	(4.5)
Non-production Expenses	220.4	233.1	238.7	238.9	251.8	258.9	264.7	270.8	261.0
Major Maintenance Expense	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Decommissioning	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8
Book Depreciation	172.5	177.7	180.6	179.7	190.2	212.3	211.5	193.5	183.6
Amortization	64.4	93.6	90.9	91.8	92.8	93.4	94.0	94.3	94.7
Operating Revenue Tax	48.4	49.6	53.2	51.2	52.6	48.1	49.0	49.7	49.0
Property Taxes	20.6	21.1	21.2	21.2	21.1	21.2	21.2	21.1	20.4
Other Taxes	12.4	15.1	19.8	19.9	20.1	20.3	20.5	20.7	20.2
Current Tax	100.2	103.2	96.3	121.2	122.8	119.5	130.7	144.2	134.8
Deferred Tax	(59.1)	(85.5)	(48.9)	(76.0)	(78.7)	(77.8)	(75.2)	(66.8)	(58.0)
ITC Amortization	(8.4)	(8.7)	(8.7)	(8.4)	(8.3)	(8.3)	(8.3)	(8.4)	(5.7)
Total Operating Expenses	906.9	938.0	1,029.0	992.1	1,035.9	1,077.9	1,105.2	1,132.6	1,128.9
Operating Income	226.0	221.1	213.5	205.0	195.5	184.3	173.7	167.0	155.5
Interest Expense	100.6	98.4	95.0	91.2	87.0	82.0	77.3	74.3	69.2
Net Income	125.4	122.7	118.5	113.8	108.5	102.3	96.4	92.7	86.3
Preferred Return	17.0	16.6	16.0	15.4	14.7	13.9	13.1	12.5	11.7
Income Available for Equity Return	108.5	106.1	102.4	98.4	93.8	88.5	83.3	80.2	74.6
Operating Income	226.0	221.1	213.5	205.0	195.5	184.3	173.7	167.0	155.5
Rate Base	2,353.3	2,301.3	2,222.8	2,133.7	2,035.1	1,919.2	1,808.2	1,738.4	1,618.9
Return on Rate Base	9.60%	9.61%	9.60%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%
Rate Base - Equity	943.2	922.3	890.9	855.2	815.7	769.2	724.7	696.7	648.9
Return on Equity	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%

Revenue Requirements Forecast

Year	1997	1998	1999	2000	2001	2002	2003	2004	2005
Generation									
Revenue from Customers	807.8	816.8	866.9	815.3	837.0	860.4	871.8	885.0	893.1
Off-system Sales	16.9	18.9	42.5	45.0	48.7	47.9	45.2	45.6	13.7
Other Revenues	15.3	13.9	14.0	14.0	14.0	14.0	14.0	14.0	14.0
Total Revenue	840.0	849.6	923.4	874.4	899.7	922.3	931.0	944.6	920.8
Operating Expenses									
Fuel & Purchased Power	200.3	214.3	226.8	203.1	210.3	219.1	227.4	235.8	269.1
Emissions	1.2	0.3	19.1	20.4	25.2	28.0	28.9	28.1	26.6
Non Fuel O&M (production)	122.0	113.6	138.2	122.1	119.4	135.1	134.6	139.4	128.6
Outage Accounting	3.1	1.8	(6.9)	(1.8)	7.8	(0.6)	(2.4)	1.6	(4.5)
Non-production Expenses	110.5	113.5	115.2	117.6	127.3	131.3	133.8	136.5	123.0
Major Maintenance Expense	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Decommissioning	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8
Book Depreciation	135.9	139.6	141.1	138.9	148.1	168.9	166.8	147.4	136.1
Amortization	65.6	94.6	91.2	91.2	91.2	91.2	91.2	91.2	91.2
Operating Revenue Tax	35.5	36.0	39.2	37.0	38.0	33.1	33.7	34.1	33.0
Property Taxes	17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.1	16.4
Other Taxes	4.3	7.0	11.6	11.6	11.7	11.8	11.9	11.9	10.7
Current Taxes	69.0	69.7	77.2	73.3	78.4	79.7	90.3	103.7	94.2
Deferred Tax	(61.6)	(87.3)	(66.3)	(66.1)	(73.5)	(78.4)	(76.5)	(68.7)	(60.3)
ITC Amortization	(6.4)	(6.7)	(6.7)	(6.5)	(6.4)	(6.4)	(6.4)	(6.4)	(3.7)
Total Operating Expenses	705.4	722.3	805.5	766.9	803.5	838.6	859.1	880.5	869.2
Operating Income	134.7	127.3	117.9	107.5	96.3	83.7	71.9	64.1	51.6
Interest Expense	59.9	56.6	52.5	47.8	42.8	37.3	32.0	28.5	23.0
Net Income	74.7	70.7	65.4	59.7	53.4	46.5	39.9	35.6	28.6
Preferred Return	10.1	9.6	8.9	8.1	7.2	6.3	5.4	4.8	3.9
Income Available for Equity Return	64.6	61.1	56.6	51.6	46.2	40.2	34.5	30.8	24.8
Operating Income	134.7	127.3	117.9	107.5	96.3	83.7	71.9	64.1	51.6
Rate Base	1,402.0	1,325.3	1,227.7	1,118.8	1,001.8	871.9	748.3	667.4	537.0
Return on Rate Base	9.60%	9.61%	9.60%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%
Rate Base - Equity	561.9	531.2	492.1	448.4	401.5	349.5	299.9	267.5	215.2
Return on Equity	11.50%	11.50%	11.49%	11.51%	11.51%	11.50%	11.50%	11.51%	11.51%

Revenue Requirements Forecast

Year	1997	1998	1999	2000	2001	2002	2003	2004	2005
Nuclear Generation									
Revenue from Customers	357.0	339.9	330.3	314.5	315.5	312.4	306.1	289.9	298.0
Off-system Sales	5.4	6.1	12.8	14.0	15.4	14.4	13.5	14.7	4.8
Other Revenues	15.3	13.9	14.0	14.0	14.0	14.0	14.0	14.0	14.0
Total Revenue	377.7	359.9	357.1	342.5	344.9	340.8	333.7	318.7	316.8
Operating Expenses	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel	29.9	32.9	29.7	30.7	32.0	31.0	31.2	34.1	32.0
Non Fuel O&M (production)	70.8	49.8	77.9	65.0	61.8	76.6	75.7	68.8	84.7
Outage Accounting	(0.6)	10.8	(8.1)	0.1	5.7	(3.1)	(3.5)	10.1	(7.3)
Non-production Expenses	68.7	64.7	68.5	67.9	75.7	78.9	79.1	76.8	81.8
Major Maintenance Expense	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Decommissioning	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8
Book Depreciation	94.6	95.0	95.2	92.4	89.7	89.9	90.3	74.4	71.2
Amortization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Revenue Tax	15.2	14.5	14.2	13.6	13.6	7.5	7.4	6.5	6.5
Property Taxes	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8
Other Taxes	6.9	6.7	6.8	6.8	6.8	6.9	6.9	7.0	7.0
Current Taxes	52.0	55.2	43.9	44.3	43.8	38.3	36.4	33.8	25.8
Deferred Taxes	(33.6)	(38.7)	(30.9)	(33.2)	(34.5)	(30.9)	(30.8)	(29.8)	(21.2)
ITC Amortization	(5.1)	(5.1)	(5.1)	(5.1)	(5.1)	(5.1)	(5.1)	(5.1)	(2.4)
Total Operating Expenses	321.5	308.5	314.7	305.1	312.1	312.7	310.2	299.1	300.7
Operating Income	56.2	51.4	42.4	37.4	32.8	28.1	23.5	19.6	16.1
Interest Expense	25.0	22.9	18.9	16.7	14.6	12.5	10.4	8.7	7.2
Net Income	31.2	28.5	23.5	20.8	18.2	15.6	13.0	10.9	8.9
Preferred Return	4.2	3.9	3.2	2.8	2.5	2.1	1.8	1.5	1.2
Income Available for Equity Return	27.0	24.7	20.3	18.0	15.7	13.5	11.3	9.4	7.7
Operating Income	56.2	51.4	42.4	37.4	32.8	28.1	23.5	19.6	16.1
Rate Base	585.1	535.3	441.2	389.9	341.3	292.4	244.3	203.6	167.4
Return on Rate Base	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%
Rate Base - Equity	234.5	214.6	176.8	156.3	136.8	117.2	97.9	81.6	67.1
Return on Equity	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%

Revenue Requirements Forecast
Nuclear Generation

Year	1997	1998	1999	2000	2001	2002	2003	2004	2005
Perry									
Off-system Sales Revenue	1.3	1.5	3.2	3.7	3.5	3.9	3.3	3.7	1.2
Revenue from Customers	145.7	138.9	132.0	125.4	121.4	121.3	114.4	98.6	96.7
Total Revenue	147.0	140.4	135.2	129.1	124.9	125.2	117.7	102.3	97.8
Operating Expenses									
Fuel	8.1	9.1	8.6	9.2	8.9	9.6	9.1	9.8	9.1
Non Fuel O&M (production)	17.0	12.2	18.9	15.9	20.0	20.9	21.3	22.3	22.8
Outage Accounting	0.0	2.8	-1.5	1.7	-1.6	1.8	-1.7	2.0	-1.8
Non-Production Expenses	7.6	6.5	7.5	7.2	8.4	8.1	8.4	8.0	9.1
Major Maintenance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Decommissioning	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Book Depreciation	58.0	58.1	58.2	56.5	55.0	55.0	55.1	38.7	34.9
Amortization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Revenue Tax	5.0	4.8	4.5	4.2	3.9	3.7	3.5	2.7	2.6
Property Taxes	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3
Other Taxes	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
Current Taxes	30.7	30.9	27.1	26.5	23.5	23.7	21.0	14.9	12.9
Deferred Taxes	-21.6	-23.0	-21.4	-22.1	-20.3	-21.7	-20.2	-14.9	-11.7
ITC Amortization	-2.9	-2.9	-2.9	-2.9	-2.9	-2.9	-2.9	-2.9	-0.1
Total Operating Expenses	118.8	115.3	115.7	112.8	111.6	115.0	110.4	97.3	94.6
Operating Income	28.3	25.2	19.5	16.3	13.3	10.2	7.3	5.1	3.3
Interest Expense	12.6	11.2	8.7	7.2	5.9	4.6	3.2	2.3	1.5
Net Income	15.7	14.0	10.8	9.0	7.4	5.7	4.0	2.8	1.8
Preferred Return	2.1	1.9	1.5	1.2	1.0	0.8	0.5	0.4	0.2
Income Available for Equity Return	13.6	12.1	9.4	7.8	6.4	4.9	3.5	2.4	1.6
Operating Income	28.3	25.2	19.5	16.3	13.3	10.2	7.3	5.1	3.3
Rate Base	294.3	262.0	202.9	169.3	138.6	106.5	75.7	53.1	34.1
Return on Operating Income	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%
Rate Base - Equity	118.0	105.0	81.3	67.9	55.6	42.7	30.3	21.3	13.7
Return on Equity	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%

Revenue Requirements Forecast
Nuclear Generation

Year	1997	1998	1999	2000	2001	2002	2003	2004	2005
Beaver Valley									
Off-system Sales Revenue	4.1	4.6	9.6	10.3	11.8	10.5	10.2	11.0	3.6
Revenue from Customers	211.3	201.0	198.3	189.1	194.1	191.1	191.8	191.3	201.4
Other Revenues	15.3	13.9	14.0	14.0	14.0	14.0	14.0	14.0	14.0
Total Revenue	230.7	219.5	222.0	213.4	220.0	215.6	216.1	216.4	219.0
Operating Expenses									
Fuel	21.8	23.8	21.1	21.5	23.1	21.4	22.1	24.3	22.9
Non Fuel O&M (production)	53.8	37.6	58.9	49.1	41.8	55.8	54.4	46.5	61.8
Outage Accounting	-0.6	8.0	-6.6	-1.6	7.3	-4.9	-1.8	8.1	-5.5
Non-Production Expenses	61.2	58.2	61.0	60.7	67.3	70.7	70.7	68.7	72.7
Major Maintenance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Decommissioning	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8
Book Depreciation	36.6	36.9	37.0	35.9	34.7	34.9	35.3	35.7	36.3
Amortization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Revenue Tax	10.1	9.7	9.8	9.4	9.7	3.9	3.9	3.9	3.9
Property Taxes	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Other Taxes	4.4	4.4	4.4	4.4	4.5	4.5	4.6	4.6	4.6
Current Taxes	21.3	24.4	16.9	17.8	20.3	14.6	15.4	18.9	12.9
Deferred Taxes	-12.0	-15.7	-9.5	-11.1	-14.3	-9.2	-10.6	-14.9	-9.5
ITC Amortization	-2.2	-2.2	-2.2	-2.2	-2.2	-2.2	-2.2	-2.3	-2.3
Total Operating Expenses	202.7	193.2	199.1	192.2	200.5	197.8	199.9	201.9	206.2
Operating Income	27.9	26.3	22.9	21.2	19.5	17.9	16.2	14.5	12.8
Interest Expense	12.4	11.7	10.2	9.4	8.7	7.9	7.2	6.4	5.7
Net Income	15.5	14.6	12.7	11.8	10.8	9.9	9.0	8.0	7.1
Preferred Return	2.1	2.0	1.7	1.6	1.5	1.3	1.2	1.1	1.0
Income Available for Equity Return	13.4	12.6	11.0	10.2	9.3	8.6	7.8	6.9	6.1
Operating Income	27.9	26.3	22.9	21.2	19.5	17.9	16.2	14.5	12.8
Rate Base	290.7	273.3	238.3	220.5	202.6	185.9	168.6	150.5	133.3
Return on Operating Income	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%
Rate Base - Equity	116.5	109.5	95.5	88.4	81.2	74.5	67.6	60.3	53.4
Return on Equity	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%

Revenue Requirements Forecast
Nuclear Generation

Year	1997	1998	1999	2000	2001	2002	2003	2004	2005
Beaver Valley 1									
Off-system Sales Revenue	3.0	3.6	7.5	7.7	9.4	8.1	7.7	8.8	2.8
Revenue from Customers	135.9	127.1	124.4	116.4	113.1	108.6	109.0	107.7	116.0
Other Revenues	11.9	10.8	10.9	10.9	10.9	10.9	10.9	10.9	10.9
Total Revenue	150.9	141.5	142.7	135.0	133.4	127.6	127.5	127.3	129.7
Operating Expenses	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel	16.9	19.3	16.6	16.2	18.3	16.7	16.6	19.3	17.9
Non Fuel O&M (production)	45.1	26.5	46.4	40.8	30.0	43.5	45.1	33.4	48.3
Outage Accounting	-3.8	9.1	-5.6	-3.7	8.3	-3.9	-4.1	9.2	-4.3
Non-Production Expenses	11.9	8.6	11.2	11.3	9.7	11.8	12.3	9.7	13.6
Major Maintenance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Decommissioning	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2
Book Depreciation	33.3	33.4	33.6	32.5	31.4	31.7	32.0	32.4	32.9
Amortization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Revenue Tax	6.6	6.2	6.3	5.9	5.9	0.0	0.0	0.0	0.0
Property Taxes	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
Other Taxes	3.6	3.5	3.6	3.6	3.6	3.7	3.7	3.7	3.8
Current Taxes	17.7	22.6	15.5	15.3	19.2	13.6	13.0	18.0	12.0
Deferred Taxes	-9.3	-14.9	-9.0	-9.4	-13.9	-8.9	-8.9	-14.6	-9.2
ITC Amortization	-1.6	-1.6	-1.6	-1.6	-1.6	-1.6	-1.6	-1.6	-1.6
Total Operating Expenses	126.7	119.1	123.3	117.2	117.2	112.9	114.3	115.8	119.7
Operating Income	24.1	22.4	19.4	17.8	16.2	14.7	13.2	11.5	10.0
Interest Expense	10.7	10.0	8.6	7.9	7.2	6.5	5.9	5.1	4.5
Net Income	13.4	12.4	10.8	9.9	9.0	8.2	7.3	6.4	5.6
Preferred Return	1.8	1.7	1.5	1.3	1.2	1.1	1.0	0.9	0.8
Income Available for Equity Return	11.6	10.8	9.3	8.5	7.8	7.0	6.3	5.5	4.8
Operating Income	24.1	22.4	19.4	17.8	16.2	14.7	13.2	11.5	10.0
Rate Base	251.3	233.3	201.7	185.5	168.5	152.9	137.3	120.0	104.1
Return on Operating Income	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%
Rate Base - Equity	100.7	93.5	80.8	74.3	67.5	61.3	55.0	48.1	41.7
Return on Equity	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%

Revenue Requirements Forecast
Nuclear Generation

Year	1997	1998	1999	2000	2001	2002	2003	2004	2005
Beaver Valley 2									
Off-system Sales Revenue	1.0	0.9	2.2	2.6	2.4	2.4	2.6	2.3	0.8
Revenue from Customers	75.4	74.0	73.9	72.7	81.0	82.5	82.8	83.6	85.4
Other Revenues	3.4	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1
Total Revenue	79.8	78.0	79.3	78.4	86.5	88.0	88.5	89.0	89.4
Operating Expenses									
Fuel	4.9	4.5	4.5	5.3	4.8	4.7	5.5	5.0	5.0
Non Fuel O&M (production)	8.7	11.1	12.5	8.4	11.8	12.2	9.3	13.1	13.5
Outage Accounting	3.2	-1.1	-1.0	2.1	-1.0	-1.0	2.3	-1.1	-1.1
Non-Production Expenses	49.3	49.7	49.8	49.4	57.6	58.9	58.4	59.0	59.1
Major Maintenance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Decommissioning	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Book Depreciation	3.3	3.4	3.4	3.4	3.3	3.2	3.2	3.3	3.4
Amortization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Revenue Tax	3.5	3.4	3.5	3.5	3.8	3.9	3.9	3.9	3.9
Property Taxes	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Other Taxes	0.8	0.8	0.8	0.8	0.9	0.9	0.9	0.9	0.9
Current Taxes	3.6	1.8	1.3	2.5	1.1	1.0	2.4	0.9	0.9
Deferred Taxes	-2.7	-0.8	-0.4	-1.7	-0.3	-0.3	-1.7	-0.3	-0.3
ITC Amortization	-0.7	-0.7	-0.7	-0.7	-0.7	-0.7	-0.7	-0.7	-0.7
Total Operating Expenses	76.0	74.2	75.7	75.1	83.2	84.8	85.5	86.1	86.6
Operating Income	3.8	3.8	3.5	3.4	3.3	3.2	3.0	2.9	2.8
Interest Expense	1.7	1.7	1.6	1.5	1.5	1.4	1.3	1.3	1.2
Net Income	2.1	2.1	1.9	1.9	1.8	1.8	1.7	1.6	1.6
Preferred Return	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2
Income Available for Equity Return	1.8	1.8	1.7	1.6	1.6	1.5	1.4	1.4	1.3
Operating Income	3.8	3.8	3.5	3.4	3.3	3.2	3.0	2.9	2.8
Rate Base	39.5	40.0	36.6	35.1	34.1	33.0	31.3	30.5	29.2
Return on Operating Income	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%
Rate Base - Equity	15.8	16.0	14.7	14.1	13.7	13.2	12.6	12.2	11.7
Return on Equity	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%

Revenue Requirements Forecast

Year	1997	1998	1999	2000	2001	2002	2003	2004	2005
Fossil Generation									
Revenue from Customers	392.7	393.7	436.4	407.4	434.9	468.4	475.1	484.6	491.5
Off-system Sales	11.5	12.8	29.6	31.0	33.3	33.5	31.7	30.8	8.9
Other Revenues									
Total Revenue	404.2	406.4	466.0	438.4	468.3	502.0	506.8	515.4	500.4
Operating Expenses	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel & Purchased Power	170.3	181.3	197.1	172.4	178.2	188.1	196.2	201.7	237.1
Emissions	1.2	0.3	19.1	20.4	25.2	28.0	28.9	28.1	26.6
Non Fuel O&M (production)	51.2	63.8	60.3	57.1	57.7	58.5	58.9	70.7	44.0
Outage Accounting	3.7	(9.0)	1.1	(1.8)	2.1	2.5	1.1	(8.5)	2.8
Non-production Expenses	41.8	48.8	46.7	49.7	51.7	52.4	54.7	59.7	41.2
Major Maintenance Expense	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fossil Decommissioning	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Book Depreciation	41.2	44.6	45.9	46.6	58.4	79.0	76.4	73.0	64.9
Amortization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Revenue Tax	17.8	17.9	20.5	19.3	20.6	22.1	22.3	22.7	22.0
Property Taxes	3.4	3.4	3.4	3.4	3.3	3.4	3.3	3.3	2.6
Other Taxes	(2.6)	0.2	4.8	4.8	4.9	4.9	4.9	5.0	3.7
Current Taxes	34.6	21.6	33.7	31.3	38.7	47.4	44.7	36.9	37.2
Deferred Tax	(4.7)	(12.9)	(12.2)	(9.7)	(15.8)	(24.4)	(22.5)	(15.7)	(16.0)
ITC Amortization	(1.3)	(1.6)	(1.6)	(1.4)	(1.3)	(1.3)	(1.3)	(1.3)	(1.4)
Total Operating Expenses	356.6	358.3	418.9	392.0	423.8	460.5	467.8	475.6	464.9
Operating Income	47.5	48.1	47.1	46.4	44.5	41.5	38.9	39.8	35.5
Interest Expense	21.2	21.4	21.0	20.6	19.8	18.5	17.3	17.7	15.8
Net Income	26.4	26.7	26.2	25.7	24.7	23.0	21.6	22.1	19.7
Preferred Return	3.6	3.6	3.5	3.5	3.3	3.1	2.9	3.0	2.7
Income Available for Equity Return	22.8	23.1	22.6	22.2	21.4	19.9	18.7	19.1	17.0
Operating Income	47.5	48.1	47.1	46.4	44.5	41.5	38.9	39.8	35.5
Rate Base	495.0	500.8	490.8	482.5	463.4	431.6	405.5	414.5	369.5
Return on Rate Base	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%
Rate Base - Equity	198.4	200.7	196.7	193.4	185.7	173.0	162.5	166.1	148.1
Return on Equity	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%

Revenue Requirements Forecast
Fossil Generation

Year	1997	1998	1999	2000	2001	2002	2003	2004	2005
Elrama									
Off-system Sales Revenue	2.24	2.88	6.76	6.88	7.58	7.82	6.58	7.06	0.00
Revenue from Customers	95.76	105.15	103.48	104.12	106.13	108.66	103.52	107.12	12.48
Total Revenue	98.00	108.02	110.24	111.00	113.71	116.48	110.09	114.18	12.48
Operating Expenses									
Fuel	34.83	41.14	38.38	37.15	39.28	42.10	39.08	42.64	0.00
Emissions	0.00	0.00	6.59	6.93	6.46	7.35	6.05	7.26	0.00
Non Fuel O&M (production)	17.84	16.72	19.99	18.19	17.71	17.64	20.69	18.21	0.00
Outage Accounting	(0.66)	1.72	(2.81)	(1.03)	0.47	0.47	(2.91)	0.00	0.00
Non-production Expenses	11.74	12.29	11.99	13.14	13.23	12.95	12.61	12.21	0.00
Major Maintenance Expense	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Decommissioning	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Book Depreciation	14.64	16.16	17.06	18.10	19.00	19.84	20.52	21.50	12.49
Amortization	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Operating Revenue Tax	4.31	4.75	4.85	4.88	5.00	5.13	4.84	5.02	0.55
Property Taxes	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.00
Other Taxes	1.23	1.24	1.18	1.25	1.25	1.25	1.27	1.27	0.00
Current Taxes	7.24	8.38	6.63	7.63	8.29	8.30	6.74	7.86	2.46
Deferred Taxes	(3.50)	(4.66)	(3.19)	(4.36)	(5.32)	(5.78)	(4.72)	(6.38)	(2.69)
ITC Amortization	(0.24)	(0.24)	(0.24)	(0.24)	(0.24)	(0.24)	(0.24)	(0.24)	(0.33)
Total Operating Expenses	88.07	98.13	101.07	102.27	105.76	109.64	104.56	109.98	12.48
Operating Income	9.93	9.90	9.17	8.73	7.95	6.84	5.54	4.19	0.00
Interest Expense	4.42	4.40	4.08	3.88	3.54	3.05	2.46	1.87	0.00
Net Income	5.51	5.49	5.09	4.84	4.41	3.80	3.07	2.33	0.00
Preferred Return	0.75	0.74	0.69	0.66	0.60	0.51	0.42	0.31	0.00
Income Available for Equity Return	4.77	4.75	4.40	4.19	3.82	3.28	2.66	2.01	0.00
Operating Income	9.9	9.9	9.2	8.7	8.0	6.8	5.5	4.2	0.0
Rate Base	103.4	103.1	95.5	90.9	82.8	71.3	57.6	43.6	0.0
Return on Rate Base	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%
Rate Base - Equity	41.4	41.3	38.3	36.4	33.2	28.6	23.1	17.5	0.0
Return on Equity	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%

Revenue Requirements Forecast
Fossil Generation

Year	1997	1998	1999	2000	2001	2002	2003	2004	2005
Cheswick									
Off-system Sales Revenue	4.2	3.7	9.6	10.1	10.5	11.1	10.3	9.1	3.6
Revenue from Customers	90.3	92.8	105.6	111.1	116.6	125.1	130.5	137.3	153.2
Total Revenue	94.5	96.5	115.2	121.1	127.0	136.2	140.7	146.4	156.9
Operating Expenses									
Fuel	39.9	36.8	45.8	48.0	47.8	52.9	52.6	48.7	55.4
Emissions	0.7	0.2	5.9	6.2	8.9	10.8	11.0	9.1	11.7
Non Fuel O&M (production)	11.0	24.6	12.6	12.2	14.0	13.8	12.5	25.4	14.7
Outage Accounting	2.7	-10.9	2.2	2.2	2.2	2.2	2.2	-10.4	2.1
Non-production Expenses	10.7	14.3	12.1	14.6	14.5	15.3	18.0	22.4	17.4
Major Maintenance Expense	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Decommissioning	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Book Depreciation	8.6	9.6	9.9	10.1	10.0	10.3	11.8	15.5	15.9
Amortization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Revenue Tax	4.2	4.2	5.1	5.3	5.6	6.0	6.2	6.4	6.9
Property Taxes	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Other Taxes	1.3	1.3	1.3	1.3	1.4	1.3	1.3	1.3	1.4
Current Taxes	7.3	1.5	10.8	11.2	13.1	14.5	15.3	10.3	17.2
Deferred Taxes	-2.9	2.9	-2.3	-2.3	-2.4	-2.6	-2.9	2.0	-2.6
ITC Amortization	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2
Total Operating Expenses	84.2	85.2	103.9	109.4	115.7	125.2	128.7	131.4	140.6
Operating Income	10.3	11.3	11.3	11.7	11.3	11.0	12.0	15.0	16.3
Interest Expense	4.6	5.0	5.0	5.2	5.0	4.9	5.3	6.7	7.2
Net Income	5.7	6.3	6.3	6.5	6.3	6.1	6.7	8.3	9.0
Preferred Return	0.8	0.8	0.8	0.9	0.9	0.8	0.9	1.1	1.2
Income Available for Equity Return	4.9	5.4	5.4	5.6	5.4	5.3	5.8	7.2	7.8
Operating Income	10.3	11.3	11.3	11.7	11.3	11.0	12.0	15.0	16.3
Rate Base	106.9	117.7	117.5	121.7	117.9	114.5	125.0	156.5	169.3
Return on Rate Base	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%
Rate Base - Equity	42.8	47.2	47.1	48.8	47.2	45.9	50.1	62.7	67.9
Return on Equity	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%

Revenue Requirements Forecast
Fossil Generation

Year	1997	1998	1999	2000	2001	2002	2003	2004	2005
Mansfield									
Off-system Sales Revenue	2.4	3.3	7.8	7.1	8.6	7.9	8.2	8.0	3.0
Revenue from Customers	91.1	98.8	109.3	84.3	88.0	87.7	91.7	96.4	105.8
Total Revenue	93.5	102.1	117.1	91.5	96.7	95.6	99.9	104.4	108.8
Operating Expenses									
Fuel	40.5	46.7	52.0	33.3	37.3	35.9	40.0	40.1	42.9
Emissions	0.0	0.0	6.0	5.3	6.2	5.8	6.9	6.9	7.6
Non Fuel O&M (production)	12.6	12.8	14.7	16.1	13.3	14.6	12.2	14.8	14.1
Outage Accounting	1.2	1.2	1.3	-3.6	0.0	0.0	1.1	1.1	1.1
Non-production Expenses	10.0	11.7	12.9	11.6	11.6	11.3	11.7	12.5	13.7
Major Maintenance Expense	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Decommissioning	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Book Depreciation	8.1	8.4	8.5	8.3	7.9	8.2	8.3	8.9	9.3
Amortization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Revenue Tax	4.1	4.5	5.2	4.0	4.3	4.2	4.4	4.6	4.8
Property Taxes	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Other Taxes	1.4	1.3	1.4	1.3	1.3	1.3	1.3	1.4	1.3
Current Taxes	5.7	6.2	6.5	4.3	5.5	5.5	5.8	6.0	5.8
Deferred Taxes	-1.6	-2.1	-2.5	-0.4	-1.7	-1.7	-2.2	-2.3	-2.2
ITC Amortization	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3
Total Operating Expenses	82.5	91.2	106.4	80.8	86.3	85.5	90.1	94.5	99.1
Operating Income	11.0	11.0	10.7	10.6	10.4	10.1	9.8	9.9	9.7
Interest Expense	4.9	4.9	4.8	4.7	4.6	4.5	4.4	4.4	4.3
Net Income	6.1	6.1	5.9	5.9	5.8	5.6	5.4	5.5	5.4
Preferred Return	0.8	0.8	0.8	0.8	0.8	0.8	0.7	0.7	0.7
Income Available for Equity Return	5.3	5.3	5.1	5.1	5.0	4.9	4.7	4.8	4.7
Operating Income	11.0	11.0	10.7	10.6	10.4	10.1	9.8	9.9	9.7
Rate Base	114.7	114.3	111.4	110.7	108.2	105.5	102.0	103.4	101.4
Return on Rate Base	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%
Rate Base - Equity	46.0	45.8	44.6	44.4	43.4	42.3	40.9	41.4	40.6
Return on Equity	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%

Revenue Requirements Forecast
Fossil Generation

Year	1997	1998	1999	2000	2001	2002	2003	2004	2005
Sammis									
Off-system Sales Revenue	1.3	1.6	3.3	3.7	3.6	3.6	3.4	3.8	1.3
Revenue from Customers	33.1	36.3	35.2	35.5	37.9	39.7	42.9	42.2	48.6
Total Revenue	34.4	37.8	38.4	39.2	41.5	43.3	46.3	45.9	49.8
Operating Expenses									
Fuel	13.6	17.3	16.1	18.7	17.9	18.5	19.5	21.6	20.8
Emissions	0.2	0.0	-0.7	-0.6	0.4	0.5	0.5	0.7	2.3
Non Fuel O&M (production)	4.4	3.9	5.7	4.3	5.8	5.4	6.7	4.8	7.0
Outage Accounting	0.3	0.3	0.3	0.3	-0.8	-0.4	0.5	0.5	0.5
Non-production Expenses	3.8	4.2	4.5	4.5	5.8	5.9	5.6	5.2	6.3
Major Maintenance Expense	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Decommissioning	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Book Depreciation	4.2	4.3	4.6	4.5	4.7	5.3	5.5	5.6	5.7
Amortization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Revenue Tax	1.5	1.7	1.7	1.7	1.8	1.9	2.0	2.0	2.2
Property Taxes	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.3	0.3
Other Taxes	0.5	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Current Taxes	2.0	2.5	2.6	2.5	2.2	2.5	2.7	2.6	2.6
Deferred Taxes	-0.5	-1.1	-1.2	-1.2	-0.7	-1.0	-1.3	-1.4	-1.4
ITC Amortization	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2
Total Operating Expenses	30.3	33.9	34.4	35.4	37.6	39.2	42.5	42.4	46.6
Operating Income	4.1	3.9	4.0	3.8	3.9	4.1	3.9	3.6	3.2
Interest Expense	1.8	1.8	1.8	1.7	1.7	1.8	1.7	1.6	1.4
Net Income	2.3	2.2	2.2	2.1	2.2	2.3	2.1	2.0	1.8
Preferred Return	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.2
Income Available for Equity Return	2.0	1.9	1.9	1.8	1.9	2.0	1.9	1.7	1.5
Operating Income	4.1	3.9	4.0	3.8	3.9	4.1	3.9	3.6	3.2
Rate Base	42.7	40.9	41.8	39.5	40.7	42.7	40.3	37.2	33.6
Return on Rate Base	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%
Rate Base - Equity	17.1	16.4	16.8	15.8	16.3	17.1	16.1	14.9	13.5
Return on Equity	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%

Revenue Requirements Forecast
Fossil Generation

Year	1997	1998	1999	2000	2001	2002	2003	2004	2005
Eastlake									
Off-system Sales Revenue	1.4	1.3	2.2	3.2	3.1	3.1	3.2	2.9	1.0
Revenue from Customers	29.6	28.0	29.3	33.7	35.5	37.7	39.8	39.4	42.6
Total Revenue	30.9	29.2	31.5	36.9	38.6	40.7	43.1	42.4	43.6
Operating Expenses									
Fuel	12.3	11.2	9.5	13.8	12.7	13.2	15.2	14.1	13.7
Emissions	0.3	0.1	1.4	2.7	3.3	3.6	4.4	4.2	5.1
Non Fuel O&M (production)	4.7	5.4	6.8	5.7	6.2	6.4	6.2	6.8	7.5
Outage Accounting	0.1	-1.4	0.2	0.3	0.3	0.3	0.3	0.3	-0.8
Non-production Expenses	3.6	3.8	3.5	4.4	5.5	5.6	5.3	5.1	6.0
Major Maintenance Expense	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Decommissioning	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Book Depreciation	3.2	3.4	3.5	3.4	3.7	4.2	4.3	4.7	5.1
Amortization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Revenue Tax	1.4	1.3	1.4	1.6	1.7	1.8	1.9	1.9	1.9
Property Taxes	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Other Taxes	0.4	0.5	0.4	0.5	0.5	0.5	0.5	0.5	0.5
Current Taxes	1.8	1.3	1.9	1.8	2.0	2.1	2.3	2.4	1.9
Deferred Taxes	-0.6	0.0	-0.6	-0.6	-0.7	-0.8	-1.0	-1.1	-0.7
ITC Amortization	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1
Total Operating Expenses	27.5	25.8	28.2	33.8	35.3	37.1	39.6	39.0	40.3
Operating Income	3.4	3.4	3.3	3.2	3.4	3.6	3.5	3.4	3.3
Interest Expense	1.5	1.5	1.5	1.4	1.5	1.6	1.5	1.5	1.5
Net Income	1.9	1.9	1.8	1.8	1.9	2.0	1.9	1.9	1.8
Preferred Return	0.3	0.3	0.3	0.2	0.3	0.3	0.3	0.3	0.2
Income Available for Equity Return	1.6	1.6	1.6	1.5	1.6	1.7	1.7	1.6	1.6
Operating Income	3.4	3.4	3.3	3.2	3.4	3.6	3.5	3.4	3.3
Rate Base	35.5	35.8	34.7	32.9	35.1	37.6	36.0	35.3	34.6
Return on Rate Base	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%
Rate Base - Equity	14.2	14.3	13.9	13.2	14.1	15.1	14.4	14.1	13.9
Return on Equity	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%

Revenue Requirements Forecast
Fossil Generation

Year	1997	1998	1999	2000	2001	2002	2003	2004	2005
Brunot Island									
Off-system Sales Revenue	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Revenue from Customers	6.0	5.7	7.4	6.2	5.9	5.7	5.6	7.1	6.2
Total Revenue	6.0	5.7	7.4	6.2	5.9	5.7	5.6	7.1	6.2
Operating Expenses									
Fuel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Emissions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non Fuel O&M (production)	0.7	0.4	0.6	0.6	0.6	0.6	0.7	0.7	0.7
Outage Accounting	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non-production Expenses	0.5	0.4	1.1	0.2	0.2	0.2	0.2	1.0	0.3
Major Maintenance Expense	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Decommissioning	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Book Depreciation	1.9	2.0	2.3	2.2	2.1	2.1	2.1	2.5	2.5
Amortization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Revenue Tax	0.3	0.2	0.3	0.3	0.3	0.3	0.2	0.3	0.3
Property Taxes	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Other Taxes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Current Taxes	1.3	1.2	1.4	1.2	1.2	1.1	1.1	1.3	1.2
Deferred Taxes	-0.7	-0.6	-0.6	-0.5	-0.5	-0.5	-0.6	-0.7	-0.6
ITC Amortization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Operating Expenses	4.4	4.0	5.4	4.3	4.2	4.1	4.1	5.4	4.7
Operating Income	1.7	1.7	2.0	1.9	1.7	1.6	1.5	1.7	1.5
Interest Expense	0.8	0.7	0.9	0.8	0.8	0.7	0.7	0.8	0.7
Net Income	0.9	0.9	1.1	1.1	1.0	0.9	0.8	0.9	0.8
Preferred Return	0.1	0.1	0.2	0.1	0.1	0.1	0.1	0.1	0.1
Income Available for Equity Return	0.8	0.8	1.0	0.9	0.8	0.8	0.7	0.8	0.7
Operating Income	1.7	1.7	2.0	1.9	1.7	1.6	1.5	1.7	1.5
Rate Base	17.6	17.5	21.3	19.7	18.2	16.7	15.2	17.6	15.8
Return on Rate Base	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%
Rate Base - Equity	7.1	7.0	8.5	7.9	7.3	6.7	6.1	7.1	6.3
Return on Equity	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%

Revenue Requirements Forecast
Fossil Generation

Year	1997	1998	1999	2000	2001	2002	2003	2004	2005
Phillips									
Off-system Sales Revenue	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Revenue from Customers	7.2	7.5	6.7	6.6	17.2	33.7	26.3	15.2	-0.3
Total Revenue	7.2	7.5	6.7	6.6	17.2	33.7	26.3	15.2	-0.3
Operating Expenses									
Fuel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Emissions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non Fuel O&M (production)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Outage Accounting	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non-production Expenses	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Major Maintenance Expense	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Decommissioning	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Book Depreciation	0.5	0.8	0.0	0.0	11.0	29.1	23.9	14.4	0.0
Amortization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Revenue Tax	0.3	0.3	0.3	0.3	0.8	1.5	1.2	0.7	0.0
Property Taxes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Taxes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Current Taxes	1.7	1.8	1.5	1.6	5.9	12.8	10.1	5.9	-0.2
Deferred Taxes	0.1	-0.1	0.2	0.2	-4.4	-12.0	-9.8	-5.9	0.1
ITC Amortization	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2
Total Operating Expenses	2.4	2.7	1.9	1.9	13.1	31.2	25.2	14.9	-0.3
Operating Income	4.8	4.8	4.8	4.8	4.1	2.5	1.1	0.3	0.0
Interest Expense	2.1	2.1	2.1	2.1	1.8	1.1	0.5	0.1	0.0
Net Income	2.7	2.7	2.7	2.7	2.3	1.4	0.6	0.2	0.0
Preferred Return	0.4	0.4	0.4	0.4	0.3	0.2	0.1	0.0	0.0
Income Available for Equity Return	2.3	2.3	2.3	2.3	2.0	1.2	0.6	0.2	0.0
Operating Income	4.8	4.8	4.8	4.8	4.1	2.5	1.1	0.3	0.0
Rate Base	50.1	50.1	49.9	49.7	43.2	26.0	11.9	3.4	0.0
Return on Rate Base	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%
Rate Base - Equity	20.1	20.1	20.0	19.9	17.3	10.4	4.8	1.4	0.0
Return on Equity	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%

Revenue Requirements Forecast
Fossil Generation

Year	1997	1998	1999	2000	2001	2002	2003	2004	2005
B.L. Cold Reserve									
Off-system Sales Revenue	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Revenue	2.4	2.4	2.4	2.3	2.3	2.3	2.3	2.3	16.5
Total Revenue	2.4	2.4	2.4	2.3	2.3	2.3	2.3	2.3	16.5
Operating Expenses									
Fuel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Emissions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non Fuel O&M (production)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Outage Accounting	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non-production Expenses	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Major Maintenance Expense	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Decommissioning	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Book Depreciation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	13.9
Amortization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Revenue Tax	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.7
Property Taxes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Taxes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Current Taxes	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	6.3
Deferred Taxes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-5.8
ITC Amortization	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1
Total Operating Expenses	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	15.1
Operating Income	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.4
Interest Expense	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.6
Net Income	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.8
Preferred Return	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Income Available for Equity Return	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.7
Operating Income	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.4
Rate Base	17.5	17.5	17.5	17.4	17.4	17.4	17.4	17.4	14.9
Return on Rate Base	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%
Rate Base - Equity	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	6.0
Return on Equity	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%

Revenue Requirements Forecast
Fossil Generation

Year	1997	1998	1999	2000	2001	2002	2003	2004	2005
Purchaser & Other									
Off-system Sales Revenue	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Revenue from Customers	21.9	2.0	22.2	20.0	25.2	27.8	32.4	37.5	106.3
Total Revenue	21.9	2.0	22.2	20.0	25.2	27.8	32.4	37.5	106.3
Operating Expenses									
Fuel	14.8	13.6	20.7	18.0	23.3	25.4	29.7	34.6	104.2
Emissions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non Fuel O&M (production)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Outage Accounting	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non-production Expenses	1.4	2.0	0.5	1.1	0.8	1.1	1.3	1.3	-2.6
Major Maintenance Expense	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Decommissioning	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Book Depreciation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Amortization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Revenue Tax	1.0	0.1	1.0	0.9	1.1	1.2	1.4	1.7	4.7
Property Taxes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Taxes	-7.4	-4.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Current Taxes	5.0	-3.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Deferred Taxes	6.8	-5.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ITC Amortization	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Operating Expenses	21.9	2.0	22.2	20.0	25.2	27.8	32.4	37.5	106.3
Operating Income	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Interest Expense	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Income	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Preferred Return	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Income Available for Equity Return	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Income	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rate Base	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Return on Rate Base	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Rate Base - Equity	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Return on Equity	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Revenue Requirements Forecast
Fossil Generation

Year	1997	1998	1999	2000	2001	2002	2003	2004	2005
Warwick									
Off-system Sales Revenue	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Revenue	15.4	15.1	14.9	3.5	0.0	0.0	0.0	0.0	0.0
Total Revenue	15.4	15.1	14.9	3.5	0.0	0.0	0.0	0.0	0.0
Operating Expenses									
Fuel	14.4	14.5	14.7	3.5	0.0	0.0	0.0	0.0	0.0
Emissions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non Fuel O&M (production)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Outage Accounting	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non-production Expenses	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Major Maintenance Expense	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Decommissioning	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Book Depreciation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Amortization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Revenue Tax	0.7	0.7	0.7	0.2	0.0	0.0	0.0	0.0	0.0
Property Taxes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Taxes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Current Taxes	1.9	1.8	1.7	0.4	0.0	0.0	0.0	0.0	0.0
Deferred Taxes	(1.9)	(1.9)	(1.9)	(0.5)	0.0	0.0	0.0	0.0	0.0
ITC Amortization	(0.4)	(0.4)	(0.4)	(0.1)	0.0	0.0	0.0	0.0	0.0
Total Operating Expenses	14.7	14.7	14.8	3.5	0.0	0.0	0.0	0.0	0.0
Operating Income	0.6	0.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0
Interest Expense	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0
Net Income	0.4	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0
Preferred Return	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Income Available for Equity Return	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0
Operating Income	0.6	0.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0
Rate Base	6.6	3.9	1.2	0.0	0.0	0.0	0.0	0.0	0.0
Return on Rate Base	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%
Rate Base - Equity	2.7	1.6	0.5	0.0	0.0	0.0	0.0	0.0	0.0
Return on Equity	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%

Revenue Requirements Forecast

Year	1997	1998	1999	2000	2001	2002	2003	2004	2005
Generation Related Regulatory Asset									
Revenue	58.1	83.3	100.3	93.5	86.5	79.6	90.6	110.5	103.6
Operating Expenses									
Warwick Fuel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non-production Expenses	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Major Maintenance Expense	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Book Depreciation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Amortization	65.6	94.6	91.2	91.2	91.2	91.2	91.2	91.2	91.2
Operating Revenue Tax	2.6	3.7	4.4	4.1	3.8	3.5	4.0	4.9	4.6
Property Taxes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Taxes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Current Taxes	(17.7)	(7.1)	(0.5)	(2.3)	(4.2)	(6.0)	9.2	33.0	31.1
Deferred Taxes	(23.3)	(35.7)	(23.2)	(23.2)	(23.2)	(23.2)	(23.2)	(23.2)	(23.2)
ITC Amortization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Operating Expenses	27.2	55.5	71.9	69.8	67.6	65.4	81.1	105.8	103.6
Operating Income	30.9	27.8	28.4	23.7	19.0	14.2	9.5	4.8	0.0
Interest Expense	13.8	12.4	12.6	10.5	8.4	6.3	4.2	2.1	0.0
Net Income	17.1	15.4	15.7	13.2	10.5	7.9	5.3	2.7	0.0
Preferred Return	2.3	2.1	2.1	1.8	1.4	1.1	0.7	0.4	0.0
Income Available for Equity Return	14.8	13.4	13.6	11.4	9.1	6.8	4.5	2.3	0.0
Operating Income	30.9	27.8	28.4	23.7	19.0	14.2	9.5	4.8	0.0
Rate Base	321.9	289.1	295.7	246.4	197.1	147.8	98.6	49.3	0.0
Return on Operating Income	9.60%	9.61%	9.60%	9.62%	9.62%	9.60%	9.60%	9.66%	0.00%
Rate Base - Equity	129.0	115.9	118.5	98.8	79.0	59.3	39.5	19.8	0.0
Return on Equity	11.49%	11.52%	11.48%	11.54%	11.53%	11.49%	11.49%	11.64%	0.00%

Revenue Requirements Forecast

Year	1997	1998	1999	2000	2001	2002	2003	2004	2005
Transmission									
Revenue from Customers	33.2	35.4	36.8	37.3	38.3	39.8	40.7	40.9	41.5
Other Revenues	6.3	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1
Total Revenues	39.5	41.5	42.8	43.4	44.4	45.9	46.7	47.0	47.5
Operating Expenses									
Non-production Expenses	12.6	13.8	14.2	13.9	14.2	14.6	14.9	15.3	15.7
Major Maintenance Expense	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Book Depreciation	4.8	4.9	5.0	5.0	5.0	5.1	5.2	5.2	5.3
Amortization	(1.2)	(1.2)	(1.0)	(0.8)	(0.6)	(0.4)	(0.2)	(0.1)	(0.0)
Operating Revenue Tax	1.7	1.8	1.9	1.9	2.0	2.0	2.1	2.1	2.1
Property Taxes	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Other Taxes	1.5	1.5	1.5	1.5	1.5	1.6	1.6	1.6	1.7
Current Taxes	5.1	5.5	5.9	6.4	6.7	7.2	7.4	7.4	7.4
Deferred Taxes	(1.2)	(1.0)	(0.8)	(0.6)	(0.4)	(0.1)	0.3	0.3	0.5
ITC Amortization	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)
Total Operating Expenses	23.6	25.6	26.9	27.6	28.7	30.2	31.4	32.0	32.8
Operating Income	15.8	15.9	15.9	15.7	15.6	15.7	15.3	15.0	14.7
Interest Expense	7.1	7.1	7.1	7.0	6.9	7.0	6.8	6.7	6.5
Net Income	8.8	8.8	8.8	8.7	8.7	8.7	8.5	8.3	8.2
Preferred Return	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.1	1.1
Income Available for Equity Return	7.6	7.6	7.6	7.5	7.5	7.5	7.4	7.2	7.1
Operating Income	15.8	15.9	15.9	15.7	15.6	15.7	15.3	15.0	14.7
Rate Base	165.0	165.3	165.4	163.7	162.6	163.1	159.7	156.3	153.1
Return on Operating Income	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%
Rate Base - Equity	66.1	66.3	66.3	65.6	65.2	65.4	64.0	62.6	61.4
Return on Equity	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%

Revenue Requirements Forecast

Year	1997	1998	1999	2000	2001	2002	2003	2004	2005
Distribution									
Revenue from Customers	240.7	255.2	260.4	263.4	271.3	278.0	285.0	291.8	304.0
Other Revenues	12.7	12.8	15.9	16.0	16.0	16.1	16.2	16.3	12.1
Total Revenues	253.4	267.9	276.2	279.3	287.4	294.1	301.2	308.0	316.0
Operating Expenses									
Non-production Expenses	97.3	105.9	109.3	107.4	110.3	113.1	116.0	119.0	122.4
Major Maintenance Expense	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Book Depreciation	31.8	33.2	34.5	35.7	37.0	38.3	39.5	40.8	42.2
Amortization	0.1	0.2	0.7	1.4	2.2	2.7	3.1	3.3	3.6
Operating Revenue Tax	11.2	11.8	12.2	12.3	12.6	12.9	13.3	13.6	13.9
Property Taxes	2.7	3.2	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Other Taxes	6.6	6.6	6.7	6.8	6.9	7.0	7.1	7.2	7.8
Current Taxes	26.2	28.0	29.3	30.8	32.3	32.7	33.0	33.1	33.2
Deferred Taxes	3.7	2.8	2.0	1.4	0.6	0.8	1.0	1.5	1.9
ITC Amortization	(1.6)	(1.6)	(1.6)	(1.6)	(1.6)	(1.6)	(1.6)	(1.6)	(1.6)
Total Operating Expenses	177.9	190.1	196.5	197.6	203.7	209.1	214.7	220.2	226.8
Operating Income	75.5	77.9	79.7	81.8	83.6	84.9	86.5	87.9	89.2
Interest Expense	33.6	34.7	35.5	36.4	37.2	37.8	38.5	39.1	39.7
Net Income	41.9	43.2	44.2	45.4	46.4	47.1	48.0	48.8	49.5
Preferred Return	5.7	5.9	6.0	6.1	6.3	6.4	6.5	6.6	6.7
Income Available for Equity Return	36.2	37.4	38.2	39.2	40.1	40.8	41.5	42.2	42.8
Operating Income	75.5	77.9	79.7	81.8	83.6	84.9	86.5	87.9	89.2
Rate Base	786.3	810.7	829.8	851.2	870.7	884.2	900.1	914.7	928.8
Return on Operating Income	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%
Rate Base - Equity	315.2	324.9	332.6	341.2	349.0	354.4	360.8	366.6	372.3
Return on Equity	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%

Rate Base and Net Book Value Forecast

Year	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Rate Base Summary										
Generation	1,101.07	1,080.06	1,036.11	931.99	872.40	804.71	724.05	649.75	618.08	536.98
Regulatory Assets	346.43	322.08	289.14	295.70	246.42	197.13	147.85	98.57	49.28	0.00
Transmission	165.12	164.99	165.34	165.38	163.68	162.59	163.09	159.72	156.27	153.14
Distribution	755.58	786.17	810.67	829.78	851.23	870.65	884.20	900.14	914.74	928.80
Total	2,368.20	2,353.30	2,301.27	2,222.85	2,133.72	2,035.08	1,919.20	1,808.18	1,738.38	1,618.92
Net Book Value Summary										
Generation	959.60	945.65	908.85	812.48	760.34	699.03	624.76	556.83	531.57	465.20
Regulatory Assets Included in Rate Base	346.43	322.08	289.14	295.70	246.42	197.13	147.85	98.57	49.28	0.00
Regulatory Assets Excluded from Rate Base	284.40	264.07	229.10	197.33	176.14	154.95	133.77	112.58	91.39	70.21
Transmission	158.13	158.43	159.19	159.63	158.34	157.66	158.57	155.62	152.58	149.86
Distribution	727.90	760.13	786.19	806.86	829.86	850.84	865.95	883.44	899.61	915.22
Total	2,476.46	2,450.36	2,372.47	2,272.00	2,171.10	2,059.62	1,930.90	1,807.04	1,724.43	1,600.48

Rate Base and Net Book Value Forecast

Year	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Net Plant										
Nuclear	906.88	836.72	753.87	609.00	525.50	444.76	363.73	283.35	217.07	156.76
Fossil	608.54	614.93	609.49	587.77	569.36	535.33	480.24	432.08	421.88	373.12
Transmission	198.76	196.37	194.65	192.99	190.08	188.14	188.23	185.03	181.85	179.27
Distribution	914.16	947.56	974.02	995.15	1,018.61	1,040.06	1,056.30	1,075.60	1,094.23	1,113.07
	2,628.34	2,595.57	2,532.03	2,384.92	2,303.55	2,208.28	2,088.50	1,976.06	1,915.04	1,822.22
Regulatory Assets										
Generation Regulatory Assets	455.26	420.67	370.73	387.23	322.69	258.15	193.62	129.08	64.54	(0.00)
Nuclear	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fossil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Transmission	32.68	33.92	35.09	36.13	36.89	37.49	37.90	38.11	38.26	38.30
Distribution	56.85	58.08	59.21	59.76	59.67	58.76	57.38	55.60	53.64	51.30
	544.79	512.67	465.03	483.12	419.25	354.41	288.89	222.79	156.44	89.60
Deferred Income Taxes										
Generation Regulatory Assets	(109.18)	(98.77)	(81.59)	(91.53)	(76.28)	(61.02)	(45.77)	(30.51)	(15.26)	0.00
Nuclear	(306.92)	(273.16)	(238.98)	(187.20)	(154.06)	(121.90)	(89.74)	(57.51)	(31.93)	(7.74)
Fossil	(171.03)	(161.03)	(149.79)	(138.09)	(127.93)	(113.01)	(89.71)	(67.70)	(48.47)	(33.69)
Transmission	(67.54)	(66.50)	(65.62)	(64.96)	(64.52)	(64.26)	(64.26)	(64.64)	(65.06)	(65.65)
Distribution	(220.21)	(224.33)	(227.58)	(230.16)	(232.08)	(233.20)	(234.50)	(236.09)	(238.16)	(240.60)
	(874.88)	(823.79)	(763.56)	(711.94)	(654.86)	(593.39)	(523.98)	(456.45)	(398.88)	(347.67)
Working Capital										
Nuclear	21.84	21.50	20.42	19.40	18.43	18.43	18.43	18.43	18.43	18.43
Fossil	41.76	41.10	41.10	41.10	41.10	41.10	41.10	41.10	41.10	30.10
Transmission	1.24	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22
Distribution	5.11	5.03	5.03	5.03	5.03	5.03	5.03	5.03	5.03	5.03
	69.94	68.85	67.77	66.75	65.78	65.78	65.78	65.78	65.78	54.78
Investment Tax Credit										
Nuclear	(56.98)	(52.54)	(48.11)	(43.01)	(37.91)	(32.80)	(27.70)	(22.60)	(17.47)	(15.12)
Fossil	(20.90)	(19.27)	(17.63)	(16.00)	(14.63)	(13.35)	(12.06)	(10.78)	(9.50)	(8.13)
Transmission	(5.75)	(5.34)	(4.93)	(4.52)	(4.11)	(3.70)	(3.29)	(2.89)	(2.48)	(2.07)
Distribution	(22.57)	(21.01)	(19.45)	(17.89)	(16.34)	(14.78)	(13.22)	(11.67)	(10.11)	(8.55)
	(106.20)	(98.16)	(90.13)	(81.42)	(72.98)	(64.63)	(56.28)	(47.93)	(39.56)	(33.87)

Rate Base and Net Book Value Forecast

Year	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Generation Summary										
Original Cost	2,804.81	2,881.51	2,937.42	2,916.60	2,955.03	2,988.39	3,021.17	3,059.41	3,130.39	3,157.46
Accumulated Depreciation	(1,289.38)	(1,429.87)	(1,574.06)	(1,719.82)	(1,860.17)	(2,008.31)	(2,177.20)	(2,343.98)	(2,491.43)	(2,627.58)
Net Plant	1,515.43	1,451.65	1,363.37	1,196.77	1,094.86	980.09	843.97	715.43	638.95	529.88
Accumulated Deferred Taxes	(477.95)	(434.19)	(388.77)	(325.29)	(281.99)	(234.91)	(179.45)	(125.21)	(80.41)	(41.42)
Net Plant Less Accum. Deferred Taxes	1,037.48	1,017.46	974.59	871.49	812.87	745.18	664.52	590.22	558.55	488.45
Working Capital	63.59	62.60	61.52	60.50	59.53	59.53	59.53	59.53	59.53	48.53
Rate Base	1,101.07	1,080.06	1,036.11	931.99	872.40	804.71	724.05	649.75	618.08	536.98
Net Plant Less Accum. Deferred Taxes	1,037.48	1,017.46	974.59	871.49	812.87	745.18	664.52	590.22	558.55	488.45
Less: Accumulated ITC	(77.88)	(71.81)	(65.74)	(59.01)	(52.53)	(46.15)	(39.77)	(33.38)	(26.97)	(23.25)
Net Book Value	959.60	945.65	908.85	812.48	760.34	699.03	624.76	556.83	531.57	465.20

Rate Base and Net Book Value Forecast

Year	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Regulatory Assets Summary										
Book Cost	544.79	544.79	544.79	625.83	625.83	625.83	625.83	625.83	625.83	625.83
Accumulated Amortization	0.00	(32.12)	(79.76)	(142.71)	(206.58)	(271.42)	(336.94)	(403.04)	(469.39)	(536.23)
Net Book Cost	544.79	512.67	465.03	483.12	419.25	354.41	288.89	222.79	156.44	89.60
Accumulated Deferred Taxes	(198.36)	(190.59)	(175.88)	(187.42)	(172.84)	(157.27)	(141.04)	(124.22)	(107.15)	(89.60)
Net Plant Less Accum. Deferred Taxes	346.43	322.08	289.14	295.70	246.42	197.13	147.85	98.57	49.28	0.00
Working Capital	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Rate Base	346.43	322.08	289.14	295.70	246.42	197.13	147.85	98.57	49.28	0.00
Regulatory Assets Excluded from Rate Base (Generation)										
Book Cost	449.13	449.13	449.13	431.03	431.03	431.03	431.03	431.03	431.03	431.03
Accumulated Amortization	0.00	(34.76)	(94.52)	(125.45)	(156.38)	(187.31)	(218.24)	(249.17)	(280.10)	(311.03)
Net Book Cost	449.13	414.37	354.61	305.58	274.65	243.72	212.79	181.86	150.93	120.00
Accumulated Deferred Taxes	(164.73)	(150.30)	(125.51)	(108.25)	(98.51)	(88.77)	(79.02)	(69.28)	(59.54)	(49.79)
Net Book Value	284.40	264.07	229.10	197.33	176.14	154.95	133.77	112.58	91.39	70.21

Rate Base and Net Book Value Forecast

Year	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Transmission Summary										
Original Cost	319.05	321.50	324.68	327.98	330.08	333.18	338.40	340.40	342.45	345.13
Accumulated Depreciation	(120.29)	(125.14)	(130.03)	(134.99)	(139.99)	(145.04)	(150.17)	(155.37)	(160.60)	(165.86)
Net Plant	198.76	196.37	194.65	192.99	190.08	188.14	188.23	185.03	181.85	179.27
Accumulated Deferred Taxes	(34.88)	(32.60)	(30.52)	(28.83)	(27.63)	(26.77)	(26.36)	(26.53)	(26.80)	(27.34)
Net Plant Less Accum. Deferred Taxes	163.88	163.77	164.12	164.16	162.46	161.37	161.87	158.50	155.05	151.92
Working Capital	1.24	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22
Rate Base	165.12	164.99	165.34	165.38	163.68	162.59	163.09	159.72	156.27	153.14
Net Plant Less Accum. Deferred Taxes	163.88	163.77	164.12	164.16	162.46	161.37	161.87	158.50	155.05	151.92
Less: Accumulated ITC	(5.75)	(5.34)	(4.93)	(4.52)	(4.11)	(3.70)	(3.29)	(2.89)	(2.48)	(2.07)
Net Book Value	158.13	158.43	159.19	159.63	158.34	157.66	158.57	155.62	152.58	149.86

Rate Base and Net Book Value Forecast

Year	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Distribution Summary										
Original Cost	1,341.65	1,406.88	1,466.56	1,522.18	1,581.37	1,639.87	1,694.39	1,753.21	1,812.68	1,873.69
Accumulated Depreciation	(427.49)	(459.32)	(492.54)	(527.02)	(562.77)	(599.81)	(638.09)	(677.61)	(718.45)	(760.62)
Net Plant	914.16	947.56	974.02	995.15	1,018.61	1,040.06	1,056.30	1,075.60	1,094.23	1,113.07
Accumulated Deferred Taxes	(163.69)	(166.42)	(168.38)	(170.40)	(172.41)	(174.44)	(177.13)	(180.49)	(184.52)	(189.31)
Net Plant Less Accum. Deferred Taxes	750.46	781.14	805.64	824.75	846.20	865.62	879.17	895.11	909.71	923.77
Working Capital	5.11	5.03	5.03	5.03	5.03	5.03	5.03	5.03	5.03	5.03
Rate Base	755.58	786.17	810.67	829.78	851.23	870.65	884.20	900.14	914.74	928.80
Net Plant Less Accum. Deferred Taxes	750.46	781.14	805.64	824.75	846.20	865.62	879.17	895.11	909.71	923.77
Less: Accumulated ITC	(22.57)	(21.01)	(19.45)	(17.89)	(16.34)	(14.78)	(13.22)	(11.67)	(10.11)	(8.55)
Net Book Value	727.90	760.13	786.19	806.86	829.86	850.84	865.95	883.44	899.61	915.22

Rate Base and Net Book Value Forecast

Year	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Nuclear Generation										
Perry										
Original Cost	868.19	879.05	883.57	847.37	849.39	852.78	854.74	858.05	860.12	863.60
Accumulated Depreciation	(394.20)	(452.23)	(510.32)	(568.54)	(625.00)	(679.97)	(734.95)	(790.02)	(828.74)	(863.61)
Net Plant	473.99	426.83	373.25	278.83	224.39	172.81	119.78	68.04	31.39	(0.00)
Accumulated Deferred Taxes	(165.73)	(144.14)	(122.29)	(86.36)	(64.97)	(44.05)	(23.14)	(2.22)	11.87	24.32
Net Plant Less Accum. Deferred Taxes	308.26	282.69	250.96	192.47	159.42	128.76	96.65	65.81	43.25	24.32
Working Capital	11.82	11.64	11.03	10.46	9.91	9.89	9.86	9.84	9.82	9.79
Rate Base	320.08	294.33	261.99	202.93	169.33	138.65	106.51	75.65	53.07	34.11
Net Plant Less Accum. Deferred Taxes	308.26	282.69	250.96	192.47	159.42	128.76	96.65	65.81	43.25	24.32
Less: Accumulated ITC	(24.25)	(21.40)	(18.54)	(15.68)	(12.83)	(9.97)	(7.11)	(4.25)	(1.40)	(1.35)
Net Book Value	284.01	261.30	232.42	176.79	146.59	118.79	89.53	61.56	41.85	22.97

Rate Base and Net Book Value Forecast

Year	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Nuclear Generation										
Beaver Valley 1										
Original Cost	653.69	663.74	668.54	654.30	659.98	663.94	669.48	675.25	679.59	685.62
Accumulated Depreciation	(275.30)	(308.62)	(342.06)	(375.68)	(408.18)	(439.61)	(471.31)	(503.34)	(535.73)	(568.67)
Net Plant	378.39	355.12	326.48	278.62	251.80	224.33	198.16	171.90	143.86	116.95
Accumulated Deferred Taxes	(123.51)	(112.63)	(101.53)	(84.85)	(73.89)	(63.39)	(52.84)	(42.22)	(31.45)	(20.46)
Net Plant Less Accum. Deferred Taxes	254.88	242.49	224.96	193.77	177.91	160.94	145.33	129.69	112.41	96.49
Working Capital	8.93	8.79	8.34	7.93	7.56	7.56	7.58	7.60	7.61	7.63
Rate Base	263.80	251.28	233.30	201.70	185.47	168.50	152.91	137.28	120.02	104.12
Net Plant Less Accum. Deferred Taxes	254.88	242.49	224.96	193.77	177.91	160.94	145.33	129.69	112.41	96.49
Less: Accumulated ITC	(19.49)	(17.92)	(16.35)	(14.78)	(13.20)	(11.63)	(10.06)	(8.49)	(6.89)	(5.29)
Net Book Value	235.39	224.57	208.61	178.99	164.71	149.31	135.27	121.20	105.52	91.21

Rate Base and Net Book Value Forecast

Year	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Nuclear Generation										
Beaver Valley 2										
Original Cost	77.52	81.08	83.90	84.68	85.85	87.47	88.84	89.72	91.45	92.83
Accumulated Depreciation	(23.02)	(26.32)	(29.76)	(33.13)	(36.54)	(39.85)	(43.06)	(46.31)	(49.62)	(53.02)
Net Plant	54.50	54.77	54.14	51.55	49.31	47.62	45.78	43.41	41.83	39.81
Accumulated Deferred Taxes	(17.67)	(16.39)	(15.16)	(15.99)	(15.19)	(14.45)	(13.76)	(13.06)	(12.35)	(11.60)
Net Plant Less Accum. Deferred Taxes	36.82	38.38	38.98	35.56	34.12	33.17	32.02	30.35	29.48	28.21
Working Capital	1.09	1.07	1.05	1.01	0.96	0.98	0.99	0.99	1.00	1.01
Rate Base	37.91	39.45	40.02	36.57	35.08	34.14	33.01	31.33	30.48	29.22
Net Plant Less Accum. Deferred Taxes	36.82	38.38	38.98	35.56	34.12	33.17	32.02	30.35	29.48	28.21
Less: Accumulated ITC	(13.24)	(13.23)	(13.22)	(12.55)	(11.88)	(11.20)	(10.53)	(9.86)	(9.19)	(8.49)
Net Book Value	23.59	25.15	25.76	23.02	22.24	21.96	21.49	20.49	20.29	19.72

Rate Base and Net Book Value Forecast

Year	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Fossil Generation										
Elrama										
Original Cost	237.66	259.95	271.43	277.56	286.10	291.76	294.49	296.00	297.05	297.05
Accumulated Depreciation	(137.74)	(152.38)	(168.54)	(185.59)	(203.70)	(222.70)	(242.54)	(263.06)	(284.56)	(297.05)
Net Plant	99.93	107.57	102.89	91.96	82.40	69.06	51.95	32.94	12.49	0.00
Accumulated Deferred Taxes	(18.75)	(14.98)	(11.03)	(6.68)	(1.90)	3.23	8.82	14.75	21.13	0.00
Net Plant Less Accum. Deferred Taxes	81.17	92.59	91.86	85.28	80.51	72.29	60.76	47.69	33.62	0.00
Working Capital	10.98	10.81	11.19	10.24	10.36	10.49	10.49	9.95	10.02	0.00
Rate Base	92.16	103.40	103.05	95.52	90.87	82.78	71.25	57.64	43.63	0.00
Net Plant Less Accum. Deferred Taxes	81.17	92.59	91.86	85.28	80.51	72.29	60.76	47.69	33.62	0.00
Less: Accumulated ITC	(2.22)	(1.98)	(1.74)	(1.51)	(1.27)	(1.03)	(0.80)	(0.56)	(0.33)	0.00
Net Book Value	78.96	90.61	90.12	83.77	79.23	71.26	59.97	47.12	33.29	0.00

Rate Base and Net Book Value Forecast

Year	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Fossil Generation										
Cheswick										
Original Cost	215.90	233.80	253.13	260.30	272.50	277.30	282.23	302.44	347.00	352.40
Accumulated Depreciation	(96.02)	(104.60)	(114.19)	(124.11)	(134.24)	(144.24)	(154.54)	(166.35)	(181.83)	(197.75)
Net Plant	119.88	129.20	138.93	136.19	138.26	133.06	127.69	136.08	165.17	154.65
Accumulated Deferred Taxes	(34.85)	(33.11)	(31.54)	(30.10)	(28.69)	(27.18)	(25.48)	(23.48)	(21.12)	2.22
Net Plant Less Accum. Deferred Taxes	85.03	96.08	107.39	106.09	109.57	105.88	102.21	112.61	144.06	156.88
Working Capital	10.96	10.79	10.26	11.39	12.18	11.99	12.27	12.37	12.48	12.45
Rate Base	95.99	106.87	117.65	117.48	121.75	117.88	114.48	124.98	156.54	169.32
Net Plant Less Accum. Deferred Taxes	85.03	96.08	107.39	106.09	109.57	105.88	102.21	112.61	144.06	156.88
Less: Accumulated ITC	(2.91)	(2.75)	(2.60)	(2.44)	(2.28)	(2.13)	(1.97)	(1.82)	(1.66)	(1.51)
Net Book Value	82.13	93.33	104.80	103.65	107.29	103.75	100.24	110.79	142.40	155.37

Rate Base and Net Book Value Forecast

Year	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Fossil Generation										
Mansfield										
Original Cost	269.35	273.68	279.82	283.33	290.92	294.50	298.60	301.47	310.05	315.92
Accumulated Depreciation	(124.63)	(132.74)	(141.10)	(149.58)	(157.87)	(165.82)	(173.97)	(182.27)	(191.13)	(200.39)
Net Plant	144.72	140.93	138.72	133.75	133.05	128.68	124.63	119.20	118.92	115.53
Accumulated Deferred Taxes	(39.17)	(38.04)	(36.40)	(34.40)	(32.52)	(30.85)	(29.12)	(27.41)	(25.62)	(23.88)
Net Plant Less Accum. Deferred Taxes	105.54	102.89	102.32	99.35	100.53	97.84	95.50	91.79	93.30	91.65
Working Capital	12.04	11.86	12.02	12.05	10.13	10.38	9.99	10.21	10.07	9.74
Rate Base	117.59	114.74	114.35	111.40	110.66	108.22	105.50	102.00	103.36	101.39
Net Plant Less Accum. Deferred Taxes	105.54	102.89	102.32	99.35	100.53	97.84	95.50	91.79	93.30	91.65
Less: Accumulated ITC	(6.80)	(6.48)	(6.17)	(5.86)	(5.55)	(5.24)	(4.93)	(4.62)	(4.30)	(3.99)
Net Book Value	98.75	96.40	96.15	93.49	94.98	92.60	90.57	87.18	88.99	87.66

Rate Base and Net Book Value Forecast

Year	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Fossil Generation										
Sammis										
Original Cost	93.56	96.18	97.59	102.13	102.74	107.66	113.74	115.68	116.89	118.11
Accumulated Depreciation	(40.17)	(44.41)	(48.72)	(53.35)	(57.80)	(62.50)	(67.79)	(73.26)	(78.86)	(84.61)
Net Plant	53.39	51.76	48.87	48.79	44.94	45.16	45.95	42.42	38.03	33.51
Accumulated Deferred Taxes	(13.56)	(13.18)	(12.24)	(11.23)	(10.19)	(9.10)	(7.95)	(6.83)	(5.65)	(4.40)
Net Plant Less Accum. Deferred Taxes	39.84	38.59	36.64	37.56	34.75	36.05	38.00	35.59	32.38	29.11
Working Capital	4.16	4.09	4.31	4.28	4.71	4.61	4.66	4.70	4.84	4.45
Rate Base	43.99	42.68	40.95	41.85	39.45	40.66	42.66	40.29	37.23	33.56
Net Plant Less Accum. Deferred Taxes	39.84	38.59	36.64	37.56	34.75	36.05	38.00	35.59	32.38	29.11
Less: Accumulated ITC	(2.84)	(2.65)	(2.46)	(2.27)	(2.08)	(1.89)	(1.70)	(1.51)	(1.33)	(1.14)
Net Book Value	37.00	35.94	34.18	35.29	32.67	34.16	36.29	34.08	31.06	27.97

Rate Base and Net Book Value Forecast

Year	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Fossil Generation										
Eastlake										
Original Cost	78.87	81.38	84.71	86.74	87.29	92.67	98.67	100.35	103.51	107.11
Accumulated Depreciation	(36.20)	(39.42)	(42.83)	(46.36)	(49.75)	(53.42)	(57.62)	(61.97)	(66.65)	(71.76)
Net Plant	42.66	41.97	41.89	40.38	37.54	39.25	41.04	38.38	36.86	35.35
Accumulated Deferred Taxes	(10.52)	(10.00)	(9.44)	(8.86)	(8.34)	(7.76)	(7.11)	(6.25)	(5.28)	(4.21)
Net Plant Less Accum. Deferred Taxes	32.15	31.96	32.44	31.52	29.20	31.49	33.93	32.13	31.58	31.14
Working Capital	3.61	3.55	3.31	3.14	3.73	3.63	3.69	3.86	3.70	3.47
Rate Base	35.76	35.52	35.75	34.66	32.93	35.11	37.62	35.99	35.28	34.60
Net Plant Less Accum. Deferred Taxes	32.15	31.96	32.44	31.52	29.20	31.49	33.93	32.13	31.58	31.14
Less: Accumulated ITC	(1.70)	(1.59)	(1.49)	(1.38)	(1.27)	(1.17)	(1.06)	(0.96)	(0.85)	(0.74)
Net Book Value	30.45	30.37	30.96	30.14	27.93	30.32	32.87	31.17	30.73	30.40

Rate Base and Net Book Value Forecast

Year	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Fossil Generation										
Brunot Island In-Service										
Original Cost	45.72	47.82	49.09	54.55	54.62	54.68	54.75	54.82	59.10	59.17
Accumulated Depreciation	(20.20)	(22.14)	(24.11)	(26.41)	(28.61)	(30.72)	(32.82)	(34.92)	(37.44)	(39.96)
Net Plant	25.52	25.68	24.98	28.14	26.00	23.96	21.93	19.90	21.66	19.22
Accumulated Deferred Taxes	(8.73)	(8.07)	(7.46)	(6.82)	(6.30)	(5.78)	(5.24)	(4.68)	(4.02)	(3.42)
Net Plant Less Accum. Deferred Taxes	16.79	17.60	17.52	21.32	19.71	18.18	16.69	15.22	17.64	15.80
Working Capital	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Rate Base	16.79	17.60	17.52	21.32	19.71	18.18	16.69	15.22	17.64	15.80
Net Plant Less Accum. Deferred Taxes	16.79	17.60	17.52	21.32	19.71	18.18	16.69	15.22	17.64	15.80
Less: Accumulated ITC	(0.73)	(0.69)	(0.64)	(0.60)	(0.55)	(0.51)	(0.47)	(0.42)	(0.38)	(0.33)
Net Book Value	16.06	16.92	16.88	20.73	19.15	17.67	16.22	14.80	17.26	15.46

Rate Base and Net Book Value Forecast

Year	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Fossil Generation										
Phillips										
Original Cost	147.02	147.51	148.31	148.31	148.31	148.31	148.31	148.31	148.31	148.31
Accumulated Depreciation	(68.63)	(69.12)	(69.92)	(69.92)	(69.92)	(80.92)	(110.02)	(133.92)	(148.32)	(148.32)
Net Plant	78.40	78.40	78.40	78.40	78.40	67.40	38.30	14.40	(0.00)	(0.00)
Accumulated Deferred Taxes	(28.26)	(28.34)	(28.27)	(28.51)	(28.69)	(24.25)	(12.28)	(2.45)	3.44	0.00
Net Plant Less Accum. Deferred Taxes	50.14	50.06	50.12	49.89	49.71	43.15	26.02	11.95	3.44	(0.00)
Working Capital	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Rate Base	50.14	50.06	50.12	49.89	49.71	43.15	26.02	11.95	3.44	(0.00)
Net Plant Less Accum. Deferred Taxes	50.14	50.06	50.12	49.89	49.71	43.15	26.02	11.95	3.44	(0.00)
Less: Accumulated ITC	(1.68)	(1.49)	(1.31)	(1.12)	(0.93)	(0.75)	(0.56)	(0.37)	(0.19)	0.00
Net Book Value	48.46	48.57	48.82	48.77	48.78	42.40	25.46	11.57	3.26	(0.00)

Rate Base and Net Book Value Forecast

Year	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Fossil Generation										
Brunot Island Cold Reserve										
Original Cost	44.83	44.83	44.83	44.83	44.83	44.83	44.83	44.83	44.83	44.83
Accumulated Depreciation	(16.07)	(16.07)	(16.07)	(16.07)	(16.07)	(16.07)	(16.07)	(16.07)	(16.07)	(29.97)
Net Plant	28.76	28.76	28.76	28.76	28.76	28.76	28.76	28.76	28.76	14.86
Accumulated Deferred Taxes	(11.25)	(11.26)	(11.28)	(11.30)	(11.31)	(11.33)	(11.34)	(11.36)	(11.37)	0.00
Net Plant Less Accum. Deferred Taxes	17.51	17.49	17.48	17.46	17.45	17.43	17.42	17.40	17.39	14.86
Working Capital	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Rate Base	17.51	17.49	17.48	17.46	17.45	17.43	17.42	17.40	17.39	14.86
Net Plant Less Accum. Deferred Taxes	17.51	17.49	17.48	17.46	17.45	17.43	17.42	17.40	17.39	14.86
Less: Accumulated ITC	(0.89)	(0.84)	(0.78)	(0.73)	(0.68)	(0.63)	(0.57)	(0.52)	(0.47)	(0.42)
Net Book Value	16.62	16.66	16.69	16.73	16.77	16.80	16.84	16.88	16.92	14.44

Rate Base and Net Book Value Forecast

Year	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Fossil Generation										
Warwick										
Original Cost	72.50	72.50	72.50	72.50	72.50	72.50	72.50	72.50	72.50	72.50
Accumulated Depreciation	(57.20)	(61.83)	(66.46)	(71.09)	(72.49)	(72.49)	(72.49)	(72.49)	(72.49)	(72.49)
Net Plant	15.29	10.67	6.04	1.41	0.00	0.00	0.00	0.00	0.00	0.00
Accumulated Deferred Taxes	(5.96)	(4.04)	(2.12)	(0.20)	0.00	0.00	0.00	0.00	0.00	0.00
Net Plant Less Accum. Deferred Taxes	9.33	6.63	3.92	1.21	0.00	0.00	0.00	0.00	0.00	0.00
Working Capital	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Rate Base	9.33	6.63	3.92	1.21	0.00	0.00	0.00	0.00	0.00	0.00
Net Plant Less Accum. Deferred Taxes	9.33	6.63	3.92	1.21	0.00	0.00	0.00	0.00	0.00	0.00
Less: Accumulated ITC	(1.15)	(0.79)	(0.44)	(0.09)	0.00	0.00	0.00	0.00	0.00	0.00
Net Book Value	8.19	5.83	3.48	1.12	0.00	0.00	0.00	0.00	0.00	0.00

Rate Base and Net Book Value Forecast

Year	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Generation-Related Regulatory Assets										
Book Cost	455.26	455.26	455.26	536.30	536.30	536.30	536.30	536.30	536.30	536.30
Accumulated Amortization	0.00	(34.59)	(84.53)	(149.07)	(213.61)	(278.15)	(342.68)	(407.22)	(471.76)	(536.30)
Net Book Cost	455.26	420.67	370.73	387.23	322.69	258.15	193.62	129.08	64.54	0.00
Accumulated Deferred Taxes	(109.18)	(98.77)	(81.59)	(91.53)	(76.28)	(61.02)	(45.77)	(30.51)	(15.26)	0.00
Net Plant Less Accum. Deferred Taxes	346.08	321.90	289.14	295.70	246.42	197.13	147.85	98.57	49.28	0.00
Working Capital	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Rate Base	346.08	321.90	289.14	295.70	246.42	197.13	147.85	98.57	49.28	0.00

Rate Base and Net Book Value Forecast

Year	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Transmission-Related Regulatory Assets										
Book Cost	32.68	32.68	32.68	32.68	32.68	32.68	32.68	32.68	32.68	32.68
Accumulated Amortization	0.00	1.23	2.41	3.45	4.21	4.81	5.22	5.43	5.58	5.62
Net Book Cost	32.68	33.92	35.09	36.13	36.89	37.49	37.90	38.11	38.26	38.30
Accumulated Deferred Taxes	(32.66)	(33.91)	(35.09)	(36.13)	(36.89)	(37.49)	(37.90)	(38.11)	(38.26)	(38.30)
Net Plant Less Accum. Deferred Taxes	0.02	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Working Capital	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Rate Base	0.02	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Rate Base and Net Book Value Forecast

Year	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Distribution-Related Regulatory Assets										
Book Cost	56.85	56.85	56.85	56.85	56.85	56.85	56.85	56.85	56.85	56.85
Accumulated Amortization	0.00	1.23	2.36	2.91	2.82	1.92	0.53	(1.25)	(3.21)	(5.55)
Net Book Cost	56.85	58.08	59.21	59.76	59.67	58.76	57.38	55.60	53.64	51.30
Accumulated Deferred Taxes	(56.52)	(57.92)	(59.21)	(59.76)	(59.67)	(58.76)	(57.38)	(55.60)	(53.64)	(51.30)
Net Plant Less Accum. Deferred Taxes	0.33	0.17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Working Capital	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Rate Base	0.33	0.17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

DUQUESNE LIGHT COMPANY
Net Present Value of
Generating Plant Assets
as of 12/31/05
$ in Millions

Combined Cycle
@ $33.8/mwh in 2006 with escalations @ 2.5%

	Plant Margin	Decommissioning	Net Plant Value
Fossil Plants:			
Cheswick	0.0	(23.6)	(23.6)
Sammis	9.6	(27.8)	(18.2)
Eastlake	0.0	(22.5)	(22.5)
Elrama	0.0	(35.0)	(35.0)
Mansfield 1	14.7	(43.0)	(28.3)
Mansfield 2	4.6	(11.1)	(6.5)
Mansfield 3	10.6	(16.9)	(6.3)
Brunot Island	11.5	(13.9)	(2.4)
Phillips	0	(9.5)	(9.5)
Total Fossil	**50.9**	**(203.4)**	**(152.4)**
Nuclear Plants:			
Beaver Valley 1	38.5	(0.1)	38.5
Beaver Valley 2	69.3	(0.1)	69.2
Perry	0.0	(1.9)	(1.9)
Total Nuclear	**107.8**	**(2.0)**	**105.8**
TOTAL PLANTS	**$158.7**	**($205.4)**	**($46.6)**

DUQUESNE LIGHT
PV of Fossil Plants
$ in Millions

	@ $33.8/mwh in 2006 with escalations @ 2.5%								
CHESWICK	2006	2007	2008	2009	2010	2011	2012	2013	2014
kwh Market Price (cents)	3.38	3.47	3.55	3.64	3.73	3.83	3.92	4.02	4.12
Unit Output (gwh)	4,197	4,032	3,876	4,195	3,528	3,865	4,211	4,032	3,828
Delivered Output (gwh)	3,946	3,790	3,644	3,943	3,316	3,633	3,959	3,790	3,599
Revenues	**133.46**	**131.39**	**129.49**	**143.63**	**123.82**	**139.05**	**155.29**	**152.38**	**148.31**
Fuel-Related Expenses									
Fuel Costs	64.40	63.33	63.44	73.77	65.30	73.86	82.77	82.20	81.49
Fuel Related ECR Costs	1.08	1.11	1.14	1.17	1.20	1.23	1.26	1.30	1.32
NOx Emissions	8.65	8.69	8.31	9.92	7.52	9.32	11.41	11.12	10.42
SO2 Emissions	6.53	6.65	6.71	8.18	6.63	8.31	10.27	10.36	10.24
Total Fuel	80.66	79.78	79.60	93.04	80.64	92.72	105.71	104.97	103.48
Non-fuel O&M Expenses									
Variable O&M	3.93	3.88	3.83	4.25	3.67	4.13	4.61	4.54	4.42
Fixed O&M	9.56	11.72	11.87	10.13	11.03	12.40	10.53	12.83	12.98
Overhaul	0.00	0.00	0.00	0.00	12.50	0.00	0.00	0.00	0.00
Subtotal	13.49	15.60	15.70	14.38	27.20	16.52	15.14	17.37	17.40
Carbon Injection Costs	3.01	2.80	2.81	3.09	2.52	2.93	3.33	3.13	3.07
FICA	0.48	0.51	0.51	0.46	0.48	0.54	0.56	0.59	0.57
Property Tax	0.84	0.84	0.84	0.84	0.84	0.84	0.84	0.84	0.84
Cap Stock Tax	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88
Total Non-fuel	18.70	20.63	20.73	19.65	31.91	21.72	20.75	22.80	22.76
Capital Expenditures	5.19	5.34	5.50	5.67	15.05	4.53	3.14	1.66	1.06
Direct Expenses	**104.55**	**105.75**	**105.83**	**118.36**	**127.60**	**118.96**	**129.59**	**129.44**	**127.30**
Direct Margin	**28.91**	**25.64**	**23.67**	**25.27**	**(3.78)**	**20.09**	**25.69**	**22.94**	**21.01**
Overhead Allocation	17.70	19.98	19.63	21.63	23.77	22.25	25.16	26.54	25.43
Expenses Incl. Corp O/H	**122.25**	**125.73**	**125.46**	**139.99**	**151.37**	**141.21**	**154.76**	**155.98**	**152.73**
Margin after Corp O/H	**11.21**	**5.66**	**4.04**	**3.64**	**(27.55)**	**(2.16)**	**0.53**	**(3.60)**	**(4.42)**
Costs per kwh (cents)									
Fuel	2.04	2.11	2.18	2.36	2.43	2.55	2.67	2.77	2.88
Non-fuel	0.47	0.54	0.57	0.50	0.96	0.60	0.52	0.60	0.63
Capital Expenditures	0.13	0.14	0.15	0.14	0.45	0.12	0.08	0.04	0.03
Direct Expenses	**2.65**	**2.79**	**2.90**	**3.00**	**3.85**	**3.27**	**3.27**	**3.42**	**3.54**
Direct Margin	**0.73**	**0.68**	**0.65**	**0.64**	**(0.11)**	**0.55**	**0.65**	**0.61**	**0.58**
Overhead Allocation	0.45	0.53	0.54	0.55	0.72	0.61	0.64	0.70	0.71
Expenses Incl. Corp O/H	**3.10**	**3.32**	**3.44**	**3.55**	**4.56**	**3.89**	**3.91**	**4.12**	**4.24**
Margin after Corp O/H	**0.28**	**0.15**	**0.11**	**0.09**	**(0.83)**	**(0.06)**	**0.01**	**(0.09)**	**(0.12)**
NPV of Margin after O/H	**(1.8)**								
NPV of Decommissioning	**23.6**								
NPV OF NET MARGIN	**(25.4)**								

DUQUESNE LIGHT
PV of Fossil Plants
$ in Millions

	@ $33.8/mwh in 2006 with escalations @ 2.5%				
SAMMIS	2006	2007	2008	2009	2010
kwh Market Price (cents)	3.38	3.47	3.55	3.64	3.73
Unit Output (gwh)	1,493	1,236	1,498	1,378	1,474
Delivered Output (gwh)	1,404	1,162	1,408	1,295	1,385
Revenues	**47.48**	**40.29**	**50.05**	**47.18**	**51.72**
Fuel-Related Expenses					
Fuel Costs	23.77	20.33	25.67	24.55	27.34
Fuel Related ECR Costs	0.03	0.03	0.03	0.03	0.03
NOx Emissions	2.05	1.77	2.24	2.15	2.39
SO2 Emissions	0.98	0.66	1.14	1.02	1.27
Total Fuel	26.83	22.80	29.08	27.75	31.03
Non-fuel O&M Expenses					
Variable O&M	1.94	1.65	2.05	1.93	2.12
Fixed O&M	3.14	3.82	3.32	6.01	3.44
Overhaul	0.00	2.28	0.00	0.00	0.00
Subtotal	5.08	7.74	5.36	7.94	5.55
FICA	0.18	0.18	0.17	0.26	0.18
Property Tax	1.49	1.49	1.49	1.49	1.49
Cap Stock Tax	0.31	0.31	0.31	0.31	0.31
Total Non-fuel	7.05	9.71	7.33	9.99	7.53
Capital Expenditures	0.58	3.02	0.14	0.43	0.14
Direct Expenses	**34.46**	**35.53**	**36.55**	**38.17**	**38.70**
Direct Margin	**13.02**	**4.76**	**13.50**	**9.00**	**13.02**
Overhead Allocation	5.83	6.71	6.78	6.97	7.21
Expenses incl. Corp O/H	**40.29**	**42.24**	**43.33**	**45.15**	**45.91**
Margin after Corp O/H	**7.19**	**(1.96)**	**6.72**	**2.03**	**5.81**
Costs per kwh (cents)					
Fuel	1.91	1.96	2.06	2.14	2.24
Non-fuel	0.50	0.84	0.52	0.77	0.54
Capital Expenditures	0.04	0.26	0.01	0.03	0.01
Direct Expenses	**2.45**	**3.06**	**2.60**	**2.95**	**2.79**
Direct Margin	**0.93**	**0.41**	**0.96**	**0.70**	**0.94**
Overhead Allocation	0.42	0.58	0.48	0.54	0.52
Expenses incl. Corp O/H	**2.87**	**3.64**	**3.08**	**3.49**	**3.31**
Margin after Corp O/H	**0.51**	**(0.17)**	**0.48**	**0.16**	**0.42**
NPV of Margin after O/H	9.6				
NPV of Decommissioning	27.8				
NPV OF NET MARGIN	(18.2)				

DUQUESNE LIGHT
PV of Fossil Plants
$ in Millions

	@ $33.8/mwh in 2006 with escalations @ 2.5%					
EASTLAKE	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
kwh Market Price (cents)	3.38	3.47	3.55	3.64	3.73	3.83
Unit Output (gwh)	1,120	1,149	1,166	1,286	1,149	1,178
Delivered Output (gwh)	1,053	1,080	1,096	1,209	1,080	1,108
Revenues	**35.62**	**37.45**	**38.94**	**44.03**	**40.33**	**42.39**
Fuel-Related Expenses						
Fuel Costs	15.56	16.42	17.16	19.52	17.95	18.94
Fuel Related ECR Costs	0.12	0.12	0.12	0.13	0.13	0.13
NOx Emissions	1.02	1.09	1.16	1.33	1.24	1.32
SO2 Emissions	5.11	5.67	6.21	7.51	7.08	7.86
Total Fuel	21.80	23.31	24.65	28.49	26.40	28.25
Non-fuel O&M Expenses						
Variable O&M	1.56	1.64	1.71	1.94	1.78	1.87
Fixed O&M	5.27	5.89	5.98	5.57	6.37	5.93
Overhaul	0.80	0.00	0.00	0.00	0.00	0.52
Subtotal	7.63	7.54	7.69	7.50	8.14	8.32
FICA	0.24	0.25	0.25	0.24	0.27	0.26
Property Tax	1.27	1.27	1.27	1.27	1.27	1.27
Cap Stock Tax	0.26	0.26	0.26	0.26	0.26	0.26
Total Non-fuel	9.41	9.32	9.48	9.28	9.95	10.12
Capital Expenditures	2.26	0.53	0.77	0.76	0.91	0.62
Direct Expenses	**33.47**	**33.15**	**34.90**	**38.53**	**37.25**	**38.99**
Direct Margin	**2.15**	**4.30**	**4.04**	**5.50**	**3.08**	**3.40**
Overhead Allocation	5.67	6.26	6.47	7.04	6.94	7.29
Expenses incl. Corp O/H	**39.14**	**39.42**	**41.37**	**45.57**	**44.19**	**46.28**
Margin after Corp O/H	**(3.52)**	**(1.96)**	**(2.43)**	**(1.55)**	**(3.86)**	**(3.90)**
Costs per kwh (cents)						
Fuel	*2.07*	*2.16*	*2.25*	*2.36*	*2.44*	*2.55*
Non-fuel	0.89	0.86	0.87	0.77	0.92	0.91
Capital Expenditures	0.21	0.05	0.07	0.06	0.08	0.06
Direct Expenses	**3.18**	**3.07**	**3.19**	**3.19**	**3.45**	**3.52**
Direct Margin	**0.20**	**0.40**	**0.37**	**0.45**	**0.29**	**0.31**
Overhead Allocation	0.54	0.58	0.59	0.58	0.64	0.66
Expenses incl. Corp O/H	**3.72**	**3.65**	**3.78**	**3.77**	**4.09**	**4.18**
Margin after Corp O/H	*(0.33)*	*(0.18)*	*(0.22)*	*(0.13)*	*(0.36)*	*(0.35)*
NPV of Margin after O/H	(8.0)					
NPV of Decommissioning	22.5					
NPV OF NET MARGIN	(30.5)					

DUQUESNE LIGHT
PV of Fossil Plants
$ In Millions

@ $33.8/mwh in 2006 with escalations @ 2.5%

ELRAMA	2006
kwh Market Price (cents)	
Unit Output (gwh)	
Delivered Output (gwh)	
Revenues	
Fuel-Related Expenses	
Fuel Costs	
Fuel Related ECR Costs	
NOx Emissions	
SO2 Emissions	
Total Fuel	
Non-fuel O&M Expenses	
Variable O&M	
Fixed O&M	
Overhaul	
Subtotal	
FICA	
Property Tax	
Cap Stock Tax	
Total Non-fuel	
Capital Expenditures	
Direct Expenses	
Direct Margin	
Overhead Allocation	
Expenses incl. Corp O/H	
Margin after Corp O/H	
Costs per kwh (cents)	
Fuel	
Non-fuel	
Capital Expenditures	
Direct Expenses	
Direct Margin	
Overhead Allocation	
Expenses incl. Corp O/H	
Margin after Corp O/H	
NPV of Margin after O/H	0.0
NPV of Decommissioning	35.0
NPV OF NET MARGIN	(35.0)

DUQUESNE LIGHT
PV of Fossil Plants
$ In Millions

	@ $33.8/mwh in 2006 with escalations @ 2.5%									
MANSFIELD 1	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
kwh Market Price (cents)	3.38	3.47	3.55	3.64	3.73	3.83	3.92	4.02	4.12	4.22
Unit Output (gwh)	1,376	1,789	1,657	1,787	1,652	1,789	1,382	1,789	1,652	1,769
Delivered Output (gwh)	1,293	1,682	1,557	1,679	1,553	1,682	1,299	1,682	1,553	1,663
Revenues	**43.75**	**58.30**	**55.34**	**61.17**	**57.97**	**64.35**	**50.96**	**67.61**	**63.98**	**70.25**
Fuel-Related Expenses										
Fuel Costs	16.85	22.55	21.48	23.84	22.66	25.26	20.06	26.74	25.38	27.99
Fuel Related ECR Costs	3.48	4.58	4.37	4.82	4.59	5.08	4.09	5.36	5.11	5.59
NOx Emissions	3.25	5.02	4.67	5.43	5.06	5.92	4.21	6.44	5.97	6.87
SO2 Emissions	(0.39)	(0.31)	(0.37)	(0.36)	(0.44)	(0.43)	(0.61)	(0.49)	(0.59)	(0.58)
Total Fuel	23.20	31.84	30.15	33.72	31.87	35.84	27.74	38.04	35.86	39.86
Non-fuel O&M Expenses										
Variable O&M	1.92	2.56	2.43	2.69	2.55	2.84	2.25	2.99	2.84	3.12
Fixed O&M	5.76	5.84	6.82	6.42	7.54	6.79	6.83	6.94	8.15	8.62
Overhaul	3.96	0.00	0.00	0.00	0.00	0.00	4.73	0.00	0.00	0.00
Subtotal	11.64	8.40	9.25	9.11	10.09	9.63	13.81	9.94	10.99	11.74
FICA	0.27	0.28	0.30	0.29	0.33	0.32	0.34	0.34	0.36	0.36
Property Tax	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48
Cap Stock Tax	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
Total Non-fuel	12.89	9.65	10.52	10.38	11.40	10.92	15.13	11.25	12.32	13.09
Capital Expenditures	6.38	1.03	0.83	0.99	2.20	2.14	5.71	0.62	0.25	0.18
Direct Expenses	**42.47**	**42.52**	**41.50**	**45.09**	**45.47**	**48.90**	**48.58**	**49.91**	**48.44**	**53.13**
Direct Margin	**1.28**	**15.78**	**13.84**	**16.08**	**12.49**	**15.45**	**2.38**	**17.70**	**15.55**	**17.12**
Overhead Allocation	7.19	8.03	7.70	8.24	8.47	9.14	9.43	10.23	9.68	11.66
Expenses Incl. Corp O/H	**49.66**	**50.55**	**49.19**	**53.33**	**53.95**	**58.05**	**58.02**	**60.14**	**58.11**	**64.79**
Margin after Corp O/H	**(5.91)**	**7.75**	**6.14**	**7.84**	**4.02**	**6.31**	**(7.06)**	**7.46**	**5.87**	**5.46**
Costs per kwh (cents)										
Fuel	1.79	1.89	1.94	2.01	2.05	2.13	2.14	2.26	2.31	2.40
Non-fuel	1.00	0.57	0.68	0.62	0.73	0.65	1.16	0.67	0.79	0.79
Capital Expenditures	0.49	0.06	0.05	0.06	0.14	0.13	0.44	0.04	0.02	0.01
Direct Expenses	**3.28**	**2.53**	**2.66**	**2.68**	**2.93**	**2.91**	**3.74**	**2.97**	**3.12**	**3.19**
Direct Margin	**0.10**	**0.94**	**0.89**	**0.96**	**0.80**	**0.92**	**0.18**	**1.05**	**1.00**	**1.03**
Overhead Allocation	0.56	0.48	0.49	0.49	0.55	0.54	0.73	0.61	0.62	0.70
Expenses Incl. Corp O/H	**3.84**	**3.01**	**3.16**	**3.18**	**3.47**	**3.45**	**4.47**	**3.58**	**3.74**	**3.90**
Margin after Corp O/H	**(0.46)**	**0.46**	**0.39**	**0.47**	**0.26**	**0.38**	**(0.54)**	**0.44**	**0.38**	**0.33**
NPV of Margin after O/H	**14.7**									
NPV of Decommissioning	**43.0**									
NPV OF NET MARGIN	**(28.3)**									

DUQUESNE LIGHT
PV of Fossil Plants
$ In Millions

	@ $33.8/mwh in 2006 with escalations @ 2.5%										
MANSFIELD 2	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
kwh Market Price (cents)	3.38	3.47	3.55	3.64	3.73	3.83	3.92	4.02	4.12	4.22	4.33
Unit Output (gwh)	404	481	463	499	461	500	404	482	461	500	455
Delivered Output (gwh)	379	452	435	469	434	470	380	453	434	470	427
Revenues	**12.83**	**15.66**	**15.46**	**17.09**	**16.19**	**17.98**	**14.89**	**18.21**	**17.87**	**19.84**	**18.50**
Fuel-Related Expenses											
Fuel Costs	4.86	5.96	5.91	6.56	6.23	6.95	5.77	7.09	6.98	7.78	7.28
Fuel Related ECR Costs	1.01	1.23	1.21	1.34	1.28	1.41	1.19	1.44	1.42	1.57	1.47
NOx Emissions	1.00	1.36	1.37	1.56	1.44	1.70	1.28	1.75	1.75	2.00	1.81
SO2 Emissions	(0.12)	(0.11)	(0.13)	(0.12)	(0.15)	(0.15)	(0.19)	(0.18)	(0.20)	(0.20)	(0.23)
Total Fuel	6.75	8.44	8.36	9.33	8.80	9.91	8.04	10.11	9.95	11.16	10.33
Non-fuel O&M Expenses											
Variable O&M	0.56	0.68	0.67	0.75	0.71	0.79	0.65	0.80	0.79	0.87	0.82
Fixed O&M	1.52	1.59	1.83	1.72	2.03	1.83	1.82	1.90	2.20	2.35	2.53
Overhaul	1.00	0.20	0.00	0.00	0.00	0.00	1.21	0.22	0.00	0.00	0.00
Subtotal	3.07	2.47	2.50	2.47	2.74	2.62	3.67	2.92	2.99	3.23	3.35
FICA	0.07	0.07	0.08	0.08	0.09	0.09	0.09	0.09	0.10	0.10	0.14
Property Tax	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13
Cap Stock Tax	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
Total Non-fuel	3.41	2.81	2.85	2.81	3.09	2.97	4.03	3.28	3.35	3.59	3.75
Capital Expenditures	0.91	1.83	0.41	0.27	0.60	0.36	1.09	1.63	0.24	0.08	0.11
Direct Expenses	**11.07**	**13.07**	**11.62**	**12.41**	**12.50**	**13.24**	**13.16**	**15.02**	**13.54**	**14.83**	**14.18**
Direct Margin	**1.76**	**2.59**	**3.84**	**4.68**	**3.70**	**4.74**	**1.73**	**3.20**	**4.33**	**5.01**	**4.32**
Overhead Allocation	1.87	2.47	2.16	2.27	2.33	2.48	2.56	3.08	2.71	3.26	2.51
Expenses incl. Corp O/H	**12.94**	**15.54**	**13.78**	**14.68**	**14.82**	**15.72**	**15.71**	**18.10**	**16.25**	**18.09**	**16.70**
Margin after Corp O/H	**(0.11)**	**0.12**	**1.68**	**2.41**	**1.37**	**2.26**	**(0.82)**	**0.12**	**1.62**	**1.75**	**1.80**
Costs per kwh (cents)											
Fuel	1.78	1.87	1.92	1.99	2.03	2.11	2.12	2.23	2.29	2.38	2.42
Non-fuel	0.90	0.62	0.65	0.60	0.71	0.63	1.06	0.72	0.77	0.77	0.88
Capital Expenditures	0.24	0.40	0.09	0.06	0.14	0.08	0.29	0.36	0.06	0.02	0.03
Direct Expenses	**2.92**	**2.89**	**2.67**	**2.65**	**2.88**	**2.82**	**3.47**	**3.32**	**3.12**	**3.16**	**3.32**
Direct Margin	**0.46**	**0.57**	**0.88**	**1.00**	**0.85**	**1.01**	**0.46**	**0.71**	**1.00**	**1.07**	**1.01**
Overhead Allocation	0.49	0.55	0.50	0.48	0.54	0.53	0.67	0.68	0.62	0.69	0.59
Expenses incl. Corp O/H	**3.41**	**3.44**	**3.17**	**3.13**	**3.42**	**3.35**	**4.14**	**4.00**	**3.75**	**3.85**	**3.91**
Margin after Corp O/H	**(0.03)**	**0.03**	**0.39**	**0.51**	**0.32**	**0.48**	**(0.22)**	**0.03**	**0.37**	**0.37**	**0.42**

NPV of Margin after O/H	4.6
NPV of Decommissioning	11.1
NPV OF NET MARGIN	(6.5)

DUQUESNE LIGHT
PV of Fossil Plants
$ in Millions

	@ $33.8/mwh in 2006 with escalations @ 2.5%												
MANSFIELD 3	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
kwh Market Price (cents)	3.38	3.47	3.55	3.64	3.73	3.83	3.92	4.02	4.12	4.22	4.33	4.44	4.55	4.66
Unit Output (gwh)	874	839	712	807	875	808	877	719	829	808	877	808	875	870
Delivered Output (gwh)	822	788	669	758	822	759	824	676	779	759	824	759	822	818
Revenues	**27.80**	**27.34**	**23.78**	**27.63**	**30.70**	**29.05**	**32.34**	**27.17**	**32.12**	**32.06**	**35.70**	**33.69**	**37.40**	**38.13**
Fuel-Related Expenses														
Fuel Costs	10.33	10.20	8.91	10.39	11.58	11.01	12.28	10.37	12.30	12.33	13.78	13.02	14.49	14.80
Fuel Related ECR Costs	2.18	2.16	1.90	2.19	2.42	2.31	2.56	2.18	2.56	2.57	2.85	2.71	3.00	3.06
NOx Emissions	2.82	2.79	2.32	2.87	3.33	3.16	3.64	2.89	3.67	3.69	4.30	4.06	4.66	4.81
SO2 Emissions	(0.18)	(0.20)	(0.25)	(0.25)	(0.25)	(0.29)	(0.29)	(0.37)	(0.35)	(0.39)	(0.38)	(0.45)	(0.45)	(0.49)
Total Fuel	15.16	14.94	12.87	15.20	17.09	16.18	18.20	15.07	18.17	18.20	20.54	19.34	21.69	22.18
Non-fuel O&M Expenses														
Variable O&M	1.05	1.03	0.90	1.05	1.17	1.11	1.23	1.04	1.23	1.23	1.37	1.30	1.44	1.47
Fixed O&M	2.65	3.01	3.56	3.35	3.71	3.54	3.15	3.76	4.08	4.50	4.67	4.78	4.91	5.01
Overhaul	0.00	0.28	1.29	0.00	0.00	0.00	0.00	1.45	0.42	0.00	0.00	0.00	0.00	0.00
Subtotal	3.70	4.32	5.75	4.39	4.88	4.64	4.39	6.24	5.73	5.73	6.04	6.07	6.35	6.48
FICA	0.13	0.13	0.14	0.14	0.16	0.15	0.16	0.16	0.17	0.18	0.25	0.25	0.26	0.26
Property Tax	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23
Cap Stock Tax	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24
Total Non-fuel	4.31	4.93	6.37	5.01	5.51	5.27	5.02	6.87	6.37	6.38	6.76	6.80	7.08	7.22
Capital Expenditures	0.43	0.69	2.69	0.48	1.07	0.40	0.51	0.82	3.21	0.57	0.96	0.64	0.32	0.19
Direct Expenses	**19.90**	**20.56**	**21.92**	**20.69**	**23.67**	**21.85**	**23.74**	**22.77**	**27.76**	**25.15**	**28.25**	**26.77**	**29.09**	**29.59**
Direct Margin	**7.90**	**6.78**	**1.85**	**6.94**	**7.03**	**7.20**	**8.61**	**4.40**	**4.36**	**6.91**	**7.45**	**6.92**	**8.32**	**8.54**
Overhead Allocation	3.37	3.88	4.07	3.78	4.41	4.09	4.61	4.67	5.55	5.52	5.00	4.70	5.61	5.18
Expenses incl. Corp O/H	**23.27**	**24.44**	**25.99**	**24.47**	**28.07**	**25.94**	**28.35**	**27.44**	**33.30**	**30.67**	**33.25**	**31.47**	**34.70**	**34.77**
Margin after Corp O/H	**4.53**	**2.89**	**(2.21)**	**3.16**	**2.63**	**3.11**	**4.00**	**(0.27)**	**(1.18)**	**1.39**	**2.45**	**2.22**	**2.71**	**3.36**
Costs per kwh (cents)														
Fuel	1.84	1.90	1.92	2.00	2.08	2.13	2.21	2.23	2.33	2.40	2.49	2.55	2.64	2.71
Non-fuel	0.52	0.63	0.95	0.66	0.67	0.69	0.61	1.02	0.82	0.84	0.82	0.90	0.86	0.88
Capital Expenditures	0.05	0.09	0.40	0.06	0.13	0.05	0.06	0.12	0.41	0.08	0.12	0.08	0.04	0.02
Direct Expenses	**2.42**	**2.61**	**3.28**	**2.73**	**2.88**	**2.88**	**2.88**	**3.37**	**3.56**	**3.31**	**3.43**	**3.53**	**3.54**	**3.62**
Direct Margin	**0.96**	**0.86**	**0.28**	**0.91**	**0.86**	**0.95**	**1.04**	**0.65**	**0.56**	**0.91**	**0.90**	**0.91**	**1.01**	**1.04**
Overhead Allocation	0.41	0.49	0.61	0.50	0.54	0.54	0.56	0.69	0.71	0.73	0.61	0.62	0.(	).6
Expenses incl. Corp O/H	**2.83**	**3.10**	**3.88**	**3.23**	**3.41**	**3.42**	**3.44**	**4.06**	**4.27**	**4.04**	**4.03**	**4.15**	**4.2**	**.2**
Margin after Corp O/H	**0.55**	**0.37**	**(0.33)**	**0.42**	**0.32**	**0.41**	**0.48**	**(0.04)**	**(0.15)**	**0.18**	**0.30**	**0.29**	**0.3**	**.4**
NPV of Margin after O/H	**10.6**													
NPV of Decommissioning	**16.9**													
NPV OF NET MARGIN	**(6.3)**													

DUQUESNE LIGHT
PV of Fossil Plants
$ In Millions

	@ $33.8/mwh in 2006 with escalations @ 2.5%						
BRUNOT ISLAND	2006	2007	2008	2009	2010	2011	2012
kwh Market Price (cents)	16.91	17.34	17.77	18.21	18.67	19.13	19.61
Unit Output (gwh)	406	111	111	111	111	111	0
Delivered Output (gwh)	382	104	104	104	104	104	0
Revenues	**64.58**	**18.09**	**18.54**	**19.00**	**19.48**	**19.97**	**0.00**
Fuel-Related Expenses							
Fuel Costs	40.31	12.52	12.86	13.21	13.56	13.93	0.00
Fuel Related ECR Costs	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NOx Emissions	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SO2 Emissions	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Fuel	40.31	12.52	12.86	13.21	13.56	13.93	0.00
Non-fuel O&M Expenses							
Variable O&M	0.53	0.15	0.15	0.16	0.16	0.17	0.00
Fixed O&M	0.71	0.73	0.75	0.77	0.79	0.81	0.00
Overhaul	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Subtotal	1.23	0.88	0.90	0.92	0.95	0.98	0.00
FICA	0.04	0.03	0.03	0.03	0.03	0.03	0.00
Property Tax	0.33	0.33	0.33	0.33	0.33	0.33	0.33
Cap Stock Tax	0.34	0.34	0.34	0.34	0.34	0.34	0.34
Total Non-fuel	1.94	1.57	1.59	1.62	1.65	1.67	0.67
Capital Expenditures	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Direct Expenses	**42.26**	**14.09**	**14.45**	**14.83**	**15.21**	**15.60**	**0.67**
Direct Margin	**22.32**	**4.00**	**4.09**	**4.18**	**4.27**	**4.36**	**(0.67)**
Overhead Allocation	7.15	2.66	2.68	2.71	2.83	2.92	0.13
Expenses incl. Corp O/H	**49.41**	**16.75**	**17.13**	**17.53**	**18.04**	**18.52**	**0.79**
Margin after Corp O/H	**15.17**	**1.33**	**1.41**	**1.47**	**1.44**	**1.45**	**(0.79)**
Costs per kwh (cents)							
Fuel	10.56	12.00	12.32	12.66	13.00	13.35	#DIV/0!
Non-fuel	0.51	1.51	1.53	1.55	1.58	1.60	#DIV/0!
Capital Expenditures	0.00	0.00	0.00	0.00	0.00	0.00	#DIV/0!
Direct Expenses	**11.07**	**13.51**	**13.85**	**14.21**	**14.58**	**14.95**	**#DIV/0!**
Direct Margin	**5.85**	**3.83**	**3.92**	**4.00**	**4.09**	**4.18**	**#DIV/0!**
Overhead Allocation	1.87	2.55	2.57	2.60	2.72	2.80	#DIV/0!
Expenses incl. Corp O/H	**12.94**	**16.06**	**16.42**	**16.81**	**17.29**	**17.75**	**#DIV/0!**
Margin after Corp O/H	**3.97**	**1.28**	**1.35**	**1.41**	**1.38**	**1.39**	**#DIV/0!**
NPV of Margin after O/H	**11.5**						
NPV of Decommissioning	**13.9**						
NPV OF NET MARGIN	**(2.4)**						

DUQUESNE LIGHT
PV of Nuclear Plants
$ in Millions

@ $33.8/mwh in 2006 with escalations @ 2.5%

BEAVER VALLEY 1	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
kwh Market Price (cents)	3.38	3.47	3.55	3.64	3.73	3.83	3.92	4.02	4.12	4.22
Unit Output (gwh)	2,781	3,172	2,790	2,781	3,172	2,781	2,790	3,172	2,781	3,137
Delivered Output (gwh)	2,614	2,982	2,622	2,614	2,982	2,614	2,622	2,982	2,614	2,949
Revenues	**88.42**	**103.37**	**93.19**	**95.22**	**111.32**	**100.04**	**102.86**	**119.88**	**107.73**	**124.57**
Fuel-Related Expenses										
Fuel Costs	15.18	17.99	16.47	17.07	20.28	18.54	19.32	22.84	20.81	24.39
Fuel Related ECR Costs	2.78	3.17	2.79	2.78	3.17	2.78	2.79	3.17	2.78	3.14
Total Fuel	17.96	21.16	19.26	19.85	23.45	21.32	22.11	26.01	23.59	27.53
Non-fuel O&M Expenses										
Variable O&M	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed O&M	35.65	36.91	38.31	39.55	40.93	42.37	43.95	45.37	46.96	48.06
CAPCO Billing	(5.30)	(5.30)	(5.30)	(5.30)	(5.30)	(5.30)	(5.30)	(5.30)	(5.30)	(5.30)
Overhaul	14.31	0.00	15.33	15.86	0.00	16.99	17.59	0.00	18.84	0.00
Subtotal	44.66	31.61	48.34	50.11	35.64	54.06	56.24	40.07	60.50	42.76
FICA	1.64	1.67	1.70	1.74	1.77	1.81	1.84	1.88	1.92	1.95
Property Tax	2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.06
Cap Stock Tax	2.15	2.15	2.15	2.15	2.15	2.15	2.15	2.15	2.15	2.15
Total Non-fuel	50.51	37.48	54.25	56.05	41.61	60.08	62.29	46.16	66.63	48.93
Capital Expenditures	5.25	3.54	5.35	5.70	3.84	5.80	6.10	4.14	6.25	6.60
Direct Expenses	**73.72**	**62.19**	**78.86**	**81.60**	**68.91**	**87.19**	**90.50**	**76.31**	**96.46**	**83.05**
Direct Margin	**14.70**	**41.18**	**14.33**	**13.62**	**42.42**	**12.84**	**12.36**	**43.57**	**11.27**	**41.52**
Overhead Allocation	12.48	11.75	14.63	14.91	12.84	16.30	17.57	15.65	19.27	18.23
Expenses incl. Corp O/H	**86.20**	**73.94**	**93.48**	**96.51**	**81.74**	**103.50**	**108.07**	**91.96**	**115.73**	**101.27**
Margin after Corp O/H	**2.22**	**29.43**	**(0.30)**	**(1.29)**	**29.58**	**(3.46)**	**(5.21)**	**27.92**	**(8.00)**	**23.30**
Costs per kwh (cents)										
Fuel	0.69	0.71	0.73	0.76	0.79	0.82	0.84	0.87	0.90	0.93
Non-fuel	1.93	1.26	2.07	2.14	1.40	2.30	2.38	1.55	2.55	1.66
Capital Expenditures	0.20	0.12	0.20	0.22	0.13	0.22	0.23	0.14	0.24	0.22
Direct Expenses	**2.82**	**2.09**	**3.01**	**3.12**	**2.31**	**3.34**	**3.45**	**2.56**	**3.69**	**2.82**
Direct Margin	**0.56**	**1.38**	**0.55**	**0.52**	**1.42**	**0.49**	**0.47**	**1.46**	**0.43**	**1.41**
Overhead Allocation	0.48	0.39	0.56	0.57	0.43	0.62	0.67	0.52	0.74	0.62
Expenses incl. Corp O/H	**3.30**	**2.48**	**3.57**	**3.69**	**2.74**	**3.96**	**4.12**	**3.08**	**4.43**	**3.43**
Margin after Corp O/H	**0.09**	**0.99**	**(0.01)**	**(0.05)**	**0.99**	**(0.13)**	**(0.20)**	**0.94**	**(0.31)**	**0.79**

NPV of Margin after O/H	38.5
Overfunded Decomm.	0.1
NPV OF NET MARGIN	38.5

DUQUESNE LIGHT
PV of Nuclear Plants
$ In Millions

@ $33.8/mwh in 2006 with escalations @ 2.5%

BEAVER VALLEY 2	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
kwh Market Price (cents)	3.38	3.47	3.55	3.64	3.73	3.83	3.92	4.02	4.12	4.22	4.33	4.44	4.55	4.66	4.78	4.90	5.02	5.15	5.28	5.41	5.54
Unit Output (gwh)	931	816	819	931	816	816	934	816	816	921	816	816	921	816	816	921	816	816	921	816	921
Delivered Output (gwh)	875	767	770	875	767	767	878	767	767	866	767	767	866	767	767	866	767	767	866	767	866
Revenues	29.60	26.60	27.35	31.88	28.65	29.36	34.42	30.85	31.62	36.56	33.22	34.05	39.37	35.77	36.67	42.40	38.53	39.49	45.66	41.49	47.97
Fuel-Related Expenses																					
Fuel Costs	4.88	4.47	4.68	5.54	5.06	5.26	6.26	5.69	5.92	6.95	6.41	6.66	7.71	7.22	7.50	8.56	8.13	8.45	9.51	9.15	9.51
Fuel Related ECR Costs	0.93	0.82	0.82	0.93	0.82	0.82	0.93	0.82	0.82	0.92	0.82	0.82	0.92	0.82	0.82	0.92	0.82	0.82	0.92	0.82	0.82
Total Fuel	5.82	5.29	5.50	6.47	5.87	6.07	7.19	6.51	6.74	7.87	7.23	7.48	8.63	8.03	8.32	9.48	8.94	9.26	10.43	9.97	10.33
Non-fuel O&M Expenses																					
Variable O&M	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed O&M	10.30	10.66	11.06	11.42	11.82	12.24	12.69	13.10	13.56	13.88	14.52	15.03	15.18	16.09	16.66	16.60	17.84	18.47	18.15	19.77	20.47
CAPCO Billing	(8.70)	(8.70)	(8.70)	(8.70)	(8.70)	(8.70)	(8.70)	(8.70)	(8.70)	(8.70)	(8.70)	(8.70)	(8.70)	(8.70)	(8.70)	(8.70)	(8.70)	(8.70)	(8.70)	(8.70)	(8.70)
Overhaul	0.00	3.85	3.98	0.00	4.26	4.41	0.00	4.73	4.89	0.00	5.24	5.43	0.00	5.81	6.02	0.00	6.45	6.67	0.00	7.15	7.40
Subtotal	1.59	5.80	6.34	2.72	7.38	7.94	3.99	9.13	9.75	5.17	11.06	11.75	6.47	13.20	13.97	7.89	15.58	16.43	9.44	18.22	19.17
FICA	0.46	0.47	0.48	0.49	0.50	0.51	0.52	0.53	0.54	0.55	0.58	0.60	0.61	0.62	0.63	0.65	0.66	0.67	0.68	0.70	0.71
Property Tax	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42
Cap Stock Tax	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44
Total Non-fuel	2.91	7.12	7.67	4.06	8.73	9.31	5.36	10.51	11.15	6.58	12.50	13.20	7.94	14.68	15.46	9.39	17.09	17.96	10.98	19.77	20.73
Capital Expenditures	0.85	1.76	1.35	0.90	1.86	1.60	0.90	2.06	1.65	1.00	3.70	2.60	2.00	3.90	3.00	2.00	4.30	3.20	2.20	4.80	1.30
Direct Expenses	9.58	14.17	14.53	11.43	16.47	16.99	13.46	19.08	19.54	15.45	23.43	23.28	18.57	26.61	26.78	20.88	30.34	30.42	23.61	34.54	32.35
Direct Margin	20.02	12.43	12.82	20.44	12.18	12.38	20.97	11.77	12.08	21.11	9.79	10.77	20.81	9.16	9.89	21.53	8.19	9.07	22.05	6.95	15.62
Overhead Allocation	1.62	2.68	2.69	2.09	3.07	3.18	2.61	3.91	3.90	3.39	4.15	4.09	3.58	4.66	5.08	4.11	5.99	5.87	5.39	6.90	7.28
Expenses Incl. Corp O/H	11.20	16.85	17.22	13.52	19.53	20.16	16.07	22.99	23.44	18.84	27.57	27.37	22.15	31.28	31.86	24.98	36.33	36.29	29.01	41.44	39.63
Margin after Corp O/H	18.40	9.75	10.13	18.35	9.11	9.20	18.35	7.86	8.18	17.72	5.65	6.68	17.23	4.50	4.81	17.42	2.20	3.20	16.66	0.05	8.34
Costs per kwh (cents)																					
Fuel	0.66	0.69	0.71	0.74	0.77	0.79	0.82	0.85	0.88	0.91	0.94	0.97	1.00	1.05	1.08	1.10	1.17	1.21	1.20	1.30	1.19
Non-fuel	0.33	0.93	1.00	0.46	1.14	1.21	0.61	1.37	1.45	0.76	1.63	1.72	0.92	1.91	2.01	1.09	2.23	2.34	1.27	2.58	2.39
Capital Expenditures	0.10	0.23	0.18	0.10	0.24	0.21	0.10	0.27	0.22	0.12	0.48	0.34	0.23	0.51	0.39	0.23	0.56	0.42	0.25	0.63	0.15
Direct Expenses	1.09	1.85	1.89	1.31	2.15	2.21	1.53	2.49	2.55	1.79	3.05	3.03	2.15	3.47	3.49	2.41	3.95	3.97	2.73	4.50	3.74
Direct Margin	2.29	1.62	1.67	2.34	1.59	1.61	2.39	1.53	1.58	2.44	1.28	1.40	2.40	1.19	1.29	2.49	1.07	1.18	2.55	0.91	1.80
Overhead Allocation	0.19	0.35	0.35	0.24	0.40	0.41	0.30	0.51	0.51	0.39	0.54	0.53	0.41	0.61	0.66	0.47	0.78	0.77	0.62	0.90	0.84
Expenses Incl. Corp O/H	1.28	2.20	2.24	1.55	2.55	2.63	1.83	3.00	3.05	2.18	3.59	3.57	2.56	4.08	4.15	2.89	4.74	4.73	3.35	5.40	4.58
Margin after Corp O/H	2.10	1.27	1.32	2.10	1.19	1.20	2.09	1.02	1.07	2.05	0.74	0.87	1.99	0.59	0.63	2.01	0.29	0.42	1.92	0.01	0.91

NPV of Margin after O/H	69.3
Underfunded Decomm.	0.1
NPV OF NET MARGIN	69.2

Exhibit DJC-3
Page 54 of 67

DUQUESNE LIGHT
PV of Nuclear Plants
$ In Millions

@ $33.8/mwh in 2006 with escalations @ 2.5%

PERRY	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
kwh Market Price (cents)	3.38	3.47	3.55	3.64	3.73	3.83	3.92	4.02	4.12	4.22	4.33	4.44	4.55	4.66	4.78	4.90	5.02	5.15	5.28	5.41	5.54
Unit Output (gwh)	1,343	1,195	1,346	1,195	1,343	1,195	1,346	1,195	1,343	1,195	1,346	1,195	1,343	1,195	1,347	1,195	1,343	1,195	1,347	1,195	1,347
Delivered Output (gwh)	1,262	1,123	1,266	1,123	1,262	1,123	1,266	1,123	1,262	1,123	1,266	1,123	1,262	1,123	1,266	1,123	1,262	1,123	1,266	1,123	1,266
Revenues	42.70	38.93	44.98	40.91	47.12	42.98	49.65	45.16	52.02	47.44	54.80	49.84	57.42	52.37	60.50	55.01	63.38	57.80	66.78	60.73	70.16
Fuel-Related Expenses																					
Fuel Costs	8.55	8.08	9.43	8.68	10.08	9.30	10.84	9.96	11.61	10.69	12.47	11.44	13.20	12.07	13.97	12.39	13.93	12.39	13.97	12.39	13.97
Fuel Related ECR Costs	1.34	1.20	1.35	1.20	1.34	1.20	1.35	1.20	1.34	1.20	1.35	1.20	1.34	1.20	1.35	1.20	1.34	1.20	1.35	1.20	1.35
Total Fuel	9.89	9.28	10.77	9.87	11.43	10.50	12.19	11.16	12.95	11.88	13.82	12.64	14.55	13.26	15.31	13.59	15.27	13.59	15.31	13.59	15.31
Non-fuel O&M Expenses																					
Variable O&M	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed O&M	23.84	20.13	25.44	21.54	27.16	23.04	29.08	24.54	31.07	26.25	33.28	34.33	35.53	36.78	38.16	38.06	38.06	38.06	38.16	38.20	38.25
Overhaul	0.00	4.19	0.00	4.48	0.00	4.80	0.00	5.14	0.00	5.51	0.00	5.90	0.00	6.32	0.00	6.55	0.00	6.55	0.00	6.65	0.00
Subtotal	23.84	24.31	25.44	26.02	27.16	27.84	29.08	29.68	31.07	31.76	33.28	40.23	35.53	43.10	38.16	44.61	38.06	44.61	38.16	44.85	38.
FICA	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	
Property Tax	11.34	11.34	11.34	11.34	11.34	11.34	11.34	11.34	11.34	11.34	11.34	11.34	11.34	11.34	11.34	11.34	11.34	11.34	11.34	11.34	11.34
Cap Stock Tax	2.36	2.36	2.36	2.36	2.36	2.36	2.36	2.36	2.36	2.36	2.36	2.36	2.36	2.36	2.36	2.36	2.36	2.36	2.36	2.36	2.36
Total Non-fuel	37.54	38.01	39.14	39.72	40.87	41.54	42.79	43.38	44.77	45.47	46.98	53.93	49.23	56.81	51.87	58.31	51.76	58.31	51.87	58.55	51.95
Capital Expenditures	0.73	2.00	0.75	2.00	0.75	2.00	0.75	2.00	0.75	2.00	0.75	2.00	0.75	2.00	0.75	2.00	0.75	2.00	0.75	2.00	0.75
Direct Expenses	48.16	49.29	50.66	51.59	53.04	54.04	55.72	56.54	58.47	59.35	61.55	68.57	64.53	72.07	67.93	73.89	67.78	73.90	67.93	74.14	68.02
Direct Margin	(5.46)	(10.35)	(5.69)	(10.68)	(5.92)	(11.06)	(6.08)	(11.38)	(6.45)	(11.91)	(6.75)	(18.72)	(7.12)	(19.70)	(7.43)	(18.88)	(4.41)	(16.09)	(1.15)	(13.41)	2.14
Overhead Allocation	8.15	9.31	9.40	9.43	9.88	10.10	10.82	11.59	11.68	13.03	10.90	12.04	12.44	12.62	12.88	14.54	13.39	14.26	15.52	14.82	15.29
Expenses Incl. Corp O/H	56.32	58.60	60.06	61.02	62.92	64.14	66.54	68.13	70.15	72.37	72.44	80.60	76.97	84.69	80.81	88.44	81.17	88.15	83.45	88.96	83.31
Margin after Corp O/H	(13.62)	(19.67)	(15.08)	(20.11)	(15.80)	(21.17)	(16.90)	(22.98)	(18.13)	(24.93)	(17.64)	(30.76)	(19.56)	(32.33)	(20.31)	(33.43)	(17.79)	(30.35)	(16.67)	(28.23)	(13.15)
Costs per kwh (cents)																					
Fuel	0.78	0.83	0.85	0.88	0.91	0.93	0.96	0.99	1.03	1.06	1.09	1.13	1.15	1.18	1.21	1.21	1.21	1.21	1.21	1.21	1.21
Non-fuel	2.97	3.39	3.09	3.54	3.24	3.70	3.38	3.86	3.55	4.05	3.71	4.80	3.90	5.06	4.10	5.19	4.10	5.19	4.10	5.21	4.10
Capital Expenditures	0.06	0.18	0.06	0.18	0.06	0.18	0.06	0.18	0.06	0.18	0.06	0.18	0.06	0.18	0.06	0.18	0.06	0.18	0.06	0.18	0.06
Direct Expenses	3.82	4.39	4.00	4.59	4.20	4.81	4.40	5.03	4.63	5.28	4.86	6.11	5.11	6.42	5.37	6.58	5.37	6.58	5.37	6.60	5.37
Direct Margin	(0.43)	(0.92)	(0.45)	(0.95)	(0.47)	(0.99)	(0.48)	(1.01)	(0.51)	(1.06)	(0.53)	(1.67)	(0.56)	(1.75)	(0.59)	(1.68)	(0.35)	(1.43)	(0.09)	(1.19)	0.17
Overhead Allocation	0.65	0.83	0.74	0.84	0.78	0.90	0.85	1.03	0.93	1.16	0.86	1.07	0.99	1.12	1.02	1.30	1.06	1.27	1.23	1.32	1.21
Expenses Incl. Corp O/H	4.46	5.22	4.75	5.43	4.99	5.71	5.26	6.07	5.56	6.44	5.72	7.18	6.10	7.54	6.38	7.88	6.43	7.85	6.59	7.92	6.58
Margin after Corp O/H	(1.08)	(1.75)	(1.19)	(1.79)	(1.25)	(1.89)	(1.33)	(2.05)	(1.44)	(2.22)	(1.39)	(2.74)	(1.55)	(2.88)	(1.60)	(2.98)	(1.41)	(2.70)	(1.32)	(2.51)	(1.04)
NPV of Margin after O/H	(124.8)																				
Underfunded Decomm.	1.9																				
NPV OF NET MARGIN	(126.7)																				

DUQUESNE LIGHT COMPANY
Net Present Value of
Generating Plant Assets
as of 12/31/05
$ in Millions

Combined Cycle
@ $44.1/mwh in 2006 with escalations @ 2.5%

	Plant Margin	Decommissioning	Net Plant Value
Fossil Plants:			
Cheswick	158.4	(23.6)	134.9
Sammis	44.4	(27.8)	16.7
Eastlake	25.8	(22.5)	3.3
Elrama	0.0	(35.0)	(35.0)
Mansfield 1	87.1	(43.0)	44.1
Mansfield 2	26.3	(11.1)	15.2
Mansfield 3	56.7	(16.9)	39.8
Brunot Island	35.5	(13.9)	21.6
Phillips	0	(9.5)	(9.5)
Total Fossil	**434.3**	**(203.4)**	**231.0**
Nuclear Plants:			
Beaver Valley 1	166.6	(0.1)	166.6
Beaver Valley 2	131.0	(0.1)	131.0
Perry	0.0	(1.9)	(1.9)
Total Nuclear	**297.7**	**(2.0)**	**295.6**
TOTAL PLANTS	**$732.0**	**($205.4)**	**$526.6**

DUQUESNE LIGHT
PV of Fossil Plants
$ In Millions

	@ $44.1/mwh in 2006 with escalations @ 2.5%								
CHESWICK	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
kwh Market Price (cents)	4.41	4.52	4.63	4.75	4.87	4.99	5.11	5.24	5.37
Unit Output (gwh)	4,197	4,032	3,876	4,195	3,528	3,865	4,211	4,032	3,828
Delivered Output (gwh)	3,946	3,790	3,644	3,943	3,316	3,633	3,959	3,790	3,599
Revenues	**173.90**	**171.21**	**168.74**	**187.16**	**161.34**	**181.19**	**202.34**	**198.56**	**193.25**
Fuel-Related Expenses									
Fuel Costs	64.40	63.33	63.44	73.77	65.30	73.86	82.77	82.20	81.49
Fuel Related ECR Costs	1.08	1.11	1.14	1.17	1.20	1.23	1.26	1.30	1.32
NOx Emissions	8.65	8.69	8.31	9.92	7.52	9.32	11.41	11.12	10.42
SO2 Emissions	6.53	6.65	6.71	8.18	6.63	8.31	10.27	10.36	10.24
Total Fuel	80.66	79.78	79.60	93.04	80.64	92.72	105.71	104.97	103.48
Non-fuel O&M Expenses									
Variable O&M	3.93	3.88	3.83	4.25	3.67	4.13	4.61	4.54	4.42
Fixed O&M	9.56	11.72	11.87	10.13	11.03	12.40	10.53	12.83	12.98
Overhaul	0.00	0.00	0.00	0.00	12.50	0.00	0.00	0.00	0.00
Subtotal	13.49	15.60	15.70	14.38	27.20	16.52	15.14	17.37	17.40
Carbon Injection Costs	3.01	2.80	2.81	3.09	2.52	2.93	3.33	3.13	3.07
FICA	0.48	0.51	0.51	0.46	0.48	0.54	0.56	0.59	0.57
Property Tax	0.84	0.84	0.84	0.84	0.84	0.84	0.84	0.84	0.84
Cap Stock Tax	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88
Total Non-fuel	18.70	20.63	20.73	19.65	31.91	21.72	20.75	22.80	22.76
Capital Expenditures	5.19	5.34	5.50	5.67	15.05	4.53	3.14	1.66	1.06
Direct Expenses	**104.55**	**105.75**	**105.83**	**118.36**	**127.60**	**118.96**	**129.59**	**129.44**	**127.30**
Direct Margin	**69.35**	**65.45**	**62.91**	**68.79**	**33.74**	**62.22**	**72.75**	**69.12**	**65.95**
Overhead Allocation	17.70	19.98	19.63	21.63	23.77	22.25	25.16	26.54	25.43
Expenses incl. Corp O/H	**122.25**	**125.73**	**125.46**	**139.99**	**151.37**	**141.21**	**154.76**	**155.98**	**152.73**
Margin after Corp O/H	**51.65**	**45.47**	**43.28**	**47.17**	**9.97**	**39.98**	**47.59**	**42.58**	**40.52**
Costs per kwh (cents)									
Fuel	2.04	2.11	2.18	2.36	2.43	2.55	2.67	2.77	2.88
Non-fuel	0.47	0.54	0.57	0.50	0.96	0.60	0.52	0.60	0.63
Capital Expenditures	0.13	0.14	0.15	0.14	0.45	0.12	0.08	0.04	0.03
Direct Expenses	**2.65**	**2.79**	**2.90**	**3.00**	**3.85**	**3.27**	**3.27**	**3.42**	**3.54**
Direct Margin	**1.76**	**1.73**	**1.73**	**1.74**	**1.02**	**1.71**	**1.84**	**1.82**	**1.83**
Overhead Allocation	0.45	0.53	0.54	0.55	0.72	0.61	0.64	0.70	0.71
Expenses incl. Corp O/H	**3.10**	**3.32**	**3.44**	**3.55**	**4.56**	**3.89**	**3.91**	**4.12**	**4.24**
Margin after Corp O/H	**1.31**	**1.20**	**1.19**	**1.20**	**0.30**	**1.10**	**1.20**	**1.12**	**1.13**
NPV of Margin after O/H	**158.4**								
NPV of Decommissioning	**23.6**								
NPV OF NET MARGIN	**134.9**								

DUQUESNE LIGHT
PV of Fossil Plants
$ In Millions

	@ $44.1/mwh in 2006 with escalations @ 2.5%				
SAMMIS	2006	2007	2008	2009	2010
kwh Market Price (cents)	4.41	4.52	4.63	4.75	4.87
Unit Output (gwh)	1,493	1,236	1,498	1,378	1,474
Delivered Output (gwh)	1,404	1,162	1,408	1,295	1,385
Revenues	**61.87**	**52.50**	**65.21**	**61.47**	**67.39**
Fuel-Related Expenses					
Fuel Costs	23.77	20.33	25.67	24.55	27.34
Fuel Related ECR Costs	0.03	0.03	0.03	0.03	0.03
NOx Emissions	2.05	1.77	2.24	2.15	2.39
SO2 Emissions	0.98	0.66	1.14	1.02	1.27
Total Fuel	26.83	22.80	29.08	27.75	31.03
Non-fuel O&M Expenses					
Variable O&M	1.94	1.65	2.05	1.93	2.12
Fixed O&M	3.14	3.82	3.32	6.01	3.44
Overhaul	0.00	2.28	0.00	0.00	0.00
Subtotal	5.08	7.74	5.36	7.94	5.55
FICA	0.18	0.18	0.17	0.26	0.18
Property Tax	1.49	1.49	1.49	1.49	1.49
Cap Stock Tax	0.31	0.31	0.31	0.31	0.31
Total Non-fuel	7.05	9.71	7.33	9.99	7.53
Capital Expenditures	0.58	3.02	0.14	0.43	0.14
Direct Expenses	**34.46**	**35.53**	**36.55**	**38.17**	**38.70**
Direct Margin	**27.41**	**16.97**	**28.66**	**23.30**	**28.69**
Overhead Allocation	5.83	6.71	6.78	6.97	7.21
Expenses Incl. Corp O/H	**40.29**	**42.24**	**43.33**	**45.15**	**45.91**
Margin after Corp O/H	**21.57**	**10.25**	**21.88**	**16.33**	**21.48**
Costs per kwh (cents)					
Fuel	1.91	1.96	2.06	2.14	2.24
Non-fuel	0.50	0.84	0.52	0.77	0.54
Capital Expenditures	0.04	0.26	0.01	0.03	0.01
Direct Expenses	**2.45**	**3.06**	**2.60**	**2.95**	**2.79**
Direct Margin	**1.95**	**1.46**	**2.04**	**1.80**	**2.07**
Overhead Allocation	0.42	0.58	0.48	0.54	0.52
Expenses incl. Corp O/H	**2.87**	**3.64**	**3.08**	**3.49**	**3.31**
Margin after Corp O/H	**1.54**	**0.88**	**1.55**	**1.26**	**1.55**
NPV of Margin after O/H	44.4				
NPV of Decommissioning	27.8				
NPV OF NET MARGIN	16.7				

DUQUESNE LIGHT
PV of Fossil Plants
$ In Millions

	@ $44.1/mwh in 2006 with escalations @ 2.5%					
EASTLAKE	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
kwh Market Price (cents)	4.41	4.52	4.63	4.75	4.87	4.99
Unit Output (gwh)	1,120	1,149	1,166	1,286	1,149	1,178
Delivered Output (gwh)	1,053	1,080	1,096	1,209	1,080	1,108
Revenues	**46.41**	**48.80**	**50.73**	**57.37**	**52.55**	**55.23**
Fuel-Related Expenses						
Fuel Costs	15.56	16.42	17.16	19.52	17.95	18.94
Fuel Related ECR Costs	0.12	0.12	0.12	0.13	0.13	0.13
NOx Emissions	1.02	1.09	1.16	1.33	1.24	1.32
SO2 Emissions	5.11	5.67	6.21	7.51	7.08	7.86
Total Fuel	21.80	23.31	24.65	28.49	26.40	28.25
Non-fuel O&M Expenses						
Variable O&M	1.56	1.64	1.71	1.94	1.78	1.87
Fixed O&M	5.27	5.89	5.98	5.57	6.37	5.93
Overhaul	0.80	0.00	0.00	0.00	0.00	0.52
Subtotal	7.63	7.54	7.69	7.50	8.14	8.32
FICA	0.24	0.25	0.25	0.24	0.27	0.26
Property Tax	1.27	1.27	1.27	1.27	1.27	1.27
Cap Stock Tax	0.26	0.26	0.26	0.26	0.26	0.26
Total Non-fuel	9.41	9.32	9.48	9.28	9.95	10.12
Capital Expenditures	2.26	0.53	0.77	0.76	0.91	0.62
Direct Expenses	**33.47**	**33.15**	**34.90**	**38.53**	**37.25**	**38.99**
Direct Margin	**12.94**	**15.65**	**15.84**	**18.84**	**15.31**	**16.24**
Overhead Allocation	5.67	6.26	6.47	7.04	6.94	7.29
Expenses Incl. Corp O/H	**39.14**	**39.42**	**41.37**	**45.57**	**44.19**	**46.28**
Margin after Corp O/H	**7.27**	**9.39**	**9.37**	**11.80**	**8.37**	**8.95**
Costs per kwh (cents)						
Fuel	2.07	2.16	2.25	2.36	2.44	2.55
Non-fuel	0.89	0.86	0.87	0.77	0.92	0.91
Capital Expenditures	0.21	0.05	0.07	0.06	0.08	0.06
Direct Expenses	**3.18**	**3.07**	**3.19**	**3.19**	**3.45**	**3.52**
Direct Margin	**1.23**	**1.45**	**1.45**	**1.56**	**1.42**	**1.47**
Overhead Allocation	0.54	0.58	0.59	0.58	0.64	0.66
Expenses incl. Corp O/H	**3.72**	**3.65**	**3.78**	**3.77**	**4.09**	**4.18**
Margin after Corp O/H	**0.69**	**0.87**	**0.85**	**0.98**	**0.77**	**0.81**
NPV of Margin after O/H	**25.8**					
NPV of Decommissioning	**22.5**					
NPV OF NET MARGIN	**3.3**					

DUQUESNE LIGHT
PV of Fossil Plants
$ In Millions

	@ $44.1/mwh in 2006 with escalations @ 2.5%
ELRAMA	2006
kwh Market Price (cents)	
Unit Output (gwh)	
Delivered Output (gwh)	
Revenues	
Fuel-Related Expenses	
Fuel Costs	
Fuel Related ECR Costs	
NOx Emissions	
SO2 Emissions	
Total Fuel	
Non-fuel O&M Expenses	
Variable O&M	
Fixed O&M	
Overhaul	
Subtotal	
FICA	
Property Tax	
Cap Stock Tax	
Total Non-fuel	
Capital Expenditures	
Direct Expenses	
Direct Margin	
Overhead Allocation	
Expenses incl. Corp O/H	
Margin after Corp O/H	
Costs per kwh (cents)	
Fuel	
Non-fuel	
Capital Expenditures	
Direct Expenses	
Direct Margin	
Overhead Allocation	
Expenses incl. Corp O/H	
Margin after Corp O/H	
NPV of Margin after O/H	0.0
NPV of Decommissioning	35.0
NPV OF NET MARGIN	(35.0)

Exhibit DJC-3
Page 60 of 67

DUQUESNE LIGHT
PV of Fossil Plants
$ in Millions

@ $44.1/mwh in 2006 with escalations @ 2.5%

MANSFIELD 1	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
kwh Market Price (cents)	4.41	4.52	4.63	4.75	4.87	4.99	5.11	5.24	5.37	5.50
Unit Output (gwh)	1,376	1,789	1,657	1,787	1,652	1,789	1,382	1,789	1,652	1,769
Delivered Output (gwh)	1,293	1,682	1,557	1,679	1,553	1,682	1,299	1,682	1,553	1,663
Revenues	**57.01**	**75.96**	**72.10**	**79.71**	**75.53**	**83.85**	**66.40**	**88.10**	**83.37**	**91.53**
Fuel-Related Expenses										
Fuel Costs	16.85	22.55	21.48	23.84	22.66	25.26	20.06	26.74	25.38	27.99
Fuel Related ECR Costs	3.48	4.58	4.37	4.82	4.59	5.08	4.09	5.36	5.11	5.59
NOx Emissions	3.25	5.02	4.67	5.43	5.06	5.92	4.21	6.44	5.97	6.87
SO2 Emissions	(0.39)	(0.31)	(0.37)	(0.36)	(0.44)	(0.43)	(0.61)	(0.49)	(0.59)	(0.58)
Total Fuel	23.20	31.84	30.15	33.72	31.87	35.84	27.74	38.04	35.86	39.86
Non-fuel O&M Expenses										
Variable O&M	1.92	2.56	2.43	2.69	2.55	2.84	2.25	2.99	2.84	3.12
Fixed O&M	5.76	5.84	6.82	6.42	7.54	6.79	6.83	6.94	8.15	8.62
Overhaul	3.96	0.00	0.00	0.00	0.00	0.00	4.73	0.00	0.00	0.00
Subtotal	11.64	8.40	9.25	9.11	10.09	9.63	13.81	9.94	10.99	11.74
FICA	0.27	0.28	0.30	0.29	0.33	0.32	0.34	0.34	0.36	0.36
Property Tax	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48
Cap Stock Tax	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
Total Non-fuel	12.89	9.65	10.52	10.38	11.40	10.92	15.13	11.25	12.32	13.09
Capital Expenditures	6.38	1.03	0.83	0.99	2.20	2.14	5.71	0.62	0.25	0.18
Direct Expenses	**42.47**	**42.52**	**41.50**	**45.09**	**45.47**	**48.90**	**48.58**	**49.91**	**48.44**	**53.13**
Direct Margin	**14.54**	**33.44**	**30.61**	**34.62**	**30.06**	**34.95**	**17.82**	**38.19**	**34.93**	**38.41**
Overhead Allocation	7.19	8.03	7.70	8.24	8.47	9.14	9.43	10.23	9.68	11.66
Expenses incl. Corp O/H	**49.66**	**50.55**	**49.19**	**53.33**	**53.95**	**58.05**	**58.02**	**60.14**	**58.11**	**64.79**
Margin after Corp O/H	**7.35**	**25.41**	**22.91**	**26.38**	**21.58**	**25.81**	**8.39**	**27.95**	**25.26**	**26.75**
Costs per kwh (cents)										
Fuel	1.79	1.89	1.94	2.01	2.05	2.13	2.14	2.26	2.31	2.40
Non-fuel	1.00	0.57	0.68	0.62	0.73	0.65	1.16	0.67	0.79	0.79
Capital Expenditures	0.49	0.06	0.05	0.06	0.14	0.13	0.44	0.04	0.02	0.01
Direct Expenses	**3.28**	**2.53**	**2.66**	**2.68**	**2.93**	**2.91**	**3.74**	**2.97**	**3.12**	**3.19**
Direct Margin	**1.12**	**1.99**	**1.97**	**2.06**	**1.94**	**2.08**	**1.37**	**2.27**	**2.25**	**2.31**
Overhead Allocation	0.56	0.48	0.49	0.49	0.55	0.54	0.73	0.61	0.62	0.70
Expenses incl. Corp O/H	**3.84**	**3.01**	**3.16**	**3.18**	**3.47**	**3.45**	**4.47**	**3.58**	**3.74**	**3.90**
Margin after Corp O/H	**0.57**	**1.51**	**1.47**	**1.57**	**1.39**	**1.53**	**0.65**	**1.66**	**1.63**	**1.61**
NPV of Margin after O/H	**87.1**									
NPV of Decommissioning	**43.0**									
NPV OF NET MARGIN	**44.1**									

DUQUESNE LIGHT
PV of Fossil Plants
$ in Millions

	@ $44.1/mwh in 2006 with escalations @ 2.5%										
MANSFIELD 2	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
kwh Market Price (cents)	4.41	4.52	4.63	4.75	4.87	4.99	5.11	5.24	5.37	5.50	5.64
Unit Output (gwh)	404	481	463	499	461	500	404	482	461	500	455
Delivered Output (gwh)	379	452	435	469	434	470	380	453	434	470	427
Revenues	**16.72**	**20.41**	**20.14**	**22.27**	**21.10**	**23.42**	**19.41**	**23.73**	**23.29**	**25.85**	**24.11**
Fuel-Related Expenses											
Fuel Costs	4.86	5.96	5.91	6.56	6.23	6.95	5.77	7.09	6.98	7.78	7.28
Fuel Related ECR Costs	1.01	1.23	1.21	1.34	1.28	1.41	1.19	1.44	1.42	1.57	1.47
NOx Emissions	1.00	1.36	1.37	1.56	1.44	1.70	1.28	1.75	1.75	2.00	1.81
SO2 Emissions	(0.12)	(0.11)	(0.13)	(0.12)	(0.15)	(0.15)	(0.19)	(0.18)	(0.20)	(0.20)	(0.23)
Total Fuel	6.75	8.44	8.36	9.33	8.80	9.91	8.04	10.11	9.95	11.16	10.33
Non-fuel O&M Expenses											
Variable O&M	0.56	0.68	0.67	0.75	0.71	0.79	0.65	0.80	0.79	0.87	0.82
Fixed O&M	1.52	1.59	1.83	1.72	2.03	1.83	1.82	1.90	2.20	2.35	2.53
Overhaul	1.00	0.20	0.00	0.00	0.00	0.00	1.21	0.22	0.00	0.00	0.00
Subtotal	3.07	2.47	2.50	2.47	2.74	2.62	3.67	2.92	2.99	3.23	3.35
FICA	0.07	0.07	0.08	0.08	0.09	0.09	0.09	0.09	0.10	0.10	0.14
Property Tax	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13
Cap Stock Tax	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
Total Non-fuel	3.41	2.81	2.85	2.81	3.09	2.97	4.03	3.28	3.35	3.59	3.75
Capital Expenditures	0.91	1.83	0.41	0.27	0.60	0.36	1.09	1.63	0.24	0.08	0.11
Direct Expenses	**11.07**	**13.07**	**11.62**	**12.41**	**12.50**	**13.24**	**13.16**	**15.02**	**13.54**	**14.83**	**14.18**
Direct Margin	**5.65**	**7.34**	**8.52**	**9.86**	**8.60**	**10.18**	**6.25**	**8.72**	**9.75**	**11.02**	**9.92**
Overhead Allocation	1.87	2.47	2.16	2.27	2.33	2.48	2.56	3.08	2.71	3.26	2.51
Expenses incl. Corp O/H	**12.94**	**15.54**	**13.78**	**14.68**	**14.82**	**15.72**	**15.71**	**18.10**	**16.25**	**18.09**	**16.70**
Margin after Corp O/H	**3.78**	**4.87**	**6.36**	**7.59**	**6.28**	**7.71**	**3.69**	**5.64**	**7.04**	**7.77**	**7.41**
Costs per kwh (cents)											
Fuel	1.78	1.87	1.92	1.99	2.03	2.11	2.12	2.23	2.29	2.38	2.42
Non-fuel	0.90	0.62	0.65	0.60	0.71	0.63	1.06	0.72	0.77	0.77	0.88
Capital Expenditures	0.24	0.40	0.09	0.06	0.14	0.08	0.29	0.36	0.06	0.02	0.03
Direct Expenses	**2.92**	**2.89**	**2.67**	**2.65**	**2.88**	**2.82**	**3.47**	**3.32**	**3.12**	**3.16**	**3.32**
Direct Margin	**1.49**	**1.62**	**1.96**	**2.10**	**1.98**	**2.17**	**1.65**	**1.92**	**2.25**	**2.35**	**2.32**
Overhead Allocation	0.49	0.55	0.50	0.48	0.54	0.53	0.67	0.68	0.62	0.69	0.59
Expenses incl. Corp O/H	**3.41**	**3.44**	**3.17**	**3.13**	**3.42**	**3.35**	**4.14**	**4.00**	**3.75**	**3.85**	**3.91**
Margin after Corp O/H	**1.00**	**1.08**	**1.46**	**1.62**	**1.45**	**1.64**	**0.97**	**1.24**	**1.62**	**1.65**	**1.73**

NPV of Margin after O/H	26.3
NPV of Decommissioning	11.1
NPV OF NET MARGIN	15.2

DUQUESNE LIGHT
PV of Fossil Plants
$ in Millions

	@ $44.1/mwh in 2006 with escalations @ 2.5%													
MANSFIELD 3	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
kwh Market Price (cents)	4.41	4.52	4.63	4.75	4.87	4.99	5.11	5.24	5.37	5.50	5.64	5.78	5.93	6.08
Unit Output (gwh)	874	839	712	807	875	808	877	719	829	808	877	808	875	870
Delivered Output (gwh)	822	788	669	758	822	759	824	676	779	759	824	759	822	818
Revenues	**36.23**	**35.62**	**30.98**	**36.00**	**40.00**	**37.86**	**42.14**	**35.41**	**41.86**	**41.78**	**46.52**	**43.90**	**48.74**	**49.68**
Fuel-Related Expenses														
Fuel Costs	10.33	10.20	8.91	10.39	11.58	11.01	12.28	10.37	12.30	12.33	13.78	13.02	14.49	14.80
Fuel Related ECR Costs	2.18	2.16	1.90	2.19	2.42	2.31	2.56	2.18	2.56	2.57	2.85	2.71	3.00	3.06
NOx Emissions	2.82	2.79	2.32	2.87	3.33	3.16	3.64	2.89	3.67	3.69	4.30	4.06	4.66	4.81
SO2 Emissions	(0.18)	(0.20)	(0.25)	(0.25)	(0.25)	(0.29)	(0.29)	(0.37)	(0.35)	(0.39)	(0.38)	(0.45)	(0.45)	(0.49)
Total Fuel	15.16	14.94	12.87	15.20	17.09	16.18	18.20	15.07	18.17	18.20	20.54	19.34	21.69	22.18
Non-fuel O&M Expenses														
Variable O&M	1.05	1.03	0.90	1.05	1.17	1.11	1.23	1.04	1.23	1.23	1.37	1.30	1.44	1.47
Fixed O&M	2.65	3.01	3.56	3.35	3.71	3.54	3.15	3.76	4.08	4.50	4.67	4.78	4.91	5.01
Overhaul	0.00	0.28	1.29	0.00	0.00	0.00	0.00	1.45	0.42	0.00	0.00	0.00	0.00	0.00
Subtotal	3.70	4.32	5.75	4.39	4.88	4.64	4.39	6.24	5.73	5.73	6.04	6.07	6.35	6.48
FICA	0.13	0.13	0.14	0.14	0.16	0.15	0.16	0.16	0.17	0.18	0.25	0.25	0.26	0.26
Property Tax	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23
Cap Stock Tax	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24
Total Non-fuel	4.31	4.93	6.37	5.01	5.51	5.27	5.02	6.87	6.37	6.38	6.76	6.80	7.08	7.22
Capital Expenditures	0.43	0.69	2.69	0.48	1.07	0.40	0.51	0.82	3.21	0.57	0.96	0.64	0.32	0.19
Direct Expenses	**19.90**	**20.56**	**21.92**	**20.69**	**23.67**	**21.85**	**23.74**	**22.77**	**27.76**	**25.15**	**28.25**	**26.77**	**29.09**	**29.59**
Direct Margin	**16.33**	**15.06**	**9.06**	**15.31**	**16.34**	**16.00**	**18.41**	**12.64**	**14.10**	**16.63**	**18.27**	**17.13**	**19.65**	**20.09**
Overhead Allocation	3.37	3.88	4.07	3.78	4.41	4.09	4.61	4.67	5.55	5.52	5.00	4.70	5.61	5.18
Expenses incl. Corp O/H	**23.27**	**24.44**	**25.99**	**24.47**	**28.07**	**25.94**	**28.35**	**27.44**	**33.30**	**30.67**	**33.25**	**31.47**	**34.70**	**34.77**
Margin after Corp O/H	**12.96**	**11.18**	**4.99**	**11.53**	**11.93**	**11.92**	**13.80**	**7.97**	**8.55**	**11.11**	**13.27**	**12.43**	**14.04**	**14.91**
Costs per kwh (cents)														
Fuel	1.84	1.90	1.92	2.00	2.08	2.13	2.21	2.23	2.33	2.40	2.49	2.55	2.64	2.71
Non-fuel	0.52	0.63	0.95	0.66	0.67	0.69	0.61	1.02	0.82	0.84	0.82	0.90	0.86	0.88
Capital Expenditures	0.05	0.09	0.40	0.06	0.13	0.05	0.06	0.12	0.41	0.08	0.12	0.08	0.04	0.02
Direct Expenses	**2.42**	**2.61**	**3.28**	**2.73**	**2.88**	**2.88**	**2.88**	**3.37**	**3.56**	**3.31**	**3.43**	**3.53**	**3.54**	**3.62**
Direct Margin	**1.99**	**1.91**	**1.35**	**2.02**	**1.99**	**2.11**	**2.23**	**1.87**	**1.81**	**2.19**	**2.22**	**2.26**	**2.39**	**2.46**
Overhead Allocation	0.41	0.49	0.61	0.50	0.54	0.54	0.56	0.69	0.71	0.73	0.61	0.62	0.68	0.63
Expenses incl. Corp O/H	**2.83**	**3.10**	**3.88**	**3.23**	**3.41**	**3.42**	**3.44**	**4.06**	**4.27**	**4.04**	**4.03**	**4.15**	**4.22**	**4**
Margin after Corp O/H	**1.58**	**1.42**	**0.75**	**1.52**	**1.45**	**1.57**	**1.67**	**1.18**	**1.10**	**1.46**	**1.61**	**1.64**	**1.71**	**1**

NPV of Margin after O/H	56.7
NPV of Decommissioning	16.9
NPV OF NET MARGIN	39.8

DUQUESNE LIGHT
PV of Fossil Plants
$ in Millions

	@ $44.1/mwh in 2006 with escalations @ 2.5%						
BRUNOT ISLAND	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
kwh Market Price (cents)	22.04	22.59	23.15	23.73	24.33	24.93	25.56
Unit Output (gwh)	406	111	111	111	111	111	0
Delivered Output (gwh)	382	104	104	104	104	104	0
Revenues	**84.15**	**23.57**	**24.16**	**24.76**	**25.38**	**26.02**	**0.00**
Fuel-Related Expenses							
Fuel Costs	40.31	12.52	12.86	13.21	13.56	13.93	0.00
Fuel Related ECR Costs	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NOx Emissions	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SO2 Emissions	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Fuel	40.31	12.52	12.86	13.21	13.56	13.93	0.00
Non-fuel O&M Expenses							
Variable O&M	0.53	0.15	0.15	0.16	0.16	0.17	0.00
Fixed O&M	0.71	0.73	0.75	0.77	0.79	0.81	0.00
Overhaul	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Subtotal	1.23	0.88	0.90	0.92	0.95	0.98	0.00
FICA	0.04	0.03	0.03	0.03	0.03	0.03	0.00
Property Tax	0.33	0.33	0.33	0.33	0.33	0.33	0.33
Cap Stock Tax	0.34	0.34	0.34	0.34	0.34	0.34	0.34
Total Non-fuel	1.94	1.57	1.59	1.62	1.65	1.67	0.67
Capital Expenditures	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Direct Expenses	**42.26**	**14.09**	**14.45**	**14.83**	**15.21**	**15.60**	**0.67**
Direct Margin	**41.89**	**9.48**	**9.70**	**9.94**	**10.17**	**10.41**	**(0.67)**
Overhead Allocation	7.15	2.66	2.68	2.71	2.83	2.92	0.13
Expenses Incl. Corp O/H	**49.41**	**16.75**	**17.13**	**17.53**	**18.04**	**18.52**	**0.79**
Margin after Corp O/H	**34.74**	**6.82**	**7.02**	**7.23**	**7.34**	**7.50**	**(0.79)**
Costs per kwh (cents)							
Fuel	10.56	12.00	12.32	12.66	13.00	13.35	#DIV/0!
Non-fuel	0.51	1.51	1.53	1.55	1.58	1.60	#DIV/0!
Capital Expenditures	0.00	0.00	0.00	0.00	0.00	0.00	#DIV/0!
Direct Expenses	**11.07**	**13.51**	**13.85**	**14.21**	**14.58**	**14.95**	**#DIV/0!**
Direct Margin	**10.97**	**9.08**	**9.30**	**9.52**	**9.75**	**9.98**	**#DIV/0!**
Overhead Allocation	1.87	2.55	2.57	2.60	2.72	2.80	#DIV/0!
Expenses Incl. Corp O/H	**12.94**	**16.06**	**16.42**	**16.81**	**17.29**	**17.75**	**#DIV/0!**
Margin after Corp O/H	**9.10**	**6.53**	**6.73**	**6.93**	**7.03**	**7.19**	**#DIV/0!**
NPV of Margin after O/H	**35.5**						
NPV of Decommissioning	**13.9**						
NPV OF NET MARGIN	**21.6**						

DUQUESNE LIGHT
PV of Nuclear Plants
$ in Millions

@ $44.1/mwh in 2006 with escalations @ 2.5%

BEAVER VALLEY 1	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
kwh Market Price (cents)	4.41	4.52	4.63	4.75	4.87	4.99	5.11	5.24	5.37	5.50
Unit Output (gwh)	2,781	3,172	2,790	2,781	3,172	2,781	2,790	3,172	2,781	3,137
Delivered Output (gwh)	2,614	2,982	2,622	2,614	2,982	2,614	2,622	2,982	2,614	2,949
Revenues	**115.21**	**134.70**	**121.42**	**124.07**	**145.06**	**130.35**	**134.03**	**156.21**	**140.38**	**162.32**
Fuel-Related Expenses										
Fuel Costs	15.18	17.99	16.47	17.07	20.28	18.54	19.32	22.84	20.81	24.39
Fuel Related ECR Costs	2.78	3.17	2.79	2.78	3.17	2.78	2.79	3.17	2.78	3.14
Total Fuel	17.96	21.16	19.26	19.85	23.45	21.32	22.11	26.01	23.59	27.53
Non-fuel O&M Expenses										
Variable O&M	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed O&M	35.65	36.91	38.31	39.55	40.93	42.37	43.95	45.37	46.96	48.06
CAPCO Billing	(5.30)	(5.30)	(5.30)	(5.30)	(5.30)	(5.30)	(5.30)	(5.30)	(5.30)	(5.30)
Overhaul	14.31	0.00	15.33	15.86	0.00	16.99	17.59	0.00	18.84	0.00
Subtotal	44.66	31.61	48.34	50.11	35.64	54.06	56.24	40.07	60.50	42.76
FICA	1.64	1.67	1.70	1.74	1.77	1.81	1.84	1.88	1.92	1.95
Property Tax	2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.06
Cap Stock Tax	2.15	2.15	2.15	2.15	2.15	2.15	2.15	2.15	2.15	2.15
Total Non-fuel	50.51	37.48	54.25	56.05	41.61	60.08	62.29	46.16	66.63	48.93
Capital Expenditures	5.25	3.54	5.35	5.70	3.84	5.80	6.10	4.14	6.25	6.60
Direct Expenses	**73.72**	**62.19**	**78.86**	**81.60**	**68.91**	**87.19**	**90.50**	**76.31**	**96.46**	**83.05**
Direct Margin	**41.50**	**72.51**	**42.57**	**42.47**	**76.15**	**43.16**	**43.53**	**79.90**	**43.91**	**79.27**
Overhead Allocation	12.48	11.75	14.63	14.91	12.84	16.30	17.57	15.65	19.27	18.23
Expenses incl. Corp O/H	**86.20**	**73.94**	**93.48**	**96.51**	**81.74**	**103.50**	**108.07**	**91.96**	**115.73**	**101.27**
Margin after Corp O/H	**29.02**	**60.76**	**27.94**	**27.56**	**63.32**	**26.85**	**25.96**	**64.25**	**24.64**	**61.05**
Costs per kwh (cents)										
Fuel	0.69	0.71	0.73	0.76	0.79	0.82	0.84	0.87	0.90	0.93
Non-fuel	1.93	1.26	2.07	2.14	1.40	2.30	2.38	1.55	2.55	1.66
Capital Expenditures	0.20	0.12	0.20	0.22	0.13	0.22	0.23	0.14	0.24	0.22
Direct Expenses	**2.82**	**2.09**	**3.01**	**3.12**	**2.31**	**3.34**	**3.45**	**2.56**	**3.69**	**2.82**
Direct Margin	**1.59**	**2.43**	**1.62**	**1.62**	**2.55**	**1.65**	**1.66**	**2.68**	**1.68**	**2.69**
Overhead Allocation	0.48	0.39	0.56	0.57	0.43	0.62	0.67	0.52	0.74	0.62
Expenses incl. Corp O/H	**3.30**	**2.48**	**3.57**	**3.69**	**2.74**	**3.96**	**4.12**	**3.08**	**4.43**	**3.43**
Margin after Corp O/H	**1.11**	**2.04**	**1.07**	**1.05**	**2.12**	**1.03**	**0.99**	**2.15**	**0.94**	**2.07**
NPV of Margin after O/H	166.6									
Overfunded Decomm.	0.1									
NPV OF NET MARGIN	166.6									

DUQUESNE LIGHT
PV of Nuclear Plants
$ in Millions

@ $44.1/mwh in 2006 with escalations @ 2.5%

BEAVER VALLEY 1	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
kwh Market Price (cents)	4.41	4.52	4.63	4.75	4.87	4.99	5.11	5.24	5.37	5.50	5.64	5.78	5.93	6.08	6.23	6.38	6.54	6.71	6.87	7.05	7.22
Unit Output (gwh)	931	816	819	931	816	816	934	816	816	921	816	816	921	816	816	921	816	816	921	816	921
Delivered Output (gwh)	875	767	770	875	767	767	878	767	767	866	767	767	866	767	767	866	767	767	866	767	866
Revenues	38.57	34.66	35.64	41.54	37.33	38.26	44.85	40.20	41.20	47.64	43.29	44.37	51.31	46.62	47.78	55.25	50.20	51.45	59.50	54.06	62.51
Fuel-Related Expenses																					
Fuel Costs	4.88	4.47	4.68	5.54	5.06	5.26	6.26	5.69	5.92	6.95	6.41	6.66	7.71	7.22	7.50	8.56	8.13	8.45	9.51	9.15	9.51
Fuel Related ECR Costs	0.93	0.82	0.82	0.93	0.82	0.82	0.93	0.82	0.82	0.92	0.82	0.82	0.92	0.82	0.82	0.92	0.82	0.82	0.92	0.82	0.82
Total Fuel	5.82	5.29	5.50	6.47	5.87	6.07	7.19	6.51	6.74	7.87	7.23	7.48	8.63	8.03	8.32	9.48	8.94	9.26	10.43	9.97	10.33
Non-fuel O&M Expenses																					
Variable O&M	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed O&M	10.30	10.66	11.06	11.42	11.82	12.24	12.69	13.10	13.56	13.88	14.52	15.03	15.18	16.09	16.66	16.60	17.84	18.47	18.15	19.77	20.47
CAPCO Billing	(8.70)	(8.70)	(8.70)	(8.70)	(8.70)	(8.70)	(8.70)	(8.70)	(8.70)	(8.70)	(8.70)	(8.70)	(8.70)	(8.70)	(8.70)	(8.70)	(8.70)	(8.70)	(8.70)	(8.70)	(8.70)
Overhaul	0.00	3.85	3.98	0.00	4.26	4.41	0.00	4.73	4.89	0.00	5.24	5.43	0.00	5.81	6.02	0.00	6.45	6.67	0.00	7.15	7.[illegible]
Subtotal	1.59	5.80	6.34	2.72	7.38	7.94	3.99	9.13	9.75	5.17	11.06	11.75	6.47	13.20	13.97	7.89	15.58	16.43	9.44	18.22	19[illegible]
FICA	0.46	0.47	0.48	0.49	0.50	0.51	0.52	0.53	0.54	0.55	0.58	0.60	0.61	0.62	0.63	0.65	0.66	0.67	0.68	0.70	0.7[illegible]
Property Tax	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42
Cap Stock Tax	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44
Total Non-fuel	2.91	7.12	7.67	4.06	8.73	9.31	5.36	10.51	11.15	6.58	12.50	13.20	7.94	14.68	15.46	9.39	17.09	17.96	10.98	19.77	20.73
Capital Expenditures	0.85	1.76	1.35	0.90	1.86	1.60	0.90	2.06	1.65	1.00	3.70	2.60	2.00	3.90	3.00	2.00	4.30	3.20	2.20	4.80	1.30
Direct Expenses	9.58	14.17	14.53	11.43	16.47	16.99	13.46	19.08	19.54	15.45	23.43	23.28	18.57	26.61	26.78	20.88	30.34	30.42	23.61	34.54	32.35
Direct Margin	28.99	20.49	21.11	30.10	20.86	21.27	31.40	21.12	21.67	32.19	19.86	21.09	32.74	20.00	21.00	34.37	19.86	21.03	35.89	19.52	30.16
Overhead Allocation	1.62	2.68	2.69	2.09	3.07	3.18	2.61	3.91	3.90	3.39	4.15	4.09	3.58	4.66	5.08	4.11	5.99	5.87	5.39	6.90	7.28
Expenses incl. Corp O/H	11.20	16.85	17.22	13.52	19.53	20.16	16.07	22.99	23.44	18.84	27.57	27.37	22.15	31.28	31.86	24.98	36.33	36.29	29.01	41.44	39.63
Margin after Corp O/H	27.37	17.81	18.42	28.01	17.79	18.10	28.78	17.21	17.76	28.80	15.71	17.00	29.16	15.34	15.93	30.27	13.87	15.16	30.49	12.62	22.88
Costs per kwh (cents)																					
Fuel	0.66	0.69	0.71	0.74	0.77	0.79	0.82	0.85	0.88	0.91	0.94	0.97	1.00	1.05	1.08	1.10	1.17	1.21	1.20	1.30	1.19
Non-fuel	0.33	0.93	1.00	0.46	1.14	1.21	0.61	1.37	1.45	0.76	1.63	1.72	0.92	1.91	2.01	1.09	2.23	2.34	1.27	2.58	2.39
Capital Expenditures	0.10	0.23	0.18	0.10	0.24	0.21	0.10	0.27	0.22	0.12	0.48	0.34	0.23	0.51	0.39	0.23	0.56	0.42	0.25	0.63	0.15
Direct Expenses	1.09	1.85	1.89	1.31	2.15	2.21	1.53	2.49	2.55	1.79	3.05	3.03	2.15	3.47	3.49	2.41	3.95	3.97	2.73	4.50	3.74
Direct Margin	3.31	2.67	2.74	3.44	2.72	2.77	3.58	2.75	2.82	3.72	2.59	2.75	3.78	2.61	2.74	3.97	2.59	2.74	4.15	2.54	3.48
Overhead Allocation	0.19	0.35	0.35	0.24	0.40	0.41	0.30	0.51	0.51	0.39	0.54	0.53	0.41	0.61	0.66	0.47	0.78	0.77	0.62	0.90	0.84
Expenses incl. Corp O/H	1.28	2.20	2.24	1.55	2.55	2.63	1.83	3.00	3.05	2.18	3.59	3.57	2.56	4.08	4.15	2.89	4.74	4.73	3.35	5.40	4.5[illegible]
Margin after Corp O/H	3.13	2.32	2.39	3.20	2.32	2.36	3.28	2.24	2.32	3.33	2.05	2.22	3.37	2.00	2.08	3.50	1.81	1.98	3.52	1.64	2.[illegible]

NPV of Margin after O/H	131.0
Underfunded Decomm.	0.1
NPV OF NET MARGIN	131.0

Exhibit DJC-3
Page 66 of 67

DUQUESNE LIGHT
PV of Nuclear Plants
$ in Millions

@ $44.1/mwh in 2006 with escalations @ 2.5%

PERRY	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
kwh Market Price (cents)	4.41	4.52	4.63	4.75	4.87	4.99	5.11	5.24	5.37	5.50	5.64	5.78	5.93	6.08	6.23	6.38	6.54	6.71	6.87	7.05	7.22
Unit Output (gwh)	1,343	1,195	1,346	1,195	1,343	1,195	1,346	1,195	1,343	1,195	1,346	1,195	1,343	1,195	1,347	1,195	1,343	1,195	1,347	1,195	1,347
Delivered Output (gwh)	1,262	1,123	1,266	1,123	1,262	1,123	1,266	1,123	1,262	1,123	1,266	1,123	1,262	1,123	1,266	1,123	1,262	1,123	1,266	1,123	1,266
Revenues	55.64	50.73	58.61	53.31	61.40	56.00	64.69	58.84	67.78	61.82	71.41	64.95	74.81	68.24	78.83	71.68	82.58	75.32	87.01	79.13	91.42
Fuel-Related Expenses																					
Fuel Costs	8.55	8.08	9.43	8.68	10.08	9.30	10.84	9.96	11.61	10.69	12.47	11.44	13.20	12.07	13.97	12.39	13.93	12.39	13.97	12.39	13.97
Fuel Related ECR Costs	1.34	1.20	1.35	1.20	1.34	1.20	1.35	1.20	1.34	1.20	1.35	1.20	1.34	1.20	1.35	1.20	1.34	1.20	1.35	1.20	1.35
Total Fuel	9.89	9.28	10.77	9.87	11.43	10.50	12.19	11.16	12.95	11.88	13.82	12.64	14.55	13.26	15.31	13.59	15.27	13.59	15.31	13.59	15.31
Non-fuel O&M Expenses																					
Variable O&M	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed O&M	23.84	20.13	25.44	21.54	27.16	23.04	29.08	24.54	31.07	26.25	33.28	34.33	35.53	36.78	38.16	38.06	38.06	38.06	38.16	38.20	38.25
Overhaul	0.00	4.19	0.00	4.48	0.00	4.80	0.00	5.14	0.00	5.51	0.00	5.90	0.00	6.32	0.00	6.55	0.00	6.55	0.00	6.65	0.00
Subtotal	23.84	24.31	25.44	26.02	27.16	27.84	29.08	29.68	31.07	31.76	33.28	40.23	35.53	43.10	38.16	44.61	38.06	44.61	38.16	44.85	3
FICA	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	
Property Tax	11.34	11.34	11.34	11.34	11.34	11.34	11.34	11.34	11.34	11.34	11.34	11.34	11.34	11.34	11.34	11.34	11.34	11.34	11.34	11.34	11.34
Cap Stock Tax	2.36	2.36	2.36	2.36	2.36	2.36	2.36	2.36	2.36	2.36	2.36	2.36	2.36	2.36	2.36	2.36	2.36	2.36	2.36	2.36	2.36
Total Non-fuel	37.54	38.01	39.14	39.72	40.87	41.54	42.79	43.38	44.77	45.47	46.98	53.93	49.23	56.81	51.87	58.31	51.76	58.31	51.87	58.55	51.95
Capital Expenditures	0.73	2.00	0.75	2.00	0.75	2.00	0.75	2.00	0.75	2.00	0.75	2.00	0.75	2.00	0.75	2.00	0.75	2.00	0.75	2.00	0.75
Direct Expenses	48.16	49.29	50.66	51.59	53.04	54.04	55.72	56.54	58.47	59.35	61.55	68.57	64.53	72.07	67.93	73.89	67.78	73.90	67.93	74.14	68.02
Direct Margin	7.47	1.44	7.94	1.71	8.36	1.96	8.97	2.30	9.31	2.47	9.86	(3.62)	10.28	(3.83)	10.90	(2.21)	14.80	1.42	19.08	4.99	23.40
Overhead Allocation	8.15	9.31	9.40	9.43	9.88	10.10	10.82	11.59	11.68	13.03	10.90	12.04	12.44	12.62	12.88	14.54	13.39	14.26	15.52	14.82	15.29
Expenses incl. Corp O/H	56.32	58.60	60.06	61.02	62.92	64.14	66.54	68.13	70.15	72.37	72.44	80.60	76.97	84.69	80.81	88.44	81.17	88.15	83.45	88.96	83.31
Margin after Corp O/H	(0.68)	(7.87)	(1.46)	(7.71)	(1.52)	(8.15)	(1.85)	(9.29)	(2.37)	(10.56)	(1.04)	(15.66)	(2.16)	(16.46)	(1.98)	(16.76)	1.41	(12.83)	3.56	(9.83)	8.11
Costs per kwh (cents)																					
Fuel	0.78	0.83	0.85	0.88	0.91	0.93	0.96	0.99	1.03	1.06	1.09	1.13	1.15	1.18	1.21	1.21	1.21	1.21	1.21	1.21	1.21
Non-fuel	2.97	3.39	3.09	3.54	3.24	3.70	3.38	3.86	3.55	4.05	3.71	4.80	3.90	5.06	4.10	5.19	4.10	5.19	4.10	5.21	4.10
Capital Expenditures	0.06	0.18	0.06	0.18	0.06	0.18	0.06	0.18	0.06	0.18	0.06	0.18	0.06	0.18	0.06	0.18	0.06	0.18	0.06	0.18	0.06
Direct Expenses	3.82	4.39	4.00	4.59	4.20	4.81	4.40	5.03	4.63	5.28	4.86	6.11	5.11	6.42	5.37	6.58	5.37	6.58	5.37	6.60	5.37
Direct Margin	0.59	0.13	0.63	0.15	0.66	0.17	0.71	0.20	0.74	0.22	0.78	(0.32)	0.81	(0.34)	0.86	(0.20)	1.17	0.13	1.51	0.44	1.85
Overhead Allocation	0.65	0.83	0.74	0.84	0.78	0.90	0.85	1.03	0.93	1.16	0.86	1.07	0.99	1.12	1.02	1.30	1.06	1.27	1.23	1.32	1.21
Expenses incl. Corp O/H	4.46	5.22	4.75	5.43	4.99	5.71	5.26	6.07	5.56	6.44	5.72	7.18	6.10	7.54	6.38	7.88	6.43	7.85	6.59	7.92	6.58
Margin after Corp O/H	(0.05)	(0.70)	(0.11)	(0.69)	(0.12)	(0.73)	(0.15)	(0.83)	(0.19)	(0.94)	(0.08)	(1.39)	(0.17)	(1.47)	(0.16)	(1.49)	0.11	(1.14)	0.28	(0.88)	0
NPV of Margin after O/H	(33.1)																				
Underfunded Decomm.	1.9																				
NPV OF NET MARGIN	(35.0)																				

CURRICULUM VITAE

DONALD J. CLAYTON
Duquesne Light Company
411 Seventh Avenue
P. O. Box 1930
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(412) 393-6230
(412) 393-6571 - FAX

Employment History

1995 - Present	Treasurer, Duquesne Light Company
1990 - 1994	Assistant Treasurer, Duquesne Light Company
1985 - 1990	Manager, Valuation and Property Records, Duquesne Light Company
1983 - 1985	Manager, Public Utility Industry Specialty Group, PriceWaterhouse
1977 - 1983	Analyst and Supervisor, Depreciation and Cost Allocation Studies, Gannett Fleming Valuation and Rate Consultants, Inc.
1974 - 1976	Fellows, Read & Weber, Inc., Assistant Engineer (Co-op Student)

Education

1977	MBA - Rensselaer Polytechnic Institute
1976	BS, Civil Engineering - Rensselaer Polytechnic Institute

Experience

As Treasurer of Duquesne Light Company, manage 50+ person staff including six direct reports and 20 professionals. responsible for Corporate Finance, Financial Planning, Cash Management, Corporate Budgeting, Shareholder Relations and Electronic Commerce.

Experience (cont.)

As Assistant Treasurer of Duquesne Light Company, responsible for Financial Planning and Corporate Budgeting. Activities in this position included the direction and development of financial models and financial forecasts for the Company and affiliates, economic and investment analysis for the Company and affiliates, preparation of credit rating agency reports, reports and filings for the Pennsylvania Public Utility Commission (PAPUC) and merger and acquisition analysis.

As Manager, Valuation and Property Records, responsible for the Company's construction cost accounting system and continuing Property Record. Also, directed the preparation of economic analysis, tax reports and information for regulatory filing before the PAPUC and the Federal Energy Regulatory Commission.

As a consultant to the utility industry, performed numerous depreciation, valuation, cost-of-service, rate design and other economic and statistical studies for electric, gas, water, sewer, telephone and railroad companies as well as municipalities and municipal agencies.

Prior experience includes community planning and infrastructure design, traffic studies and hydraulics analysis.

Clients Served

Depreciation and Valuation Studies

Duquesne Light Company
The Peoples Natural Gas Company
Dauphin Consolidated Water Supply Company
Northern Telephone Limited
The Penn Central Corporation
The Bloomburg Water Company
Columbia Gas of Pennsylvania
Union Pacific Railroad Company
Philadelphia Suburban Water Company
T. W. Phillips Gas and Oil Company
Atlanta Gas Light Company
The Elizabethville Water Company
The Roaring Creek Water Company
Burlington Northern
United Telephone System - Eastern Group
Anchorage Water and Waste Water Utility

Clients Served (cont.)

Cost of Service and Rate Design Studies

Latrobe Municipal Authority
Greater Johnstown Water Authority
T.W. Phillips Gas and Oil Company
Peoples Gas System, Inc.
The City of Myrtle Beach (Water and Sewer)
The Metropolitan Government of Nashville (Water and Sewer)
Morenci Water and Electric Company
AJO Improvement Company
International Flavors and Fragrances, Inc.

Economic and Statistical Studies

City of Phoenix Arizona (street lighting study)
City of Pittsburgh (street lighting study)
New Jersey Telephone Company
The Penn Central Corporation
Duquesne Light Company

Expert Testimony

Pennsylvania Public Utility Commission:

P-00951001 - Sale of Ft. Martin Power Station
G-00940392 - Affiliated Interest Filing - Headquarters Building Lease
G-00940376 - Affiliated Interest Filing - Wood Run Facility Lease
P-900485 - Accounting and ratemaking petition related to the GPU/DQE power sale and transmission line project
R-870651 - Duquesne Light Company base rate case
R-870378 - Duquesne Light Company base rate case

Superior Court of Monmouth County New Jersey - Cost of service testimony (L-040293-84)
City Council of Phoenix - Testimony related to acquisition of street lighting system

Formal Papers and Presentations

"Regulatory Concerns Associated with Implementing FAS No. 96", EEI Depreciation Committee, 1986
"Capital recovery concerns in the Electric Utility Industry and the Duquesne Plan", Iowa State Regulatory Conference, 1987
"Duquesne Light Company's Past and Future Stranded Cost Mitigation Strategies", IBC Industry Forum - Stranded Cost Recovery, 1997

Professional Certification

Registered Professional Engineer - Pennsylvania

Other Activities

Treasurer - FEDUPAC and PENNDUPAC (the Company's Federal and State political action committees)
Board Member - Juvenile Diabetes Foundation of Pittsburgh

Duquesne Light Company
Historic Mitigation Efforts
Reductions to Stranded Cost

	1989-1996	1997-1998	1999-2005	Total
Increase in Nuclear Depreciation	50	50	175	275
Ft. Martin Plan Extended through 2005				
Increase in Depreciation and Amortization	25	125	525	675
Gain on Sale of Ft. Martin Plant	130	-	-	130
Increase in Decommissioning	5	5	60	70
Early Window Amortization	2	8	30	40
Total Ft. Martin Plan	212	188	790	1,190
Tax Planning	20	50	200	270
Interest Cost Savings	45	15	50	110
Total Pre-Tax Reduction	277	253	1,040	1,570
Tax Effect	107	84	349	540
Total Stranded Cost Reduction	170	169	691	1,030

DUQUESNE LIGHT COMPANY
Actual - Per Books Income Statements

	1996	1995	1994	1993	1992	1991	1990	1989
Operating Revenues	$1,177	1,180	$1,169	$1,161	$1,150	$1,173	$1,115	$1,119
Fuel and purchased power	237	232	244	238	239	251	220	215
Operating and maintenance	331	332	349	368	348	346	350	356
Depreciation and amortization	216	191	163	151	128	119	122	120
Taxes other than income	85	86	86	70	85	95	81	93
Interest and other charges	101	103	107	120	132	143	158	165
Income before taxes	207	236	220	214	218	219	184	170
Income taxes	84	93	84	77	108	101	84	75
Net income - operations	$123	$143	$136	$137	$110	$118	$100	$95
Return on average common equity	11.6%	12.7%	12.3%	12.4%	10.1%	11.2%	9.7%	9.2%

DLC MITIGATION STRATEGIES IMPLEMENTED
1989-1996

Mitigation Strategies:

- Aggressive Fuel Cost Reductions (13%)
- Capital & O&M Targeted Reduction Program
- Work force Reduction (1,000 Employees)
- Sale/leaseback of Beaver Valley Unit No. 2
- Debt Refinancing - $60 million annual reduction in interest expense
- Equity Buyback $270 million
- Replacement of restrictive mortgage indenture
- Aggressively pursued long-term power contracts...Sale of Ft. Martin Plant
- Write-down of nuclear with $130 million gain on sale of plant
- Five-year rate freeze
- Capped ECR at 14.7 cents
- Agreed to increase depreciation of nuclear plants investment
- Increased funding of nuclear decommissioning costs by $5.0 million annually
- Wrote-off $9.0 million of regulatory assets associated with "Early Window"
- Began amortizing regulatory asset associated with "Early Window"
- Instituted a $500,000 credit for low-income customers
- Invested in tax mitigating investments

DUQUESNE LIGHT COMPANY
No Mitigation - Pro-forma Income Statements

	1996	1995	1994	1993	1992	1991	1990	1989
Operating Revenues	$1,177	$1,180	$1,169	1,161	$1,150	$1,173	$1,115	$1,119
Fuel and purchased power	273	265	257	249	241	234	227	220
Operating and maintenance	377	364	352	340	321	310	299	288
Depreciation and amortization	140	140	140	140	140	140	140	140
Taxes other than income	117	113	109	105	102	99	96	93
Interest and other charges	165	165	165	165	165	165	165	165
Income before taxes	105	133	146	162	181	225	188	213
Income taxes	47	53	64	64	89	100	79	89
Net income - operations	$58	$80	$82	$98	$92	$125	$109	$124
Return on average common equity	4.2%	5.8%	5.9%	7.1%	6.8%	9.3%	8.3%	9.4%
Annual revenue increase avoided	$216	$176	$172	$141				
% Annual revenue increase	18.3%	14.9%	14.7%	12.2%				
Cumulative revenue increase avoided for 12.87% ROE	$705	$490	$313	$141				
% Cumulative revenue increase	15.1%	13.9%	13.4%	12.2%				

Regulatory Assets @ 12/31/96

			Generation (1)		Generation (2)				Total Duquesne
	Trans.	Distr.	Fossil	Nuclear	Nuclear	Fossil	Other	Total	Light
10-K Regulatory Assets									
Regulatory Tax Receivable	32.66	56.52			172.66	132.29		304.94	394.12
Unamortized Debt Premium/Discount (3)	6.46	27.18	9.68	16.45	15.95	9.39		25.34	85.11
Beaver Valley 2 Lease Premium				3.68	4.50			4.50	8.19
Total Unamortized Debt Cost	6.46	27.18	9.68	20.13	20.46	9.39	0.00	29.84	93.30
Deferred Rate Synch. Costs					41.45			41.45	41.45
BV2 Sale/Leaseback Premium				9.05	21.01			21.01	30.06
Deferred Employee Costs (4)	0.70	11.09			10.51	7.29		17.80	29.59
Deferred Nuclear Maintenance					13.46			13.46	13.46
DOE Decom & Decon					9.78			9.78	9.78
Deferred Coal Costs						12.19		12.19	12.19
Other									
Deferred Caretaker Costs						6.77		6.77	6.77
BV2 Training Costs					2.62			2.62	2.62
Low Level Rad. Waste					2.27			2.27	2.27
Coal Cost Equalization						0.32		0.32	0.32
Deferred Oxford Centre Costs	0.00	0.07			0.07	0.05		0.12	0.20
PA Deregulation Expenses	0.01	0.09			0.08	0.06		0.14	0.23
Demand Side Management	0.00	0.06			0.06	0.04		0.10	0.16
Corporate Development Project	0.00	0.04			0.04	0.03		0.07	0.11
Section 211	0.00	0.04			0.04	0.03		0.06	0.10
1996 Management Audit	0.00	0.02			0.02	0.01		0.03	0.05
Administrative & General	0.00	0.01			0.01	0.01		0.01	0.02
Total Other	0.02	0.33	0.00	0.00	5.20	7.31	0.00	12.51	12.86
Total Regulatory Assets per 10-K	**39.85**	**95.12**	**9.68**	**29.18**	**294.52**	**168.46**	**0.00**	**462.99**	**636.81**
Adjustments									
PV Beaver Valley Lease					291.44			291.44	291.44
Nuclear Decommissioning					0.00			0.00	0.00
Pre-Accrue Nuclear Outages					16.64			16.64	16.64
Gain on Sale/Leaseback (5)					61.13			61.13	61.13
Deferred Rate Synch. Costs (5)					0.27			0.27	0.27
Beaver Valley 2 (5)					0.17			0.17	0.17
Fossil Decommissioning						0.00		0.00	0.00
Deferred Fuel Cost						14.81		14.81	14.81
Transition Costs							18.10	18.10	18.10
Total Adjustments	0.00	0.00	0.00	0.00	369.64	14.81	18.10	402.55	402.55
Adjusted Regulatory Assets	**39.85**	**95.12**	**9.68**	**29.18**	**664.16**	**183.27**	**18.10**	**865.54**	**1,039.35**

(1) Recovered through interest and lease expense.
(2) Recovered through amortization.
(3) Allocation based on gross plant balances.
(4) Allocation based on labor costs.
(5) Shown as deferred tax assets in 1996 Form 10-K.

Allocation Percentages	Trans.	Distr.	Fossil	Nuclear	Total
Labor Costs	2.37%	37.47%	24.65%	35.51%	100.00%
Gross Plant	7.59%	31.94%	22.40%	38.07%	100.00%

Amortization Schedule
Regulatory Assets
Generation

	Actual Year - End 1996	Estimated Change 1997	Estimated Change 1998	Estimated Year - End 1998	1999	2000	2001	2002	2003	2004	2005	Net Balance 12/31/2005
Total Regulatory Assets												
10-K Regulatory Assets												
Regulatory Tax Receivable	304.94	(32.26)	(36.97)	235.72	(33.67)	(33.67)	(33.67)	(33.67)	(33.67)	(33.67)	(33.67)	(0.00)
Unamortized Debt Costs (1)	29.84	0.00	0.00	29.84	(4.26)	(4.26)	(4.26)	(4.26)	(4.26)	(4.26)	(4.26)	(0.00)
Deferred Rate Synch. Costs	41.45	(4.14)	(4.14)	33.16	(4.74)	(4.74)	(4.74)	(4.74)	(4.74)	(4.74)	(4.74)	(0.00)
BV2 Sale/Leaseback Premium	21.01	0.00	0.00	21.01	(3.00)	(3.00)	(3.00)	(3.00)	(3.00)	(3.00)	(3.00)	0.00
Deferred Employee Costs (2)	17.80	0.00	0.00	17.80	(2.54)	(2.54)	(2.54)	(2.54)	(2.54)	(2.54)	(2.54)	0.00
Deferred Nuclear Maintenance	13.48	0.56	(10.77)	3.25	(0.46)	(0.46)	(0.46)	(0.46)	(0.46)	(0.46)	(0.46)	(0.00)
DOE Decom & Decon	9.78	(1.30)	(1.30)	7.18	(1.03)	(1.03)	(1.03)	(1.03)	(1.03)	(1.03)	(1.03)	0.00
Deferred Coal Costs	12.19	0.31	1.00	13.50	(1.93)	(1.93)	(1.93)	(1.93)	(1.93)	(1.93)	(1.93)	0.00
Other												
Deferred Caretaker Costs	6.77	0.00	0.00	6.77	(0.97)	(0.97)	(0.97)	(0.97)	(0.97)	(0.97)	(0.97)	0.00
BV2 Training Costs	2.62	(0.10)	(0.10)	2.42	(0.35)	(0.35)	(0.35)	(0.35)	(0.35)	(0.35)	(0.35)	0.00
Low Level Rad. Waste	2.27	0.00	0.00	2.27	(0.32)	(0.32)	(0.32)	(0.32)	(0.32)	(0.32)	(0.32)	0.00
Coal Cost Equalization	0.32	(0.10)	(0.10)	0.12	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	0.00
Other Regulatory Assets	0.53	0.00	0.00	0.53	(0.08)	(0.08)	(0.08)	(0.08)	(0.08)	(0.08)	(0.08)	0.00
Total Other	12.51	(0.20)	(0.20)	12.11	(1.73)	(1.73)	(1.73)	(1.73)	(1.73)	(1.73)	(1.73)	0.00
Total Regulatory Assets per 10-K	462.99	(37.03)	(52.39)	373.57	(53.37)	(53.37)	(53.37)	(53.37)	(53.37)	(53.37)	(53.37)	(0.00)
Adjustments												
PV Beaver Valley Lease	291.44	(25.00)	(50.00)	216.44	(13.78)	(13.78)	(13.78)	(13.78)	(13.78)	(13.78)	(13.78)	120.00
Pre-Accrue Nuclear Outages	16.64	0.00	0.00	16.64	(2.38)	(2.38)	(2.38)	(2.38)	(2.38)	(2.38)	(2.38)	0.00
Gain on Sale/Leaseback (3)	61.13	(3.00)	(3.00)	55.13	(7.88)	(7.88)	(7.88)	(7.88)	(7.88)	(7.88)	(7.88)	0.00
Deferred Rate Synch. Costs (3)	0.27	0.00	0.00	0.27	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	0.00
Beaver Valley 2 (3)	0.17	0.00	0.00	0.17	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.00)
Deferred Fuel Cost	14.81	0.00	0.00	14.81	(2.12)	(2.12)	(2.12)	(2.12)	(2.12)	(2.12)	(2.12)	0.00
Transition Costs	18.10	0.00	0.00	18.10	(2.59)	(2.59)	(2.59)	(2.59)	(2.59)	(2.59)	(2.59)	0.00
Total Adjustments	402.55	(28.00)	(53.00)	321.55	(28.79)	(28.79)	(28.79)	(28.79)	(28.79)	(28.79)	(28.79)	120.00
Adjusted Regulatory Assets	865.54	(65.03)	(105.39)	695.12	(82.16)	(82.16)	(82.16)	(82.16)	(82.16)	(82.16)	(82.16)	120.00
Remove outage accounting (4)		(0.56)	10.77									
FAS 109 Plant (5)	0.00	0.00	0.00	62.94	(8.99)	(8.99)	(8.99)	(8.99)	(8.99)	(8.99)	(8.99)	(0.00)
Total	865.54	(65.59)	(94.61)	758.06	(91.15)	(91.15)	(91.15)	(91.15)	(91.15)	(91.15)	(91.15)	120.00
Regulatory Assets Recovered through Interest/Lease Expense												
Unamortized Debt Cost	26.13	(2.90)	(2.90)	20.32	(2.90)	(2.90)	(2.90)	(2.90)	(2.90)	(2.90)	(2.90)	0.00
BV2 Sale/Leaseback Premium	12.73	(1.41)	(1.41)	9.90	(1.41)	(1.41)	(1.41)	(1.41)	(1.41)	(1.41)	(1.41)	(0.00)
Total	38.86	(4.32)	(4.32)	30.22	(4.32)	(4.32)	(4.32)	(4.32)	(4.32)	(4.32)	(4.32)	(0.00)
Total Generation	904.39	(69.91)	(98.93)	788.28	(95.47)	(95.47)	(95.47)	(95.47)	(95.47)	(95.47)	(95.47)	120.00

(1) Allocation based on gross plant balances.
(2) Allocation based on labor costs.
(3) Shown as deferred tax assets in 1996 Form 10-K.
(4) Outage accounting is reflected in the revenue requirement for the generating unit
(5) FAS 109 allocated to plant is reflected in the generating plant balance through 12/31/98

Amortization Schedule
Regulatory Assets
Generation

	Actual Year - End 1996	Estimated Change 1997	Estimated Change 1998	Estimated Year - End 1998	1999	2000	2001	2002	2003	2004	2005	Net Balance 12/31/2006
Regulatory Assets												
Nuclear Related												
10-K Regulatory Assets												
Regulatory Tax Receivable	172.68	(22.76)	(26.73)	123.17	(17.60)	(17.60)	(17.60)	(17.60)	(17.60)	(17.60)	(17.60)	0.00
Unamortized Debt Premium/Discount (1)	15.95	0.00	0.00	15.95	(2.28)	(2.28)	(2.28)	(2.28)	(2.28)	(2.28)	(2.28)	(0.00)
Beaver Valley 2 Lease Premium	4.50	0.00	0.00	4.50	(0.64)	(0.64)	(0.64)	(0.64)	(0.64)	(0.64)	(0.64)	0.00
Total Unamortized Debt Cost	20.46	0.00	0.00	20.46	(2.92)	(2.92)	(2.92)	(2.92)	(2.92)	(2.92)	(2.92)	0.00
Deferred Rate Synch. Costs	41.45	(4.14)	(4.14)	33.16	(4.74)	(4.74)	(4.74)	(4.74)	(4.74)	(4.74)	(4.74)	(0.00)
BV2 Sale/Leaseback Premium	21.01	0.00	0.00	21.01	(3.00)	(3.00)	(3.00)	(3.00)	(3.00)	(3.00)	(3.00)	0.00
Deferred Employee Costs (2)	10.51	0.00	0.00	10.51	(1.50)	(1.50)	(1.50)	(1.50)	(1.50)	(1.50)	(1.50)	0.00
Deferred Nuclear Maintenance	13.46	0.56	(10.77)	3.25	(0.46)	(0.46)	(0.46)	(0.46)	(0.46)	(0.46)	(0.46)	(0.00)
DOE Decom & Decon	9.78	(1.30)	(1.30)	7.18	(1.03)	(1.03)	(1.03)	(1.03)	(1.03)	(1.03)	(1.03)	0.00
Other												
BV2 Training Costs	2.62	(0.10)	(0.10)	2.42	(0.35)	(0.35)	(0.35)	(0.35)	(0.35)	(0.35)	(0.35)	0.00
Low Level Rad. Waste	2.27	0.00	0.00	2.27	(0.32)	(0.32)	(0.32)	(0.32)	(0.32)	(0.32)	(0.32)	0.00
Other Regulatory Assets	0.31	0.00	0.00	0.31	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	0.00
Total Other	5.20	(0.10)	(0.10)	5.00	(0.71)	(0.71)	(0.71)	(0.71)	(0.71)	(0.71)	(0.71)	(0.00)
Total Regulatory Assets per 10-K	294.52	(27.75)	(43.05)	223.73	(31.96)	(31.96)	(31.96)	(31.96)	(31.96)	(31.96)	(31.96)	(0.00)
Adjustments												
PV Beaver Valley Lease	291.44	(25.00)	(50.00)	216.44	(13.78)	(13.78)	(13.78)	(13.78)	(13.78)	(13.78)	(13.78)	120.00
Pre-Accrue Nuclear Outages	16.64	0.00	0.00	16.64	(2.38)	(2.38)	(2.38)	(2.38)	(2.38)	(2.38)	(2.38)	0.00
Gain on Sale/Leaseback (3)	61.13	(3.00)	(3.00)	55.13	(7.88)	(7.88)	(7.88)	(7.88)	(7.88)	(7.88)	(7.88)	0.00
Deferred Rate Synch. Costs (3)	0.27	0.00	0.00	0.27	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	0.00
Beaver Valley 2 (3)	0.17	0.00	0.00	0.17	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.00)
Total Adjustments	369.64	(28.00)	(53.00)	288.64	(24.09)	(24.09)	(24.09)	(24.09)	(24.09)	(24.09)	(24.09)	120.00
Adjusted Regulatory Assets	664.16	(55.75)	(96.05)	512.37	(56.05)	(56.05)	(56.05)	(56.05)	(56.05)	(56.05)	(56.05)	120.00
Remove outage accounting (4)		(0.56)	10.77									
FAS 109 Plant (5)	0.00	0.00	0.00	62.94	(8.99)	(8.99)	(8.99)	(8.99)	(8.99)	(8.99)	(8.99)	(0.00)
Total	664.16	(56.31)	(85.27)	575.31	(65.04)	(65.04)	(65.04)	(65.04)	(65.04)	(65.04)	(65.04)	120.00
Regulatory Assets Recovered through Interest/Lease Expense												
Unamortized Debt Premium/Discount	16.45	(1.83)	(1.83)	12.79	(1.83)	(1.83)	(1.83)	(1.83)	(1.83)	(1.83)	(1.83)	(0.00)
BV2 Sale/Leaseback Premium	12.73	(1.41)	(1.41)	9.90	(1.41)	(1.41)	(1.41)	(1.41)	(1.41)	(1.41)	(1.41)	(0.00)
Total	29.18	(3.24)	(3.24)	22.69	(3.24)	(3.24)	(3.24)	(3.24)	(3.24)	(3.24)	(3.24)	(0.00)
Total Nuclear Generation	693.34	(59.55)	(88.52)	598.00	(68.29)	(68.29)	(68.29)	(68.29)	(68.29)	(68.29)	(68.29)	120.00

(1) Allocation based on gross plant balances.
(2) Allocation based on labor costs.
(3) Shown as deferred tax assets in 1996 Form 10-K.
(4) Outage accounting is reflected in the revenue requirement for the generating unit
(5) FAS 109 allocated to plant is reflected in the generating plant balance through 12/31/98

Amortization Schedule
Regulatory Assets
Generation

	Actual Year - End 1996	Estimated Change 1997	Estimated Change 1998	Estimated Year - End 1998	1999	2000	2001	2002	2003	2004	2005	Net Balance 12/31/2005
Regulatory Assets												
Fossil Related												
10-K Regulatory Assets												
Regulatory Tax Receivable	132.29	(9.49)	(10.24)	112.55	(16.08)	(16.08)	(16.08)	(16.08)	(16.08)	(16.08)	(16.08)	0.00
Unamortized Debt Costs (1)	9.39	0.00	0.00	9.39	(1.34)	(1.34)	(1.34)	(1.34)	(1.34)	(1.34)	(1.34)	(0.00)
Deferred Employee Costs (2)	7.29	0.00	0.00	7.29	(1.04)	(1.04)	(1.04)	(1.04)	(1.04)	(1.04)	(1.04)	0.00
Deferred Coal Costs	12.19	0.31	1.00	13.50	(1.93)	(1.93)	(1.93)	(1.93)	(1.93)	(1.93)	(1.93)	0.00
Other												
Deferred Caretaker Costs	6.77	0.00	0.00	6.77	(0.97)	(0.97)	(0.97)	(0.97)	(0.97)	(0.97)	(0.97)	0.00
Coal Cost Equalization	0.32	(0.10)	(0.10)	0.12	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	0.00
Other Regulatory Assets	0.22	0.00	0.00	0.22	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.00)
Total Other	7.31	(0.10)	(0.10)	7.11	(1.02)	(1.02)	(1.02)	(1.02)	(1.02)	(1.02)	(1.02)	0.00
Total Regulatory Assets per 10-K	168.48	(9.28)	(9.34)	149.84	(21.41)	(21.41)	(21.41)	(21.41)	(21.41)	(21.41)	(21.41)	0.00
Adjustments												
Deferred Fuel Cost	14.81	0.00	0.00	14.81	(2.12)	(2.12)	(2.12)	(2.12)	(2.12)	(2.12)	(2.12)	0.00
Total Adjustments	14.81	0.00	0.00	14.81	(2.12)	(2.12)	(2.12)	(2.12)	(2.12)	(2.12)	(2.12)	0.00
Total	183.27	(9.28)	(9.34)	164.65	(23.52)	(23.52)	(23.52)	(23.52)	(23.52)	(23.52)	(23.52)	0.00
Regulatory Assets Recovered through Interest Expense												
Unamortized Debt Premium/Discount	9.68	(1.08)	(1.08)	7.53	(1.08)	(1.08)	(1.08)	(1.08)	(1.08)	(1.08)	(1.08)	(0.00)
Total Fossil Generation	192.95	(10.36)	(10.42)	172.17	(24.60)	(24.60)	(24.60)	(24.60)	(24.60)	(24.60)	(24.60)	0.00

(1) Allocation based on gross plant balances.
(2) Allocation based on labor costs.

Amortization Schedule
Regulatory Assets
Generation

	Actual Year - End 1996	Estimated Change 1997	Estimated Change 1998	Estimated Year - End 1998	1999	2000	2001	2002	2003	2004	2005	Net Balance 12/31/2005
Regulatory Assets												
Other												
Total Regulatory Assets per 10-K	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Adjustments												
Transition Costs	18.12	0.00	0.00	18.10	(2.59)	(2.59)	(2.59)	(2.59)	(2.59)	(2.59)	(2.59)	0.00
Total Adjustments	18.10	0.00	0.00	18.10	(2.59)	(2.59)	(2.59)	(2.59)	(2.59)	(2.59)	(2.59)	0.00
Total Other Regulatory Assets	18.10	0.00	0.00	18.10	(2.59)	(2.59)	(2.59)	(2.59)	(2.59)	(2.59)	(2.59)	0.00

Net Regulatory Assets @ 12/31/96
Tax Effect

	Trans.	Distr.	Generation (1) Fossil	Generation (1) Nuclear	Generation (2) Nuclear	Generation (2) Fossil	Generation (2) Other	Generation (2) Total	Total Duquesne Light
10-K Regulatory Assets									
Regulatory Tax Receivable	(32.66)	(56.52)			(34.22)	(46.22)		(80.44)	(169.61)
Unamortized Debt Premium/Discount (3)	(2.68)	(11.28)	(4.02)	(6.83)	(5.70)	(3.35)		(9.05)	(33.85)
Beaver Valley 2 Lease Premium				(1.53)	(1.61)			(1.61)	(3.14)
Total Unamortized Debt Cost	(2.68)	(11.28)	(4.02)	(8.35)	(7.31)	(3.35)		(10.66)	(36.99)
Deferred Rate Synch. Costs					(3.05)			(3.05)	(3.05)
BV2 Sale/Leaseback Premium				(3.75)	(8.72)			(8.72)	(12.47)
Deferred Employee Costs (4)	(0.29)	(4.60)			0.00	0.00		0.00	(4.89)
Deferred Nuclear Maintenance					(5.59)			(5.59)	(5.59)
DOE Decom & Decon					(4.07)			(4.07)	(4.07)
Deferred Coal Costs						0.00		0.00	0.00
Other									
Deferred Caretaker Costs						(2.86)		(2.86)	(2.86)
BV2 Training Costs					(0.92)			(0.92)	(0.92)
Low Level Rad. Waste					0.00			0.00	0.00
Coal Cost Equalization						0.00		0.00	0.00
Deferred Oxford Centre Costs	0.00	0.00			0.00	0.00		0.00	0.00
PA Deregulation Expenses	0.00	0.00			0.00	0.00		0.00	0.00
Demand Side Management	0.00	0.00			0.00	0.00		0.00	0.00
Corporate Development Project	0.00	0.00			0.00	0.00		0.00	0.00
Section 211	0.00	0.00			0.00	0.00		0.00	0.00
1996 Management Audit	0.00	0.00			0.00	0.00		0.00	0.00
Administrative & General	0.00	0.00			0.00	0.00		0.00	0.00
Total Other	0.00	0.00			(0.92)	(2.86)	0.00	(3.77)	(3.77)
Total Regulatory Assets per 10-K	(35.63)	(72.40)	(4.02)	(12.11)	(63.87)	(52.43)	0.00	(116.30)	(240.45)
Adjustments									
PV Beaver Valley Lease					(120.93)			(120.93)	(120.93)
Nuclear Decommissioning					0.00			0.00	0.00
Pre-Accrue Nuclear Outages					(6.90)			(6.90)	(6.90)
Gain on Sale/Leaseback (5)					0.00			0.00	0.00
Deferred Rate Synch. Costs (5)					0.00			0.00	0.00
Beaver Valley 2 (5)					0.00			0.00	0.00
Fossil Decommissioning						0.00		0.00	0.00
Deferred Fuel Cost						(6.14)		(6.14)	(6.14)
Transition Costs							(7.51)	(7.51)	(7.51)
Total Adjustments	0.00	0.00	0.00	0.00	(127.83)	(6.14)	(7.51)	(141.49)	(141.49)
Adjusted Regulatory Assets	(35.63)	(72.40)	(4.02)	(12.11)	(191.70)	(58.57)	(7.51)	(257.78)	(381.93)

Amortization Schedule
Regulatory Assets
Generation

	Actual Year - End 1996	Estimated Change 1997	Estimated Change 1998	Estimated Year - End 1998	1999	2000	2001	2002	2003	2004	2005	Net Balance 12/31/2005
Total Tax Effect												
10-K Regulatory Assets												
Regulatory Tax Receivable	(60.44)	10.60	12.67	(57.17)	8.17	8.17	8.17	8.17	8.17	8.17	8.17	0.00
Unamortized Debt Costs (1)	(10.66)	0.00	0.00	(10.66)	1.52	1.52	1.52	1.52	1.52	1.52	1.52	0.00
Deferred Rate Synch. Costs	(3.05)	1.72	1.72	0.39	(0.06)	(0.06)	(0.06)	(0.06)	(0.06)	(0.06)	(0.06)	(0.00)
BV2 Sale/Leaseback Premium	(8.72)	0.00	0.00	(8.72)	1.25	1.25	1.25	1.25	1.25	1.25	1.25	(0.00)
Deferred Employee Costs (2)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Deferred Nuclear Maintenance	(5.59)	(0.23)	4.47	(1.35)	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.00
DOE Decom & Decon	(4.07)	0.54	0.54	(2.99)	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.00
Deferred Coal Costs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other												
Deferred Caretaker Costs	(2.86)	0.00	0.00	(2.86)	0.41	0.41	0.41	0.41	0.41	0.41	0.41	(0.00)
BV2 Training Costs	(0.92)	0.04	0.04	(0.84)	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.00
Low Level Rad. Waste	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal Cost Equalization	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Regulatory Assets	0.00	0.00	0.00	(0.13)	0.02	0.02	0.02	0.02	0.02	0.02	0.02	(0.00)
Total Other	(3.77)	0.04	0.04	(3.82)	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.00
Total Regulatory Assets per 10-K	(116.30)	12.67	19.44	(84.32)	12.05	12.05	12.05	12.05	12.05	12.05	12.05	0.00
Adjustments												
PV Beaver Valley Lease	(120.93)	10.37	20.75	(89.81)	5.72	5.72	5.72	5.72	5.72	5.72	5.72	(49.79)
Pre-Accrue Nuclear Outages	(6.90)	0.00	0.00	(6.90)	0.99	0.99	0.99	0.99	0.99	0.99	0.99	(0.00)
Gain on Sale/Leaseback (3)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Deferred Rate Synch. Costs (3)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Beaver Valley 2 (3)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Deferred Fuel Cost	(6.14)	0.00	0.00	(6.14)	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.00
Transition Costs	(7.51)	0.00	0.00	(7.51)	1.07	1.07	1.07	1.07	1.07	1.07	1.07	0.00
Total Adjustments	(141.49)	10.37	20.75	(110.37)	8.65	8.65	8.65	8.65	8.65	8.65	8.65	(49.79)
Adjusted Regulatory Assets	(257.78)	23.04	40.19	(194.68)	20.70	20.70	20.70	20.70	20.70	20.70	20.70	(49.79)
Remove outage accounting (4)		0.23	(4.47)									
FAS 109 Plant	0.00	0.00	0.00	(17.56)	2.51	2.51	2.51	2.51	2.51	2.51	2.51	(0.00)
Total Amortization Tax Effect	(257.78)	23.28	35.71	(212.24)	23.21	23.21	23.21	23.21	23.21	23.21	23.21	(49.79)
Regulatory Assets Recovered through Interest/Lease Expense												
Unamortized Debt Cost	(10.84)	1.20	1.20	(8.43)	1.20	1.20	1.20	1.20	1.20	1.20	1.20	0.00
BV2 Sale/Leaseback Premium	(5.28)	0.59	0.59	(4.11)	0.59	0.59	0.59	0.59	0.59	0.59	0.59	0.00
Total	(16.12)	1.79	1.79	(12.54)	1.79	1.79	1.79	1.79	1.79	1.79	1.79	0.00
Total Generation	(273.91)	25.07	37.51	(224.78)	25.00	25.00	25.00	25.00	25.00	25.00	25.00	(49.79)

(1) Allocation based on gross plant balances.
(2) Allocation based on labor costs.
(3) Shown as deferred tax assets in 1996 Form 10-K.
(4) Outage accounting is reflected in the revenue requirement for the generating unit
(5) FAS 109 allocated to plant is reflected in the generating plant balance through 12/31/98

Amortization Schedule
Regulatory Assets
Generation

	Actual Year - End 1996	Estimated Change 1997	Estimated Change 1998	Estimated Year - End 1998	1999	2000	2001	2002	2003	2004	2005	Net Balance 12/31/2005
Tax Effect												
Nuclear Related												
10-K Regulatory Assets												
Regulatory Tax Receivable	(34.22)	7.33	8.97	(17.92)	2.56	2.56	2.56	2.56	2.56	2.56	2.56	0.00
Unamortized Debt Premium/Discount (1)	(5.70)	0.00	0.00	(5.70)	0.81	0.81	0.81	0.81	0.81	0.81	0.81	(0.00)
Beaver Valley 2 Lease Premium	(1.61)	0.00	0.00	(1.61)	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.00
Total Unamortized Debt Cost	(7.31)	0.00	0.00	(7.31)	1.04	1.04	1.04	1.04	1.04	1.04	1.04	(0.00)
Deferred Rate Synch. Costs	(3.05)	1.72	1.72	0.39	(0.06)	(0.06)	(0.06)	(0.06)	(0.06)	(0.06)	(0.06)	(0.00)
BV2 Sale/Leaseback Premium	(8.72)	0.00	0.00	(8.72)	1.25	1.25	1.25	1.25	1.25	1.25	1.25	(0.00)
Deferred Employee Costs (2)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Deferred Nuclear Maintenance	(5.59)	(0.23)	4.47	(1.35)	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.00
DOE Decom & Decon	(4.07)	0.54	0.54	(2.99)	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.00
Other												
BV2 Training Costs	(0.92)	0.04	0.04	(0.84)	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.00
Low Level Rad. Waste	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Regulatory Assets	0.00	0.00	0.00	(0.13)	0.02	0.02	0.02	0.02	0.02	0.02	0.02	(0.00)
Total Other	(0.92)	0.04	0.04	(0.96)	0.14	0.14	0.14	0.14	0.14	0.14	0.14	(0.00)
Total Regulatory Assets per 10-K	(63.87)	9.40	15.74	(38.86)	5.55	5.55	5.55	5.55	5.55	5.55	5.55	0.00
Adjustments												
PV Beaver Valley Lease	(120.93)	10.37	20.75	(89.81)	5.72	5.72	5.72	5.72	5.72	5.72	5.72	(49.79)
Pre-Accrue Nuclear Outages	(6.90)	0.00	0.00	(6.90)	0.99	0.99	0.99	0.99	0.99	0.99	0.99	(0.00)
Gain on Sale/Leaseback (3)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Deferred Rate Synch. Costs (3)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Beaver Valley 2 (3)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Adjustments	(127.83)	10.37	20.75	(96.71)	6.70	6.70	6.70	6.70	6.70	6.70	6.70	(49.79)
Adjusted Regulatory Assets	(191.70)	19.77	36.49	(135.57)	12.25	12.25	12.25	12.25	12.25	12.25	12.25	(49.79)
Remove outage accounting		0.23	(4.47)									
FAS 109 Plant	0.00	0.00	0.00	(17.56)	2.51	2.51	2.51	2.51	2.51	2.51	2.51	(0.00)
Total	(191.70)	20.00	32.02	(153.13)	14.76	14.76	14.76	14.76	14.76	14.76	14.76	(49.79)
Regulatory Assets Recovered through Interest/Lease Expense												
Unamortized Debt Cost	(6.83)	0.76	0.76	(5.31)	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.00
BV2 Sale/Leaseback Premium	(5.28)	0.59	0.59	(4.11)	0.59	0.59	0.59	0.59	0.59	0.59	0.59	0.00
Total	(12.11)	1.35	1.35	(9.42)	1.35	1.35	1.35	1.35	1.35	1.35	1.35	0.00
Total Nuclear Generation	(203.81)	21.35	33.37	(162.55)	16.11	16.11	16.11	16.11	16.11	16.11	16.11	(49.79)

(1) Allocation based on gross plant balances.
(2) Allocation based on labor costs.
(3) Shown as deferred tax assets in 1996 Form 10-K.
(4) Outage accounting is reflected in the revenue requirement for the generating unit
(5) FAS 109 allocated to plant is reflected in the generating plant balance through 12/31/98

Amortization Schedule
Regulatory Assets
Generation

	Actual Year - End 1996	Estimated Change 1997	Estimated Change 1998	Estimated Year - End 1998	1999	2000	2001	2002	2003	2004	2005	Net Balance 12/31/2005
Tax Effect												
Fossil Related												
10-K Regulatory Assets												
Regulatory Tax Receivable	(48.22)	3.27	3.69	(39.25)	5.61	5.61	5.61	5.61	5.61	5.61	5.61	(0.00)
Unamortized Debt Costs (1)	(3.35)	0.00	0.00	(3.35)	0.48	0.48	0.48	0.48	0.48	0.48	0.48	(0.00)
Deferred Employee Costs (2)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Deferred Coal Costs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other												
Deferred Caretaker Costs	(2.86)	0.00	0.00	(2.86)	0.41	0.41	0.41	0.41	0.41	0.41	0.41	(0.00)
Coal Cost Equalization	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Regulatory Assets	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Other	(2.86)	0.00	0.00	(2.86)	0.41	0.41	0.41	0.41	0.41	0.41	0.41	(0.00)
Total Regulatory Assets per 10-K	(52.43)	3.27	3.69	(45.46)	6.49	6.49	6.49	6.49	6.49	6.49	6.49	(0.00)
Adjustments												
Deferred Fuel Cost	(8.14)	0.00	0.00	(8.14)	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.00
Total Adjustments	(8.14)	0.00	0.00	(8.14)	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.00
Total	(58.57)	3.27	3.69	(51.60)	7.37	7.37	7.37	7.37	7.37	7.37	7.37	(0.00)
Regulatory Assets Recovered through Interest Expense												
Unamortized Debt Cost	(4.02)	0.45	0.45	(3.12)	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.00
Total Fossil Generation	(62.59)	3.72	4.14	(54.73)	7.82	7.82	7.82	7.82	7.82	7.82	7.82	(0.00)

(1) Allocation based on gross plant balances.
(2) Allocation based on labor costs.

Amortization Schedule
Regulatory Assets
Generation

	Actual Year - End 1996	Estimated Change 1997	Estimated Change 1998	Estimated Year - End 1998	1999	2000	2001	2002	2003	2004	2005	Net Balance 12/31/2005
Tax Effect												
Other												
10-K Regulatory Assets												
Total Regulatory Assets per 10-K	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Adjustments												
Transition Costs	(7.51)	0.00	0.00	(7.51)	1.07	1.07	1.07	1.07	1.07	1.07	1.07	0.00
Total Adjustments	(7.51)	0.00	0.00	(7.51)	1.07	1.07	1.07	1.07	1.07	1.07	1.07	0.00
Total Other Regulatory Assets	(7.51)	0.00	0.00	(7.51)	1.07	1.07	1.07	1.07	1.07	1.07	1.07	0.00

Net Regulatory Assets @ 12/31/96

			Generation (1)		Generation (2)				Total Duquesne
	Trans.	Distr.	Fossil	Nuclear	Nuclear	Fossil	Other	Total	Light
10-K Regulatory Assets									
Regulatory Tax Receivable	0.00	0.00			138.44	86.07		224.51	224.51
Unamortized Debt Premium/Discount (3)	3.78	15.90	5.66	9.62	10.25	6.03		16.29	51.26
Beaver Valley 2 Lease Premium				2.16	2.89			2.89	5.05
Total Unamortized Debt Cost	3.78	15.90	5.66	11.78	13.15	6.03		19.18	56.31
Deferred Rate Synch. Costs					38.39			38.39	38.39
BV2 Sale/Leaseback Premium				5.29	12.30			12.30	17.59
Deferred Employee Costs (4)	0.41	6.49			10.51	7.29		17.80	24.70
Deferred Nuclear Maintenance					7.87			7.87	7.87
DOE Decom & Decon					5.71			5.71	5.71
Deferred Coal Costs						12.19		12.19	12.19
Other									
Deferred Caretaker Costs						3.92		3.92	3.92
BV2 Training Costs					1.70			1.70	1.70
Low Level Rad. Waste					2.27			2.27	2.27
Coal Cost Equalization						0.32		0.32	0.32
Deferred Oxford Centre Costs	0.00	0.07			0.07	0.05		0.12	0.20
PA Deregulation Expenses	0.01	0.09			0.08	0.06		0.14	0.23
Demand Side Management	*0.00*	*0.06*			*0.06*	*0.04*		*0.10*	*0.16*
Corporate Development Project	0.00	0.04			0.04	0.03		0.07	0.11
Section 211	0.00	0.04			0.04	0.03		0.06	0.10
1996 Management Audit	0.00	0.02			0.02	0.01		0.03	0.05
Administrative & General	0.00	0.01			0.01	0.01		0.01	0.02
Total Other	0.02	0.33			4.29	4.45	0.00	8.73	9.09
Total Regulatory Assets per 10-K.	**4.21**	**22.72**	**5.66**	**17.07**	**230.65**	**116.04**	**0.00**	**346.69**	**396.36**
Adjustments									
PV Beaver Valley Lease					170.51			170.51	170.51
Nuclear Decommissioning					0.00			0.00	0.00
Pre-Accrue Nuclear Outages					9.73			9.73	9.73
Gain on Sale/Leaseback (5)					61.13			61.13	61.13
Deferred Rate Synch. Costs (5)					0.27			0.27	0.27
Beaver Valley 2 (5)					0.17			0.17	0.17
Fossil Decommissioning						0.00		0.00	0.00
Deferred Fuel Cost						8.66		8.66	8.66
Transition Costs							10.59	10.59	10.59
Total Adjustments	0.00	0.00	0.00	0.00	241.81	8.66	10.59	261.06	261.06
Adjusted Regulatory Assets	**4.21**	**22.72**	**5.66**	**17.07**	**472.46**	**124.70**	**10.59**	**607.75**	**657.42**

(1) Recovered through interest and lease expense.
(2) Recovered through amortization.
(3) Allocation based on gross plant balances.
(4) Allocation based on labor costs.
(5) Shown as deferred tax assets in 1996 Form 10-K.

Allocation Percentages	Trans.	Distr.	Fossil	Nuclear	Total
Labor Costs	2.37%	37.47%	24.65%	35.51%	100.00%
Gross Plant	7.59%	31.94%	22.40%	38.07%	100.00%
Effective Tax Rate	41.49%				

Amortization Schedule
Regulatory Assets
Generation

	Actual Year - End 1996	Estimated Change 1997	Estimated Change 1998	Estimated Year - End 1998	1999	2000	2001	2002	2003	2004	2005	Net Balance 12/31/2005
Total Net Regulatory Assets												
10-K Regulatory Assets												
Regulatory Tax Receivable	224.51	(21.65)	(24.30)	178.55	(25.51)	(25.51)	(25.51)	(25.51)	(25.51)	(25.51)	(25.51)	0.00
Unamortized Debt Costs (1)	19.18	0.00	0.00	19.18	(2.74)	(2.74)	(2.74)	(2.74)	(2.74)	(2.74)	(2.74)	0.00
Deferred Rate Synch. Costs	38.39	(2.42)	(2.42)	33.54	(4.79)	(4.79)	(4.79)	(4.79)	(4.79)	(4.79)	(4.79)	(0.00)
BV2 Sale/Leaseback Premium	12.30	0.00	0.00	12.30	(1.76)	(1.76)	(1.76)	(1.76)	(1.76)	(1.76)	(1.76)	(0.00)
Deferred Employee Costs (2)	17.80	0.00	0.00	17.80	(2.54)	(2.54)	(2.54)	(2.54)	(2.54)	(2.54)	(2.54)	0.00
Deferred Nuclear Maintenance	7.87	0.33	(6.30)	1.90	(0.27)	(0.27)	(0.27)	(0.27)	(0.27)	(0.27)	(0.27)	0.00
DOE Decom & Decon	5.71	(0.76)	(0.76)	4.19	(0.60)	(0.60)	(0.60)	(0.60)	(0.60)	(0.60)	(0.60)	(0.00)
Deferred Coal Costs	12.19	0.31	1.00	13.50	(1.93)	(1.93)	(1.93)	(1.93)	(1.93)	(1.93)	(1.93)	0.00
Other												
Deferred Caretaker Costs	3.92	0.00	0.00	3.92	(0.56)	(0.56)	(0.56)	(0.56)	(0.56)	(0.56)	(0.56)	0.00
BV2 Training Costs	1.70	(0.06)	(0.06)	1.58	(0.23)	(0.23)	(0.23)	(0.23)	(0.23)	(0.23)	(0.23)	0.00
Low Level Rad. Waste	2.27	0.00	0.00	2.27	(0.32)	(0.32)	(0.32)	(0.32)	(0.32)	(0.32)	(0.32)	0.00
Coal Cost Equalization	0.32	(0.10)	(0.10)	0.12	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	0.00
Other Regulatory Assets	0.53	0.00	0.00	0.40	(0.06)	(0.06)	(0.06)	(0.06)	(0.06)	(0.06)	(0.06)	(0.00)
Total Other	8.73	(0.16)	(0.16)	8.29	(1.18)	(1.18)	(1.18)	(1.18)	(1.18)	(1.18)	(1.18)	0.00
Total Regulatory Assets per 10-K	346.69	(24.36)	(32.95)	289.25	(41.32)	(41.32)	(41.32)	(41.32)	(41.32)	(41.32)	(41.32)	(0.00)
Adjustments												
PV Beaver Valley Lease	170.51	(14.63)	(29.25)	126.63	(8.06)	(8.06)	(8.06)	(8.06)	(8.06)	(8.06)	(8.06)	70.21
Pre-Accrue Nuclear Outages	9.73	0.00	0.00	9.73	(1.39)	(1.39)	(1.39)	(1.39)	(1.39)	(1.39)	(1.39)	0.00
Gain on Sale/Leaseback (3)	61.13	(3.00)	(3.00)	55.13	(7.88)	(7.88)	(7.88)	(7.88)	(7.88)	(7.88)	(7.88)	0.00
Deferred Rate Synch. Costs (3)	0.27	0.00	0.00	0.27	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	0.00
Beaver Valley 2 (3)	0.17	0.00	0.00	0.17	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.00)
Deferred Fuel Cost	8.66	0.00	0.00	8.66	(1.24)	(1.24)	(1.24)	(1.24)	(1.24)	(1.24)	(1.24)	(0.00)
Transition Costs	10.59	0.00	0.00	10.59	(1.51)	(1.51)	(1.51)	(1.51)	(1.51)	(1.51)	(1.51)	0.00
Total Adjustments	261.06	(17.63)	(32.25)	211.18	(20.14)	(20.14)	(20.14)	(20.14)	(20.14)	(20.14)	(20.14)	70.21
Adjusted Regulatory Assets	607.75	(41.99)	(65.20)	500.43	(61.46)	(61.46)	(61.46)	(61.46)	(61.46)	(61.46)	(61.46)	70.21
Remove outage accounting (4)		(0.33)	6.30									
FAS 109 Plant (5)	0.00	0.00	0.00	45.38	(6.48)	(6.48)	(6.48)	(6.48)	(6.48)	(6.48)	(6.48)	(0.00)
Total	607.75	(42.31)	(58.90)	545.81	(67.94)	(67.94)	(67.94)	(67.94)	(67.94)	(67.94)	(67.94)	70.21
Regulatory Assets Recovered through Interest/Lease Expense												
Unamortized Debt Cost	15.29	(1.70)	(1.70)	11.89	(1.70)	(1.70)	(1.70)	(1.70)	(1.70)	(1.70)	(1.70)	0.00
BV2 Sale/Leaseback Premium	7.45	(0.83)	(0.83)	5.79	(0.83)	(0.83)	(0.83)	(0.83)	(0.83)	(0.83)	(0.83)	(0.00)
Total	22.73	(2.53)	(2.53)	17.68	(2.53)	(2.53)	(2.53)	(2.53)	(2.53)	(2.53)	(2.53)	0.00
Total Generation	630.49	(44.84)	(61.42)	563.50	(70.47)	(70.47)	(70.47)	(70.47)	(70.47)	(70.47)	(70.47)	70.21

(1) Allocation based on gross plant balances.
(2) Allocation based on labor costs.
(3) Shown as deferred tax assets in 1996 Form 10-K.
(4) Outage accounting is reflected in the revenue requirement for the generating unit
(5) FAS 109 allocated to plant is reflected in the generating plant balance through 12/31/98

Amortization Schedule
Regulatory Assets
Generation

	Actual Year - End 1998	Estimated Change 1997	Estimated Change 1998	Estimated Year - End 1998	1999	2000	2001	2002	2003	2004	2005	Net Balance 12/31/2005
Net Regulatory Assets												
Nuclear Related												
10-K Regulatory Assets												
Regulatory Tax Receivable	138.44	(15.43)	(17.75)	105.25	(15.04)	(15.04)	(15.04)	(15.04)	(15.04)	(15.04)	(15.04)	(0.00)
Unamortized Debt Premium/Discount (1)	10.25	0.00	0.00	10.25	(1.46)	(1.46)	(1.46)	(1.46)	(1.46)	(1.46)	(1.46)	0.00
Beaver Valley 2 Lease Premium	2.89	0.00	0.00	2.89	(0.41)	(0.41)	(0.41)	(0.41)	(0.41)	(0.41)	(0.41)	0.00
Total Unamortized Debt Cost	13.15	0.00	0.00	13.15	(1.88)	(1.88)	(1.88)	(1.88)	(1.88)	(1.88)	(1.88)	0.00
Deferred Rate Synch. Costs	38.99	(2.42)	(2.42)	33.54	(4.79)	(4.79)	(4.79)	(4.79)	(4.79)	(4.79)	(4.79)	(0.00)
BV2 Sale/Leaseback Premium	12.30	0.00	0.00	12.30	(1.76)	(1.76)	(1.76)	(1.76)	(1.76)	(1.76)	(1.76)	(0.00)
Deferred Employee Costs (2)	10.51	0.00	0.00	10.51	(1.50)	(1.50)	(1.50)	(1.50)	(1.50)	(1.50)	(1.50)	0.00
Deferred Nuclear Maintenance	7.87	0.33	(6.30)	1.90	(0.27)	(0.27)	(0.27)	(0.27)	(0.27)	(0.27)	(0.27)	0.00
DOE Decom & Decon	5.71	(0.76)	(0.76)	4.19	(0.60)	(0.60)	(0.60)	(0.60)	(0.60)	(0.60)	(0.60)	(0.00)
Other												
BV2 Training Costs	1.70	(0.06)	(0.06)	1.58	(0.23)	(0.23)	(0.23)	(0.23)	(0.23)	(0.23)	(0.23)	0.00
Low Level Rad. Waste	2.27	0.00	0.00	2.27	(0.32)	(0.32)	(0.32)	(0.32)	(0.32)	(0.32)	(0.32)	0.00
Other Regulatory Assets	0.31	0.00	0.00	0.16	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	0.00
Total Other	4.29	(0.06)	(0.06)	4.04	(0.58)	(0.58)	(0.58)	(0.58)	(0.58)	(0.58)	(0.58)	0.00
Total Regulatory Assets per 10-K	230.65	(18.35)	(27.30)	184.87	(26.41)	(26.41)	(26.41)	(26.41)	(26.41)	(26.41)	(26.41)	0.00
Adjustments												
PV Beaver Valley Lease	170.51	(14.63)	(29.25)	126.63	(8.06)	(8.06)	(8.06)	(8.06)	(8.06)	(8.06)	(8.06)	70.21
Pre-Accrue Nuclear Outages	9.73	0.00	0.00	9.73	(1.39)	(1.39)	(1.39)	(1.39)	(1.39)	(1.39)	(1.39)	0.00
Gain on Sale/Leaseback (3)	61.13	(3.00)	(3.00)	55.13	(7.88)	(7.88)	(7.88)	(7.88)	(7.88)	(7.88)	(7.88)	0.00
Deferred Rate Synch. Costs (3)	0.27	0.00	0.00	0.27	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	0.00
Beaver Valley 2 (3)	0.17	0.00	0.00	0.17	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.00)
Total Adjustments	241.81	(17.63)	(32.25)	191.93	(17.39)	(17.39)	(17.39)	(17.39)	(17.39)	(17.39)	(17.39)	70.21
Adjusted Regulatory Assets	472.46	(35.98)	(59.56)	376.80	(43.80)	(43.80)	(43.80)	(43.80)	(43.80)	(43.80)	(43.80)	70.21
Remove outage accounting (4)		(0.33)	6.30									
FAS 109 Plant (5)	0.00	0.00	0.00	45.38	(6.48)	(6.48)	(6.48)	(6.48)	(6.48)	(6.48)	(6.48)	(0.00)
Total	472.46	(36.30)	(53.25)	422.18	(50.28)	(50.28)	(50.28)	(50.28)	(50.28)	(50.28)	(50.28)	70.21
Regulatory Assets Recovered through Interest/Lease Expense												
Unamortized Debt Cost	9.62	(1.07)	(1.07)	7.48	(1.07)	(1.07)	(1.07)	(1.07)	(1.07)	(1.07)	(1.07)	0.00
BV2 Sale/Leaseback Premium	7.45	(0.83)	(0.83)	5.79	(0.83)	(0.83)	(0.83)	(0.83)	(0.83)	(0.83)	(0.83)	(0.00)
Total	17.07	(1.90)	(1.90)	13.28	(1.90)	(1.90)	(1.90)	(1.90)	(1.90)	(1.90)	(1.90)	0.00
Total Nuclear Generation	489.53	(38.20)	(55.15)	435.46	(52.18)	(52.18)	(52.18)	(52.18)	(52.18)	(52.18)	(52.18)	70.21

(1) Allocation based on gross plant balances.
(2) Allocation based on labor costs.
(3) Shown as deferred tax assets in 1996 Form 10-K.
(4) Outage accounting is reflected in the revenue requirement for the generating unit.
(5) FAS 109 allocated to plant is reflected in the generating plant balance through 12/31/99

Amortization Schedule
Regulatory Assets
Generation

	Actual Year - End 1996	Estimated Change 1997	Estimated Change 1998	Estimated Year - End 1998	1999	2000	2001	2002	2003	2004	2005	Net Balance 12/31/2005
Net Regulatory Assets												
Fossil Related												
10-K Regulatory Assets												
Regulatory Tax Receivable	86.07	(6.22)	(6.55)	73.30	(10.47)	(10.47)	(10.47)	(10.47)	(10.47)	(10.47)	(10.47)	0.00
Unamortized Debt Costs (1)	6.03	0.00	0.00	6.03	(0.86)	(0.86)	(0.86)	(0.86)	(0.86)	(0.86)	(0.86)	(0.00)
Deferred Employee Costs (2)	7.29	0.00	0.00	7.29	(1.04)	(1.04)	(1.04)	(1.04)	(1.04)	(1.04)	(1.04)	0.00
Deferred Coal Costs	12.19	0.31	1.00	13.50	(1.93)	(1.93)	(1.93)	(1.93)	(1.93)	(1.93)	(1.93)	0.00
Other												
Deferred Caretaker Costs	3.92	0.00	0.00	3.92	(0.56)	(0.56)	(0.56)	(0.56)	(0.56)	(0.56)	(0.56)	0.00
Coal Cost Equalization	0.32	(0.10)	(0.10)	0.12	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	0.00
Other Regulatory Assets	0.22	0.00	0.00	0.22	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.00)
Total Other	4.45	(0.10)	(0.10)	4.25	(0.61)	(0.61)	(0.61)	(0.61)	(0.61)	(0.61)	(0.61)	0.00
Total Regulatory Assets per 10-K	116.04	(6.01)	(5.65)	104.38	(14.91)	(14.91)	(14.91)	(14.91)	(14.91)	(14.91)	(14.91)	0.00
Adjustments												
Deferred Fuel Cost	8.66	0.00	0.00	8.66	(1.24)	(1.24)	(1.24)	(1.24)	(1.24)	(1.24)	(1.24)	(0.00)
Total Adjustments	8.66	0.00	0.00	8.66	(1.24)	(1.24)	(1.24)	(1.24)	(1.24)	(1.24)	(1.24)	(0.00)
Total	124.70	(6.01)	(5.65)	113.04	(16.15)	(16.15)	(16.15)	(16.15)	(16.15)	(16.15)	(16.15)	0.00
Regulatory Assets Recovered through Interest Expense												
Unamortized Debt Cost	5.66	(0.63)	(0.63)	4.40	(0.63)	(0.63)	(0.63)	(0.63)	(0.63)	(0.63)	(0.63)	(0.00)
Total Fossil Generation	130.36	(6.64)	(6.28)	117.45	(16.78)	(16.78)	(16.78)	(16.78)	(16.78)	(16.78)	(16.78)	(0.00)

(1) Allocation based on gross plant balances.
(2) Allocation based on labor costs.

Amortization Schedule
Regulatory Assets
Generation

	Actual Year - End 1996	Estimated Change 1997	Estimated Change 1998	Estimated Year - End 1998	1999	2000	2001	2002	2003	2004	2005	Net Balance 12/31/2005
Net Regulatory Assets												
Other												
10-K Regulatory Assets												
Total Regulatory Assets per 10-K	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Adjustments												
Transition Costs	10.59	0.00	0.00	10.59	(1.51)	(1.51)	(1.51)	(1.51)	(1.51)	(1.51)	(1.51)	0.00
Total Adjustments	10.59	0.00	0.00	10.59	(1.51)	(1.51)	(1.51)	(1.51)	(1.51)	(1.51)	(1.51)	0.00
Total Other Regulatory Assets	10.59	0.00	0.00	10.59	(1.51)	(1.51)	(1.51)	(1.51)	(1.51)	(1.51)	(1.51)	0.00

Regulatory Assets @ 12/31/96
Included in Rate Base

	Trans.	Distr.	Generation (1) Fossil	Generation (1) Nuclear	Generation (2) Nuclear	Generation (2) Fossil	Generation (2) Other	Generation (2) Total	Total Duquesne Light
10-K Regulatory Assets									
Regulatory Tax Receivable	32.66	56.52			172.66	132.29		304.94	394.12
Unamortized Debt Premium/Discount (3)	0.00	0.00	0.00	0.00	15.95	9.39		25.34	25.34
Beaver Valley 2 Lease Premium				0.00	4.50			4.50	4.50
Total Unamortized Debt Cost	0.00	0.00	0.00	0.00	20.46	9.39		29.84	29.84
Deferred Rate Synch. Costs					0.00			0.00	0.00
BV2 Sale/Leaseback Premium				0.00	21.01			21.01	21.01
Deferred Employee Costs (4)	0.00	0.00			0.00	0.00		0.00	0.00
Deferred Nuclear Maintenance					13.46			13.46	13.46
DOE Decom & Decon					0.00			0.00	0.00
Deferred Coal Costs						12.19		12.19	12.19
Other									
Deferred Caretaker Costs						6.77		6.77	6.77
BV2 Training Costs					2.62			2.62	2.62
Low Level Rad. Waste					2.27			2.27	2.27
Coal Cost Equalization						0.32		0.32	0.32
Deferred Oxford Centre Costs	0.00	0.07			0.07	0.05		0.12	0.20
PA Deregulation Expenses	0.01	0.09			0.08	0.06		0.14	0.23
Demand Side Management	0.00	0.06			0.06	0.04		0.10	0.16
Corporate Development Project	0.00	0.04			0.04	0.03		0.07	0.11
Section 211	0.00	0.04			0.04	0.03		0.06	0.10
1996 Management Audit	0.00	0.02			0.02	0.01		0.03	0.05
Administrative & General	0.00	0.01			0.01	0.01		0.01	0.02
Total Other	0.02	0.33	0.00	0.00	5.20	7.31	0.00	12.51	12.86
Total Regulatory Assets per 10-K	**32.68**	**56.85**	**0.00**	**0.00**	**232.79**	**161.17**	**0.00**	**393.96**	**483.49**
Adjustments									
PV Beaver Valley Lease					0.00			0.00	0.00
Nuclear Decommissioning					0.00			0.00	0.00
Pre-Accrue Nuclear Outages					0.00			0.00	0.00
Gain on Sale/Leaseback (5)					61.13			61.13	61.13
Deferred Rate Synch. Costs (5)					0.00			0.00	0.00
Beaver Valley 2 (5)					0.17			0.17	0.17
Fossil Decommissioning						0.00		0.00	0.00
Deferred Fuel Cost						0.00		0.00	0.00
Transition Costs (6)							0.00	0.00	0.00
Total Adjustments	0.00	0.00	0.00	0.00	61.30	0.00	0.00	61.30	61.30
Adjusted Regulatory Assets	**32.68**	**56.85**	**0.00**	**0.00**	**294.09**	**161.17**	**0.00**	**455.26**	**544.79**

(1) Recovered through interest and lease expense.
(2) Recovered through amortization.
(3) Allocation based on gross plant balances, 8/17 included in rate base.
(4) Allocation based on labor costs.
(5) Shown as deferred tax assets in 1996 Form 10-K.
(6) Item is included in rate base beginning 1/1/99.

Allocation Percentages	Trans.	Distr.	Fossil	Nuclear	Total
Labor Costs	2.37%	37.47%	24.65%	35.51%	100.00%
Gross Plant	7.59%	31.94%	22.40%	38.07%	100.00%

Amortization Schedule

Generation Regulatory Assets Included in Rate Base

	Actual Year - End 1996	Estimated Change 1997	Estimated Change 1998	Estimated Year - End 1998	1999	2000	2001	2002	2003	2004	2005	Net Balance 12/31/2005
Total Generation												
10-K Regulatory Assets												
Regulatory Tax Receivable	304.94	(32.26)	(36.97)	235.72	(33.67)	(33.67)	(33.67)	(33.67)	(33.67)	(33.67)	(33.67)	(0.00)
Unamortized Debt Costs (1)	29.84	0.00	0.00	29.84	(4.26)	(4.26)	(4.26)	(4.26)	(4.26)	(4.26)	(4.26)	(0.00)
Deferred Rate Synch. Costs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
BV2 Sale/Leaseback Premium	21.01	0.00	0.00	21.01	(3.00)	(3.00)	(3.00)	(3.00)	(3.00)	(3.00)	(3.00)	0.00
Deferred Employee Costs (2)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Deferred Nuclear Maintenance	13.46	0.56	(10.77)	3.25	(0.46)	(0.46)	(0.46)	(0.46)	(0.46)	(0.46)	(0.46)	(0.00)
DOE Decom & Decon	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Deferred Coal Costs	12.19	0.31	1.00	13.50	(1.93)	(1.93)	(1.93)	(1.93)	(1.93)	(1.93)	(1.93)	0.00
Other												
Deferred Caretaker Costs	6.77	0.00	0.00	6.77	(0.97)	(0.97)	(0.97)	(0.97)	(0.97)	(0.97)	(0.97)	0.00
BV2 Training Costs	2.62	(0.10)	(0.10)	2.42	(0.35)	(0.35)	(0.35)	(0.35)	(0.35)	(0.35)	(0.35)	0.00
Low Level Rad. Waste	2.27	0.00	0.00	2.27	(0.32)	(0.32)	(0.32)	(0.32)	(0.32)	(0.32)	(0.32)	0.00
Coal Cost Equalization	0.32	(0.10)	(0.10)	0.12	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	0.00
Other Regulatory Assets	0.53	0.00	0.00	0.53	(0.08)	(0.08)	(0.08)	(0.08)	(0.08)	(0.08)	(0.08)	0.00
Total Other	12.51	(0.20)	(0.20)	12.11	(1.73)	(1.73)	(1.73)	(1.73)	(1.73)	(1.73)	(1.73)	0.00
Total Regulatory Assets per 10-K	393.96	(31.59)	(46.94)	315.43	(45.06)	(45.06)	(45.06)	(45.06)	(45.06)	(45.06)	(45.06)	(0.00)
Adjustments												
PV Beaver Valley Lease	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Nuclear Decommissioning	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Pre-Accrue Nuclear Outages	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gain on Sale/Leaseback (3)	61.13	(3.00)	(3.00)	55.13	(7.88)	(7.88)	(7.88)	(7.88)	(7.88)	(7.88)	(7.88)	0.00
Deferred Rate Synch. Costs (3)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Beaver Valley 2 (3)	0.17	0.00	0.00	0.17	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.00)
Fossil Decommissioning	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Deferred Fuel Cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Transition Costs (4)	0.00	0.00	0.00	18.10	(2.59)	(2.59)	(2.59)	(2.59)	(2.59)	(2.59)	(2.59)	0.00
Total Adjustments	61.30	(3.00)	(3.00)	73.40	(10.49)	(10.49)	(10.49)	(10.49)	(10.49)	(10.49)	(10.49)	0.00
Adjusted Regulatory Assets	455.26	(34.59)	(49.94)	388.83	(55.55)	(55.55)	(55.55)	(55.55)	(55.55)	(55.55)	(55.55)	(0.00)
FAS 109 Plant (5)	0	0.00	0.00	62.94	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	62.67
Total Generation	455.26	(34.59)	(49.94)	451.77	(55.59)	(55.59)	(55.59)	(55.59)	(55.59)	(55.59)	(55.59)	62.67

(1) Allocation based on gross plant balances.

(2) Allocation based on labor costs.

(3) Shown as deferred tax assets in 1996 Form 10-K.

(4) Included in rate base beginning 1/1/99

(5) FAS 109 allocated to plant is reflected in the generating plant balance through 12/31/98

Amortization Schedule

Generation Regulatory Assets Included in Rate Base

Nuclear Related	Actual Year - End 1996	Estimated Change 1997	Estimated Change 1998	Estimated Year - End 1998	1999	2000	2001	2002	2003	2004	2005	Net Balance 12/31/2006
10-K Regulatory Assets												
Regulatory Tax Receivable	172.66	(22.76)	(26.73)	123.17	(17.60)	(17.60)	(17.60)	(17.60)	(17.60)	(17.60)	(17.60)	0.00
Unamortized Debt Premium/Discount (1)	15.95	0.00	0.00	15.95	(2.28)	(2.28)	(2.28)	(2.28)	(2.28)	(2.28)	(2.28)	(0.00)
Beaver Valley 2 Lease Premium	4.50	0.00	0.00	4.50	(0.64)	(0.64)	(0.64)	(0.64)	(0.64)	(0.64)	(0.64)	0.00
Total Unamortized Debt Cost	20.46	0.00	0.00	20.46	(2.92)	(2.92)	(2.92)	(2.92)	(2.92)	(2.92)	(2.92)	0.00
Deferred Rate Synch. Costs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
BV2 Sale/Leaseback Premium	21.01	0.00	0.00	21.01	(3.00)	(3.00)	(3.00)	(3.00)	(3.00)	(3.00)	(3.00)	0.00
Deferred Employee Costs (2)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Deferred Nuclear Maintenance	13.46	0.56	(10.77)	3.25	(0.46)	(0.46)	(0.46)	(0.46)	(0.46)	(0.46)	(0.46)	(0.00)
DOE Decom & Decon	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other												
BV2 Training Costs	2.62	(0.10)	(0.10)	2.42	(0.35)	(0.35)	(0.35)	(0.35)	(0.35)	(0.35)	(0.35)	0.00
Low Level Rad. Waste	2.27	0.00	0.00	2.27	(0.32)	(0.32)	(0.32)	(0.32)	(0.32)	(0.32)	(0.32)	0.00
Other Regulatory Assets	0.31	0.00	0.00	0.31	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	0.00
Total Other	5.20	(0.10)	(0.10)	5.00	(0.71)	(0.71)	(0.71)	(0.71)	(0.71)	(0.71)	(0.71)	(0.00)
Total Regulatory Assets per 10-K	232.79	(22.30)	(37.60)	172.89	(24.70)	(24.70)	(24.70)	(24.70)	(24.70)	(24.70)	(24.70)	0.00
Adjustments												
PV Beaver Valley Lease	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Nuclear Decommissioning	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Pre-Accrue Nuclear Outages	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gain on Sale/Leaseback (3)	61.13	(3.00)	(3.00)	55.13	(7.88)	(7.88)	(7.88)	(7.88)	(7.88)	(7.88)	(7.88)	0.00
Deferred Rate Synch. Costs (3)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Beaver Valley 2 (3)	0.17	0.00	0.00	0.17	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.00)
Total Adjustments	61.30	(3.00)	(3.00)	55.30	(7.90)	(7.90)	(7.90)	(7.90)	(7.90)	(7.90)	(7.90)	(0.00)
Adjusted Regulatory Assets	294.09	(25.30)	(40.60)	228.18	(32.60)	(32.60)	(32.60)	(32.60)	(32.60)	(32.60)	(32.60)	0.00
FAS 109 Plant (4)	0.00	0.00	0.00	62.94	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	62.67
Total Nuclear Generation	294.09	(25.30)	(40.60)	291.12	(32.64)	(32.64)	(32.64)	(32.64)	(32.64)	(32.64)	(32.64)	62.67

(1) Allocation based on gross plant balances.

(2) Allocation based on labor costs.

(3) Shown as deferred tax assets in 1996 Form 10-K.

(4) FAS 109 allocated to plant is reflected in the generating plant balance through 12/31/98

Amortization Schedule

Generation Regulatory Assets Included in Rate Base

	Actual Year - End 1996	Estimated Change 1997	Estimated Change 1998	Estimated Year - End 1998	1999	2000	2001	2002	2003	2004	2005	Net Balance 12/31/2005
Fossil Related												
10-K Regulatory Assets												
Regulatory Tax Receivable	132.29	(9.49)	(10.24)	112.55	(16.08)	(16.08)	(16.08)	(16.08)	(16.08)	(16.08)	(16.08)	0.00
Unamortized Debt Costs (1)	9.39	0.00	0.00	9.39	(1.34)	(1.34)	(1.34)	(1.34)	(1.34)	(1.34)	(1.34)	0.00
Deferred Employee Costs (2)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Deferred Coal Costs	12.19	0.31	1.00	13.50	(1.93)	(1.93)	(1.93)	(1.93)	(1.93)	(1.93)	(1.93)	0.00
Other												
Deferred Caretaker Costs	6.77	0.00	0.00	6.77	(0.97)	(0.97)	(0.97)	(0.97)	(0.97)	(0.97)	(0.97)	0.00
Coal Cost Equalization	0.32	(0.10)	(0.10)	0.12	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	0.00
Other Regulatory Assets	0.22	0.00	0.00	0.22	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	0.00
Total Other	7.31	(0.10)	(0.10)	7.11	(1.02)	(1.02)	(1.02)	(1.02)	(1.02)	(1.02)	(1.02)	0.00
Total Regulatory Assets per 10-K	161.17	(9.28)	(9.34)	142.55	(20.36)	(20.36)	(20.36)	(20.36)	(20.36)	(20.36)	(20.36)	(0.00)
Adjustments												
Fossil Decommissioning	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Deferred Fuel Cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Total Adjustments	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Total Fossil Generation	161.17	(9.28)	(9.34)	142.55	(20.36)	(20.36)	(20.36)	(20.36)	(20.36)	(20.36)	(20.36)	(0.00)

(1) Allocation based on gross plant balances.

(2) Allocation based on labor costs.

Amortization Schedule
Generation Regulatory Assets Included in Rate Base

	Actual Year - End 1996	Estimated Change 1997	Estimated Change 1998	Estimated Year - End 1998	1999	2000	2001	2002	2003	2004	2005	Net Balance 12/31/2005
Other												
10-K Regulatory Assets												
Total Regulatory Assets per 10-K	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Adjustments												
Transition Costs	0.00	0.00	0.00	18.10	(2.59)	(2.59)	(2.59)	(2.59)	(2.59)	(2.59)	(2.59)	0.00
Total Adjustments	0.00	0.00	0.00	18.10	(2.59)	(2.59)	(2.59)	(2.59)	(2.59)	(2.59)	(2.59)	0.00
Total Other	0.00	0.00	0.00	18.10	(2.59)	(2.59)	(2.59)	(2.59)	(2.59)	(2.59)	(2.59)	0.00

Duquesne Light Company

Transition Cost Summary
($ millions)

Pilot Program Implementation Expense	$2.5
Customer Education	2.0
Restructuring Filing Expense	1.0
Restructuring Implementation Expense	8.3
Deferred Pilot Program Cost	4.4
Total Transition Cost	$18.2

Duquesne Light Company

Committed Generation Related Depreciation and Amortization
1999 - 2005
($ Millions)

1999	202.2
2000	264.7
2001	261.2
2002	268.9
2003	266.8
2004	247.4
2005	236.1
	1,747.3

DUQUESNE LIGHT COMPANY
Fossil and Nuclear Plant Decommissioning Estimates
$ in Millions

	Decomm. Cost	NPV @ 12/31/05	Funding Level	(Under)/Over Funding
Elrama	43.41	35.05	0.00	(35.05)
Cheswick	59.39	23.59	0.00	(23.59)
Eastlake	45.22	22.54	0.00	(22.54)
Sammis	51.83	27.78	0.00	(27.78)
Brunot Island	28.63	13.87	0.00	(13.87)
Phillips	11.76	9.49	0.00	(9.49)
Mansfield 1	114.06	43.00	0.00	(43.00)
Mansfield 2	31.79	11.11	0.00	(11.11)
Mansfield 3	60.74	16.94	0.00	(16.94)
Total Fossil	**$446.82**	**$203.36**	**$0.00**	**($203.36)**
Beaver Valley 1	587.68	106.53	106.46	(0.06)
Beaver Valley 2	198.74	30.06	30.01	(0.06)
Perry	342.64	51.83	49.93	(1.90)
Total Nuclear	**$1,129.06**	**$188.42**	**$186.40**	**($2.02)**
Total Generation	**$1,575.87**	**$391.78**	**$186.40**	**($205.38)**

Exhibit DJC-7
Page 1 of 5

DUQUESNE LIGHT COMPANY

Detail of Fossil Decommissioning

$ in Millions

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total	NPV @ 2006
Elrama - Year 1	4.918	4.918	4.918	4.918	4.918																	24.589	20.496
Elrama - Year 2		3.765	3.765	3.765	3.765	3.765																18.824	14.551
Elrama - Year 3			0.000	0.000	0.000	0.000	0.000															0.000	0.000
Total Elrama	4.918	8.683	8.683	8.683	8.683	3.765	0.000															43.414	35.048
Cheswick - Year 1										4.504	4.504	4.504	4.504	4.504								22.522	9.525
Cheswick - Year 2											4.608	4.608	4.608	4.608	4.608							23.041	9.037
Cheswick - Year 3												2.764	2.764	2.764	2.764	2.764						13.822	5.028
Total Cheswick										4.504	9.113	11.877	11.877	11.877	7.373	2.764						59.385	23.590
Eastlake - Year 1							3.190	3.190	3.190	3.190	3.190											15.949	8.457
Eastlake - Year 2								4.135	4.135	4.135	4.135	4.135										20.673	10.166
Eastlake - Year 3									1.719	1.719	1.719	1.719	1.719									8.594	3.919
Total Eastlake							3.190	7.324	9.043	9.043	9.043	5.853	1.719									45.216	22.542
Sammis - Year 1						3.772	3.772	3.772	3.772	3.772												18.859	10.783
Sammis - Year 2							4.046	4.046	4.046	4.046	4.046											20.229	10.727
Sammis - Year 3								2.548	2.548	2.548	2.548	2.548										12.741	6.265
Total Sammis						3.772	7.818	10.366	10.366	10.366	6.594	2.548										51.829	27.775
Brunot Island - Year 1								4.569	4.569	4.569	4.569	4.569										22.843	11.233
Brunot Island - Year 2									1.157	1.157	1.157	1.157	1.157									5.786	2.639
Brunot Island - Year 3										0.000	0.000	0.000	0.000	0.000								0.000	0.000
Total Brunot Island								4.569	5.726	5.726	5.726	5.726	1.157	0.000								28.629	13.871
Phillips - Year 1	1.332	1.332	1.332	1.332	1.332																	6.659	5.551
Phillips - Year 2		1.020	1.020	1.020	1.020	1.020																5.098	3.941
Phillips - Year 3			0.000	0.000	0.000	0.000	0.000															0.000	0.000
Total Phillips	1.332	2.351	2.351	2.351	2.351	1.020	0.000															11.757	9.492
Mansfield 1 - Year 1											10.595	10.595	10.595	10.595	10.595							52.975	20.778
Mansfield 1 - Year 2												12.216	12.216	12.216	12.216	12.216						61.081	22.217
Mansfield 1 - Year 3													0.000	0.000	0.000	0.000	0.000					0.000	0.000
Total Mansfield 1											10.595	22.811	22.811	22.811	22.811	12.216	0.000					114.056	42.995
Mansfield 2 - Year 1												2.953	2.953	2.953	2.953	2.953						14.766	5.371
Mansfield 2 - Year 2													3.405	3.405	3.405	3.405	3.405					17.025	5.743
Mansfield 2 - Year 3														0.000	0.000	0.000	0.000	0.000				0.000	0.000
Total Mansfield 2												2.953	6.358	6.358	6.358	6.358	3.405	0.000				31.791	11.114
Mansfield 3 - Year 1															5.642	5.642	5.642	5.642	5.642			28.211	8.185
Mansfield 3 - Year 2																6.506	6.506	6.506	6.506	6.506		32.528	9.752
Mansfield 3 - Year 3																	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Mansfield 3															5.642	12.148	12.148	12.148	12.148	6.506	0.000	60.740	16.936
																						$446.816	$203.364

DUQUESNE LIGHT COMPANY

Detail of Projected Nuclear Decommissioning Trust Fund Activity

$ in Millions

		1997 Balance	1998 Balance	1999 Balance	2000 Balance	2001 Balance	2002 Balance	2003 Balance	2004 Balance	2005 Balance	Required Balance	Funding (Over)/ Under
After-Tax Interest Rate	7.5%											
Beaver Valley 1												
Trust Fund Beginning Balance		27.667	34.110	41.037	48.482	56.486	65.090	74.340	84.284	94.973		
Interest on Balance		2.075	2.558	3.078	3.636	4.236	4.882	5.576	6.321	7.123		
Contribution		4.210	4.210	4.210	4.210	4.210	4.210	4.210	4.210	4.210		
Interest on Contribution		0.158	0.158	0.158	0.158	0.158	0.158	0.158	0.158	0.158		
End of Year Fund Balance		**34.110**	**41.037**	**48.482**	**56.486**	**65.090**	**74.340**	**84.284**	**94.973**	**106.464**	**106.527**	**0.064**
Beaver Valley 2												
Trust Fund Beginning Balance		5.326	7.344	9.513	11.845	14.352	17.047	19.944	23.058	26.406		
Interest on Balance		0.399	0.551	0.713	0.888	1.076	1.279	1.496	1.729	1.980		
Contribution		1.560	1.560	1.560	1.560	1.560	1.560	1.560	1.560	1.560		
Interest on Contribution		0.059	0.059	0.059	0.059	0.059	0.059	0.059	0.059	0.059		
End of Year Fund Balance		**7.344**	**9.513**	**11.845**	**14.352**	**17.047**	**19.944**	**23.058**	**26.406**	**30.005**	**30.063**	**0.057**
		1.565										
Perry												
Trust Fund Beginning Balance		6.244	9.816	13.656	17.785	22.223	26.994	32.122	37.636	43.563		
Interest on Balance		0.468	0.736	1.024	1.334	1.667	2.025	2.409	2.823	3.267		
Contribution		2.992	2.992	2.992	2.992	2.992	2.992	2.992	2.992	2.992		
Interest on Contribution		0.112	0.112	0.112	0.112	0.112	0.112	0.112	0.112	0.112		
End of Year Fund Balance		**9.816**	**13.656**	**17.785**	**22.223**	**26.994**	**32.122**	**37.636**	**43.563**	**49.934**	**51.831**	**1.897**
Total												
Trust Fund Beginning Balance		39.237	51.270	64.206	78.112	93.061	109.131	126.407	144.978	164.942		
Interest on Balance		2.943	3.845	4.815	5.858	6.980	8.185	9.481	10.873	12.371		
Contribution		8.762	8.762	8.762	8.762	8.762	8.762	8.762	8.762	8.762		
Interest on Contribution		0.329	0.329	0.329	0.329	0.329	0.329	0.329	0.329	0.329		
End of Year Fund Balance		**51.270**	**64.206**	**78.112**	**93.061**	**109.131**	**126.407**	**144.978**	**164.942**	**186.403**	**$188.421**	**$2.018**

DUQUESNE LIGHT COMPANY

Detail of Nuclear Decommissioning Costs

$ in Millions

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Beaver Valley 1 (1997 CAPCO$)		27.464	18.673	3.813	3.813	3.823	3.813	3.813	3.813	3.823	3.813	3.813	3.206	2.810	18.69
Beaver Valley 1 (1997 DLC$)	47.50%	13.045	8.869	1.811	1.811	1.816	1.811	1.811	1.811	1.816	1.811	1.811	1.523	1.335	8.878
Inflation factor		2.107	2.191	2.279	2.370	2.465	2.563	2.666	2.772	2.883	2.999	3.119	3.243	3.373	3.508
Cash Expenditures		27.485	19.434	4.127	4.292	4.476	4.642	4.828	5.021	5.236	5.431	5.648	4.940	4.502	31.145
Discount factor (to year 2005)		2.216	2.382	2.560	2.752	2.959	3.181	3.419	3.676	3.951	4.248	4.566	4.909	5.277	5.673
Amt Required (2005 DLC$)		**12.405**	**8.159**	**1.612**	**1.559**	**1.513**	**1.459**	**1.412**	**1.366**	**1.325**	**1.278**	**1.237**	**1.006**	**0.853**	**5.490**
Beaver Valley 2 (1997 CAPCO$)	47.50%	377.009											25.489	48.963	56.753
Beaver Valley 2 (1997 DLC$)	13.74%												3.502	6.728	7.798
Inflation factor													3.243	3.373	3.508
Cash Expenditures													11.359	22.693	27.355
Discount factor (to year 2005)													4.909	5.277	5.673
Amt Required (2005 DLC$)													**2.314**	**4.300**	**4.822**
Perry (1997 CAPCO$)	650												43.946	84.417	97.847
Perry (1997 DLC$)	13.74%												6.038	11.599	13.444
Inflation factor													3.243	3.373	3.508
Cash Expenditures													19.584	39.125	47.163
Discount factor (to year 2005)													4.909	5.277	5.673
Amt Required (2005 DLC$)													**3.989**	**7.414**	**8.314**

Exhibit DJC-7
Page 4 of 5

DUQUESNE LIGHT
Detail of Nuclear Dec
$ in Millions

	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	
Beaver Valley 1 (1997 CAPCO$)	42.688	65.805	65.718	52.785	14.326	4.160									
Beaver Valley 1 (1997 DLC$)	20.277	31.257	31.216	25.073	6.805	1.976									
Inflation factor	3.648	3.794	3.946	4.104	4.268	4.439									
Cash Expenditures	73.978	118.600	123.182	102.897	29.044	8.772									587.679
Discount factor (to year 2005)	6.098	6.556	7.047	7.576	8.144	8.755									
Amt Required (2005 DLC$)	12.131	18.091	17.479	13.582	3.566	1.002									106.527
Beaver Valley 2 (1997 CAPCO$)	53.143	49.267	51.701	30.167	25.320	16.805	1.598	1.593	1.593	1.593	1.598	1.593	1.593	8.238	
Beaver Valley 2 (1997 DLC$)	7.302	6.769	7.104	4.145	3.479	2.309	0.220	0.219	0.219	0.219	0.220	0.219	0.219	1.132	
Inflaction factor	3.648	3.794	3.946	4.104	4.268	4.439	4.616	4.801	4.993	5.193	5.400	5.617	5.841	6.075	
Cash Expenditures	26.640	25.685	28.032	17.010	14.849	10.249	1.013	1.051	1.093	1.137	1.186	1.230	1.279	6.876	198.737
Discount factor (to year 2005)	6.098	6.556	7.047	7.576	8.144	8.755	9.412	10.117	10.876	11.692	12.569	13.512	14.525	15.614	
Amt Required (2005 DLC$)	4.368	3.918	3.978	2.245	1.823	1.171	0.108	0.104	0.101	0.097	0.094	0.091	0.088	0.440	30.063
Perry (1997 CAPCO$)	91.624	84.942	89.137	52.010	43.655	28.973	2.755	2.747	2.747	2.747	2.755	2.747	2.747	14.203	
Perry (1997 DLC$)	12.589	11.671	12.247	7.146	5.998	3.981	0.378	0.377	0.377	0.377	0.378	0.377	0.377	1.952	
Inflaction factor	3.648	3.794	3.946	4.104	4.268	4.439	4.616	4.801	4.993	5.193	5.400	5.617	5.841	6.075	
Cash Expenditures	45.930	44.283	48.330	29.328	25.601	17.670	1.747	1.812	1.885	1.960	2.044	2.120	2.205	11.855	342.642
Discount factor (to year 2005)	6.098	6.556	7.047	7.576	8.144	8.755	9.412	10.117	10.876	11.692	12.569	13.512	14.525	15.614	
Amt Required (2005 DLC$)	7.532	6.755	6.858	3.871	3.143	2.018	0.186	0.179	0.173	0.168	0.163	0.157	0.152	0.759	51.831

Duquesne Light Company
Feasibility of Financing Plan

	RATEBASE ($BILLIONS)	DEBT ($MILLIONS)	% CAP	PREFERRED ($MILLIONS)	% CAP	COMMON ($MILLIONS)	% CAP	TOTAL CAP ($MILLIONS)
12/31/96	$2.47	$1,241	50%	$239	10%	$990	40%	$2,470
1997 REFINANCINGS								
FMB MATURED 6.3%		($15)						
FMB MATURED 6.0%		($30)						
FMB MATURED 5.9%		($5)						
ISSUE NEW DEBT		$47						
DEBENTURE BT 5.0%		($2)						
PREFERRED TENDER				($65)				
COMMON EQUITY						($50)		
12/31/97	2.35	$1,236	53%	$174	7%	$940	40%	$2,350
1998 REFINANCINGS								
FMB MATURED 5.85%		($35)						
FMB MATURED 6.15%		($35)						
FMB MATURED 6.55%		($5)						
ISSUE NEW DEBT		$43						
DEBENTURE BT 5.0%		($3)						
COMMON EQUITY						($15)		
12/31/98	2.30	$1,201	52%	$174	8%	$925	40%	$2,300
1999 REFINANCINGS								
FMB MATURED 5.90%		($75)						
ISSUE NEW DEBT		$41						
COMMON EQUITY						($46)		
12/31/99	2.22	$1,167	53%	$174	8%	$879	40%	$2,220
2000 REFINANCINGS								
FMB MATURED 6.45%		($45)						
FMB MATURED 6.10%		($55)						
ISSUE NEW DEBT		$40						
COMMON EQUITY						($30)		
12/31/2000	2.13	$1,107	52%	$174	8%	$849	40%	$2,130
2001 REFINANCINGS								
PARTIAL CALL 8.75%		($65)						
COMMON EQUITY						($25)		
12/31/2001	2.04	$1,042	51%	$174	9%	$824	40%	$2,040
2002 REFINANCINGS								
PARTIAL CALL 8.75%		($35)						
PARTIAL CALL 7.625%		($35)						
COMMON EQUITY						($45)		
12/31/2002	1.93	$972	50%	$174	9%	$779	40%	$1,925
2003 REFINANCINGS								
FMB MATURED 6.70%		($55)						
FMB MATURED 6.65%		($45)						
ISSUE NEW DEBT		$45						
COMMON EQUITY						($50)		
12/31/2003	1.82	$917	50%	$174	10%	$729	40%	$1,820
2004 REFINANCINGS								
FMB MATURED 6.625%		($100)						
ISSUE NEW DEBT		$65						
COMMON EQUITY						($35)		
12/31/2004	1.75	$882	50%	$174	10%	$694	40%	$1,750
2005 REFINANCINGS *								
FMB MATURED 5.90%		($75)						
ISSUE NEW DEBT		$20						
RETIRE ESOP PREFERENCE STK				($24)				
COMMON EQUITY						($31)		
12/31/2005	1.64	$827	50%	$150	9%	$663	40%	$1,640

* Duquesne reserves the right to exclude equity (and associated earnings) from calculations for ratemaking purposes if financial covenants require maintenance of equity above indicated levels.

PENNSYLVANIA ELECTRIC COMPANIES
WEIGHTED COST OF CAPITAL
As of 12/31/96

PP & L Resources	Ratio	Cost Rate	Wtd Cost Rate	
				from 1997 transition filing
Common Equity	45.20%	11.50%	5.20%	
Preferred & Preference	7.80%	7.10%	0.55%	
Long-Term Debt	47.00%	7.89%	3.71%	
	100.00%		9.46%	
			7.92%	Wtd. after-tax

PECO	Ratio	Cost Rate	Wtd Cost Rate	
				from 1997 transition filing
Common Equity	50.60%	11.60%	5.87%	
Preferred & Preference	3.00%	7.70%	0.23%	
Long-Term Debt	46.40%	8.51%	3.95%	
	100.0%		10.05%	
			8.41%	Wtd. after-tax

Metropolitan Edison	Ratio	Cost Rate	Wtd Cost Rate	
				from 1997 transition filing
Common Stock	49.97%	12.20%	6.10%	
Preferred Stock	7.74%	8.76%	0.68%	
Long-Term Debt	42.29%	7.59%	3.21%	
	100.00%		9.98%	

Pennsylvania Electric	Ratio	Cost Rate	Wtd Cost Rate	
				from 1997 transition filing
Common Equity	48.79%	12.00%	5.85%	
Preferred & Preference	7.63%	8.38%	0.64%	
Long-Term Debt	43.58%	7.24%	3.16%	
	100.00%		9.65%	

West Penn Power	Ratio	After tax Cost Rate	Wtd Cost Rate	
				from proposed 1997 transition filing
Common Equity	46.80%	11.50%	5.38%	
Preferred & Preference	4.30%	4.15%	0.18%	
Long-Term Debt	48.90%	7.46%	3.65%	
	100.00%		9.21%	
			7.71%	Wtd. after-tax

VOLUME I

Duquesne Statement No. 1

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

DUQUESNE LIGHT COMPANY
DOCKET NO. R-00974104

Direct Testimony
of
Michael M. Schnitzer

Contents:

Regarding the Known and Measurable Standard and Duquesne's Market-Based Approach to Stranded Cost Calculation and Recovery

Qualifications

Q. Please state your name, position and business address.

A. My name is Michael M. Schnitzer. I am a Director of The NorthBridge Group, 950 Winter Street, Waltham, Massachusetts 02154. The NorthBridge Group is an economic and strategic consulting firm specializing in the electric and natural gas industries.

Q. Please briefly describe your educational and business background.

A. I received a Master of Science degree in management from the Sloan School of Management, Massachusetts Institute of Technology, in 1979. My concentration was in finance. I received a Bachelor of Arts degree in chemistry, with honors, from Harvard College in 1975.

In 1992, I co-founded The NorthBridge Group. Prior to that, I was a Managing Director of Putnam, Hayes & Bartlett, which I joined in 1979. At NorthBridge and Putnam, Hayes and Bartlett, I have consulted for private sector clients in the electric utility, natural gas, private power, steel and coatings industries, and for several public and nonprofit agencies. My utility work has focused on resource planning, regulatory policy, finance, and industry restructuring issues. Further details of my professional and educational background are set forth in Exhibit MMS-1.

Q. Please list the regulatory commissions before which you have testified.

A. I have provided testimony or affidavits on a variety of matters before the Arkansas, Delaware, Indiana, Maine, Maryland, Massachusetts, New Hampshire, New Mexico, New York, Ohio, Pennsylvania, Rhode Island, Texas, Vermont and Wisconsin Public Utility Commissions.

Purpose of Testimony and Conclusions

Q. What is the purpose of your testimony?

A. The first purpose of my testimony is to address the proper determination of stranded costs under the Electric Generation Customer Choice and Competition Act, 66 Pa. C.S. Sections 2801-2812 ("Customer Choice Act"). Specifically, I will address the application of the "known and measurable" standard to the determination of stranded costs.

The second purpose of my testimony is to address whether Duquesne Light Company ("Duquesne" or "Company") is entitled to a price cap on generation for all years from 1999 to 2005 ("Transition Period") under section 2804(4)(v) of the Customer Choice Act. Specifically, I will address the nature of the evidentiary showings by Duquesne necessary to meet the requirements of this section.

The third purpose of my testimony is to address the calculation by Duquesne of a known and measurable CTC for each year of the Transition Period using an annual solicitation for sale of power to set the market price. I will also address the benefits of such a proposal from the standpoint of economic efficiency and fairness while

Duquesne continues to bear an obligation to serve under a generation price cap.

The fourth purpose of my testimony is to address Duquesne's proposal for a final market-based determination of stranded costs under the known and measurable standard. I will also distinguish Duquesne's market valuation proposal from a one-time administrative determination of stranded costs.

The fifth purpose of my testimony is to address the customer safeguards built into Duquesne's price cap and market valuation proposal. I will address the customer protection features of the guaranteed amortization, the ROE spillover and the early market valuation trigger mechanisms. I will also address the proper treatment of asset sales and plant shutdowns during the Transition Period.

Q. Would you please summarize your conclusions?

A. Yes, there are five main conclusions corresponding to the purposes of my testimony. First, a market-based determination of stranded costs is inherently superior to an administrative determination. Only a market-based determination can reasonably satisfy the known and measurable standard required by the Customer Choice Act. By contrast, an administrative determination of future market prices based on inherently uncertain predictions about producer and consumer behavior and forecasts of future events or trends cannot, by definition, establish known stranded costs. There is no reason to rely on an administrative determination of market prices today when a feasible and practical alternative has been proposed by Duquesne that would permit a market-based valuation to take place in 2003.

Second, Duquesne is entitled to a price cap on generation rates under section 2804(4)(v) of the Customer Choice Act for each year of the Transition Period, subject to early termination of the cap. To meet the requirements of this section Duquesne must make a prima facie showing that:

- Excess earnings achieved under the cap will be utilized to mitigate transition or stranded costs for the benefit of ratepayers under the proposed minimum amortization commitments and ROE spillover mechanism; and
- The market value of generation beginning in 2006 will be below the book value of generation and generation-related regulatory assets net of the committed minimum level of amortization.

Based on the testimony of Mr. Clayton, I conclude that Duquesne has made these two showings and is therefore entitled to the price cap through 2005.

Third, the Duquesne proposal to set customer-specific CTCs annually based on the market price of electricity as determined by the results of a market-based solicitation meets the known and measurable standard. The CTC will be calculated as a residual of the capped generation rate and the market price of power. The winning bids in the solicitation will set the market price of power for the applicable year, which in turn will establish known and measurable CTCs. This will ensure that customers, competitive suppliers and Duquesne's investors will be treated fairly during the Transition Period and that price signals will be economically efficient. By contrast—where customers are protected by a price cap—an *ex ante* calculation of CTCs based

on a one-time administrative estimation of market prices is inherently flawed. Use of this method is not consistent with encouraging competition as the resulting market price signals will be distorted. Economic efficiency requires that CTCs be set using market-based evidence of current market prices.

Fourth, the proposed market-based determination of stranded costs as of December 31, 2005 provides a known and measurable methodology to calculate stranded costs on a net present value basis. Duquesne proposes to determine the fair market value of its generating assets on the basis of prices contained in consummated market transactions in the relevant market. The final market-based valuation will be conducted in 2003 by an unbiased arbitration panel that will issue a report on its findings of market value to the Commission. Duquesne will agree to be bound by the panel's determination of market value, subject only to Duquesne's right to sell assets or sell an equity interest in a subsidiary generation company if the Commission alters or rejects the panel's finding of market value. The panel's valuation (or the valuation from such a sale or spin-off) will be known and measurable and will be used to assess whether Duquesne will have fully amortized its stranded costs under the price cap during the Transition Period.

Fifth, the proposed "true-up" methodology of the final market-based valuation protects customers by ensuring that Duquesne does not over recover its stranded costs and that customers do not "pay twice" for the costs of generation. If the market valuation is higher than anticipated, the accelerated recovery under the price cap will

be reduced accordingly. In addition, Duquesne has committed to a ROE spillover mechanism to protect customers during the Transition Period. This mechanism ensures that Duquesne will not earn more than the allowed ROE, but provides no symmetric protection to the Company for downside risk. Duquesne has a reasonable opportunity to earn a fair rate of return during the Transition Period, but still bears the risk of fulfilling its depreciation and amortization commitment. Finally, the proposed early trigger mechanisms to the final market-based valuation provide additional protection for customers if market prices rise significantly or if the committed level of depreciation and amortization is fully recovered under the price cap prior to 2003. Duquesne also has the right incentives to sell profitable generation and shutdown unprofitable generation during the Transition Period, and the potential proceeds from sale and savings from shutdown are appropriately credited to customers.

Market-Based Determination of Stranded Costs is Inherently Superior

Q. Please elaborate on your first conclusion.

A. The definition of "transition and stranded costs" contained in Section 2803 of the Customer Act is premised on each utility having the burden of demonstrating "known and measurable net electric generation-related costs, determined on a net present value basis over the life of the asset or liability as part of its restructuring plan." Only a market-based determination can reasonably satisfy that standard. An administrative process is theoretically inferior to a market-based approach and has in practice proven to be grossly inaccurate. Such an administrative determination is also unnecessary; a

feasible and practical alternative has been proposed by Duquesne that would permit a market-based valuation to take place in 2003.

Administrative Approaches are Inferior to Market-Based Approaches

Q. In theory, why should a market-based approach be inherently superior to an administrative approach?

A. In concept, stranded asset quantification seems simple enough. Utilities currently value generating assets on their books at original cost less accumulated depreciation. But when competition is substituted for regulation, the market value of generation may be less than the book value. The difference between net book value and competitive market value represents that portion of book value stranded by competitive retail access.

The key quantification question concerns the market value of generation. The value of an electric generation plant in a competitive market is what a willing buyer would pay for the right to receive the net after-tax cash flows from the plant in the future. These after-tax cash flows, in turn, depend largely on the prevailing market price for power. Thus, in an administrative determination, the critical component is a forecast of future market price. It is this requirement to forecast market price that makes an administrative determination inferior to a market-based determination.

Q. Why is that?

A. The administrative determination of market prices requires predictions about both supply and demand over a long period of time. Three sets of assumptions are critical. The first is the set of assumptions made about the new supply technology of choice: all such estimates must assume a new supply technology and its associated costs. Historically, the technology chosen has often been wrong (coal instead of gas, for instance) but even in cases where the technology type was correct, technological progress was ignored or underestimated. Costs and thus prices are usually projected assuming that technology never improves, costs never decline and efficiency gains are never realized. This type of "fixed technology" estimate has historically proven to be very inaccurate.

The second is the set of assumptions made about new supply timing and market equilibrium: administrative forecasts all assume a "need date" for new supply and typically assume the market stays in equilibrium thereafter. Both assumptions have often proven to be incorrect—the need is often later than forecast, and supply and demand subsequently get out of balance, with the result of falling market prices.

The third is the set of assumptions made about fuel prices: estimates of oil and gas prices in particular are made for a long period of time. Historically, these estimates have proven to be far off the mark—almost invariably high. As a consequence, market price projections have been overstated significantly.

Q. What is the consequence of basing market forecasts on these types of assumptions?

A. The forecasts are highly sensitive to the initial assumptions chosen by the analysts making the forecasts. When the results of the forecasts are used in an administrative context to determine or allocate value, the vastly different results obtained by changing the assumptions leads to a "battle of the experts." The consequence is a contentious and time-consuming process that seeks to substitute an administrative determination for the judgment of the marketplace.

However, there is simply no substitute for the market itself in determining market prices in the future. A myriad of individual buyers and sellers, freely taking positions and risking real dollars enter into numerous transactions. The composite of these voluntary individual economic decisions defines the market. The prices that result are by definition superior to the best documented forecast or most sophisticated model.

Q. What is the result of engaging in an adminstrative determination of stranded costs?

A. Outside of Pennsylvania, the restructuring process in other states has advanced to the stage where some state commissions have proposed an administrative determination of an allowable level of utility stranded costs. Although costs and unit performance are also at issue in these proceedings, the greatest sensitivity in the stranded cost value results from differences in the future forecasts of the market price of electricity. As the proceedings progress, the parties and the regulators often back away from a determination on an administrative basis and seek alternative solutions.

For example, in Massachusetts the Department of Public Utilities ("MDPU") originally proposed draft regulations for administratively determining stranded costs.

After holding extensive hearings in the summer of 1996, the MDPU declined to promulgate the regulations that would have implemented this procedure. Similarly, in California an administrative determination process was scrapped. The California PUC will use actual market prices from the newly established power exchange to set the CTC equivalent access charges.

In New Hampshire, the Public Utility Commission ("NHPUC") retained La Capra Associates[3] to estimate market prices and stranded generation costs. The La Capra analysis supported a "high market price" while the experts retained by utilities supported a "low market price." The NHPUC issued an order in that state's restructuring on February 28, 1997 that relied on an initial administrative estimate of market prices to establish an interim stranded cost charge, but recognized the need for a market-based "true-up" of that estimate. However, the NHPUC's Order in the case of Public Service Company of New Hampshire (PSNH) led to a PSNH claim that it had been denied a reasonable opportunity to recover its stranded costs. PSNH sought and obtained a Temporary Restraining Order against the NHPUC. The litigation over the order has been stayed as mediation efforts and settlement discussion attempt to resolve this impasse.

Q. What has been the Pennsylvania experience with the administrative determination of stranded costs?

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[3] La Capra Associates has also been retained by the Pennsylvania Office of Consumer Advocate and has filed testimony on market prices and stranded generation costs in Docket No. R-00973953.

A. The Qualified Rate Order ("QRO") proceeding for PECO Energy Company ("PECO") illustrates the wide differences in value that can result from different assumptions. PECO had claimed total stranded generation plant of $3.566 billion of which it was seeking to securitize $2.435 billion under a QRO. The Commission concluded that PECO had not met its burden of proof with respect to the $2.435 billion estimate and accepted adjustments proposed by the Philadelphia Area Industrial Energy Users Group ("PAIEUG"). In total, these adjustments reduced the $2.435 billion by $1.828 billion or approximately 75 percent.

The wide bid-ask spread from the QRO proceeding has been reconfirmed in the PECO restructuring docket. PECO has sponsored testimony from three "low market price" experts. In response, the Office of Consumer Advocate ("OCA") and PAIEUG have filed testimony sponsored by "high market price" experts. Each side finds fault with the other's methodology, modeling techniques and input assumptions. The estimates confirm the bargaining positions of the parties staked out at the start of the restructuring process. Both sides support the selection of their own estimate as the basis for a one-time determination of stranded costs decades into the future. Thus, the Commission is presented with two diametrically opposed views of the likely path of future market prices and must choose.

Q. What do you conclude about market-based and administrative approaches?

A. Because expert forecasts of market price depend critically on input assumptions, vastly different results can be obtained by varying the assumptions and calculating

present values based on projections far into the future. The results are inconclusive because it costs nothing to change an assumption. Markets are different because participants risk real dollars on their assumptions. Parties may disagree on the future course of events, but in the market they must back up their predictions with cash or credit. This basic difference – bearing the cost of being wrong – separates market evidence from mere forecasts.

Administrative Determinations of Future Costs Have Failed Historically

Q. What is the historical experience with determining future prices in an administrative proceeding?

A. There is a great deal of empirical evidence available because administrative determination of market prices is not a new idea. Past administrative determinations of future "avoided costs" have been notoriously inaccurate. Relying on these administrative forecasts has resulted in the payment of billions of dollars of above-market costs by utilities to non-utility generators. The Public Utilities Regulatory Policies Act of 1978 ("PURPA") resulted in utilities and Commissions forecasting the "avoided cost" of adding new generation capacity in order to determine the prices that would be paid to qualifying facilities ("QFs") under PURPA. At that time the price of oil was high and then current forecasts called for future prices to exceed $100 per barrel.

In California, one of the first states to implement PURPA, oil was the marginal

generating resource for utilities, and the resulting avoided costs and prices offered to QFs were, in retrospect, extremely high. As a result, resources that could qualify under PURPA would still be profitable under California's standard offer prices despite their high costs of producing electricity. The standard offer contracts remained open for an extended period of time. Utilities were required to take all offered power at the posted prices from qualified sellers leading to the purchase of thousands of MWs of very costly power. The magnitude of these above-market commitments became apparent as market oil prices declined significantly throughout the last half of the 1980s, but contract prices remained fixed.

In New York, the California experience with administrative forecasting was played out with a new wrinkle. The state legislature took the additional step of mandating a *floor* to the administratively determined price to encourage development of the independent power industry. Under the so-called "six cent" law, New York PURPA contracts specified that co-generators be paid the greater of utility avoided costs or six cents per kWh. As oil prices declined, the "gas bubble" did not end, and load grew more slowly than forecast, the mandated pricing in these contracts proved very profitable for sellers and extremely burdensome for utilities and customers. The cost of these co-generation commitments ultimately led Niagara Mohawk ("NIMO") to threaten bankruptcy in order to bring sellers under the six cent contracts to the bargaining table. A settlement of these above-market contracts was finally signed by the producers and NIMO in July 1997, calling for payment of $3.6 billion in cash and 46 million shares of NIMO common equity to terminate or restructure the contracts.

The QF experience of California and New York was played out to lesser degrees in other jurisdictions around the nation. The worst excesses of the administered QF rates were corrected when Massachusetts, California and other states turned to competitive bidding. However, the bidding was still subject to administrative interference. The quantity to be bought was determined administratively on an own load basis and when load grew more slowly than forecast, a surplus developed and the avoided cost estimate again proved to be above the actual market price. The bid process was further hampered in states such as Massachusetts, where regulators attempted to monetize externalities and assign values to air pollutants. Again, the result of these administrative determinations of value was to artificially inflate the market price and increase the costs that would be ultimately borne by customers of the purchasing utilities.

Pennsylvania has had similar experience with avoided cost projections. While Duquesne has virtually no PURPA contract exposure, other Pennsylvania utilities bear the burden of "long-term power supply agreements as required by federal law." Contracts were signed and approved by the Commission at prices discounted from estimated avoided costs that turned out to be well above actual market prices. The above-market cost of PURPA contracts based on administered prices is explicitly recognized in Pennsylvania as Principle 15 in section 2802 of the Customer Choice Act, and again in section 2804(4)(iii). In this later section the legislature specifically exempts the "costs cancellation, buyout, buydown or renegotiation of nonutility generating project obligations of the utility" from the price caps otherwise applicable

during the Transition Period. In Pennsylvania, as elsewhere, the hangover from past administrative determinations of avoided costs has worsened the stranded cost problem.

Q. What do you conclude based on the experience in California, New York and other states?

A. Administrative determinations of cost or price are a poor substitute for the market. Our historical experience with administrative determinations reveals three types of errors repeated over and over again that correspond to the three key inputs over which the "experts" disagree. Errors in these projections have consistently been made on the assumptions about technology of choice, new supply timing and market equilibrium, and fuel prices. As a consequence, market price projections have been overstated significantly.

Markets, on the other hand, reflect the collective expectations of all market participants — participants betting their own money. Future expectations of individual parties are not always realized, but contracts freely entered into at arm's length reflect a competitive outcome that fairly allocates risk between the parties and discounts the future appropriately. Administrative determination of market price is an unproductive path which should be avoided — already the predictable debate over technology and cost, need date, and fuel prices has been joined in other Pennsylvania restructuring dockets. Administrative determination was a failure under PURPA, costing customers billions of dollars. This failure should not to be repeated in the

Pennsylvania restructuring at the further expense of customers and shareholders. Stranded costs determined from such administrative estimates of market price cannot be known and measurable.

One Time Calculation of Stranded Costs Today is Unnecessary

Q. You also state that a one-time administrative calculation of stranded cost is unnecessary. Why is this?

A. An administration determination of stranded costs is unnecessary and unwarranted because a feasible and practical market-based alternative exists and is available to the Commission. As described later in my testimony and also by Mr. Marshall, Duquesne has put forward a specific proposal for a market-based valuation of its generation in 2003. Completing a "once and for all time" stranded cost calculation today based on an administrative determination of future market prices simply places too much weight on the accuracy of the market price forecasts. Both consumer and shareholder advocates are rightly concerned that getting the market price wrong will set the level of stranded costs too high or too low, without recourse should the future turn out differently than forecast.

In the PECO restructuring proceeding, the intervenor testimony echoes this concern. The Office of Trial Staff witness Paul J. Metro testified at pp. 16-17 of his testimony that it would be possible for the stranded costs to be zero and also possible for the generation units' market value to be zero, thus indicating that all net generating plant

and CWIP were stranded. Thus, he concluded that the range of stranded costs could be $0 to $6,688,384,000. Similarly, the Office of Small Business Advocate witness Brian Kalcic proposes at pp. 7-8 of his testimony that the Commission should implement a market value/stranded cost adjustment so as to implicitly share the risks associated with the uncertainty of future market price forecasts between customers and shareholders. The risks associated with an administrative determination are unnecessary and unwarranted given the alternative of Duquesne's market-based proposal.

Q. How does Duquesne's proposal answer these concerns?

A. Duquesne's proposal for a final market-based valuation in 2003 avoids the problems of an administrative determination of stranded costs today. Consumer advocates are rightly concerned that if the forecast of market price is set too low, and utilities effectively own the generation independent of any obligation to serve following the Transition Period, then any upside value will accrue to shareholders. This is the articulated fear that customers will "pay twice" for generation: once through the CTC charges and again in the form of higher market prices following the Transition Period. Duquesne's proposal to accelerate amortization under a rate cap and make a market valuation late in the Transition Period avoids this risk. As we will demonstrate, Duquesne is entitled to a continuation of its rate cap and the customer is held harmless from the risk that Duquesne will recover too much under the cap, by operation of the ROE spillover, the final market valuation and the early valuation triggers.

Q. But, why wait to do a market valuation until 2003?

A. A market valuation of utility generation assets that are undergoing deregulation is very difficult to achieve in 1997. First, for electricity there are no clear guideposts to market value as with other commodities. Public markets are not liquid and products are not standardized. Although electricity is becoming a commodity product at the wholesale level, the market in electricity forward and futures contracts is only in its infancy. There are some nascent spot contracts for electricity such as the California-Oregon border contracts. But the physical properties of electricity make a standardized contract problematic. Electricity must be instantaneously produced and consumed as storage opportunities are limited (e.g., pumped hydro). Transmission constraints make the assessment of basis risk between different markets difficult. As a result, the current market for forward electricity contracts specify physical delivery at a particular busbar or interconnection.

Contrast the development of forward and futures contracts in natural gas. Henry Hub in Louisiana is the delivery point against which all contracts can be settled. The basis differentials for other delivery points are also established. The standard terms and conditions for allocating risk between buyers and sellers have been hammered out since gas deregulation began in the 1980s. Many financial institutions and energy companies are now quoting fixed gas prices on a forward basis for ten years or more into the future. Electricity markets are at an early stage of development compared to natural gas markets, but they will catch up.

Second, current uncertainty about future environmental regulations in a deregulated market casts a shadow over any reasoned debate about market prices. Future environmental standards for existing units are a source of great uncertainty. On June 25, 1997 the President announced new rules to be promulgated by the Environmental Protection Agency that would restrict ozone compounds and particulates resulting from the combustion of fossil fuels in power plants. If the rulemaking is implemented and its validity is upheld by the courts, the retrofit costs to existing coal units would make many of these units uneconomic at current prices. The effect of the regulations on overall market prices will depend on the cost impact to the existing supply of generation and the cost of entry of new gas-fired capacity. Thus, shutdown decisions would need to consider both the added costs of compliance with the new standards and the second order impact on market prices as other operating units are shut down and new gas-fired units are built.

Third, until the current round of industry restructuring is complete, uncertainty about the details of a fully deregulated market structure and its effect on future market prices is similarly a cause of concern. The structural overhang of continued regulation retards the development of liquidity in the power markets. The debate over bid-based versus cost-based dispatch has been joined in Pennsylvania and elsewhere. On one side certain economists argue that competitive bids for dispatch by an Independent System Operator ("ISO") will largely duplicate the cost-based dispatch seen in PJM and other tight pools today. Critics argue that bids will necessarily be higher in a competitive bid structure because utilities will seek to recover certain costs

that today are recovered in embedded cost rates. Similar debates rage over the value of capacity in a deregulated market. Will the capacity value be set by the price required to recover the cost of new combustion turbine construction or will cheaper alternatives (e.g., economic curtailment) be viable as capacity alternatives? The impact of other structural issues (e.g., load pockets and transmission pricing) on the overall level of market prices will become clearer as ISOs are formed and competitive markets develop. The uncertainty today over future market prices will be reduced as these structural issues are resolved.

Market Based Determination of Stranded Cost is a Superior Approach

Q. Please summarize your conclusion regarding the superiority of a market-based determination of stranded costs.

A. Only a market-based determination can reasonably satisfy the known and measurable standard required by the Customer Choice Act. Administrative determinations of market price are inherently unreliable and inferior to the market itself. They require key assumptions concerning what customers and competing suppliers will do over long periods of time—assumptions that are unavoidably uncertain. Past experience with avoided cost forecasts under PURPA confirms this unreliability and susceptibility to error—errors in underlying assumptions resulted in significant overestimation of market prices. A one-time administrative determination of stranded costs today can and should be avoided. An alternative market-based approach has been proposed by Duquesne that is both feasible and practical, but must wait for the

electricity markets to mature and the uncertainty over structural issues to subside.

Duquesne is Entitled to a Price Cap On Generation Under Section 2804(4)(v)

Q. On what basis is Duquesne entitled to a price cap on generation under the Customer Choice Act?

A. Section 2804(4)(v) provides that: "If an electric distribution utility rolls its energy cost rate into base rates at a combined level that does not exceed its combined level of such rates which have been approved by the Commission as of the Effective Date of this Chapter, the utility shall not be required to reduce its capped rates below the capped level upon the complaint of any party if the Commission determines that any excess earnings achieved under the cap are being utilized to mitigate transition or stranded costs for the benefit of ratepayers or to offset other known and measurable cost increases that would be recoverable under traditional ratemaking but are not included within the capped rates."

This section of the Customer Choice Act is comparable to the treatment Duquesne received under the Fort Martin plan. Under that plan Duquesne agreed to freeze rates at current levels through 2000 and committed to a schedule of accelerated amortization of its nuclear plants and increased decommissioning funding that would offset any excess earnings from continued collection of current rates.

Duquesne Needs to Make Two Showings to Obtain Rate Cap

Q. How can Duquesne establish that any excess earnings during the Transition Period under the rate cap will be used to mitigate transition and stranded costs?

A. To make the case for holding rates at the capped levels throughout the Transition Period, Duquesne must make a prima facie showing of two propositions. The first is that a mechanism exists to ensure that if revenues under the rate cap are greater than the normal cost of service, these "excess earnings" will be utilized to mitigate transition or stranded costs for the benefit of ratepayers.

Q. Is proof of that proposition alone sufficient to satisfy the conditions of section 2804(4)(v)?

A. No, it is not. The second required showing is that the "excess earnings" available under the price cap to mitigate stranded costs are less than or equal to the stranded costs that need to be recovered. Thus, to make this additional showing Duquesne must demonstrate that stranded costs still remain in 2006 even after the "excess earnings" mitigation or, put another way, that the market value of generation beginning in 2006 is still below the book value of generation and generation-related regulatory assets net of all mitigation during the price cap period.

Q. Does this two-part showing require that Duquesne calculate a value for stranded costs as of January 1, 1999?

A. No, what is important is the potential stranded cost left over in 2006 after all "excess earnings" amortization and depreciation have been recognized on Duquesne's books. Thus, an estimate of the amount of mitigation that can be achieved under the price cap and an estimate of the range of stranded costs remaining as of January 1, 2006 are necessary to satisfy the conditions of Section 2804(4)(v). Forecasting a likely range of market prices beyond 2005 is necessary to make this latter calculation and showing.

Duquesne has Made the Appropriate Showing for Each Proposition

Q. Has Duquesne made the appropriate showing of the first proposition?

A. Yes. Two provisions of Duquesne's proposal ensure that excess earnings will be used to mitigate stranded costs for the benefit of ratepayers. The first of these is the minimum depreciation and amortization commitment—a commitment by Duquesne to amortize at least $1.7 billion of generation and generation-related regulatory assets during the price cap period. The second is the ROE spillover mechanism through which Duquesne commits to apply any earnings in excess of the ROE-deadband to further accelerate the $1.7 billion amortization commitment. The combined effect of the minimum amortization commitment and the ROE spillover mechanism guarantees that "excess earnings achieved under the cap will be utilized to mitigate transition or stranded costs for the benefit of ratepayers" as required by Section 2804(4)(V).

Q. Please elaborate on the minimum commitments.

A. Mr. Clayton demonstrates in his testimony that under the minimum depreciation and amortization schedule proposed, the projected book value of Duquesne's generating assets and regulatory assets as of December 31, 2005 is $535 million—reflecting $1.7 billion of depreciation and amortization between 1999 and 2005. Mr. Clayton quantified this $1.7 billion level of amortization as the amount that can be achieved under the generation price cap, while still providing the Company with an opportunity to earn a fair return on invested capital. He did this by solving for the depreciation and amortization schedule that would yield no more than an 11.5% return in each year given the forecast of revenues earned under the price cap and the projected costs over the price cap period. This is similar to the analysis performed in support of the Fort Martin plan.

Q. What is the effect of the ROE spillover mechanism?

A. As described by Mr. Clayton, the ROE spillover operates to guarantee that any excess earnings will be used to further accelerate depreciation or amortization and comply with the statutory requirement that excess earnings be used to mitigate transition or stranded costs for the benefit of ratepayers.

Q. Turning to the second showing, how do we know that these excess earnings will mitigate stranded costs and not simply reduce the book value of generation below market?

A. This is the second showing that Duquesne must make to satisfy the conditions of Section 2804(4)(v). Recall that Mr. Clayton projects a December 31, 2005 generation

book value of $535 million. Based on a present value margin analysis of Duquesne's generating units from 2006 to the end of unit life—comparing the cost of operation to the revenue each unit can earn at market—Mr. Clayton establishes that the market value of Duquesne's generation as of December 31, 2005 will range between $(47) million and $527 million -- less than the $535 million book value. Therefore, there is a prima facie showing that stranded costs will still exist in 2005 even after the $1.7 billion of committed depreciation and amortization is netted from the current book value of generation.

Q. On what basis did Mr. Clayton project the market value of Duquesne's generation beyond 2006?

A. The revenues he projects are based on a range of ceiling market prices that I have developed based on the cost of new entry beyond 2005. The support for these market prices is detailed in the following section of my testimony.

New Entry Prices Establish Price Ceiling of $34/MWh to $44/MWh in 2006

Q. What do you mean by a range of ceiling market prices?

A. I have developed an upper bound range of market prices based on the cost of entry by new construction assuming that such entry is in fact economic in 2006. These prices represent a "ceiling" on the market price, because if market prices were to exceed the ceiling it would be economic for new entrants to contest the market at those prices. As I will discuss later in my testimony, this is a conservative assumption that will

tend to overstate the range of market prices. Based on this assumption we can establish a ceiling for market prices beyond 2005 based on the costs of new construction and operation. This range of ceiling prices has been used by Mr. Clayton to estimate Duquesne's remaining stranded costs as of December 31, 2005.

Q. How did you estimate the price level necessary to permit entry?

A. I assumed that the technology of choice for new entrants in 2006 will be a gas-fired combined cycle unit, and I developed a range of break-even prices based on publicly available data on the cost of new construction. The range of prices results from alternate assumptions concerning capital cost, heat rate and the capital structure and payback requirements of the project. The details of each set of alternate assumptions are set out in Exhibit MMS-2 to my testimony[4].

Q. How did you account for gas prices?

A. I prepared a gas price forecast consistent with current forward market prices for natural gas. First, I obtained quotes for forward prices through 2005 for gas delivered to Henry Hub in Louisiana. Then, I adjusted the forward price stream to create a risk adjusted present value equivalent spot price stream through 2005. The spot price equivalent shown in Exhibit MMS-3 is $2.6/MMBtu in 2005. Finally, I assumed that the price of natural gas would escalate beyond 2005 at the general rate of inflation.

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[4] Exhibit MMS-2 contains the assumptions for a 2005 ceiling price range. As shown, I escalated the 2005 ceiling price by 2.5 percent to obtain 2006 values.

Q. How did you account for the cost of transporting gas between Henry Hub and ECAR?

A. I adjusted for the projected basis differential between Henry Hub and delivery to a new facility located in ECAR based on a 4 year basis differential quote between Henry Hub and the TCO pool. I then assumed that the basis differential would remain the same in real terms thereafter. The calculations and the supporting data for the base case gas analysis are set out in Exhibit MMS-3.

Q. What were the resulting ceiling price estimates?

A. Exhibit MMS-2 sets out two estimates for the market price ceiling based on different assumptions. I have labeled the estimates Low and High to reflect the resulting market prices for electricity. The estimates are presented as a real levelized price (based on an 84% capacity factor) that begins in 2006 and grows with an annual estimate of general inflation of 2.5%. The Low estimate is $34/MWH ($2006) and the High estimate is $44/MWH ($2006).

Q. Why did you calculate the range of estimates based on an 84% capacity factor?

A. The estimates reflect a range of entry prices for new baseload capacity. The Duquesne generation portfolio is almost entirely composed of baseload units. As detailed in Mr. Clayton's testimony, for purposes of his margin analysis, he assumed that the Duquesne units would be fully dispatched at their equivalent availability in 2006 and beyond. Based on this dispatch of Duquesne generation, the average capacity factor of the units would be 84%. The appropriate ceiling price to use for the margin analysis is a ceiling price calculated at the same 84% capacity factor.

Q. Please describe briefly the steps in the analysis that you used to arrive at your estimates.

A. The starting point is a range of estimates of total plant capital costs of a combined cycle unit obtained from a review of industry sources. The revenues necessary to recover the capital costs with a fair return on that capital were then projected using a revenue requirements model. A real levelized charging factor was then calculated for each estimate based on the capital structure and the time horizon for recovery of the equity capital and repayment of the debt.

Q. What assumptions have you made about the appropriate capital structure?

A. In a competitive merchant plant environment the debt to equity ratio will be smaller and the time horizon for recovery will be shorter than under traditional utility financing and cost recovery assumptions. Therefore, I have assumed that a competitive capital structure would require two-thirds equity and one-third debt using an equity rate of 14% and a debt rate of 8.5% with a recovery period of 10 to 15 years. This set of assumptions results in a real levelized charging factor of 18% to 23%, depending on the recovery period.

Q. But isn't Mr. Clayton using a utility cost of capital to discount the net cash flows in his margin analysis?

A. Yes. Therefore, to be totally consistent with his analysis we should use a utility capital structure and time horizon for recovery to project the market price ceiling. Alternatively, he could use a competitive cost of capital to establish the discount rate

for purposes of his margin analysis. If the market price is projected using a higher cost of capital than is used for discounting cash flows, the result will be to overstate the market values of Duquesne's generation.

Q. How have you accounted for these differences?

A. To account for this potential mismatch of ceiling market prices and discount rates, I have completed an alternate set of calculations using the Duquesne capital structure and a recovery period of 20 years. The alternate assumptions result in a real levelized charging factor of 12%. As shown in Exhibit MMS-2, the High estimate of $44/MWh ($2006) uses the 23% charging factor, while the Low estimate of $34/MWh ($2006) uses the 12% charging factor.

Q. How did you project operating costs for the combined cycle unit?

A. The fixed and variable operation and maintenance ("O & M") estimates for operation of the combined cycle unit were based on the 1993 EPRI TAG escalated based on the general inflation rate. Estimates for administrative and general ("A & G") expenses were based on 50% of the fixed O & M estimates. The high heat rate for the combined cycle unit was based on a review of industry sources, while the low case assumes further technological progress of 0.5% per year.

The case-specific total combined cycle fixed costs for each year are the sum of the fixed O & M and the A & G expenses added to the product of the capital costs and the real levelized carrying charge. The case-specific combined cycle variable costs for

each year are the variable O & M expenses added to the product of the forecast spot gas price and the unit heat rate. The new entry ceiling prices are calculated by averaging the combined cycle fixed cost over 7350 hours (for the 84% capacity factor calculation) and adding the combined cycle variable costs.

Market Prices Could be Lower than the Ceiling Price Range

Q. You mentioned earlier that the new entry costs you derived for 2006 were ceiling prices. Do you think the actual market price is likely to be higher or lower?

A. The actual market price is likely to be lower.

Q. Why?

A. There are a number of factors that could drive the market price lower. Improvements in generation technology could reduce the new entry price level below the range I have calculated. This could arise through significant improvement in combined cycle cost or efficiency, or from a breakthrough in a different competing technology. For example, there are a number of promising new peaking technologies under development, some at projected capital costs in the $100 to $150 per kW range. As I stated earlier, a major weakness of past avoided cost projections has been the assumption of constant technology.

Another group of factors could result in the market clearing at a level below the new entry price, even in 2006. The first of these is customer demand response during "super peak" periods. During these periods, peak load in ECAR tends to decrease by

approximately 8.5% between the peak hour and the 100th highest hour. This means that with current technology building new capacity to serve these super peak hours may exceed $500/MWh. What we don't know is how many customers might be willing to reduce their consumption for a price far less than the cost of new construction. If the response is significant, the new entry date would be delayed, and 2006 prices could be lower than the combined cycle market price ceiling.

The availability of supply side resources less costly than the combined cycle unit could also cause the market to clear at lower prices than the combined cycle market price ceiling. For example, co-generation opportunities that are not yet economic at today's depressed wholesale prices, but which are cheaper than the new combined cycle, could be available in sufficient quantity to offset or reduce the need for new capacity in ECAR through 2006 resulting in lower market prices. Or, given the availability of coal energy in many hours of the year, it may be that new technology peaking capacity could be the economic choice through 2006 and the prices will not have risen to the combined cycle new entry level. Finally, opportunities in competitive markets and the interest of new entrants in building new plants for "strategic" market reasons could result in excess entry, and the creation of a new "temporary" surplus, driving market prices down again.

It is not a certainty that any of these factors will play a role between now and 2006, but there are many of them, they are not mutually exclusive, and they all operate to drive prices down, not up. Moreover, the results of Duquesne's recent solicitation

suggest that it is likely prices will be below the ceiling price range, at least for some period of time beyond 2006.

1997 Solicitation Suggests Lower Prices

Q. Does Duquesne have evidence of the market price for power during the Transition Period?

A. Yes, as detailed in the testimony of Mr. Irvin, Duquesne issued a solicitation to sell firm power on June 6, 1997 ("1997 Solicitation"). Duquesne offered to sell a minimum of 50 MW of firm power for a one-year period and a minimum of 100 MW of firm power for an eight-year period commencing on January 1, 1998.

Q. How were the winning bids selected?

A. The winning bids for the one-year contract were selected based on the highest prices offered for 1998. The winning bids for the eight-year contract were selected based on the highest prices offered on a present value basis over the contract term.

Q. Please summarize the results of the 1997 Solicitation?

A. As Mr. Irvin's testimony indicates the nominal levelized price of the winning eight-year bids was $20.19/MWh over the term of the contract. Over the same period, the real levelized equivalent bid price[5] would be $18.7/MWh ($1998). The difference

[5] Beginning in 1998 and growing at an assumed inflation rate of 2.5% per annum.

between the two price streams is that the real levelized price stream starts at a value of $18.7/MWh in 1998 and increases each year by the assumed rate of general inflation (2.5% annually) through 2005. The nominal levelized price stream starts at a higher value of $20.19/MWh in 1998 and remains the same in each year. On a present value basis the two streams are equivalent.

Q. How are the real levelized forward market prices you derived from the 1997 Solicitation relevant to the market prices Mr. Clayton used in his margin analysis beyond 2005?

A. The forward market price for power of $18.7/MWh ($1998) established by the 1997 Solicitation is very low compared to the cost of new entry. The winning bids reflect a supply/demand balance in ECAR with ample energy available most hours of the year that continues throughout the Transition Period. When supply and demand comes back into balance in the region, we would expect the market price for power to be rising toward replacement cost levels. However, the solicitation results strongly suggest that combined cycle new entry will not be economic by 2006.

Q. How did you conclude that combined cycle new entry is unlikely to be economic by 2006?

A. The winning bids for the eight-year solicitation were chosen on a present value basis. Therefore, the annual bid prices are only relevant as inputs to the present value of the entire price stream, and not as indicia of the prices in each year. Finance theory suggests that the present value of the forward price stream should be equivalent to the

present value of expected future spot prices (appropriately risk adjusted) over the same period. To derive these future spot prices, I first calculated an all-hours equivalent of the winning 75% capacity factor bid prices and discounted this price stream. I then calculated an all-hours spot price stream that was equivalent on a present value basis discounted at a risk-adjusted discount rate. In this calculation, I used a 200 basis point risk premium to solve for the equivalent all-hours real levelized spot price stream. The calculation I describe results in spot prices approximately 8% higher than forward prices in each of the eight years of the contract when presented on a real levelized basis. However, the present value of the spot price stream calculated at a higher risk adjusted discount rate is still equivalent to the present value of the forward price stream calculated a lower risk free discount rate.

Q. What does this tell us about the path of expected all-hours spot prices?

A. The analysis above is described in terms of present value equivalents. The resulting real levelized all-hours spot price is $19.4/MWh ($1998). However, this value is higher than the equivalent all-hours spot price of $17.8/MWh ($1998) derived from the winning bids for the one-year contract. Presenting the spot prices on a real levelized basis would likely overstate the expected spot prices in the early years of the contract period and understate them in the later years. Therefore, I recalculated a present value equivalent spot price stream that began at the one-year price of $17.8/MWh and grew at slightly more than double the rate of inflation through 2005. In effect, I solved for the escalation rate starting from 1998 spot prices that would make the present value of the two streams equivalent. The last year of this equivalent

stream is $25.6/MWh ($2005), representing the estimated 2005 future spot price implicit in the solicitation results. Exhibit MMS-4 sets out the derivation of the 2005 future spot price estimate.

Q. What do you conclude based on this analysis?

A. The 1997 Solicitation suggests that there is a significant gap between the likely 2005 spot market price and the market ceiling established by the cost of new capacity. The all hours spot price equivalent I calculated for 2005 was $25.6/MWh ($2005); adjusting to an 84% capacity factor basis would increase this spot price equivalent to $26.5/MWh ($2005). This $26.5/MWh value is still far below even the Low estimate of the market price ceiling based on cost of economic new entry in 2006. Therefore, it is highly unlikely that new combined cycle capacity would be economic to build in 2006 based on the results of the 1997 Solicitation, particularly if required new entry prices are at the high end of the range.

Q. Have you assessed the impact of new combined cycle capacity not being economic until after 2006?

A. Yes. I have developed two additional market price estimates based on the cost of new entry in the year 2010 under the High and Low competitive capital structure assumptions shown on Exhibit MMS-2. In each case, I calculated a spot price trajectory between 2006 and 2010 required to reach the appropriate new entry price in 2010. These two additional cases are summarized on Exhibit MMS-5.

Q. What do the results of these additional cases show?

A. Unsurprisingly, the real levelized prices of these delayed entry cases are lower than their corresponding 2006 entry cases. In the High case, the real levelized price falls from $44/MWh to $41/MWh under delayed entry assumptions. In the Low case, the price falls from $37/MWh to $35/MWh, a smaller reduction.

Q. What do you conclude from this delayed entry analysis?

A. Because market evidence indicates that economic combined cycle entry in 2006 is unlikely, particularly at the high end of the new entry range, the $44/MWh High price estimate is unrealistically high. By using the High estimate of $44/MWh Mr. Clayton's margin analysis likely overstates the market value of Duquesne's generation and thereby understates the remaining stranded costs. Based on the delayed entry case, $41/MWh is a more realistic figure for the High case, which would reduce Mr. Clayton's year-end 2005 market value from $527 million to $278 million, and increase remaining stranded costs by approximately $249 million.

Q. Mr. Schnitzer you have discussed the 1997 Solicitation results only in the context of post-2005 prices. Is the level of market prices between 1999 and 2005 important for any other reason?

A. The principal value of 1999 to 2005 prices is as evidence of the likely market price in 2006 and beyond. That is because market prices during the Transition Period do not have much effect on the amount of amortization that can be realized under the price cap from sales to existing customers. This amount depends mainly on the revenues

that can be earned under the price cap and the cost of producing that power. This is because Duquesne is proposing to calculate its CTC as a residual from the generation cost of service, and thus the combination of market prices and the CTC will result in revenues equal to current rates times purchases by jurisdictional customers. This is true even if the customer has chosen an alternative generation supplier. A higher or lower market price during the Transition Period will only change the proportions of revenue recovered through the CTC and through sales at the market price. Total revenues will remain unchanged as long as the market price has been used to set the CTC. Market prices will have an effect on off-system sales margins, but their contribution to the $1.7 billion depreciation and amortization commitment is quite modest.

Q. You have used the all-hours expected spot prices from 1999 and 2005 to assess the likelihood of new combined cycle entry in 2006. What other use is made of the all-hours expected spot price stream?

A. Mr. Karl's testimony describes how he uses the escalating all-hours spot price stream as an input to calculate the prices that would be faced by Duquesne's generation in the market during the Transition Period. Mr. Karl uses this spot market price stream to determine the dispatch of the Duquesne units during the Transition Period and the resulting off-system sales and purchases are reflected in Mr. Clayton's projections of the costs and revenues of operating Duquesne's system.

Use of Market Price Estimates is Appropriate for Section 2804(4)(V) Showing

Q. Why is appropriate to use these market price estimates to determine stranded costs as of 2005?

A. The purpose for which these estimates are being used by Mr. Clayton is not to make a claim for a one-time administrative determination of stranded costs in that amount. Rather, he is seeking to establish the more limited claim that Duquesne is entitled to the rate cap under section 2804(4)(v) of the Customer Choice Act. The actual determination of stranded costs under the Duquesne proposal will be completed in 2003 using a market-based valuation.

I have provided a high and a low estimate of the market price ceiling established by the entry costs of a combined cycle unit coming into service in ECAR in 2006. In discussing the uncertainties surrounding the input to these estimates, I concluded that resolution of the uncertainty would likely result in a decrease in the costs of new entry or a delay in the year of entry beyond 2006. Indeed, the results of the 1997 Solicitation suggest that 2006 is highly unlikely as a year of combined cycle entry.

However, over the full range of post-2005 ceiling prices, Mr. Clayton demonstrates that the book value of generation and generation-related regulatory assets remaining at the end of 2005 (after netting the committed level of amortization) will exceed the market value of generation. Thus, even under conservative assumptions Duquesne has demonstrated that it will have stranded costs remaining in 2005 even after

applying all "excess earnings" under the price cap to stranded cost mitigation. Moreover, even in the unlikely event that prices rise, or stranded costs are amortized more quickly than forecast, Duquesne has proposed specific market-based early valuation triggers that protect customers from a continuation of the rate cap for too long and recovery of too much stranded costs by Duquesne. Thus Duquesne has made both parts of the two part showing, and is entitled to a price cap through 2005.

Market Based CTCs are Superior

Q. How does the calculation of stranded costs relate to the setting of CTCs?

A. In Pennsylvania utilities are permitted to collect their stranded costs through a competitive transition charge or CTC. Section 2808(A) of the Customer Choice Act provides in part that: "To provide each electric utility with an opportunity to recover its transition or stranded costs following the Commission's determination under subsection (c), every customer accessing the transmission or distribution network shall pay a competitive transition charge to the electric distribution company in whose certificated territory that customer is located."

In the restructuring filings prior to August 1, 1997 (i.e., PECO, Pennsylvania Power and Light and the GPU Companies) the parties have performed a one-time calculation of stranded costs as of the beginning of the Transition Period. This present value of stranded costs is then used to calculate a CTC revenue requirement over the Transition Period to establish CTC rates for each class.

Q. How does Duquesne's calculation of CTC's differ from the approach of the other utilities in Pennsylvania?

A. Duquesne will sell a substantial block of power in each year of the Transition Period in order to establish an objective market price. The terms and conditions of the sale will be similar to the one-year 1997 Solicitation. These annual solicitations will determine the market value of power and the customer's opportunity cost of leaving Duquesne in that year. The resulting prices will be used to determine customer-specific CTCs.

Administratively Determined CTCs are Inferior

Q. Does the process proposed by the other Pennsylvania utilities send the right price signals to customers and suppliers?

A. No, not when customers have the protection of a rate cap during the Transition Period. For example, the methodology offered by PECO in its restructuring case proposes to calculate the CTC revenue requirement and levelize it over the seven-year Transition Period. Because the Customer Choice Act requires utilities to unbundle rates, PECO also proposes to calculate the "market rate" it will offer to generation customers as a residual after deducting the levelized CTC from the generation price cap. As the OCA points out in the testimony of witness Lee Smith (pp. 8-11), the PECO calculation of the "market rate" will set the implicit market price signal too low, and, assuming market prices increase over time, this disparity will widen during the Transition Period.

A similar criticism is voiced by PAIEUG in the testimony of witness Stephen J. Baron (pp. 27-34). Both witnesses make the point that if PECO establishes a levelized CTC based on a one-time determination of stranded costs, customers will be sent the same price signal for each year of the Transition Period, even as the actual market price for power changes over time. Customers always have the protection of the PECO generation rate cap, and if the residual "market price" calculated is less than the actual market price, customers will stay with PECO. This result, as the OCA and PAIEUG point out, can hinder competition and retard the development of a healthy retail electricity market. As OCA witness Lee Smith states at p. 8 "The company's proposed generation component, which is fixed for the transition period, does not bear any relationship to the cost of providing power to the retail customer."

Q. Does the OCA offer a better alternative to the PECO CTC methodology?

A. No, the OCA simply proposes to substitute an administratively determined "avoidable generation component" that increases over time. This component however is subject to the OCA's own criticism, that it does not bear any relationship to the cost (i.e., purchased at market) of providing power to the retail customer.

Q. Does PAIEUG offer a better alternative to the PECO CTC methodology?

A. No, PAIEUG simply proposes to replace the administratively determined "market price residual" with an administratively determined "CTC residual." At p. 33 of his testimony witness Baron states: "Under the alternative approach, which I am recommending, estimated market prices for each of the seven years would be

subtracted from the unbundled generation component, leaving a residual value that would then become the CTC for each year. Since market prices change during the seven year transition period, increasing over time, the residual CTC would also vary (though fixed for each year at the time of the unbundling) during the seven year period...Under this approach, the market rate component of PECO's unbundled rate schedules would reflect expectations for market rates in each year of the transition period."

Both the OCA and PAIEUG are carrying over the administrative determination of stranded costs to an administrative determination of CTCs and implicit market price signals sent to customers. In essence, both the OCA and PAIEUG propose to administratively estimate – in advance – the market price to customers that continue to take generation service from PECO, and do not propose to adjust this price to reflect actual changes in the market.

Q. Why is that a problem?

A. Under a price cap, the net opportunity cost[6] to a utility of not selling generation to an existing customer at capped embedded cost generation rates will change. If the market price rises, the net opportunity cost falls and vice-versa. Similarly, for customers, their opportunity cost of not purchasing power from competitive suppliers

[6] The net opportunity cost is the difference between embedded cost generation rates and the current market price.

of generation will rise and fall depending on the market price of power. Only by setting the CTC based on the current year's market price are the customer and competitive suppliers faced with the right price signals.

Estimating the Price Signal in Advance Distorts Economic Behavior

Q. Why is it important to use the current market-determined price to set the CTC price signal?

A. Consider the following illustrative example where the incumbent utility is subject to a rate cap. In year 1 the generation rate cap is 6.0 cents/kwh and the market price for year 3 is forecast to be 2.5 cents/kwh. The utility fixes the CTC for year 3 in advance at 3.5 cents/kwh (6.0-2.5) based on the forecast market price. In year 3 the actual market price turns out to be 3.0 cents/kwh, but customers choosing whether to leave their incumbent supplier are still faced with the fixed price signal of 2.5 cents/kwh. By fixing the CTC artificially high based on an erroneous market price forecast customers will not leave the utility in year 3 because the market price has risen above their price signal of 2.5 cents/kwh. Competitive suppliers will be disadvantaged by the combination of the rate cap and the CTC. Customers will choose to stay with their incumbent supplier even if a competing supplier could discount the market price two mills below 3.0 cents/kwh.

Conversely, suppose the same example as above, except that in year 3 the actual market price turns out to be 2.0 cents/kwh. Customers choosing whether to leave

their incumbent supplier are still faced with the fixed price signal of 2.5 cents/kwh. By fixing the CTC artificially low based on an erroneous market price forecast customers will leave even when it is not economic to do so. A competing supplier could sell to customers at a premium of two mills above the market price of 2.0 cents/kwh and still offer them savings. The incumbent utility will be disadvantaged by not being able to resell the lost load above the current market price of 2.0 cents/kwh

Duquesne's CTC Methodology is Superior and Sends the Right Price Signals

Q. Why is the Duquesne CTC methodology superior to the administrative proposals already advanced in Pennsylvania?

A. Duquesne's proposal properly reflects the uncertainty in future spot market prices. As the market price for power changes over time, the net opportunity cost to Duquesne of not selling generation to an existing customer at capped embedded cost generation rates will change. If the market price rises, the net opportunity cost falls and vice-versa. By having the opportunity to sell the lost load in the market, at the market price, Duquesne offsets the lost opportunity to sell at the capped generation rate by the revenues obtained at current market. The customer's CTC is established annually based on the then current market price for firm power determined in the most recent annual solicitation. In each year of the Transition Period the customer faces a price signal based on the difference between that year's market price and the generation rate cap. Based on this price signal, customers can choose to leave

Duquesne when the price of a competitive supplier is favorable compared to Duquesne. Customers can return to Duquesne as a generation supplier at unbundled rates and may do so if the unbundled generation rate is competitive with market.

Market Prices are Required to Establish CTCs

Q. What do you conclude about establishing CTCs under a rate cap?

A. Where customers are protected by a rate cap, determining CTCs on a one-time *ex ante* basis using an administrative determination of stranded costs and estimated market prices is inherently flawed. The correct price signals will only be sent if CTCs are determined as a residual of the generation price cap and the current market price determined from market evidence.

Q. How does this customer-specific CTC approach proposed by Duquesne meet the known and measurable standard?

A. The market-based RFP approach determines a known and measurable one-year market price that is used to calculate stranded costs based on the difference between market and the customer's current embedded cost generation rate.

2003 Market-Based Valuation Meets Known and Measurable Standard

Q. Please explain how the market-based valuation methodology permits a final valuation of stranded costs consistent with the known and measurable standard.

A. The Customer Choice Act requires a calculation of stranded costs to meet a known and measurable standard. The conclusion I reached in the first part of my testimony was that a market-based determination of stranded costs was inherently superior to an administrative determination. I concluded that only a market-based approach could reasonably satisfy the known and measurable standard required by the Customer Choice Act. However, because markets for standardized commodity contracts such as forward and futures contracts are only now beginning to develop and environmental and restructuring uncertainties have not been resolved, a market valuation for the years beyond 2005 should be deferred until later in the Transition Period.

Accordingly, Duquesne has not sought to calculate a final value for stranded costs as of January 1, 1999 as have the other utilities in Pennsylvania. Duquesne has instead shown that it cannot fully recover its stranded costs through application of "excess earnings" through 2005 under the rate cap.

Public sources of objective market data will likely be available late in the Transition Period that will permit a known and measurable valuation of stranded costs as of December 31, 2005. The final market valuation proposed by Duquesne would be scheduled to begin in 2003. The intent of this proposal is to complete the final market valuation by the end of 2003 in time to permit any changes to the CTC to become effective January 1, 2004.

Final Market Valuation Based on Independent Appraisal

Q. How would a final market valuation be conducted?

A. The Duquesne proposal has three basic elements. First, the final valuation will be based on objective evidence of market values, not market price forecasts. Second, the final valuation will be conducted by an unbiased arbitration panel that will submit a final valuation report to the Commission. Third, upon receipt of the valuation report, the Commission will retain the final authority to determine the market value of Duquesne's generation assets and, hence, stranded costs under the Customer Choice Act.

Q. Please elaborate on the first element of the Duquesne proposal.

A. The market value of Duquesne's generation will be set on the basis of actual market prices contained in consummated market transactions in the relevant market, such as futures contracts, forward contracts or asset sales. To ensure the availability of market evidence, Duquesne will commit to sell long-term firm power under a competitive solicitation to provide evidence of long-term forward prices. The sale of power by other utilities will be considered as market evidence if such sales are in the relevant market and, as to asset sales, are for comparable generation assets within the relevant power market.

Q. Please elaborate on the second element of the Duquesne proposal.

A. A three-member arbitration panel will be selected to ensure a fair and unbiased composition. Duquesne will select one member, a consumer representative (such as the Office of Consumer Advocate or the Commission staff) will select the second member, and these members will select the third member. The panel will base its decision solely on objective evidence of market values as described in the first element.

Q. How would the panel calculate the final market value?

A. The actual methodology would be up to the panel's discretion. One methodology might determine the final market valuation of Duquesne's remaining generation assets from 2006 onward using a net present value calculation of after-tax cash flows, based on the market evidence gathered by the panel. In such an analysis it is anticipated that the panel would use the then current best estimates of the cost of capital, unit availability, capital expenditures, fuel costs, and operating expenses in making a determination of value.

Q. What input from the public will be permitted?

A. To ensure public participation, any interested party may submit evidence of such market values to the panel. After considering the evidence and deliberating, the panel will issue a written report detailing its findings on market value. This written report will be submitted to the Commission for review and public comment.

Q. Please elaborate on the third element of Duquesne's proposal.

A. Upon receipt of the arbitration panel's report, the Commission may solicit public comment and render its decision on the market value of Duquesne's generation, and hence on Duquesne's stranded costs, pursuant to traditional hearing procedures. In reaching its decision, the Commission will, of course, not be bound by the panel's findings on market value. Nor, does Duquesne propose to bind any intervening party to these findings. All intervening parties may contest the Commission's determination of market value, whether or not such determination is based on the panel's findings or other evidence.

Q. Will Duquesne be bound by the panel's finding of market value?

A. Duquesne will commit to bind itself to the panel's findings subject only to the following condition: if the Commission rejects the panel's findings and substitutes a market valuation that is adverse to Duquesne, Duquesne will be permitted to establish market values through the sale of some or all of its generating assets or the sale of an equity interest in a new corporation ("Genco") to which Duquesne's generating assets would be transferred. If Duquesne sells individual generating assets, the sales prices will determine the value of only those assets sold by Duquesne. If Duquesne sells an equity interest in Genco, the price will set the value of all generating assets owned by Genco. The market values established through the asset sale or the generation company spinoff would be used to calculate the final market value of those generation assets.

Q. Does Duquesne have any other recourse if the Commission's decision is adverse?

A. If Duquesne chooses not to sell assets or an equity interest in Genco, it may contest the Commission's rejection or modification of the panel's findings by pursuing an appeal of the Commission order or requesting further hearings (or rehearing) before the Commission.

Q. What is the ultimate purpose of the final market valuation?

A. The final market valuation will provide objective market evidence of Duquesne's stranded costs as of the end of the Transition Period. If this valuation demonstrates that Duquesne will have fully amortized its stranded costs prior to the end of 2005, then Duquesne will reduce the Transition Period accordingly and cease to collect a CTC from its customers. This will ensure that customers do not reimburse Duquesne for more than its stranded costs. Alternatively, if this valuation confirms that Duquesne cannot fully recover its stranded costs prior to the end of 2005, the final market valuation will provide the basis for any further relief that Duquesne is entitled to seek under the Customer Choice Act or pursuant to the protections provided by other laws.

Q. Doesn't Duquesne's proposal for an arbitration panel charged with preparing a market valuation fall prey to the criticisms you have made about administrative forecasts?

A. No. The key distinction is in the nature of the valuation: the panel proposed by Duquesne will prepare its valuation based on actual market prices contained in transactions between willing buyers and sellers, such as the winning bid prices revealed in a Duquesne solicitation or the prices revealed in other forward market

buy/sell transactions. The practice of forecasting that I criticized earlier is something quite different: the prediction of future market prices based on a myriad of assumptions about future market behavior of individual agents that collectively determine supply and demand. It is these assumptions that routinely prove materially inaccurate, and often prove to be grossly so.

These assumptions suffer from a related infirmity. Given that they represent the predictions of economists and experts, rather than the risk-taking actions of market participants, they provide Duquesne's investors no reasonable ability to hedge the financial effects of using such assumptions to set the level of stranded costs, and hence CTC rates. For example, if economists predict market prices of $40/MWH, but market participants are not willing to purchase power at that price, Duquesne cannot effectively sell power in an effort to hedge the risk that such market price estimates will prove inaccurate.

Under Duquesne's proposal, only the prices contained in actual market transactions or public offers to buy and sell power would serve as the basis of stranded cost calculations, thus providing Duquesne a reasonable opportunity to recover its stranded costs by accepting the offers of market participants to purchase power at those prices. The use of an independent panel simply provides a neutral party with specific valuation expertise to consider the relevant market data.

Market Valuation Should Be Deferred Until Later in the Transition Period

Q. Assuming you are correct that only a market-based valuation should be used to establish stranded costs, why not simply use the market price data available today to establish the value of Duquesne's generating assets?

A. There are two reasons why the market valuation should be deferred until later in the Transition Period. The first is that the market for long-term power in ECAR today is sufficiently illiquid that there are not sufficient long-term transaction data to confidently establish a market value. The results of the 1997 Solicitation provide some market data, but these 8-year bids are not of sufficient term to establish a market value for Duquesne's generation.

Q. Will this situation change in the foreseeable future?

A. Yes, as I stated earlier in my testimony, I expect that electricity market will follow other deregulated markets, particularly natural gas in developing a more robust and liquid market for forward and futures contracts. In addition, generating asset sales within ECAR may answer the question of whether, as some have suggested, there is a premium associated with asset ownership that would cause values calculated on the basis of market prices for power to understate asset value. In any event, even if none of this evidence does materialize by 2003, the arbitration panel will be able to rely on the market evidence from Duquesne's long-term solicitation in 2003. Therefore, in all cases the final market valuation will be based on actual transactions and hence the final stranded costs will be known and measurable in a meaningful sense.

Q. What is the second reason for deferring the market valuation?

A. The second reason has to do with the price cap and a customer's right to service at the price cap during the Transition Period. As has already been described, the price cap approach to stranded cost recovery under the Customer Choice Act requires that two questions be addressed:

- How much "excess earnings" are available to mitigate stranded costs during the price cap period; and
- Are there stranded costs remaining at the end of the price cap period after taking account of the "excess earnings" mitigation -- does the book value still exceed the market value of generation?

It is clear that the required valuation is as of the end of the price cap period -- not at the beginning. Given that the valuation date is as of the end of the price cap period, it is preferable to delay the valuation process to a date much closer to the valuation date. To perform the valuation any earlier, even with market data, is to invite unnecessary risk and uncertainty associated with the volatility in market prices. If we ask the market today, we will get its best estimate of post-2005 market price, an estimate with a high variance (i.e., a greater level of uncertainty). But if we ask the market in 2003, we will get a more certain estimate of post-2005 prices. Duquesne's proposal properly recognizes that a later valuation of generating assets as of 2005 is preferable to an earlier valuation as of 2005. This later valuation is clearly more likely to produce a "known and measurable" calculation of the net present value of stranded

costs over the life of Duquesne's generating assets, as required by the Customer Choice Act.

Proposed Final Market Valuation is Fair to Customers and Shareholders

Q. Why is a final market valuation fair to customers and shareholders?

A. Mr. Clayton has committed Duquesne to a minimum level of accelerated depreciation and amortization and coupled this with the guarantee of an ROE spillover. This is complemented by the "true-up" of the final market valuation. This ensures that Duquesne does not over recover its stranded costs and that customers do not pay twice for the costs of generation. If the market valuation is higher than the committed level of book value (appropriately adjusted for capital expenditures) then the accelerated recovery under the price cap will end before 2005. A negative residual value determined by the final market valuation will give Duquesne the opportunity to request that the Commission extend the price cap to allow further recovery.

Q. When would an earlier valuation date than 2003 be appropriate?

A. Two events would trigger an early final market valuation process to determine the residual market value of the generation assets. First, if the long term market price of power rises significantly prior to 2003, then it is possible that the residual market value at the end of 2005 will significantly exceed the unamortized book value of generation and early termination of the CTC might be possible. The proposed solution is to establish market price triggers for the years 2001 and 2002, and to accelerate the

final market valuation to 2001 or 2002 if the trigger prices are exceeded. Mr. Clayton's testimony includes the calculation of the "early trigger" market prices for generation for each year. The evidence to determine whether the market price exceeds the trigger price is Duquesne's annual solicitation for sale of firm power held in 2000 and 2001 to established the customer specific CTCs for 2001 and 2002. Second, as described by Mr. Clayton, if Duquesne has fully completed its scheduled $1.7 billion amortization prior to 2003, then an immediate final market valuation can take place to determine if CTC collection should be reduced or eliminated.

Q. Do either of the early triggers settle the issue of residual market value?

A. No. The triggers merely accelerate the final market valuation mechanism. That mechanism, and not the triggering events, determines the residual market value.

Asset Sales Should Recognize Margin Contribution Under Price Cap

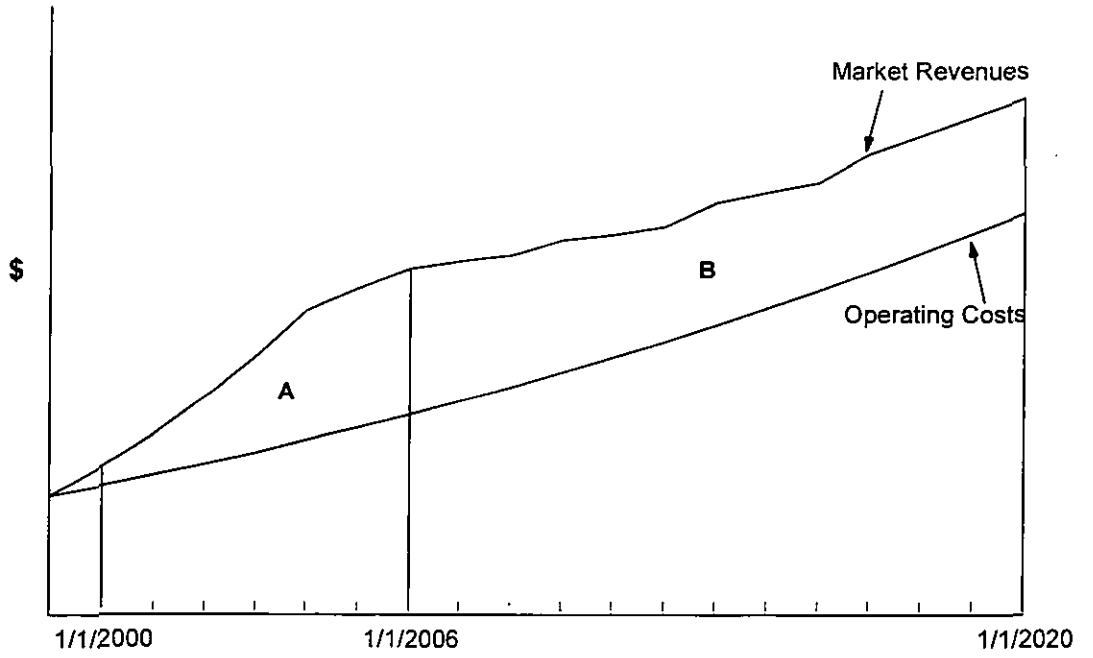
Q. Please describe the issues that arise as a result of generating asset sales.

A. Sales of generating assets during the Transition Period raise complicated valuation issues while the rate cap remains in place. During the Transition Period Duquesne effectively earns generation revenues equal to the generation rate cap based on a combination of CTC revenue and market generation revenue. This combined revenue level is what has allowed Duquesne to commit to accelerated amortization of generation and regulatory assets. The question is how to treat the proceeds from asset sales for purposes of writing down the book value of generation.

Q. When an asset is sold doesn't one simply credit the purchase price against the book value of the asset and any associated regulatory assets?

A. No, that would ignore the effect of the rate cap. The operating margin from generation during the Transition Period (i.e., the difference between to go costs and market revenues) helps to fund the accelerated amortization that Duquesne has committed to as part of this proposal. The contribution to amortization by sales made under the rate cap prior to December 31, 2005 is part and parcel of the stranded cost package. With an asset sale, this operating margin contribution is lost to Duquesne and goes instead to the new generation owner. Thus, if an asset is sold, the foregone operating margin contribution through the end of 2005 must be deducted from the sale proceeds before crediting against book value.

This can be conceptualized more easily as an asset sale coupled with a contract back through 2005. If Duquesne sold a generating asset that would otherwise have provided power at an average to-go cost of $15.00/MWH through 2005 then the operating margin from that output will be reflected in the purchase price. As well, any residual market value in the asset beyond 2005 will also be reflected. If the purchaser agrees to sell the output back to Duquesne at the "to go" costs during the Transition Period, then the purchase price paid will be automatically reduced by otherwise foregone operating margin over this period, discounted to the date of purchase. This is illustrated by the graphical example below. The area A represents the contribution margin within the Transition Period.



Area B represents the contribution margin that determines the market value of the asset beyond 2005. Any credit against the book value must separate the sources of value to the purchaser and only credit the value of Area B in order to avoid over crediting.

The above described adjustment to sales proceeds protects investors from double counting Transition Period operating margin. In a similar vein, the book value of the plant must be adjusted downward to equal the present value of the estimated 2005 book value to ensure that customers receive the full benefit of the committed amortization.

Q. Please summarize your conclusions regarding asset sales.

A. The proposed treatment of asset sale proceeds is necessary to properly account for the residual market value in the asset sale price. This accounting can be accomplished through an explicit contract back from the purchaser at the unit's to go costs for the remainder of the Transition Period. Alternatively, an implicit contract could be calculated to remove this source of value from the purchase price. This treatment satisfies the known and measurable standard. Similarly, the proposed book value adjustment also satisfies the known and measurable standard.

Duquesne's Proposal Provides Customers with Any Benefits From Economic Shut Downs

Q. The market prices determined by the 1997 Solicitation are quite low: how does Duquesne's proposal address unit shut down during the Transition Period?

A. Let me first describe the two principles which define a properly structured shutdown analysis. The first principle is that a proper analysis should only consider the true avoidable costs of continued operation. The second principle is that, given the irreversibility of a shutdown decision for a nuclear unit or some coal units, the analysis should consider the "option value" of continued operation.

Q. Please address the first principle regarding avoidable costs.

A. A basic economic principle is that sunk costs should play no role in the decision of whether to continue to operate a plant, or to shut it down. The reason for this is that

sunk costs cannot be "saved," and thus are irrelevant to the decision of whether it is cheaper to continue to operate a facility, or to shut it down. While the principle may be clear, it is sometimes less clear whether a particular cost is sunk or not. For some categories of cost this determination is quite straightforward. For example, the net book value of a facility is clearly a sunk cost, while the projected cost of fuel not yet purchased is clearly not a sunk cost.

While it is tempting to generalize from these examples that all dollars already spent are sunk, and all those not yet spent are not – this is in fact not correct. Two categories of costs "not yet spent" may nevertheless represent sunk costs for the purposes of economic analysis. First, costs which have not yet been incurred but for which there is an obligation or commitment to fund independent of whether the generating facility remains open or shuts down. Obligations such as contractual commitments to pay lease expenses, fuel or equipment costs would all – net of salvage value – represent sunk costs. Second, allocated operating costs which are assigned to a particular project or facility using some accounting convention, rather than being a cost directly incurred by the facility, may represent – at least in part – sunk costs.

The common feature of these two exceptions is that they represent operating costs which are not avoidable by shutting down the facility. Contractual purchase obligations, net of salvage or resale value, are not avoidable. Allocated or assigned costs, or a portion thereof, may not be avoidable. Any such costs that are not

avoidable by closing the facility, even though the cash costs have literally not yet been spent, are still considered to be sunk costs for purposes of economic evaluation. Thus, a properly structured economic analysis must carefully distinguish between those operating costs that are avoidable, and those that are not.

Q. Please elaborate on your second principle related to option value.

A. Many types of facilities have the characteristic that once shut down they cannot be restarted except perhaps at great economic costs. Other facilities can be shut down and later reopened at will with little or no economic penalty. For this latter type of facility the economic analysis of continued operation is quite simple. The avoidable costs for a period of time (e.g., a year) can be compared to the anticipated revenue if the facility operates. If avoidable costs exceed anticipated revenues the facility can be closed for the period. This decision can be made without consideration of subsequent periods, because the decision to shut down today has no implications for the ability of the facility to reopen tomorrow should anticipated revenue then exceed avoidable cost.

Q. What about facilities that once shutdown cannot be reopened or can be reopened only at great cost?

A. For these facilities a simple one period analysis is not adequate. A decision to remain open for one period (a year or a fuel cycle) must consider not just the profit or loss from revenues less avoidable costs in that period, but also the value of the option to remain open the next period. Similarly, a decision to shut down at a particular time

carries with it not only the economics of the next period, but also forecloses the option to operate the facility in all subsequent periods.

Thus for this second type of facility, a decision to remain open in one period preserves the option – but not the obligation – to remain open in subsequent periods. A decision to close the facility cancels the option to operate the facility in all subsequent periods. In some cases it may make sense to operate the facility at a loss (avoidable costs in excess of revenues) for some length of time to preserve the option to make money in the future. In such cases the value of the option to operate in the future must exceed the cost of preserving the option.

The value of the option is an empirical question. It depends on the avoidable cost of operating the facility relative to the expected revenue, but also on the uncertainty or volatility of the revenue. Other things being equal, the more uncertain the revenue, the more valuable the option to remain open. For facilities facing an irreversible shutdown decision this option value must be included in an economic analysis of continued operation.

Q. How does Duquesne's proposal deal with shutdown?

A. The question is how to deal with the closure of a generating plant that was economic to operate at the time of the Commission's order, but becomes uneconomic to operate during the Transition Period. Under Duquesne's proposal two things are clear. First, Duquesne has the right incentives to shut down uneconomic units, appropriately considering option value. Second, customers receive any benefits from economic

shutdown because any "excess earnings" that result from the shutdown will be used to further accelerate the amortization of stranded or transition costs and help end the Transition Period early.

Q. Please elaborate on Duquesne's incentives to shut down uneconomic generation.

A. Duquesne continues to have an obligation to serve at capped rates during the Transition Period. If the shutdown decision is the result of operating costs that are higher than expected at the time of the restructuring order, then Duquesne must buy at market to cover the lost output. Duquesne will compare the actual avoidable to go costs of operating the unit against market price in making the shutdown decision. If purchases at market are less expensive (appropriately considering option value) then Duquesne will shut the unit down and discharge its obligation to serve from the market. This cost to cover at market may be in fact be greater than the anticipated operating costs for the unit at the time of the restructuring order. However, since actual costs have risen, and Duquesne is at risk for increased market costs due to the shutdown, it has the right incentives to do the analysis correctly and shut down the unit when it is economic to do so.

Conversely, if the shutdown decision is the result of market prices that are lower than expected at the time of the restructuring order, then Duquesne lowers its cost of meeting its obligation to serve under the rate cap. This lower cost allows Duquesne a greater opportunity to earn its allowed return under the price cap and to further accelerate the recovery of stranded and transition costs under the ROE spillover. Therefore, in this case too, Duquesne has the right incentives to do the analysis

correctly and shut down the unit when it is economic to do so.

Q. Please elaborate on the customer benefits and protections if Duquesne shuts down a generation unit.

A. As discussed above, Duquesne has the right economic incentives to do the shut down analysis correctly. If shutdown results from higher than anticipated costs or worse performance, customers nonetheless receive the benefit of the guaranteed amortization, whether or not Duquesne is able to earn its allowed return. If shutdown results from lower than expected market prices, customers receive the benefit of any cost reduction through the ROE spillover. Finally, the operating margin from generating assets that are shut down during the Transition Period is effectively valued at zero, thus resolving the question of residual market value. Duquesne will not end up owning a potentially valuable asset after the Transition Period.

Q. Please summarize your conclusion with respect to plant shutdown.

A. The proper incentives to shut down a plant when it is economic to do so combined with the ROE spillover mechanism ensure that Duquesne will minimize, but not over recover its stranded costs through economic shutdown. The adjustments to the book value of generation and regulatory assets in the event of a plant shutdown are known and measurable.

Summary

Q. Please summarize your testimony.

A. I have five major conclusions concerning the known and measurable standard and Duquesne's market-based approach to stranded cost calculation and recovery:

- A market-based determination of stranded costs is inherently superior to an administrative determination. Only a market-based determination can reasonably satisfy the known and measurable standard required by the Customer Choice Act.
- Duquesne is entitled to a price cap on generation rates under section 2804(4)(V) of the Customer Choice Act for each year of the Transition Period, subject to early termination of the cap.
- The Duquesne proposal to set customer-specific CTCs annually based on the market price of electricity as determined by the results of a market-based solicitation is efficient, fair to investors and customers, and meets the known and measurable standard.
- The proposed market-based determination of stranded costs as of December 31, 2005 provides a known and measurable methodology to calculate stranded costs on a net present value basis.
- The proposed "true-up" methodology of the final market-based valuation protects customers by ensuring that Duquesne does not over recover its stranded costs and that customers do not "pay twice" for the costs of generation.

Q. Does this conclude your testimony?

A. Yes it does.

MICHAEL M. SCHNITZER DIRECTOR

Michael Schnitzer is a Director of The NorthBridge Group. He focuses on management consulting and works with clients to address strategy issues central to maximizing performance. Helping clients develop effective responses to increasingly deregulated markets is central to Mr. Schnitzer's work for electric and gas utilities. He has developed initiatives in marketing, pricing, regulatory relations and supply planning. He also has broad experience in utility reorganizations, having served as a financial advisor to secured parties in three utility bankruptcies and has developed and evaluated a wide array of restructuring proposals. Mr. Schnitzer's project assignments have included:

UTILITY

- For several major electric utilities, Mr. Schnitzer has assisted in the development of restructuring plans to facilitate retail access.
- For several major electric utilities, Mr. Schnitzer has assisted in the development of Acid Rain compliance plans, helping his clients take full advantage of the flexibility afforded under the Clean Air Act Amendments of 1990.
- For several major electric utilities, Mr. Schnitzer has assessed the merits of proposed policies requiring utilities to incorporate monetized environmental externalities in their resource planning process.
- For several groups of non-utility parties, Mr. Schnitzer has helped develop comprehensive cost recovery programs, including incentives, for utility-sponsored conservation and load management programs.
- For several major electric utilities, Mr. Schnitzer has analyzed financial restructuring opportunities -- including leverage, sale/leaseback and splitting off generating assets -- to develop strategies for improving competitiveness and increasing shareholder value.
- For several major utilities, Mr. Schnitzer has assessed transmission capacity, expansion costs and policies for encouraging economic transmission expansions.
- For several major electric utilities, Mr. Schnitzer has assessed short- and long-term wholesale opportunities and developed marketing plans and proposals for specific candidate buyers.
- For a major investor in an electric utility, Mr. Schnitzer has analyzed rate levels and asset values under alternative financial structures and ratemaking treatments.
- For a gas utility, Mr. Schnitzer identified necessary changes in regulatory policy to permit fair competition in gas purchasing and transportation.
- For several major utilities, Mr. Schnitzer has analyzed the economics of completing their construction programs and evaluated alternative ratemaking treatments of new generating capacity.

MANUFACTURING

- For a private sector steel client, Mr. Schnitzer assessed the profitability of new steel investments and the key conditions that will determine profitability, including an assessment of international competitors.

- For a private sector steel client, Mr. Schnitzer evaluated the relationship among labor costs, profitability and investment opportunity over the coming decade.

- For a private sector steel client, Mr. Schnitzer developed an integrated production and costing model to evaluate modernization and cost-reducing investment opportunities, and he assessed the effectiveness of marketing and sales activities, recommending ways in which these activities could be strengthened.

- For a major coatings manufacturer, Mr. Schnitzer analyzed alternative plant configurations and production strategies to identify profitable investment opportunities and developed new procedures for production scheduling and inventory control to reduce costs and improve sales.

Mr. Schnitzer has testified before the Maine, New Hampshire, Ohio, Pennsylvania, Rhode Island and Texas Public Utility Commissions, the Arkansas, Delaware, Maryland, New Mexico and Wisconsin Public Service Commissions, the Indiana Utility Regulatory Commission, the Massachusetts Department of Public Utilities and the Vermont Public Service Board. He is a former adjunct research fellow at the Energy and Environmental Policy Center, John F. Kennedy School of Government, Harvard University.

Before joining NorthBridge, Mr. Schnitzer was a Managing Director at Putnam, Hayes & Bartlett, Inc., where he co-directed the firm's regulated industry practice. Prior to that he was a member of the executive staff of the Appalachian Mountain Club. His experience as assistant to the executive director included the development of financial models and organizational strategic plans, as well as the negotiation of multi-party real estate transactions and the settlement of environmental litigation.

Mr. Schnitzer received an A.B. in chemistry, with honors, from Harvard University, and an M.S. in management from the Sloan School, Massachusetts Institute of Technology.

DERIVATION OF NEW ENTRY CEILING PRICE RANGE IN 2006

EXHIBIT MMS - 2

		Competitive Capital Structure & Investment Horizon	DQE Capital Structure & Investment Horizon	Units [1]	Proposed Source/Derivation
Inputs	CC capital investment - low	395	395	$/kw	Survey of recent industry information.
	CC capital investment - high	500	500	$/kw	Survey of recent industry information.
	Capital structure	67.0	40.1	% equity	Competitive data based on assumption. DQE data provided by the Company.
	Risk-free rate	7.0	7.0	%	Financial market data.
	Equity premium	7.0	4.5	%	Competitive data based on analysis of historic financial market data. DQE data provided by the Company.
	Debt premium	1.5	1.5	%	Competitive data based on analysis of historic financial market data. DQE data provided by the Company.
	Income tax rate	41.5	41.5	%	Data provided by the Company.
	Investment horizon - long	15	20	years	Competitive data based on assumption. DQE data provided by the Company.
	Investment horizon - short	10	20	years	Competitive data based on assumption. DQE data provided by the Company.
	CC Fixed O&M	35.6	35.6	$/kw-yr	1993 EPRI-TAG escalated at inflation.
	CC A&G	17.8	17.8	$/kw-yr	Assumption.
	Property tax rate	0.8	0.8	%	Data provided by the Company.
	Gas spot price	2.9	2.9	$/mmbtu	Analysis of current forward contracts for gas.
	Variable O&M	0.5	0.5	$/mwh	1993 EPRI-TAG escalated at inflation.
	Heat rate -- low	6,365	6,365	btu/kwh	High heat rate decreased at annual rate of 0.5%.
	Heat rate -- high	6,625	6,625	btu/kwh	Survey of recent industry information.
	Inflation	2.5	2.5	%	Data provided by the Company.
	CC capacity factor	84	84	%	Average of DQE baseload units.
Intermediate Calculations	Capital carrying charge - low	18	12	%	First year real levelized revenue requirement using long investment horizon.
	Capital carrying charge - high	23	12	%	First year real levelized revenue requirement using short investment horizon.
	CC fixed cost - low	125.5	101.1	$/kw-yr	Low investment x low carrying charge (includes property taxes) plus fixed O&M and A&G.
	CC fixed cost - high	169.3	113.8	$/kw-yr	High investment x high carrying charge (includes property taxes) plus fixed O&M and A&G.
	Gas expected spot cost	2.9	2.9	$/mmBtu	Analysis of current forward contracts for gas.
	CC variable cost - low	18.9	18.9	$/mwh	Gas at low heat rate + variable O&M.
	CC variable cost - high	19.7	19.7	$/mwh	Gas at high heat rate + variable O&M.
Final Calculations	2005 avg long-run mkt price - low	36	33	$/mwh	Low values for CC fixed cost and CC variable cost.
	2005 avg long-run mkt price - high	43	35	$/mwh	High values for CC fixed cost and CC variable cost.
	2006 avg long-run mkt price - low	37	34	$/mwh	2005 average long-run market price (low) escalated at inflation.
	2006 avg long-run mkt price - high	44	36	$/mwh	2005 average long-run market price (high) escalated at inflation.

Notes: [1] Units are in 2005 dollars unless otherwise noted.

DERIVATION OF NATURAL GAS SPOT PRICE IN 2005

EXHIBIT MMS - 3

	1997	1998	1999	2000	2001	2002	2003	2004	2005
Forward Contract at Henry Hub									
PV of forward quote at risk-free discount rate	13.1								
Equivalent spot price estimate escalated at inflation rate		2.2	2.2	2.3	2.4	2.4	2.5	2.5	2.6
PV of equivalent spot price estimate at risk-adjusted discount rate	13.1								
Basis Differential from Henry Hub to TCO									
Basis differential escalated at inflation rate		0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Estimate of delivered natural gas spot price		2.4	2.5	2.6	2.6	2.7	2.8	2.8	2.9

Notes:

The risk-free discount rate is assumed to be 7%.
The risk-adjusted discount rate is assumed to be 9%.
The annual inflation rate is assumed to be 2.5%.

DERIVATION OF SPOT EQUIVALENT TO SOLICITATION RESULTS IN 2005

EXHIBIT MMS - 4

	1997	1998	1999	2000	2001	2002	2003	2004	2005
All-hours equivalent of 8-Year Solicitation Results									
PV of solicitation results at risk-free discount rate	116.1								
Equivalent spot price estimate escalated at inflation rate		19.4	19.9	20.4	20.9	21.4	22.0	22.5	23.1
PV of equivalent spot price estimate at risk-adjusted discount rate	116.1								
All-hours equivalent of 1-Year Solicitation Results									
PV of solicitation results at risk-free discount rate	16.3								
Equivalent spot price estimate		17.8							
PV of equivalent spot price estimate at risk-adjusted discount rate	16.3								
Alternative all-hours equivalent 8-Year Solicitation Results									
Alternative spot price estimate using 1-year results in 1998		17.8	18.7	19.7	20.8	21.9	23.1	24.3	25.6
PV of alternative spot price estimate at risk-adjusted discount rate	116.1								

Notes:

The risk-free discount rate is assumed to be 7%.
The risk-adjusted discount rate is assumed to be 9%.
The annual inflation rate is assumed to be 2.5%.

DERIVATION OF ALTERNATIVE NEW ENTRY CEILING PRICES

EXHIBIT MMS - 5

	High End of Price Range based on Competitive Capital Structure & Investment Horizon	Equivalent Spot Price Ramped-up to High End of Competitive Price Range by 2010	Implied Growth in Spot Price Ramp-up to High End	Real Levelized Equivalent to Spot Price Ramp-up to High End	Low End of Price Range based on Competitive Capital Structure & Investment Horizon	Equivalent Spot Price Ramped-up to Low End of Competitive Price Range by 2010	Implied Growth in Spot Price Ramp-up to Low End	Real Levelized Equivalent to Spot Price Ramp-up
2005	43	27		40	36	27		35
2006	44	30	12.8%	41	37	29	9.0%	35
2007	45	34	12.8%	42	38	32	9.0%	36
2008	46	38	12.8%	43	39	34	9.0%	37
2009	47	43	12.8%	44	40	37	9.0%	38
2010	48	48	12.8%	45	41	41	9.0%	39
2011	50	50	2.5%	47	42	42	2.5%	40
2012	51	51	2.5%	48	43	43	2.5%	41
2013	52	52	2.5%	49	44	44	2.5%	42
2014	53	53	2.5%	50	45	45	2.5%	43
2015	55	55	2.5%	51	46	46	2.5%	44
2016	56	56	2.5%	53	47	47	2.5%	45
2017	58	58	2.5%	54	49	49	2.5%	47
2018	59	59	2.5%	55	50	50	2.5%	48
2019	60	60	2.5%	57	51	51	2.5%	49
2020	62	62	2.5%	58	52	52	2.5%	50
2021	64	64	2.5%	60	54	54	2.5%	51
2022	65	65	2.5%	61	55	55	2.5%	53
2023	67	67	2.5%	63	56	56	2.5%	54
2024	68	68	2.5%	64	58	58	2.5%	55
2025	70	70	2.5%	66	59	59	2.5%	57
Present Value:		492		492		424		424

FILE CONTINUED